Rio Tinto | NZAS
Tiwai Road, Invercargill, New Zealand,
Private Bag 90110, Invercargill, 9840

21 July 2026

Submission on *A proposed reliability obligation to manage dry-year risk*

New Zealand Aluminium Smelters Limited (NZAS) welcomes the opportunity to comment on MBIE's June 2026 consultation paper, *A proposed reliability obligation to manage dry-year risk*. We support the Government's objective of a reliable, affordable and highly renewable electricity system, and we recognise the seriousness of the dry year challenge the paper seeks to address.

Because the proposal is a major, behaviour-changing intervention carrying substantial penalties, and because it would directly affect NZAS, we considered it important that our submission be informed by rigorous independent analysis. We therefore commissioned Sapere Research Group to review the proposal. Sapere's independent report accompanies this submission and should be read in conjunction with it.

The consultation paper canvasses a two-layer obligation - a long-term obligation and a short-term backstop. Both the Sapere report and this submission concentrate on the long-term reliability obligation, because that is the element of the proposal that would affect NZAS most directly.

Background on NZAS

NZAS operates the Tiwai Point smelter near Invercargill, which opened in 1971 and is fully owned and operated by Rio Tinto. NZAS is the only smelter in the world to produce high-purity aluminium using largely renewable power. Because electricity is the largest single input cost for an aluminium smelter and is not internationally traded, the cost and reliability of NZAS's power supply are the primary determinants of its competitiveness and long-term viability.

Aluminium products are one of New Zealand's largest export categories and among its biggest exports to Japan and Korea. Around 92% of NZAS's production in 2025 was exported to 17 countries, with Japan (33%), Europe (28%) and Korea (24%) the largest destinations. Aluminium is also a critical input to the low-carbon transition: as the Royal United Services Institute has noted, it is used in solar panels, electric-vehicle bodies and wind-turbine housings, and organisations such as the World Bank and the International Energy Agency anticipate large increases in demand from these technologies.[1]

The aluminium produced at Tiwai Point is among the lowest carbon intensity in the world, emitting roughly 2 tonnes of CO_2 per tonne of aluminium against a global average of about 12 tonnes. The high-purity and ultra-high-purity grades produced at Tiwai are highly valued internationally, to the extent that the United States has previously granted New Zealand high-purity aluminium an exemption from its general aluminium tariffs.

[1] Royal United Services Institute, "Aluminium: A New Critical Mineral Frontier" (rusi.org), citing World Bank and International Energy Agency estimates.

NZAS is New Zealand's largest single electricity consumer, with a near-constant load of about 572 MW, NZAS is also the country's largest single provider of dry-year demand response: its ability to reduce load is equivalent to roughly 7% of national hydro storage capacity, and in the 2024 dry year it supplied the market's largest single tranche of winter relief. NZAS is, in short, **not a source of dry-year risk but one of the system's principal sources of dry-year resilience**.

Comments on Proposal

We do not believe the proposed long-term obligation has been shown to be adequately justified, and that - as drafted - it would fall on NZAS in ways that are perverse, distorting and unfair. The proposal does not take into account the simple fact that NZAS is *not* a source of dry-year risk but is in fact one of the system's principal sources of dry-year resilience.

As New Zealand's largest electricity user, we are very cognisant of our responsibility to contribute towards the resilience of the overall energy system in New Zealand.

As the provider of one of the largest single-site, long duration demand response agreements, in terms of percentage of national grid, anywhere in the world, we are already committed to being a responsible participant in the New Zealand energy system. In 2024, we demonstrated this, with the full curtailment of one of our three potlines, for only the second time in our history, and provided approximately 4% of the New Zealand's electricity supply back into the market, to help with the severe energy issues that winter. We have commitments to undertake this obligation in accordance with the terms of the contracts, if asked, over the lifetime of our electricity contracts, which run through to 2044.

We understand the significance of our position to meet this need when it occurs, and have previously varied the demand response contract with Meridian Energy to reduce consumption more than we were contractually obliged to.[2]

From an economic perspective, our role in both the Southland and New Zealand economy is substantial, with the economic activity generated by the production of aluminium producing export income and GDP that helps drive the Southland, and wider economy[3]. Any curtailment of this production does have side effects for our longer term operational stability, and as currently envisaged, we would be the only industrial entity in New Zealand to bear the burden of this productivity impact.

We strongly feel that it is unreasonable for NZAS to be the only industrial user caught by the obligation. The consultation paper states that the threshold captures the gentailers and NZAS, exempting every other large user who would then benefit from the cover the obligated parties are forced to hold without contributing to it. Allocating a share to NZAS - a party already fully hedged its electricity needs and the country's largest single provider of dry-year demand response - would force it to buy cover it does not need, subsidising users who bear none of the burden.

[2] 9888005b036530a4478d6f2312074c898c5878c1.pdf

[3] https://cdn.sanity.io/files/jhthdezs/production/e74a21dfe2d9dfef960478dd51974b0a4d49c5c8.pdf

If implemented, this additional regulatory and fiscal burden on settled long-term electricity arrangements may adversely effect the perceptions of regulatory certainty and New Zealand's attractiveness for internationally mobile investment.

The Sapere report has identified three main concerns as follows:

First, it is unreasonable for NZAS to be the only industrial user caught by the obligation. The consultation paper states that the threshold captures the gentailers and NZAS, exempting every other large user who would then benefit from the cover the obligated parties are forced to hold without contributing to it. Allocating a share to NZAS - a party already fully hedged and the country's largest single provider of dry-year demand response - would force it to buy cover it does not need, subsidising users who bear none of the burden.

Second, the regulatory analysis does not justify intervention. The paper describes a problem but does not pin down its cause, and it does not test its concern against the recognised sources of market failure. It also weighs the obligation against today's arrangements rather than against the system as it will be once the already-approved Energy Package - above all the LNG import facility - is in place. That facility directly addresses the gas shortage that drove the 2024 event and much of the investment gap the consultation paper relies on.

Third, even if a problem remains after those reforms, the proposed policy would work against its own aims and face significant practical difficulties. A penalty-backed volume requirement replaces the market's price signal with an administrative target; if set too high it would depress the high prices that reward firm supply and push out the commercial investment the scheme wants. The forecast trigger invites gaming, some of which would perversely worsen the measured shortfall. And because cover only "counts" if it is physical, tied to a trigger, and switched on and off, the scheme pushes parties toward contingent rather than firm contracts, physical rather than financial cover, short rather than long commitments, and minimum volumes. Each of these shifts has an efficiency cost and several of them work against the Government's objectives.

In the appendix, we expand on these three concerns, drawing from the Sapere report, and we recommend the report be read in conjunction with this submission.

Conclusion

The proposed long-term reliability obligation has not yet been shown to be justified, and as drafted it would fall on NZAS in ways that are perverse and plainly unfair:

- It would treat the country's largest and most demand-flexible electricity user, already fully hedged under twenty-year contracts and the single largest provider of dry-year demand response, as an obligated buyer of cover it does not need;
- It would force it to subsidise exempt users who free-ride on the scheme;
- and it would put at risk the finely engineered demand-response and firm-cover commitments that make NZAS one of the system's principal sources of dry-year resilience. Those commitments were entered in good faith in 2024, under the market rules then in force. The most sensible way to preserve them is to exempt NZAS from the obligation - in effect grandfathering the very demand-reduction options the consultation paper should want to protect.

More broadly, we recommend that the Government:

- Do further work to clarify the problem that remains once the approved elements of the Energy Package - the LNG import facility foremost among them - have been implemented, and ensure that all options are put on the table and assessed on a consistent, like-for-like basis; and
- If it nonetheless proceeds with a reliability-obligation approach, compare a generator-based model carefully and on a like-for-like basis with the wholesale-purchaser model, and base any allocation on the uncovered volume rather than on the gross expected level of demand.

NZAS would welcome the opportunity to discuss this submission and the accompanying independent report with officials.

_____

Contact:

Simon King
External Affairs Director
NZAS/Rio Tinto
Privacy of natural persons

Appendix

NZAS's key concerns with the proposed long-term reliability obligation

Our concerns, drawn from the independent Sapere report that is attached to this submission, fall under three headings: the regulatory analysis does not justify intervention; even if a problem remains after the approved reforms, the scheme risks serious distortions to investment and contracting; and it is unreasonable for NZAS to be the only industrial user caught by the obligation.

(a) The independent report finds the regulatory analysis inadequate

The long-term obligation is a major, behaviour-changing intervention backed by heavy penalties,[4] so it attracts the most demanding level of regulatory analysis under the Ministry for Regulation's 2026 guidance. The Sapere report finds four main shortcomings.

The problem is described, not defined. The stated problem - that "additional incentives are required"[5] - is a solution rather than a diagnosis, and the consultation paper never identifies which market failure it targets.

It is internally inconsistent about the reliability standard. The consultation paper describes the reliability standard as already set at the efficient level yet also argues the system runs with too little buffer and the standard may be too low. If the standard is right, any obligation should be no higher than it; if it is wrong, the fix is to revisit the standard, not to bolt an extra obligation onto one the consultation paper calls efficient.

It uses the wrong baseline for comparison. The obligation's benefits are assessed against today's arrangements, not the system once the Energy Package agreed in late 2025 is in place - above all the LNG import facility. This is important as the consultation paper itself calls the shortage of gas to fuel existing plant the "most immediate constraint" to dry-year security, and records that in 2024 the largest, most efficient gas unit ran at only 65% of capacity for want of fuel despite high prices.[6] Reliable gas supply addresses that directly and, on the consultation paper's own logic, may largely resolve the concern used to justify intervention.

It compares options unevenly. The generator-based alternative is discounted on design challenges while near identical difficulties in the purchaser model are treated as issues to be resolved in future development.

(b) The independent report finds the scheme risks serious distortions to investment and contract efficiency

Even if a problem remains after the approved reforms, the Sapere report finds the consultation paper's preferred instrument - a penalty-backed, forecast-triggered volume obligation on a few purchasers - would work against its aim of more, earlier and cheaper firm energy.

It overrides the price signal and can depress the returns to firm supply. Firming generators earn their keep from occasional high prices in tight supply periods, and firms invest where those returns justify the cost. A penalty-backed volume requirement replaces that with an administrative target. If that volume exceeds what

[4] MBIE consultation, para.90: the greater of $10 million, three times commercial gain, or 10% of turnover.

[5] MBIE consultation, p.5 (problem statement)

[6] MBIE consultation, para.17 and Box 5.

is efficient - likely, since the consultation paper treats the current standard as optimal - the group over-buys, flattening the price peaks that reward firm supply and pushing out the voluntary investment the scheme wants. Market participants will anticipate these effects even in years where the obligation has yet to be triggered.

The trigger creates timing distortions. Because the obligation switches on and off and is allocated by measured demand, parties will adjust to the rule and manage the numbers that feed into it. Some responses perversely worsen the measured shortfall - holding back firm capacity being developed, or briefly removing existing capacity during the assessment window - so the shortfall is enlarged and spread across everyone.

It adds investment uncertainty. The obligation's size is determined by a forecast scenario that experts will dispute, and which may be revised repeatedly. Revising the obligations mid-stream raises the return investors require on long-lived projects, deterring the durable investment the scheme seeks. This compares unfavourably with the certainty provided under the Commerce Commission's Input Methodologies.

It distorts contracting. Because the obligation may be switched on and off and compliance is tied to physical assets, the scheme rewards keeping options open - pushing parties from fixed contracts toward contingent contracts, from financial toward physical cover, from long toward short commitments, and toward the minimum volume. These shifts do not reflect the underlying risk, they impose real cost, and push parties away from the durable, firm commitments the consultation paper says it wants.

(c) It is unreasonable for NZAS to be the only industrial user subject to the obligation, producing cross-subsidy and free-riding

The consultation paper states that the proposed 500 GWh threshold will result in the obligation being applicable to the four gentailers and NZAS alone. Every other large industrial and commercial user - including prospective large loads such as data centres - would be exempt. The Sapere report (pp. 29-30) questions whether this is correct and also identifies two related problems, both of which bear directly on NZAS.

Free-riding. Because the obligated parties would be legally bound to hold extra cover once the obligation triggers - thereby dampening high prices - non-obligated users can rely on that protection and have less reason to arrange their own cover. The likely result is less precautionary contracting across the wider market and a concentration of reliability risk on a small number of balance sheets: a perverse outcome for a scheme meant to deepen contracting and spread risk.

Cross-subsidy. NZAS as a large industrial user, already fully covered, would be required to hold cover partly for the benefit of users who bear none of the obligation. If MBIE's proposal to limit the obligation to the four gentailers and NZAS remains, it would result in the one industrial user above the threshold carrying a share of a system-wide obligation, while every other industrial user free-rides. This would be a subsidy from NZAS to those users, with no sound reason for singling out NZAS to bear it.

This is not the first time NZAS has been placed in that position. In the 2019 transmission pricing review, Rio Tinto objected that the Authority had no basis to require some commercial customers to subsidise others, and that the proposal would have seen NZAS pay a subsidy of around $1 million a year for other industrial customers, some of which paid little or nothing for their grid use.[7] The present proposal repeats that pattern:

[7] Rio Tinto, Submission to Electricity Authority on The Transmission Pricing Review, 1 October 2019.

it asks the largest, most exposed and most demand-flexible user to underwrite the reliability of users who would contribute nothing to the scheme.

NZAS contracts illustrate the key risks

The risks above are not hypothetical for NZAS. In May 2024, NZAS signed a suite of twenty-year electricity contracts with Meridian, Contact and Mercury, running to 31 December 2044. They were negotiated in good faith, at arm's length between well-advised parties, under the market rules then in force, which contained no long-term reliability obligation. Slightly over two years later, the proposal would apply an obligation to those settled arrangements on terms that may disadvantage NZAS, undermining our efficient, fully hedged contractual arrangements.

NZAS is the odd one out in the obligated group identified in the consultation paper. It is not a gentailer, holds no generation and sells no electricity to consumers; it is the Tiwai Point smelter, the country's largest single electricity user. It is already fully covered - its three Core Agreements with Meridian, Contact and Mercury fix a price for a fixed quantity equal to its near-constant 572 MW demand - and it is the country's largest single provider of dry-year demand response. The proposal would therefore treat as an obligated buyer of winter cover a party that is already fully covered and that in 2024 supplied the largest single tranche of winter relief. Because the NZAS contracts are finely tuned to each party's needs, they show how the obligation would put that hard-won efficiency at risk.

Uncertain compliance of the existing contracts

A first question is whether NZAS's existing contracts would count toward an obligation at all. As proposed, they probably would not. The trigger and the shortfall are both measured against the forecast's Expected Scenario and cover only qualifies if it can "shift the margins and close the shortfall" in that forecast. But the System Operator's assessment already appears to include both the NZAS load and its demand response (Sapere report, p. 19). Cover already built into the forecast cannot, by definition, shift the margin - so the demand-response arrangement would not be available as new qualifying cover.

Setting that aside, the contracts expose three difficulties common to the whole scheme.

First, verification. The NZAS Demand Response Agreements were deliberately drafted so that the only consequence of NZAS not meeting a call is a reduction in its payments and hedge cover - no other consequences or liability follow. Whether that meets the consultation paper's requirement of a "clear and enforceable entitlement"[8] to physical cover is unclear: a test strict enough to exclude weak paper commitments risks excluding one of the most reliable dry-year resources in the country - one that performed exactly as intended in 2024 - while a looser test admits much else.

Second, split control and economic interest. The NZAS Demand Response Agreements assign control over the options entirely to Meridian, whereas the economic interest is split 75:25 between Meridian and Contact, and NZAS is the party that actually curtails. So a key question that needs to be clearly defined and answered, if this proposal were to proceed in its current form, and one which would in all likelihood be open to legal interpretation and challenge, is *'Whose cover is it?'* If it follows control, it is all Meridian's; if economic interest, it splits 75:25; if the party that physically reduces, it is NZAS's. This is not a flaw in the contract, which allocates

[8] MBIE consultation, para.86.

control and interest deliberately; it is that the scheme adds a third idea - regulatory credit - with as yet no rule to reconcile it.

Third, full cover forces a pointless on-sell. NZAS is already fully hedged for a known, constant load, so its uncovered winter position is close to zero. Yet the obligation would be allocated by share of expected winter demand. To meet an allocation based on demand it has already covered, NZAS would have to either buy cover it does not need and on-sell the surplus to satisfy the arithmetic, or deliberately loosen its full hedge to leave room for a separately-badged "qualifying" tranche. Either way the obligation creates buying and selling that adds nothing to physical supply - the opposite of the under-covered party the obligation is meant to address.

Risk of distorting efficient contracts

The NZAS contracts are the product of a long, voluntary, arm's-length negotiation. Asking which of these features the scheme would have pushed the parties to drop shows how the distortions could play out in practice (Sapere report, pp. 22–24).

The NZAS Core Agreements are exposed on two fronts. Its full-volume cover - an efficient response to a constant load - becomes a liability under a scheme that rewards holding cover at the minimum and keeping spare capacity in reserve for the next trigger; the incentive is to contract for less than full cover, loosening an efficient hedge. And because the Core Agreements are financially settled, while the consultation paper's test favours a physical link to winter delivery, NZAS would be pushed to bolt a physical overlay onto a contract that did not need one.

The NZAS Demand Response Agreements are a more finely engineered instrument. Its limited-liability remedy is not a loophole but a deliberate efficiency: a smelter cannot commit to shed load regardless of the state of its pots, its committed sales and input contracts and safety limits. Limited liability, together with a payment-adjustment remedy, lets NZAS offer deep, credible flexibility while retaining the discretion an industrial process needs. A rule demanding a harder, strictly enforceable commitment would either exclude the country's largest dry-year lever or raise the price of the very cover the scheme wants to expand. And the efficient concentration of control in one party would be broken if credit followed control, giving Contact a reason to demand a share of control and reviving the coordination problems the single-controller design avoids.

The NZAS contracts show the allocation rule is wrong

Imagine every load were like NZAS - fully covered under firm contracts. Every generator would then have a known legal commitment to deliver, no demand would be uncovered, and an unbiased forecast would show no shortfall: the trigger should never fire. So a fully covered party like NZAS contributes nothing to the shortfall - it has already done, for its own load, exactly what the obligation would require. To hand it a share of a shortfall it did not create, sized by its demand, is to charge the party that solved its part of the problem for the failures of those that did not.

The flaw is that expected demand measures a party's size, not its contribution to the shortfall. The sensible alternative is to allocate by uncovered winter volume - each party's expected winter demand, less its firm cover and any reliable self-supply. That is harder to administer, but the answer is to give attention to how uncovered demand could be measured appropriately, not to charge on a measure that is simply wrong (Sapere report, pp. 24–25).

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:	SIMON KING
Email address:	Privacy of natural persons
Phone number:	
Organisation:	NEW ZELAND ALUMINIUM SMELTERS LIMITED

☐ 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 disagree that tenor gap, lack of coordination, and the role played by the Huntly Rankine units are major contributing factors – the consultation paper asserts rather than tests these against the market-failure taxonomy and never establishes they reflect a genuine failure rather than a rational response to fuel-supply risk (refer Sapere report, section 2).

The consultation paper's concern about a tenor gap and financing constraint simply indicates that project finance may be unsuitable for investment in dry year firming generation, and that balance sheet financing may be more appropriate for the risks involved. There is no reason to believe that asset-heavy entities, such as generation companies, have insufficient balance sheet funding capacity to invest if the returns are sufficiently attractive.

The consultation paper's claim that the current framework lacks a coordinating mechanism to bring investment forward in the face of unavoidable uncertainty is incorrect. The price mechanism is the coordinating mechanism. Except where certain market imperfections exist (such as significant information asymmetry and externality issues), the pricing system in a market economy is an effective and efficient coordination mechanism.

The consultation paper's suggestion that existing firm generation is a problem is unfounded. In any market, existing supply will remain in place until it is outcompeted by more efficient investments, and current and potential suppliers are always faced with judging the optimal timing for replacement investment. There is nothing special about this situation.

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.

Following LNG procurement, the principal remaining barrier is sovereign policy and regulatory uncertainty — the risk that future interventions create stranded assets.

We agree with the Government-commissioned report by Frontier (2025) that factors external to the wholesale electricity market are counteracting the incentives provided by the prospect of high spot market prices in dry years and that government policy uncertainty is a key contributor. Inherent political incentives associated with electricity as an essential good and the policy volatility observed in recent years means that any investor would be prudent to assume ongoing policy uncertainty under the status quo.

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.

Agree in part that a residual case for further measures *might* exist after the Energy Package reforms, but only to the extent it addresses policy uncertainty by credibly mitigating the political incentive for future intervention.

A key conclusion in the Market Development Advisory Group's Final Report (2023) was the critical need to maintain public and political confidence in the wholesale market and its ability to convey investment and contracting signals. The observed policy uncertainty, well described in Frontier (2025), suggests a lack of political confidence. The appropriate policy response depends on what is driving the policy volatility. Candidate drivers include:

a. **A lack of confidence that the current arrangements are sufficient to achieve policy markers' long run policy objective (assumed to be maximum economic welfare).**
b. **A misalignment between how the market will deliver the objective (via high scarcity pricing) versus the political preference to minimise the political cost of adjustment.**
c. **A political time-inconsistency whereby the political tolerance for dry risk within the electoral cycle is lower than implied by the long run objective.**
d. **Changes in the long run policy objective, e.g. environmental and social objectives vs. economic objectives.**

Future policy development needs to have a strong understanding of the specific factors most responsible for driving policy volatility.

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.

Agree because minimising regulatory uncertainty is important given the major investment required for the energy transition. But any new measure built on existing architecture must still be justified against economic-welfare principles and a defensible problem definition, not adopted merely because it extends familiar machinery.

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.

Disagree: a penalty-backed quantity obligation would substitute an administrative target for the market price signal, cause over-procurement that suppresses scarcity rents and crowds out voluntary firming, while distorting investment and undermining efficient contracting. Implementation will also face many difficult practical issues. Sapere report sections 3 – 6 discusses these issues.

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.

Disagree with placing the obligation on purchasers: purchaser reluctance to enter long-dated contracts may reflect real costs. *Prima facie*, generators — as the cohort with the best information, incentive and capability to manage the risk — are the better locus, whereas obligating purchasers risks the perverse contracting outcomes, including on NZAS.

Sapere report section 2.7 discusses the asymmetric treatment of the two approaches in the consultation paper, with the generator approach discounted prematurely while near identical difficulties in the purchaser approach are left as issues to be resolved in future development. The consultation paper fell short of the analytical consistency and depth required to compare the two approaches.

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.

Disagree with the proposed level of the de minimis as allows too much scope for free riding by non-obligated purchasers, so it should be set much lower level. Sapere report section 3.3 discusses these distortions.

The de minimis should also be paired with transferability (a cap-and-trade approach) so that parties can reassign obligations to the least-cost parties and minimise compliance cost and distortion.

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.

No comment.

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.

Disagree: allocations based on expected winter demand would systematically over charge the well covered and under charge the exposed. Allocation should instead be by net uncovered winter quantity.

As discussed in the Sapere report (sections 5.2.3 and 5.4) and our submission letter (pp.8-9), basing the obligation on expected winter demand would:

- **Impose an obligation on fully covered parties that contribute nothing to the shortfall**
- **Force fully covered parties to either:**
  - **procure and on-sell additional cover they do not need, or**
  - **restructure their contracts to less than 100% cover to create headroom to bolt on a separate 'qualifying' tranche if and when the obligation is triggered.**

Either way the result is misaligned with the consultation paper's aims. Applying a demand-based allocation to a fully covered party does not correct any under-procurement; it manufactures churn — an on-sell here, a re-contract there — with no effect on physical adequacy.

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

Please explain your views.

No comment.

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.

No comment.

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.

No comment.

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.

It will be impossible to calibrate penalties to this objective. Different investors have different hurdle rates and face different commercial situations, and it is not possible for policymakers and regulators to gather and understand the dispersed information required for this task.

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.

Ensure the winter energy target and adequacy forecasts are sourced from independent entities free from other incentives (for example, AEMO is a completely independent entity to grid operator and other market participants); Allow Electricity Authority to receive contestable forecasts as a discipline on the main provider; Minimise distortions and compliance cost by allowing obligations to be transferrable (cap & trade approach); Mitigate investment risk by providing compensation rights for losses incurred if the goal posts are shifted during the compliance period. Sapere report sections 3.4 and 6 discuss several of these issues.

Short-term Obligation [We purposefully leave this blank]

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.

[insert response here]

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.

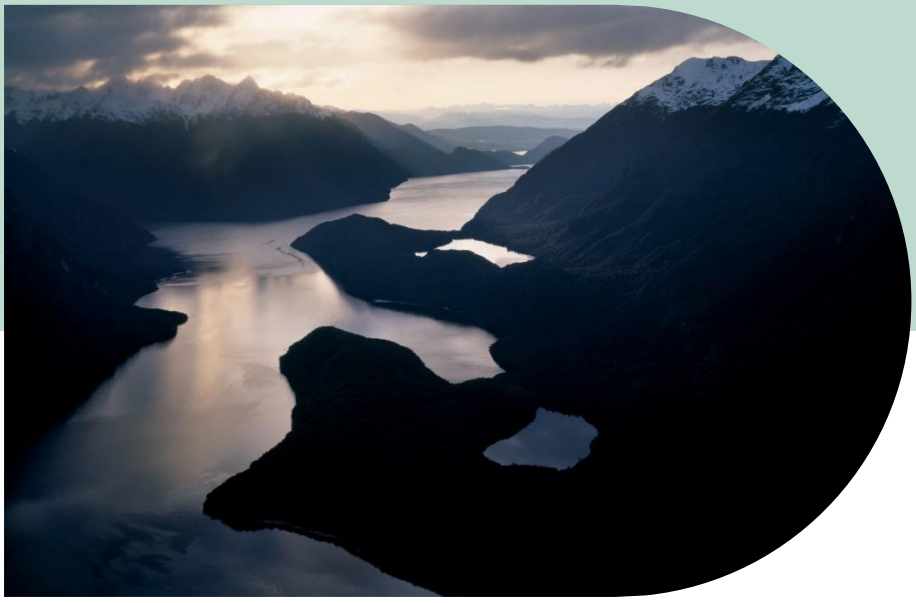
[insert response here]

Government's proposed long-term reliability obligation

Review of MBIE consultation paper dated June 2026

Eric Hansen and Peggy Alivianur

20 July 2026



Contents

Glossary iii

Executive summary v

1. Introduction 1

2. Inadequate regulatory analysis 2

   2.1 What good regulatory practice requires - and what the paper does well 2

   2.2 The problem is described, not defined 3

   2.3 Missing money or missing markets? 3

   2.4 A substantive internal inconsistency: the standards paradox 4

   2.5 An incomplete set of options 5

   2.6 The counterfactual omits the reforms already approved but not yet in effect 5

   2.7 Inconsistent treatment of the purchaser and generator options 7

3. Risk of serious unintended consequences for efficient investment 8

   3.1 The obligation overrides the price signal and can depress the returns to firming 8

   3.2 The trigger creates timing distortions 9

   3.3 The *de minimis* creates scale distortions and free riding 10

   3.4 Operational uncertainty further undermines investment 11

4. Risk of perverse contracting outcomes 13

   4.1 Efficient contracting: contract forms compete to allocate risk and decision rights 13

   4.2 Fixed contracts may be discouraged in favour of contingent contracts 14

   4.3 Pure financial derivatives may be discouraged in favour of physically settled derivatives 15

   4.4 Long-term contracts may be discouraged in favour of short-term contracts 15

   4.5 Incentive to comply at minimum contract size 15

5. NZAS contracts illustrate significant risks 17

   5.1 NZAS contract terms relevant to the obligation 17

   5.2 Uncertain compliance of existing NZAS contracts 18

   5.3 Risk of distorting efficient contracts 21

   5.4 NZAS contracts show the allocation rule is wrong 24

6. Implementation and other practical issues 26

   6.1 Verified cover is not the same as delivered energy 26

   6.2 Perverse incentives are likely 27

   6.3 SOSA sets up a trajectory that should not be used for this policy 30

7. Conclusions 35

References 36

Tables

Table 1 Historical winter energy demand in GWh 29
Table 2 Winter energy demand 2025 in GWh between the two winter periods 33

Figures

Figure 1 Comparison of national level realised winter energy demand and SOSA forecast demand by grid offtake (GWh) 31

Glossary

Abbreviation	Stands for
AEMO	Australian Energy Market Operator
ASX	Australian Securities Exchange
CfD	Contract for Differences
DR	Demand Response
EDB	Electricity Distribution Business
EMI	Electricity Market Information
GWh	Gigawatt-hour
ISDA	International Swaps and Derivatives Association
LNG	Liquefied Natural Gas
MBIE	Ministry of Business, Innovation and Employment
MfR	Ministry for Regulation
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NZAS	New Zealand Aluminium Smelters Limited
NZ-WEM	New Zealand Winter Energy Margin
OTC	Over-the-Counter
RRO	Retailer Reliability Obligation
SI-WEM	South Island Winter Energy Margin
SOSA	Security of Supply Assessment
SSAD	System Security Assumptions Document

Abbreviation	Stands for
TPR	Transmission Planning Report
TWh	Terawatt-hour
VoLL	Value of Lost Load

Acknowledgements

This report has been drafted with the assistance of Claude ai./projects and reviewed internally by David Reeve. All errors remain the authors' responsibility.

Executive summary

In June 2026 MBIE published a consultation paper in which it proposed a new Long-Term Reliability Obligations scheme to manage dry-year risk. The scheme would involve a mandatory, penalty-backed requirement on a small cohort of large wholesale purchasers to hold verifiable forward cover against a forecast shortfall in the winter energy margin. This is a structural, behaviour-changing intervention, and as such it requires rigorous regulatory analysis.

The consultation paper acknowledges that the proposed policy is not costless and that an obligation set too high risks over-investment. Our concern is not that the paper ignores the existence of potential shortcomings, but that it asserts rather than analyses them and misjudges their significance.

We reach three broad conclusions on the proposed long-term reliability obligation:

First, the regulatory analysis is inadequate to justify intervention. The paper describes a problem but does not define it: its stated problem - that 'additional incentives are required' - names a remedy rather than a cause, and it never tests its concern against recognised sources of market failure. The range of options is foreclosed prematurely without proper comparative assessment of their economic welfare implications. The benefits are asserted against the current arrangements rather than the correct counterfactual incorporating key elements of the Energy Package already approved. In particular, the LNG import facility addresses the fuel-supply constraint that drove the 2024 dry year event and much of the supposed investment barrier. The consultation paper falls short on the analysis required to claim that a residual problem exists sufficient to justify further intervention. Finally, the central design choice - obligating purchasers rather than generators - rests on an asymmetric analysis that discounted the generator model prematurely while leaving near identical difficulties in the preferred model as issues to be resolved in future development.

Second, even if a residual problem survives the reforms, the proposed policy would create significant distortions that work against its objectives. A penalty-backed quantity obligation would substitute an administrative target for the market price signal. Where the mandated volume exceeds the efficient level of cover, the resulting over-procurement would suppress scarcity rents and crowd out the voluntary commercial firming the scheme is meant to encourage. The forecast trigger introduces potentially serious timing distortions, several of which would perversely worsen the measured shortfall. The *de minimis* creates further distortions that deter scaling, new-entrant sizing, and invite free-riding by non-obligated purchasers. It would also concentrate reliability risk on a few balance sheets. Revision uncertainty raises the effective hurdle rate for long-lived commitments, perversely deterring investments that would otherwise come forward.

Compounding this, a compliance test that is narrow (physical), state-contingent (triggered and revisable) and discontinuous (on/off) undermines efficient contracting. The proposed approach induces a compliance-optionality premium that tilts contracting across four margins - from fixed contracts toward contingent contracts, from financially settled toward physically-settled contracts, from long- toward short-dated contracts, and toward minimum contract size. Each has an inefficiency cost and most work against the policy's objective of achieving dry-year security at minimum long run cost to consumers.

Third, implementation will face practical difficulties. A planning forecast is not well positioned to bear the weight of a compliance trigger. The Security of Supply Assessment is already systematically prudent before any penalty attaches: four consecutive assessments embedded winter demand growth of at least 3 per cent per annum against realised growth of approximately 0.2 per cent. The institutional incentives that produced that pattern are asymmetric and will intensify, not correct, once penalties attach.

And compliance and reliability are not the same thing. The dry-year problem is physical; the compliance test is contractual. A contract that points to a physical resource does not demonstrate that the resource is fuelled and will dispatch when inflows fail. Australia's market operator has warned about similar issues and the 2025 NEM Wholesale Market Settings Review recommended the Retailer Reliability Obligation be phased out, citing declining contract liquidity and reduced hedge access for smaller retailers.

The NZAS (New Zealand Aluminium Smelter) contracts illustrate several of the issues. NZAS is already 100% hedged under twenty-year contracts and is the country's single largest provider of dry-year demand response. Its existing cover already sits inside the SOSA Expected Scenario (and so cannot, by construction, count as incremental qualifying cover); its finely-engineered contracts expose genuine ambiguity in the verifiability test and the attribution of cover across divided control and economic interest; and a demand-based allocation would compel a fully covered party to procure or on-sell cover it does not need.

The NZAS contracts demonstrate a flaw in the proposal that obligations be allocated based on expected winter demand: that approach would measure exposure to the system, not contribution to the shortfall, and would systematically over-charge the well-covered while under-charging the exposed. The coherent alternative is to allocate by uncovered winter quantity.

Taken together, the paper has not shown that a penalty-backed quantity obligation is warranted rather than being duplicative of reforms already underway, nor that it is the right intervention if a residual problem remains. We recommend that the Government undertake further work to clarify the problem definition and ensure all feasible options are identified and assessed on a consistent like-for-like basis. If the Government proceeds with a reliability obligations approach, we recommend that a generator-focused model be compared carefully on a like-for-like basis with the wholesale purchaser model, and that any allocation method be based on the net uncovered quantity rather than on the gross expected level.

1. Introduction

On 9 June 2026 the Ministry of Business, Innovation and Employment (MBIE) released a consultation paper, *A proposed reliability obligation to manage dry-year risk*, giving effect to Action 2.5 of the Energy Package agreed by Cabinet in late 2025. New Zealand Aluminium Smelters Limited commissioned Sapere to prepare an independent report reviewing the proposals in the consultation paper.

The consultation paper proposes a two-layer obligation. The long-term reliability obligation - the focus of this report - would be triggered where a shortfall in the winter energy margin is forecast several years ahead. The shortfall would be allocated across large wholesale purchasers, identified by a 500 GWh *de minimis* threshold and allocated in proportion to expected winter demand. Each obligated party would have to demonstrate verified forward cover, framed around physically backed rather than financial arrangements, with non-compliance subject to significant penalties. A short-term reliability obligation focussed on fuel supply would provide an in-year backstop directed at generators. Review of the short-term obligation is outside the scope of this report.

The report is structured as follows. Section 2 assesses the regulatory analysis. Sections 3 to 5 assume a residual problem survives, and examine the consequences for investment, for contracting, and - through the NZAS contracts - for real, long-dated arrangements. Section 6 addresses implementation. Section 7 concludes.

Our contractual analysis draws on the publicly available NZAS agreements with Meridian; NZAS advises it holds materially similar arrangements with Contact and Mercury, which we have not sighted. Our empirical work uses published EMI data and successive Transpower Security of Supply Assessments.

The NZAS suite of agreements is used not because it is a special case to be accommodated, but because it is the clearest available example of the proposed test applied to real, sophisticated, long-dated contracts.

Dry-year risk is real, and the 2024 winter demonstrated its consequences. Our argument is that the consultation paper has not established that the proposed scheme is the efficient response to what remains of that risk once the measures already agreed take effect.

2. Inadequate regulatory analysis

The proposed Long-Term Reliability Obligation is a structural, behaviour-changing intervention: a mandatory forward-cover requirement, backed by significant penalties. An intervention of that character attracts the most demanding tier of regulatory analysis. This section assesses the consultation paper against the two resources the Ministry for Regulation issued in May 2026 to operationalise the Regulatory Standards Act 2025: Problem definition and options identification, and Cost-benefit analysis (MfR, 2026a; 2026b).

It might be objected that it is premature to hold a consultation document to the standard required for a finalised proposal. Two considerations counter that. First, the Ministry for Regulation's guidance applies to early policy development, not only to the final proposal (MfR, 2026a, p. 5): consultation status relaxes the demand for complete quantification, but not the need for a defensible problem definition and counterfactual. Second, the consultation paper is not genuinely exploratory. It advances a settled two-layer preferred design and directs its questions to implementation - thresholds, timing, allocation, penalties - rather than to whether intervention is warranted. The analytical die is substantially cast, and the standards below apply with full force.

Our conclusion is not that the consultation paper fails to acknowledge the proposal's potential shortcomings, but that it fails to analyse meaningfully their significance. The consultation paper reasons by assertion rather than diagnosis: it isolates no market failure; it does not draw the distinction, standard in the electricity literature, between 'missing money' and 'missing markets', though the choice of instrument may depend on it; it contains an important internal contradiction in its analysis; it forecloses the option set on political rather than economic welfare grounds; it measures the obligation against a counterfactual that omits reforms already approved but not yet in effect; and it compares its preferred approach with a leading alternative on an uneven footing.

2.1 What good regulatory practice requires - and what the paper does well

The Ministry for Regulation's problem-definition resource sets out a sequenced test. It asks, first, whether a market failure is present - defined narrowly as an externality, information failure, market power, public good, or behavioural bias - and second, whether it is significant enough to warrant a response. Options identification then asks, before any regulatory option is reached, whether private or lighter-touch responses would suffice, and whether the proposed regulation itself risks government failure, including the 'nirvana fallacy' of comparing an imperfect market with an idealised regulatory outcome (MfR, 2026a, pp. 7-13).

The cost-benefit resource requires a defined factual and counterfactual, identification and (where possible) monetisation of costs and benefits relative to that counterfactual, discounting to a net present value, explicit treatment of uncertainty, and identification of distributional effects (MfR, 2026b). Two features bear on this paper. First, analytical depth should be proportionate: a detailed, monetised analysis is expected for significant regulatory changes that induce structural or behavioural change and are likely to involve costs or benefits that are large in dollar terms - which this obligation plainly is.

Second, the analysis is meant to be done early, to compare options, since leaving it to the end 'robs it of some of its potential to improve decision-making' (MfR, 2026b, p. 7).

It is worth acknowledging what the consultation paper does well. It is candid about cost, stating that increasing reliability is not without cost and that an obligation set too high could result in over-investment in firming resources and higher overall costs (MBIE, 2026, para. 36). It does not hide the alternatives, tabulating a capacity market, strategic reserve, public fuel reserve, de-risking mechanism, reliability must-run contracts and a legislated minimum capacity (MBIE, 2026, Table 4). It is transparent that its principal comparator, Australia's Retailer Reliability Obligation, is imperfect, being a capacity- rather than energy-adequacy mechanism. And it correctly identifies many of the potential issues that required discussion - the tenor gap, revenue uncertainty, forecast fragility, free-riding and penalty calibration.

2.2 The problem is described, not defined

The consultation paper's stated problem definition is that, 'due to the exposure of New Zealand's electricity system to dry-year risk … additional incentives are required to manage dry-year risk' (MBIE, 2026, p. 5). That names a remedy, not a cause: it states the desired response in the same breath as the problem, pre-empting the question the guidance asks first - what prevents efficient outcomes emerging unaided. The MfR guidance is explicit that intervention 'should be approached with caution and supported by clear and robust evidence', and that the first step is to identify which of the five recognised failures is present (MfR, 2026a, p. 7). The consultation paper does not do this.

A candidate diagnosis is undeveloped in the text. The consultation paper suggests a 'tenor gap' - firm plant may need contracts of ten to fifteen years to be financeable, while buyers are reluctant to commit for that long (MBIE, 2026, para. 8, A25–A28) - and to a coordination difficulty in bringing lumpy investment forward. Those are recognisable candidates: an information/coordination failure, or an incomplete-contracts problem. But the consultation paper never asks whether what it observes is a market failure or a rational response to something outside the market.

The distinction matters because the guidance treats one of the consultation paper's central pieces of evidence as the opposite of a market failure: '[p]rice spikes in response to … supply shocks are … not evidence of a market failure. If anything, they suggest the market is working well, because the high prices ration demand when supplies are limited' (MfR, 2026a, p. 9). Much of the consultation paper's motivating narrative - the 2024 event, with spot prices above $800/MWh, industrial curtailment and Methanex on-selling gas - is precisely such a supply-shock spike with a demand-side response (MBIE, 2026, Box 5). Without deeper analysis, that episode does not establish a market failure; it may equally show the price mechanism performing its rationing role.

2.3 Missing money or missing markets?

The electricity-economics literature has, for decades, distinguished two quite different reasons an energy-only market might under-deliver reliable capacity. The distinction is not a nicety: the appropriate remedy differs depending on which problem is present, and an instrument aimed at the wrong one can leave the underlying problem untouched or worse.

A missing money problem exists where the revenues available from the energy and ancillary-services markets are inadequate to cover the investment and operating costs of the capacity the system needs (Joskow, 2008; Newbery, 2016). It arises when scarcity prices are prevented from rising to the value of lost load - by administrative price caps, or by out-of-market actions in which the system operator dispatches or contracts plant outside the merit order and thereby suppresses the market price. The failure of prices to rise high enough suppresses long-term generator investment. This is the missing money problem.

A missing markets problem is different: the revenue may be potentially adequate, but the contract structures and markets needed to allocate and hedge the relevant risks are absent or too thin (in some cases because the risk cannot be contracted at all). The concept, which originates as a type of market failure, has been extended to cases induced by policy intervention that undermine market functioning. In electricity markets a key risk is that 'politicians and/or regulators are not willing to offer hedges against future market interventions that could adversely affect generator profits' (Newbery, 2016, p. 402).

The missing money and missing market concepts are not always cleanly separable, and one driver straddles both: policy and regulatory uncertainty. Policy conduct can produce missing money directly, because administrative price caps and out-of-market interventions are themselves policy choices. Policy can equally produce missing markets: a policy risk that cannot be hedged thins the forward and contract markets that help facilitate investment. Policy uncertainty is therefore not a third category but a cross-cutting driver capable of operating through either channel, or both.

The remedy differs by which problem predominates. Missing money may call for measures that restore or protect scarcity revenues, while missing markets may require measures that complete the contract market or credibly constrain future intervention. Without identifying the failure it is addressing, the consultation paper cannot show that a penalty-backed quantity obligation is the right instrument rather than one that leaves the problem unmitigated.

2.4 A substantive internal inconsistency: the standards paradox

The consultation paper contains at least one important contradiction in its treatment of the reliability standard against which the problem is defined.

On one hand, Box 6 describes the current methodology for setting the security standard as a 'cost benefit derived standard', optimised where the marginal cost of additional generation is equal to the marginal benefit of reducing expected energy supply shortfalls, using the value of lost load (VoLL) as the key input (MBIE, 2026, Box 6). On that account the standard should, by construction, be the efficient level of reliability[1] - one that does not attempt to eliminate all risk of shortage, because doing so would cost more than it is worth.

[1] This relies on the inputs being updated regularly as the Energy Package requires. Unfortunately, the current standards are based on 2012 data, undermining the credibility of the security standard as an optimised value relevant for 2026.

On the other hand, the consultation paper asserts that 'the current system appears to operate with very limited buffer which risks underestimating the asymmetric cost of supply shortfalls' and that the spillover benefits of avoiding dry-year conditions is 'potentially vast' (MBIE, 2026, para. 37, 43). That is a claim that the standard itself - not merely delivery against it - is set too low.

These are different critiques with different remedies. If the Box 6 optimisation is right, the problem is delivery against an already-efficient standard, and any obligation should be calibrated to it and no higher. If instead the standard's own assumptions - the estimated VoLL, including the treatment of asymmetric and economy-wide costs - are wrong, the response is to revisit the standard-setting methodology, not to layer a separate obligation on a standard the consultation paper simultaneously calls efficient.

2.5 An incomplete set of options

Even where a significant problem is established, the Ministry for Regulation's guidance requires that private and lighter-touch responses be tested before a mandate is reached, and that the proposed regulation be checked for government-failure risk (MfR, 2026a, pp. 11–13). The consultation paper's options analysis falls short at each stage.

The 'do nothing' and private-solution option is not seriously tested. The guidance requires it be evaluated, because private solutions avoid the compliance costs and distortions to incentives that arise from regulation and can be more flexible. The consultation paper instead characterises the status quo as 'intolerable reliability risk' and 'unacceptable affordability pressures' (MBIE, 2026, para. 13, A46), foreclosing the counterfactual rhetorically.

The wider options are discounted on grounds that are not analytical. The consultation paper lists six alternatives but sets them aside substantially because they would require the Crown to stand in the market, might need ongoing Crown funding, would conflict with other elements of the Energy Package, or simply because Ministers rejected them (MBIE, 2026, para. 174). Ministerial preference is a legitimate constraint on what is adopted; it is not an analytical reason an option lacks net benefit.

Government-failure and nirvana-fallacy risks are not assessed. The guidance requires the proposed regulation itself to be tested for capture, rent-seeking, regulatory-creep and information-burden risks, and warns against comparing an imperfect market with a regulatory nirvana (MfR, 2026a, pp. 12–13). Deficiencies in the implementation and operation of regulatory policy can render the claimed benefits unachievable.

2.6 The counterfactual omits the reforms already approved but not yet in effect

Whatever the diagnosis, the case for a further intervention must be assessed against the right counterfactual. The Ministry for Regulation's cost-benefit guidance is explicit: where 'the current situation is expected to evolve without regulatory change, the appropriate counterfactual will be this evolved situation', and the impacts that count are 'only those that are additional to what would otherwise occur in the counterfactual' (MfR, 2026b, p. 9). This is important here, because the

consultation paper establishes that the system is midway through a substantial, already-approved reform programme whose effects have not yet been felt.

The consultation paper devotes a chapter to the Energy Package that Cabinet agreed in late 2025 (MBIE, 2026, paras 16–23; Table 2) - a suite of decisions already taken. It includes procurement of a liquefied natural gas import facility (Action 1.1); removal of capital constraints on the majority-Crown-owned gentailers, with an expectation that each bring forward new generation (Action 1.2); measures to reduce sovereign policy risk (Action 2.1); and a strengthened Electricity Authority with a new statutory dry-year function and higher penalties (Action 2.2). By the consultation paper's own account these are agreed but not yet operative, awaiting legislative and Code change (MBIE, 2026, para. 23).

The correct counterfactual is therefore the system after that package takes effect - not the pre-reform status quo, still less the 2024 experience that preceded all of it. Yet the consultation paper states the obligation's benefits against the unreformed baseline, even while conceding that the reforms 'should improve market functioning' (MBIE, 2026, para. 47).

The point is sharpest for the LNG import facility, and bears on the 2024 winter experience used to motivate the intervention. The consultation paper identifies the shortage of gas to fuel existing plant as 'the most immediate constraint' to dry-year security of supply, and Box 5 records that in 2024 the largest, most efficient gas unit ran at only 65 per cent of capacity for want of fuel, though prices sat well above its running cost (MBIE, 2026, para. 17; Box 5). A reliable LNG import capability addresses that failure mode directly, supplying fuel for gas-fired firming with a high degree of reliability so that available plant can run when needed. On the consultation paper's own logic, it may substantially resolve the concern Box 5 is used to illustrate.

It also bears on the investment problem the consultation paper diagnoses. The paper accepts that declining domestic gas has 'significantly worsened a longstanding dry-year risk', and that even where high spot prices might justify gas-fired firming, 'the business case is much less compelling if there is uncertainty about whether fuel can be sourced' (MBIE, 2026, A8; A37). Because a new firming plant has an operating life measured in decades, an investor needs confidence in fuel supply over that horizon; the prospect of rapidly declining domestic gas made that confidence unattainable and is likely to have been a key reason for the absence of new gas-fired firming. By providing a durable, reliable fuel source the LNG facility removes much of that barrier - as the paper concedes, it 'may materially improve physical fuel availability and reduce one of the most immediate barriers to gas-backed dry-year firming' (MBIE, 2026, A38). The consultation paper's residual objection, that LNG 'does not in itself guarantee that enough fuel will be procured in a timely way' (MBIE, 2026, para. 9) is second-order: a gas generator has strong commercial incentives to procure fuel, to meet its commitments or capture scarcity revenues, and it is not obvious why that ordinary decision needs a new penalty-backed obligation.

None of this establishes that no residual problem remains. But it does establish that the size of any residual problem - and hence the case for further structural intervention - cannot be judged against the pre-reform baseline the consultation paper uses. A defensible assessment would specify the evolved counterfactual, credit the approved measures (the LNG facility foremost among them), and test whether a material shortfall is likely to persists once they are in place. Until then, the consultation paper has not shown the obligation is warranted rather than duplicative of reforms already underway.

2.7 Inconsistent treatment of the purchaser and generator options

The consultation paper's central design choice - to place the long-term obligation on large wholesale purchasers rather than on generators - is presented as reasoned, but the reasoning is applied asymmetrically. The following identifies three inconsistencies.

An uneven analytical burden

The consultation paper subjects the generator-focused alternative to a catalogue of 'significant design and policy challenges' - allocation across generators with different technologies and exposure, the need for long-term contracting, and a risk of disincentivising demand response (MBIE, 2026, para. 101 - 105). The consultation paper does not apply the same scrutiny to the preferred purchaser model, whose challenges are largely identical: allocation across purchasers is acknowledged to raise issues regarding demand-forecasting error, customer switching and spot-exposed load (MBIE, 2026, para. 79); cost recovery still runs through contracts; and demand-response credit attribution is unresolved.

Good regulatory practice requires a common basis of comparison and like-for-like treatment. Presenting the difficulties for one option as disqualifying while accepting similar difficulties associated with the other option is an inappropriate basis for choosing between them.

A demand-response claim without basis

The consultation paper argues that a generator-centred obligation could disincentivise demand-side solutions (MBIE, 2026, para. 104). The paper provides no basis for this assertion. On the contrary, competitive pressure to meet an obligation at least cost would give an obligated generator every incentive to procure demand response wherever it is cheaper than building firm generation, and the demand would have a corresponding incentive to contract where the payment exceeds its cost of curtailment.

Insufficient analytical depth to discriminate between the options

The consultation paper highlights that wholesale purchasers are 'often unwilling or unable' to enter long-dated contracts (MBIE, 2026, A27), whereas it nowhere suggests generators are unwilling or unable to enter long-dated arrangements.

A credible assessment of the relative merits of imposing obligations on purchasers versus generators requires a deeper understanding of whether the contracting frictions faced by purchasers reflect a market failure or are an efficient response to real costs (as discussed further in section 4.1). If purchaser behaviour reflects real costs then, *prima facie,* it may be better from an economic welfare perspective to impose the long-term reliability obligation on generators rather than on wholesale purchasers. The consultation paper falls short of the analytical consistency and depth required to assess these issues.

3. Risk of serious unintended consequences for efficient investment

The previous section argued that the consultation paper has not defined the problem, not adequately tested its proposal against other options, or specified a proper counterfactual. This section and the following two sections consider the situation where a residual problem remains after the approved Energy Package and that a case for intervention can be made. Even then, the *particular* policy the consultation paper prefers - a penalty-backed, forecast-triggered quantity obligation on a small cohort of large purchasers - carries foreseeable effects that the paper does not analyse and that, in several cases, work against its own objectives of more, earlier and efficient long-duration firm energy at least long-run cost to consumers (MBIE, 2026, para. 32 - 33).

These effects are not incidental frictions. Each flows from a specific design choice: overriding the price signal with a large asymmetric penalty calibrated to *tilt* or *force* investment (MBIE, 2026, para. 92; Table 3); requiring a sub-total cohort to cover 100 per cent of an administratively-defined shortfall (para. 76); triggering and allocating off a single forecast scenario that may be revised repeatedly (para. 65, 71–72); and framing qualifying cover around physical resources that *shift the margins* in the Security of Supply Assessment (para. 80–81). Each choice has a predictable behavioural response, and the responses compound.

The consultation paper presents the obligation as a measure to *strengthen* incentives to secure long-duration firm energy in advance (MBIE, 2026, para. 33, 49). Our analysis suggests the opposite is the more likely effect. A binding quantity requirement, enforced by a large penalty, does not sharpen the market's existing price-based incentive to invest; it substitutes an administrative target for that incentive, overriding the price signal on the obligated parties and distorting the investment, contracting, competitive and operational decisions of obligated and non-obligated parties alike.

3.1 The obligation overrides the price signal and can depress the returns to firming

In an energy-only market, firm and peaking resources recover their fixed costs from infrequent but high scarcity rents (Hogan, 2005; Joskow, 2008). A commercial entity weighs the expected value of those rents against cost and proceeds where the balance is positive; a dry-year firming opportunity is thus a profitable opportunity pursued voluntarily, in competition with rivals seeking the same rents.

The obligation changes the objective function, and its primary lever is a *quantity* rather than a price signal. Each obligated party must hold verifiable cover sufficient to meet its allocated share of the identified shortfall. That mandated volume, not the expected scarcity value of cover, becomes the binding determinant of how much firming is procured: the party secures the required quantity irrespective of whether the marginal unit is justified by the price signal. The penalty is a secondary, enforcing mechanism - it is what makes the quantity requirement binding. Attaching a cost of up to the greater of $10 million, three times commercial gain, or ten per cent of turnover to any shortfall (MBIE, 2026, para. 166) converts the volume target into a compliance imperative, and the consultation paper is explicit that it calibrates that penalty to *tilt* borderline cases to financial close or, in the

stronger variant, *force* investment (MBIE, 2026, Table 3). A mandated quantity, enforced by penalty, is by construction designed to override the price signal.

Two consequences follow. First, where the mandated quantity - the administratively defined shortfall - exceeds the efficient level of cover, the cohort over-procures. This is a live possibility since Box 6 presents the existing standard as already VoLL-optimised. Second, over-procurement is self-undermining: additional firm supply secured to close a possibly overstated shortfall reduces the frequency and height of the scarcity spikes that reward *all* firming, including the voluntary commercial firming the scheme wants. The instrument would then crowd out the market response it is meant to reinforce.

3.2 The trigger creates timing distortions

The consultation paper seeks to limit the policy intervention to circumstances where the forecast winter energy margin falls below a defined trigger threshold. While the intent to avoid market invention in normal circumstances is laudable, the effect of the trigger mechanism is to introduce a discontinuity that is likely to create numerous timing distortions that undermine market-led investment, efficient risk allocation and least-cost supply.

Because the obligation is triggered off a forecast and is allocated by a measured demand share, it is subject to two well-known limitations. The first is the Lucas critique: rational agents optimise against the policy rule, so behaviour before the rule is a poor guide to behaviour after it (Lucas, 1976). Obligated parties, their counterparties, and non-obligated parties affected by the other's actions will each try to anticipate whether and when the obligation triggers, bringing forward or delaying investment, contractual arrangements and operational decisions in their own interest. Some of these distortions have the perverse effect of *worsening the measured shortfall* (as illustrated in the examples below).

The second limitation is Goodhart's law: when a measure becomes a target it ceases to be a good measure, because parties manipulate its inputs (Goodhart, 1984). Under the proposal to allocate by share of expected winter demand, each obligated party will have an incentive to minimises its demand inputs feeding the SOSA forecast during the measurement window, then maximises actual demand afterwards to spread the fixed cost over a larger base.

Five adverse examples follow - the first two inflating the assessed shortfall, the following three distorting how it is allocated and contracted:

- *Withholding firming under development from the forecast.* Where an obligated party is developing a firming resource, they have an incentive to stop short of the actions required for that resource to be included in the SOSA forecast - deferring the commitment, contractual step or commissioning that would make it countable - thereby becoming available for the obligated party to meet its obligations once triggered.
- *Temporarily unwinding existing firming.* Where firming resources already exist, an obligated party has an incentive during the assessment window to make the resource temporarily unavailable.
- *Distortions to retail competition.* An obligated retailer has an incentive to soften marketing and customer acquisition while demand data are gathered for the forecast, then to compete hard

once obligations are allocated. Competitive intensity would track the regulatory calendar rather than customer value, artificially destabilising the retail market for non-obligated rivals.

- *Distortions to industrial scheduling.* A large industrial user above the *de minimis* threshold has an incentive to schedule maintenance and other demand-reducing activity during the pre-forecast period, for reasons unconnected to efficiency.
- *Distortions to efficient contracting*. Where an obligated party would otherwise enter a long-term contract for a new or existing firming resource not captured in the SOSA forecast, they now have an incentive to withhold the contract until it can be used to meet their obligations once triggered. Instead, they may preserve the opportunity through a first-right of refusal agreement or some other option contract. This is discussed further in Section 4.

In the first two cases the assessed shortfall is increased, and the resulting obligation burden is distributed across *all* obligated parties in proportion to demand share, while the specific party responsible for the withheld resource retains it and may use it in full to meet its own long-term reliability obligation. This applies equally to demand-side flexibility as it does to firming generation. The paradox is that an instrument justified by reliability could reduce it.

These are incentive-compatibility problems any mechanism designer needs to consider. Their magnitude depends on design detail - the length and timing of the measurement window, whether shares are trued up *ex post*, how far ahead the forecast is struck. Careful measurement may dampen them but cannot make them disappear because the party that shapes the measure captures the gain.

3.3 The *de minimis* creates scale distortions and free riding

The inclusion of a *de minimis* threshold, currently proposed at 500 GWh of aggregate winter load (MBIE, 2026, para. 59), introduces further incentive-compatibility problems. The public-economics literature on *notches* is relevant: where liability jumps discontinuously at a threshold, agents bunch just below it and distort real decisions to avoid crossing it, producing a deadweight loss that a smooth schedule would avoid (Kleven & Waseem, 2013; Kleven, 2016; Slemrod, 2013). The consultation paper anticipates this issue, contemplating rules against artificial fragmentation of load to avoid liability (MBIE, 2026, para. 61).

Two distortions follow, each running against the consultation paper's claim that the exclusion 'supports market dynamism' (MBIE, 2026, para. 58). A further distortion is the adverse impact of free riding on the incentive to arrange winter energy cover.

3.3.1 The *de minimis* threshold tilts competition in favour of smaller parties

A non-obligated retailer avoids the compliance cost, administrative burden and cover requirement its larger rivals bear, so an independent retailer that approached the *de minimis* threshold faces a discrete step-up in cost at the margin of expansion - the growth notch bunching models predict will deter scaling (Kleven & Waseem, 2013).

The consultation paper asserts that a *de minimis* is pro-competitive (para. 58). An instrument that raises incumbents' costs while exempting smaller and growing rivals from a shared benefit is not self-evidently more pro-competitive than the alternatives the paper rejects.

3.3.2 The *de minimis* threshold distorts new-entrant scale

A prospective large load with discretion over its own size has an incentive to design its winter draw to sit marginally below the threshold, or to fragment across entities, rather than optimise on engineering and commercial grounds. Investment and siting then respond to the notch, not the fundamentals.

The severity of notch distortions depends on how elastic the affected decisions are and on how the threshold is measured and policed. A well-drafted anti-avoidance rule raises the cost of gaming, but such rules are administratively costly and invite definitional disputes, and they do not remove the underlying incentive - they attenuate the distortion rather than eliminate it (Slemrod, 2013).

3.3.3 Free riding will undermine precautionary contracting for winter energy cover

Because the obligated parties will be legally bound to take extra cover once the obligations are triggered (thereby dampening scarcity prices), non-obligated purchasers anticipate that this will occur and therefore have less incentive to arrange their own cover. The predicted result is *less* precautionary contracting across the broader market and a concentration of reliability risk on a few balance sheets - a perverse outcome for a scheme meant to deepen contracting and spread risk (MBIE, 2026, para. 32).

3.4 Operational uncertainty further undermines investment

The staged design outlined in the consultation paper - a warning at five years, a binding obligation at three, a compliance assessment at one - is intended to manage forecast uncertainty (MBIE, 2026, para. 69 - 70). However, in practice it introduces uncertainty about how the *regime* will operate, from two sources, both bearing directly on investment.

The first is the sensitivity of allocation to contested assumptions. The obligation's size and distribution turn on a single *Expected Scenario* and its embedded assumptions - future demand, hydrology, generation availability, fuel supply, new investment. Reasonable experts will differ, and small changes may move the allocated obligation materially. There is a risk that the required obligation amounts are determined more by modelling choices rather than by reliability outcomes.

The second is revision risk. The consultation paper states that obligations may need to be revised as the outlook changes between and within stages (MBIE, 2026, para. 71 - 72). Repeated revision during the very years in which parties are contracting and building is corrosive to investment and distorts the resource mix:

- If an obligation can be revised or removed, a firming resource with a short, reversible gestation acquires an artificial option value over a resource with a longer or irreversible lead time, even where the latter is more efficient.

- This is a direct application of the economics of investment under uncertainty - irreversibility plus uncertainty raises the value of waiting and the effective hurdle rate, most sharply for the largest, longest-lived commitments (Dixit & Pindyck, 1994).

The Commerce Commission's Input Methodologies - where providing investment certainty is an explicit statutory objective - recognises the serious risk that uncertain regulatory practice has for efficient capital commitment.

If the proposed long-term reliability obligations scheme cannot offer comparable certainty, the corollary is that *ex post* changes to allocated obligations may need to include compensation rights for parties that invested in good-faith reliance.

4. Risk of perverse contracting outcomes

This section argues that a long-term reliability obligation would undermine efficient contracting in perverse ways that work against the outcomes that the policy aims to achieve. As with the previous section, perverse effects occur because compliance is defined against a narrow, physically specified and state-contingent test that encourages and enables obligated parties to distort decisions in favour of minimising their compliance burden.

In three related ways, the long-term reliability obligation scheme would tilt obligated parties away from the fixed contracts to contingent contracts, from financially-settled derivatives to physically-settled contracts, and from long-dated commitments to short-dated ones - not because these tilts are an efficient response to the underlying risk, but because they best preserve compliance optionality against a regulatory trigger.

4.1 Efficient contracting: contract forms compete to allocate risk and decision rights

The starting point is the theory of efficient contracting. In the frictionless benchmark of complete contingent markets - a distinct security for every future state of the world - the first-best is attainable without any need for a designed instrument: all risks are allocated to those best able to bear them, investment is efficient, and welfare is maximised (Arrow, 1964; Debreu, 1959).

Real contracting departs from that benchmark because contracts are incomplete. It is not possible to anticipate every future state, it is too costly to specify all contingencies, and some actions are non-verifiable and so unenforceable (Coase, 1937; Grossman & Hart, 1986; Hart & Moore, 1990). Incompleteness has a corollary that is central to what follows: no single contract form is efficient in all circumstances. Different forms - fixed or contingent, financial or physical, long-dated or short - economise on different combinations of risk-bearing and transaction cost, and are aligned, transaction by transaction, with the governance arrangement that performs the exchange at least cost (Williamson, 1985).

A standard forward contract requires the counterparties to agree on only one thing, the average expected spot price; an option requires agreement on a model of the world and the distribution of tail events and so carries valuation and counterparty-risk burdens that a symmetric contract does not. A pure financial derivative economises on the transaction costs of physical delivery, lets parties without physical assets participate and enables greater liquidity than a either physical contract. A long-dated contract supplies provides greater certainty whereas a short-dated contract preserves the flexibility to re-optimise as conditions change.

It follows that contract forms exist in what is effectively a competitive market for contracts. A forward contract survives alongside the spot market only where it adds value the spot market cannot - by reallocating risk to the party better able to bear or mitigate it, or by reallocating decision rights over future actions (Williamson, 1985; Bessembinder & Lemmon, 2002). The same discipline operates among other contract forms: a given form persists in use only where, for the circumstances at hand, its net benefits exceed those of the alternatives. This is the survivor principle applied to contract design -

the forms that endure are those that prove efficient in the settings where they are used (Stigler, 1958). Absent intervention, the selection among fixed and contingent, financial and physical, long and short is made by the parties, who alone hold the information about their own risk preferences, information positions and investment plans, and who bear the consequences of their choices.

The relevance for regulatory design is direct. An instrument that privileges one contract form over others - independently of the circumstances of the transaction - overrides this decentralised selection. Where the privileged form is not the one the parties would have chosen, the instrument displaces a more efficient arrangement with a less efficient one, and the resulting loss is a real deadweight cost, not a transfer. The Government has itself acknowledged the value of 'decentralised risk management' in promoting efficient reliability and security of supply (Office of the Minister for Energy, 2024). The three subsections that follow show that the obligation, as framed, does precisely what good design should avoid: it re-prices the choice among contract forms in a direction disconnected from their underlying efficiency.

4.2 Fixed contracts may be discouraged in favour of contingent contracts

The discussion of timing distortions in Section 3.2 established that, where an obligated party would otherwise enter a firm long-term contract for a firming resource not captured in the SOSA forecast, the trigger mechanism gives it an incentive to withhold that firm commitment - deferring it, or replacing it with a first-right-of-refusal or other option contract - so that the resource remains available to be counted toward its own obligation once triggered.

The mechanism is an application of the economics of investment and commitment under uncertainty. Because the obligation switches on and off with the passage of time and revisable forecasts, a reversible or contingent commitment acquires an option value over an irreversible, firm one: the party that keeps its arrangement contingent retains the ability to direct the resource to compliance if and when the obligation triggers, and to walk away if it does not (Dixit & Pindyck, 1994). That option value is manufactured by the regulatory design; it does not reflect any change in the efficient allocation of dry-year risk between the parties.[2]

The discouragement of fixed long-dated contracts that help support firming investment works against the consultation paper's objectives for the long-term obligations scheme.

The magnitude of the effect may be mitigated by adjusting the scheme design - such as allowing contingent arrangements such as first-rights to count as qualifying cover and providing for allocations to be trued up *ex post* - but which may introduce other complications.

[2] The tilt does not imply that contingent contracts are inefficient; options, caps and first-rights genuinely allocate one tail of a distribution and are the efficient instrument in many settings.

4.3 Pure financial derivatives may be discouraged in favour of physically settled derivatives

The consultation paper frames qualifying cover around resources that 'shift the margins and close the shortfall assessed by the SOSA' and provide 'dependable winter energy support' (MBIE, 2026, para. 80 - 81). On that criterion, an over-the-counter hedge with a clear linkage to a physical resource may qualify, but a pure financial derivative - an ASX future, or an OTC Contract for Differences with no link to specific physical assets - would not. The consequence is a discouragement of pure financial derivatives that are cash-settled in favour of derivatives with physical settlement.

4.4 Long-term contracts may be discouraged in favour of short-term contracts

The third tilt operates on the tenor of the cover used to comply. Because the obligation may be triggered and lapsed many times into the future, and any given obligation may be revised during the compliance period, an obligated party choosing how to meet an allocated obligation faces a state-contingent liability that switches on and off.

Against a liability of that shape, short-dated cover has an option advantage over long-dated cover. A stack of short instruments can be let expire, or unwound, once the relevant winter has passed and the margin has recovered so that the obligation lapses; the party is then free of cover it no longer needs and retains the ability to recontract afresh if/when the obligation is re-invoked. A long-dated contract, by contrast, commits the party across the states in which the obligation is absent, exposing it to the carrying cost and price risk of holding cover in years when none is required. As in the fixed-versus-contingent case, this is a manufactured option value: the on/off trigger confers an advantage on short, reversible commitments that reflects the regulatory design, not the efficient tenor of dry-year risk management (Dixit & Pindyck, 1994).

The inefficiency is again self-undermining of the consultation paper's objectives.

The strength of the effect depends on design - in particular, whether qualifying cover must span multiple future winters (though parties would still prefer the shortest qualifying tenor). The tilt also bites hardest for parties that rely on contracts to comply; a vertically integrated party meeting its obligation from owned generation is comparatively insulated.

4.5 Incentive to comply at minimum contract size

A further tilt operates on the volume of cover rather than its form or tenor. Each obligated party must hold qualifying cover at least equal to its allocated share of the identified shortfall. Because over-compliance is normally unrewarded and costly, the requirement on its own gives each party an incentive to secure cover at exactly that minimum.

The prospect that a new, additional obligation may be triggered in future years turns this static incentive into a further distortion. By the same reasoning that drove the previous three subsections:

since qualifying cover - physical firming, demand response, and the counterparties able to supply them - is scarce and rivalrous, a party that controls such resources has an incentive to commit only the minimum the current obligation requires, and to keep its remaining qualifying capability uncommitted and outside the SOSA forecast, held in reserve to meet the next obligation from resources it controls rather than contracting them away now. This is the quantity analogue of the withholding distortion (Section 2.2) and the fixed-versus-contingent tilt: the margin is volume rather than form or tenor, but the driver - preserving compliance optionality against a future trigger - is identical.

Again, the magnitude is design dependent. For example, introducing a scheme whereby excess compliance can be banked for future compliance may mitigate the perverse incentive. Additional complexity is added, however.

Conclusion

Taken together, the four tilts share a single driver: a compliance test that is narrow (physical), state-contingent (triggered and revisable) and discontinuous (on/off) attaches a compliance-optionality premium to the contingent, the physical, the short dated and the minimally sized. The obligation does not merely add a constraint to the contracting problem; it re-prices the relative attractiveness of contracting arrangements across four margins - form, instrument, tenor and volume - in a direction disconnected from their underlying efficiency, overriding the decentralised selection that an efficient contract market performs. In each case it tilts toward the arrangement that least supports the durable, firm, adequately sized, investment-backing commitment the consultation paper says would be beneficial to dry year security of supply.

5. NZAS contracts illustrate significant risks

The consultation paper states that the proposed *de minimis* threshold will result in the long-term obligation being applicable to the four large gentailers (Contact, Genesis, Mercury and Meridian) and NZAS (MBIE, 2026, para. 59).[3] Of that cohort, NZAS is the anomaly. It is not a gentailer, holds no generation and sells no electricity to consumers; it is a single industrial site - the Tiwai Point smelter - that is New Zealand's largest electricity consumer.

NZAS is New Zealand's largest provider of long-term firming contracts and the single most consequential provider of dry-year demand response (equivalent to about 7% of national hydro storage capacity in the 2024 (Electricity Authority, 2024)). The proposal would therefore conscript, as an obligated purchaser of winter cover, a party that is already 100% covered and that in the 2024 dry year supplied the market's largest single tranche of winter relief.

NZAS meets its electricity needs under a suite of twenty-year contracts signed in May 2024 with Meridian, Contact and Mercury.[4] The subsections that follow show that these contracts are carefully constructed to meet the differing needs and economic interests of each party, and that - precisely because they are finely tuned - they illustrate how the proposed obligation would put that hard-won contractual efficiency at risk.

5.1 NZAS contract terms relevant to the obligation

Core agreement

The three Core Agreements are contract for differences with the net effect that NZAS pays a fixed price for a fixed quantity. The Meridian contract includes a formula by which the fixed price may be adjusted annually from 2028. Other features relevant to the proposed long-term reliability obligation are:

- *Term:* the term runs for 20 years to 31 December 2044, so NZAS is contractually hedged for a long period if the proposed obligation scheme were established.
- *Quantity:* the total contracted quantity across the three generation companies equals the smelter's constant demand of 572 MW, so NZAS is already 100% covered.
- *Reference to physical generation:* in the case of Meridian, the contract references the 'underlying generation assets' of the Manapouri Power Station and the Waitaki scheme (Ohau A–C, Benmore, Aviemore, Waitaki), and the parties' force-majeure rights are defined by reference to Meridian's ability to generate and NZAS's ability to consume.

[3] In contrast, our analysis in section 6.2.3 suggests that the long-term obligation could be applicable to nine entities.

[4] The NZAS suite of contracts with Meridian are available from the Meridian website. These contracts include the Core Agreement (an ISDA electricity swap), the Demand Response Agreement, the ISDA Schedule, the Amended and Restated Reduction Line Agreement, the Hedge Settlement Agreement and its Side Letter, each dated 30 or 31 May 2024. NZAS advised that they hold materially similar arrangements with Contact and Mercury. We have not sighted these other contracts.

- *On-sale:* the agreement preserves NZAS's ability to on-sell any unused megawatt quantities 'without being subject to any worse terms than if it had consumed the relevant quantity itself' (Core Agreement, para. 1.9). NZAS can therefore release energy it does not use.

Demand response agreement

The Demand Response Agreement grants Meridian a suite of call options over NZAS's load. Four Options are distinguished by depth and minimum duration: Option 1 at 25 MW for a minimum of 10 days, Option 2 at 50 MW for a minimum 15 days, Option 3 at 100 MW for a minimum 22 days, and Option 4 at 185 MW for a minimum 30 days. Exercise of the options is subject to restrictions such as stand-down periods between calls and caps on the number of calls. Option 1, for example, may be exercised at most six times in any 12-month period.

Payments are specified in three forms: (i) a per-unit amount for delivered reduction, tiered by volume; (ii) an annual compliance premium payable in full if either no call is made or where actual reductions in response to a call reach at least 95% of the called reduction (with a sliding scale for actual reductions between 51% and 94% of the called amount); and (iii) a standing annual demand response premium payable regardless of whether the options are ever called. NZAS is therefore paid to hold the option open, paid more when it performs well against a call, and paid per unit when it actually curtails.

Two further features are relevant to the proposed long-term reliability obligation scheme:

- *A split between control and economic interest: Control* is undivided, with Meridian holding the exclusive right to exercise the options and discretion to set all trigger conditions within contract parameters. *Economic interest* is split, with 75% of the delivered reduction applicable to Meridian and 25% to Contact Energy. Contact, however, holds no control right whatsoever over the demand reductions. Mercury NZ, though a counterparty to the smelter, has no role in the demand-response options.
- *Liability limited to financial consequences:* NZAS is expected to comply with Meridian's call instructions irrespective of whether doing so is financially beneficial at prevailing aluminium prices. Nevertheless, the demand response agreement provides that the only consequences to NZAS of failing to reduce energy consumption in line with instructions are reductions in the per unit and performance payments and a reduction in the covered quantity equal to the demand reduction quantity, and that 'no other consequences or liability for NZAS will flow from such failure' (Demand Response Agreement, para. 4).

5.2 Uncertain compliance of existing NZAS contracts

The consultation paper proposed to allocate to each obligated wholesale purchaser a share of any forecast shortfall in the winter energy margin and require the obligated party to add new verifiable winter energy cover to that level (MBIE, 2026, para. 75, 80). A natural first question is whether NZAS's existing contracts could themselves be counted toward such an obligation?

The trigger and the shortfall are both measured against the SOSA's Expected Scenario (MBIE, 2026, para. 65 - 67; Box 1). Qualifying cover, in turn, is defined by its ability to 'shift the margins and close the shortfall assessed by the SOSA' (MBIE, 2026, para. 80), and the paper is explicit that, for cover to be effective, the underlying arrangement must 'confer a sufficient incentive on the seller to tilt

investment cases that aren't currently in the Expected Scenario of the SOSA' (MBIE, 2026, para. 86). Cover already embedded in the reference case therefore cannot, by construction, shift the margin.

That matters here because the System Operator's assessment already appears to internalise both the NZAS load and its demand response. The SOSA reference case has for some years included the Tiwai smelter load across the assessment horizon (Transpower, 2024). For SOSA 2026 the System Operator states that its demand-response modelling 'starts from the current level of contracted demand response' and incorporates further response captured through its survey of participants (Transpower, 2026). On the balance of the public record, the May 2024 Meridian–NZAS demand-response arrangement is therefore likely to be reflected, at least in substance, in the Expected Scenario against which any shortfall is measured[5].

If that is correct, the Demand Response Agreement would not be available to any of the contract parties as incremental qualifying cover: it is already counted on the supply-adequacy side of the ledger.

The remainder of this subsection sets that threshold point to one side and asks the counterfactual question: supposing the demand response were not already in the forecast, would the NZAS contracts in fact qualify, and how cleanly could the resource be allocated between the parties? The exercise is worthwhile because the difficulties it surfaces - verifiability, divided control, and pre-existing full cover - are generic to the scheme. They would recur wherever the obligation met a real, negotiated commercial arrangement.

5.2.1 Would the Demand Response Agreement qualify as verifiable winter energy cover?

Set aside the double-counting problem and suppose the Demand Response Agreement were offered as qualifying cover. Whether it would satisfy the consultation paper's verifiability test is genuinely uncertain, and the uncertainty turns on a feature the contract was deliberately drafted to include.

The consultation paper does not treat the mere existence of a contract as sufficient. The compliance assessment likewise asks whether an arrangement gives the obligated party a 'sufficiently clear and enforceable entitlement' to the cover (MBIE, 2026, para. 86).

Against that standard, the Demand Response Agreement has an unusual property. As noted above, NZAS is expected to comply with a call, but the only consequence of non-compliance is a reduction in its option payments and level of hedge cover: 'no other consequences or liability for NZAS will flow from such failure' (Demand Response Agreement, para. 4). The option appears to be closer to a price-incentivised request than to a specifically enforceable entitlement to a physical reduction. Meridian cannot compel the megawatts; it can only decline to pay for those not delivered.

[5] 2026 SOSA – Final report page 8 states that *'The demand response assumption in the Reference and Expected Future case were updated from the default SSAD assumption of 2% for the NZ-WEM and SI-WEM to better reflect the New Zealand Aluminium Smelter (NZAS) demand response potential. 8 This resulted in an increase to the modelled demand response for the SI-WEM from 2% to ~5% but largely left the NZ-WEM assumption unchanged at 2%. This update was in response to feedback received on the draft SOSA.'*

Two readings are possible and it is not clear which is intended under the policy:

- On a formal-enforceability reading, an entitlement whose sole remedy is withholding payment is not a 'clear and enforceable entitlement' to physical cover, and the arrangement fails the test. That reading would exclude one of the most reliable dry-year resources in the country - a resource that performed exactly as intended in 2024 - which would be a perverse result.
- On an economic-readiness reading, the arrangement plainly is 'in a state of readiness': it is a live, paid-for option that has been exercised in practice, and the payment structure gives NZAS a pecuniary incentive to perform. On this reading it should qualify, and the formal remedy is beside the point.

The point is not to resolve the ambiguity but to show that the consultation paper's verifiability test does not, as drafted, resolve it. The contract terms are established; what is contested is how an as-yet-unwritten compliance rule would classify them. A rule strict enough to exclude weak paper commitments risks excluding strong economic ones; a rule loose enough to admit this arrangement admits a great deal else. The consultation does not grapple with the trade-off.

5.2.2 Divided control and economic interest complicate allocation

A second difficulty is structural. Even if the demand response qualified, the scheme would have to decide whose cover it is - and the contract splits the two attributes that ordinarily travel together.

Recall that control over the options is undivided and sits entirely with Meridian, which alone may exercise them and set the trigger conditions. Economic interest is divided 75:25 between Meridian and Contact (who holds no control right whatsoever). NZAS, the party that actually curtails, is the counterparty to both.

The compliance framework the consultation paper sketches asks whether cover 'had in fact been allocated to the purchaser, for that period … in a way that avoids double counting' (MBIE, 2026, para. 84). That question has no clean answer here:

- If cover follows control, the entire demand response resource would count for Meridian and nothing for Contact - even though Contact received a quarter of the delivered reduction.
- If cover follows economic interest, it would be split 75:25 between Meridian and Contact - even though Contact cannot cause a single megawatt to be curtailed and could not, acting alone, call upon the demand reduction.
- If cover follows the party bearing the physical obligation to reduce, it would sit with NZAS - however, NZAS would be crediting itself with a resource that has contracted to surrender to Meridian.

Each rule double-counts or under-counts relative to another. This is not a drafting issue in the contracts; the contract allocates control and economic interest deliberately and coherently, because for its purposes the directing of curtailment and settling of payments need not coincide. The problem is that the obligation imports a third concept, regulatory compliance credit, and provides no rule for reconciling it with the other two. The consultation paper's own framing of qualifying cover presumes an integration of control, interest and delivery that this efficient contract does not exhibit - and that many real contracts will not exhibit.

5.2.3 100% fixed-volume cover forces a perverse on-sell

The third difficulty is the most concrete, and it does not depend on any of the classification questions above.

NZAS's three Core Agreements across the three generation companies each fix a price for a fixed quantity equal to the smelter's near constant demand of 572 MW. In net terms, NZAS is already fully hedged: it has, in effect, 100% cover for 100% of a known, near-constant load, for twenty years. Its uncovered winter position - the quantity of its load that is exposed to dry-year scarcity and not backed by a firm forward arrangement - is therefore approximately zero.

Now apply the allocation rule. The consultation paper proposes that the obligation be allocated by share of expected winter demand, and that the obligated cohort must, between themselves, secure cover for 100% of the identified shortfall (MBIE, 2026, para. 75 - 76). NZAS's expected winter demand is large - it is the country's largest single load - so its allocated share of any shortfall would be correspondingly large, notwithstanding that its own exposure is nil.

To meet an allocation calculated on a demand it has already fully covered, NZAS has two options, and both are perverse:

1. *Procure additional cover it does not need.* NZAS would contract for further qualifying winter cover on top of a load that is already 100% covered. Since its physical demand is fixed and constant, the only way to hold cover in excess of demand without simply wasting it is to on-sell the surplus energy - which the Core Agreement expressly permits. The obligation would thus turn NZAS into a forced on-seller of energy purely to satisfy a compliance arithmetic.
2. *Restructure or shed cover to create headroom.* Alternatively - and this is the distortion analysed in Section 5.3 below - NZAS might contract for less than 100% firm cover so as to leave room to bolt on a separately-badged 'qualifying' tranche if and when the obligation triggered, deliberately loosening an efficient full hedge to accommodate the rule.

Either way the result is misaligned with the consultation paper's intent to address the tenor gap. NZAS is the polar opposite as it is already fully covered. Applying a demand-based allocation to a fully covered party does not correct any under-procurement; it manufactures churn - an on-sell here, a re-contract there - with no effect on physical adequacy. Section 5.4 develops the general form of this objection.

5.3 Risk of distorting efficient contracts

The NZAS suite of contracts is the product of a lengthy, voluntary, arm's-length negotiation between sophisticated and well-advised counterparties, each protecting distinct commercial interests. On the revealed-preference logic that runs through the economics of contracting, an arrangement of that

character is *prima facie* efficient: the forms chosen survived because, for these parties in these circumstances, their net benefits exceeded those of the alternatives (Coase, 1937; Williamson, 1985).[6]

It is natural to ask a specific counterfactual: if the parties had been negotiating after the obligation scheme was in force, which of these efficient features would the scheme have pushed them to abandon? Section 4 established, in the abstract, that a compliance test which is narrow (physical), state-contingent (triggered and revisable) and discontinuous (on/off) attaches a compliance-optionality premium to the contingent, the physical, the short-dated and the minimally-sized, and so tilts contracting across four margins - form, instrument, tenor and volume - in a direction disconnected from underlying efficiency. The two subsections below trace those tilts through the two central NZAS instruments.

5.3.1 Distortion of the Core Agreement

Two efficient features of the Core Agreement are exposed.

Full-volume cover may be pared back to preserve headroom

The three Core Agreements cover 100% of NZAS's constant demand - an efficient response to a load that is genuinely constant and a price exposure the smelter wishes to mitigate. Under the obligation, that very completeness becomes a liability. Because a fresh obligation may be triggered in future years, and because qualifying cover is scarce and rivalrous, an obligated party has an incentive to hold cover at the minimum its current obligation requires and keep residual qualifying capability uncommitted, in reserve against the next trigger (the volume tilt of Section 4).

Translated to NZAS, the incentive is to contract for less than 100% firm cover - say 90% firm plus a contingent tranche - to leave headroom into which a separately-badged qualifying contract can be written if the obligation lands, rather than being caught already fully committed and forced into the on-sell described above. The scheme would thus reward the deliberate loosening of an efficient full hedge. That is a real deadweight loss, not a transfer: the smelter ends up bearing residual price risk it had rationally chosen to eliminate, purely to manage a regulatory contingency.

Financial settlement may be pushed toward physical settlement

All three Core Agreements are contract for differences (CfD) - a financially-settled swap. That is an efficient design: it gives NZAS a clean price hedge without entangling it in the dispatch of specific plant. But the consultation paper's qualifying-cover test privileges resources with a demonstrable link to physical winter delivery (MBIE, 2026, para. 80 - 81, 84 - 66), and a purely financial CfD may not qualify - the same instrument-margin tilt identified in Section 4.[7]

---

[6] Revealed preference establishes that the arrangement was privately efficient for the contracting parties given the environment they faced. It does not establish social efficiency in the event of externalities the parties did not price.

[7] We acknowledge that the consultation paper has not stated whether purely financially settled instruments would qualify as verifiable winter energy cover. The consultation paper's 'shift the margins' framing (para. 80) implies they would not, since they deliver cash rather than firm megawatt-hours.

To make its cover count, NZAS (or Meridian on its behalf) would face pressure to bolt a physical overlay onto a contract that did not need one: for example, to list nominated firming resources as reserved for NZAS, or to convert part of the swap into a physically-referenced entitlement with exclusive access. Each such graft adds transaction cost, narrows the pool of assets available to other purchasers, and moves the contract away from the financially-settled form the parties efficiently chose - without adding a megawatt to the system.

5.3.2 Distortion of the Demand Response Agreement

The Demand Response Agreement is the more delicately engineered instrument, and correspondingly the more fragile under the scheme. Two of its efficient features are at risk.

Enforcement calibration

The agreement's limited-liability remedy - payment adjustment as the sole consequence of a missed call - is not a loophole; it is very likely a negotiated efficiency. A smelter cannot commit to a hard, specifically enforceable obligation to shed load without regard to the state of its pots, its metal sales and raw material purchase contracts and its safety constraints; a payment-adjustment remedy lets it offer deep, credible flexibility while retaining the residual discretion an industrial process requires. The premium Meridian pay is priced against exactly that remedy.

If the compliance rule demanded a higher, specifically enforceable standard for the resource to count as verifiable cover, one of three things would follow, each welfare-reducing:

- NZAS declines to accept the harder obligation, and the resource - the largest dry-year lever in the country - simply does not qualify, leaving it outside the compliance system even though it remains physically available,
- NZAS accepts a harder obligation only at a materially higher premium (compensating it for surrendering operational discretion and bearing genuine performance risk), raising the cost of the very cover the scheme seeks to expand, or
- the parties preserve feasibility by shrinking the resource - fewer callable megawatts, tighter exercise windows, more conservative trigger conditions - so that what NZAS can hard-commit to is smaller than what it is presently willing to offer on a softer remedy.

In each case the scheme trades a large, flexibly governed resource for a smaller, rigidly governed one, or for none at all. That is the opposite of the consultation paper's objective.

Reallocation of control

The agreement vests exclusive control in Meridian while splitting economic interest with Contact. That concentration of control is efficient: a single controller, holding the system view and the trigger discretion, avoids the coordination and hold-up problems that would arise if two competing generators each held partial call rights over the same load. But if compliance credit follows control, Contact has a regulatory reason to demand a share of control it does not currently hold and does not efficiently need - so that it, too, can 'point to' the resource as its own qualifying cover.

Fracturing an exclusive call right across two rival controllers to satisfy an attribution rule would import precisely the coordination costs the undivided design avoids and could degrade the resource's

reliability at the point it is most needed. Here the scheme would distort not the price or tenor of the contract but its governance - the allocation of decision rights - which the incomplete-contracts literature identifies as important for efficient contracting (Grossman & Hart, 1986; Hart & Moore, 1990).

Having said the above, we acknowledge that each of distortions discussed is contingent on design choices on which the consultation has sought feedback - the evidential standard for demand response, the attribution rule for shared cover, whether contingent and financially-settled instruments qualify. A well-designed scheme may mitigate the distortions to some extent, but mitigation is not costless and is not guaranteed.

5.4 NZAS contracts show the allocation rule is wrong

The proposed obligation scheme would require NZAS to procure fresh winter cover for a load that - in the very dry conditions the obligation exists to guard against - NZAS stands ready not to draw. To treat such a party as an under-covered purchaser needing to be compelled to buy more is to invert the economics of its position. This is a symptom of an allocation rule that measures the wrong quantity.

Consider a stylised benchmark that isolates the logical structure of the rule. Suppose every load in the system were like NZAS in the relevant respect: each had a known, constant winter demand, and each held 100% verifiable winter energy cover under legally enforceable, fixed contracts. Trace the implication through the supply side. If every load is fully and firmly covered, then every generation counterparty has a known, contracted delivery obligation, including to stand behind those firm sales in dry conditions. There is no uncovered demand anywhere in the system.

In that world, an unbiased forecast of the Winter Energy Margin would show no shortfall. The Expected Scenario would net every firm sale against the firming procured to support it, and the margin would sit at or above the standard by construction. No shortfall would be identified; the trigger would never be pulled, and the obligation would never arise.

The thought experiment establishes that a fully covered party like NZAS contributes nothing to the shortfall. It has already done, for its own load, exactly what the obligation would compel: secured firm cover ahead of time. To then allocate it a share of a shortfall it did not create - and to size that share by its expected demand, is to charge the party that solved its part of the problem for the failure of parties that did not.

This exposes the logical flaw in allocation by expected winter demand. Expected demand measures exposure to the system, not contribution to the shortfall. The two coincide only in the limiting case where no load is forward-covered - in which case share-of-demand and share-of-uncovered-load are the same number. As soon as loads differ in how much firm cover they already hold, the two diverge, and demand-based allocation systematically over-charges the well-covered and under-charges the exposed.

The coherent alternative is to allocate by uncovered winter quantity: each party's expected winter demand, net of its fixed-volume firm cover and any self-supply of sufficient reliability.

Uncovered-quantity allocation likely would be harder to administer than demand-based allocation, but administrative convenience implies finding ways to simplify the measurement of the uncovered demand, not to allocate on a quantity that is theoretically the wrong one.

6. Implementation and other practical issues

MBIE's proposed approach is also likely to raise several practical implementation challenges. Disputes are likely to arise not only about the forecast itself but also about the assumptions embedded within it, including the definition of winter, treatment of hydro storage, demand projections, generation availability and new investment assumptions.

Small changes to methodology may have significant commercial consequences, creating incentives for participants to challenge forecasts and lobby for particular modelling choices, potentially reducing confidence in the objectivity of the policy.

The Australian Retailer Reliability Obligation (RRO), referred to in the consultation paper, provides a cautionary example because, despite broad support for its objective, its implementation has exposed several practical and design challenges. Many of these issues could arise under the MBIE's proposed reliability obligation if the policy is not thought through properly. Where relevant, we have included the Australian experience to corroborate our view.

In this section, we elaborate on those practical issues and challenges that could render this policy mechanism unworkable in the context set out.

6.1 Verified cover is not the same as delivered energy

New Zealand's electricity system relies heavily on hydro generation, which becomes less effective during a dry year when lake inflows are low. The dry-year problem is fundamentally a physical resource problem. When hydro storage is constrained, the system needs alternative sources of energy such as:

- Diesel
- Imported LNG
- Coal
- Geothermal
- Other firming generation

Suppose there is a shortfall of 1 TWh and the policy requires the obligated cohort to procure 1 TWh of firm energy cover. If there is not enough qualifying energy available in the market, the policy is likely to increase significantly the price of scarce reliability products.

This is not merely a theoretical risk. When Australia's Retailer Reliability Obligation (RRO) was triggered in South Australia, the Australian Energy Council warned that the obligation was likely to place upward pressure on electricity prices in the affected region (O'Mahony, 2020). More recently, the 2025 NEM Wholesale Market Settings Review recommended that the RRO be phased out, citing declining contract liquidity and reduced access to affordable hedge products for smaller retailers (NEM Wholesale Market Settings Review, 2025).

While these Australian experiences highlight the market impacts of reliability obligations, they also raise a separate question relevant to the MBIE proposal. That is, whether compliance with a cover obligation necessarily means that additional energy will be available during a dry year.

In Section 4.3, we noted that the consultation paper appears to favour qualifying cover that is linked to physical resources rather than purely financial contracts. However, pointing to a physical resource in a contract is not the same as demonstrating that the resource exists and will be capable of dispatching energy when a dry year occurs.

This distinction is important because the short-term obligation is intended to address a physical reliability problem rather than simply create contractual arrangements. Its effectiveness will therefore depend on whether the verification requirements demonstrate that the physical resources supporting those contracts will be available and capable of delivering energy when required. A contract may otherwise satisfy the policy's formal requirements without necessarily guaranteeing the availability of the underlying energy.

In other words, verifying that a contract exists is not the same as verifying that real, deliverable energy exists. A scheme that only checks contracts, without also checking whether the underlying physical resource is genuinely available, risks satisfying the compliance requirement without improving reliability outcomes. As currently written, the policy paper does not appear to address this issue.

The uncertainty identified in Section 5.2 regarding the NZAS Demand Response Agreement illustrates the same point. The consultation paper is not clear whether 'verified' cover means simply that an arrangement is real and legally enforceable, or whether it must also be demonstrated that the arrangement can reliably deliver the energy or demand reduction required during a dry-year event.

Australia's experience suggests that this distinction matters. AEMO warned against broadening the eligibility of qualifying contracts 'at the expense of allowing contracts to be used that have only a tenuous relationship with physical dispatchable capacity' (AEMO, 2023, p. 4). Even the operator of an established reliability obligation considered it necessary to caution against compliance being achieved through contracts that do not correspond to genuinely deliverable capacity.

Ultimately, the effectiveness of a cover obligation depends not only on whether contracts can be verified, but also on whether the physical resources behind those contracts can actually deliver energy when the system needs it most. Compliance and reliability are not necessarily the same thing.

6.2 Perverse incentives are likely

SOSA already assumes a degree of demand response from market participants, including NZAS. As discussed throughout this submission, the proposed obligation may unintentionally create incentives that alter participant behaviour rather than improve reliability outcomes. These incentives arise through the treatment of demand response, uncertainty regarding how demand response will be recognised under the scheme, and the operation of the proposed *de minimis* threshold. In each case, participants may be encouraged to optimise their own compliance position rather than contribute to overall system efficiency.

6.2.1 SOSA assumptions may weaken the demand response market

Perverse incentives are likely to arise where large industrial participants are capable of providing demand-side response and already hold demand response (DR) financial contracts. If demand response already assumed within SOSA cannot count as incremental qualifying cover, these participants may be incentivised to withhold or backtrack from existing arrangements rather than maintain them.

In Section 5, we set out, using the Meridian–NZAS Demand Response Agreement as a specific example, how this incentive operates once cover embedded in the SOSA reference case cannot qualify as incremental cover. We also explained how the governance features of that arrangement, including divided control and economic interest, interact with an obligation that rewards flexibility retained rather than flexibility committed. The general incentive problem described here and the specific mechanics traced in Sections 5.2 and 5.3 are manifestations of the same distortion that the proposed policy could inadvertently create.

From the perspective of an individual participant, this weakens the incentive to make flexible load available and instead encourages behaviour that minimises the participant's own allocation outcome rather than maximising overall system efficiency. This mirrors the 'distortions to industrial scheduling' mechanism identified in Section 3.2, where a large industrial user above the *de minimis* threshold has an incentive to time demand-reducing activity around the measurement window rather than for efficiency reasons. It also compounds the free-riding dynamic identified in Section 3.3, where non-obligated parties reduce their own precautionary contracting because they anticipate that obligated parties will be compelled to procure additional cover on their behalf.

6.2.2 Unclear definition of demand response will likely result in market inefficiencies

The incentive issues described above are compounded by uncertainty regarding how demand response will be treated under the proposed framework.

Much of the dry-year problem identified by MBIE concerns prolonged energy shortages that can persist for weeks or months. While some forms of demand response may be highly effective for managing short-term peak demand events, such as ripple control schemes, they may be less capable of providing sustained reductions over an extended winter period without significant welfare and social consequences for participating consumers. The consultation paper would benefit from clearly defining how different categories of demand response contribute to long-duration energy adequacy and how that contribution will be assessed.

At present, the consultation paper does not clearly distinguish between forms of demand response that are primarily designed to manage short-duration peak demand events and those capable of contributing to long-duration energy adequacy (MBIE, 2026, para. 81). As a result, participants may face uncertainty regarding what qualifies, how much value particular demand response arrangements will receive, and whether existing demand response capability is already reflected within the SOSA assumptions.

This uncertainty may create incentives for over-procurement of firming resources. If obligations are calculated using shortfalls that already incorporate assumed demand response, participants may collectively procure more firming capacity than is efficiently required. The resulting increase in demand for firming products and demand response contracts could place upward pressure on the price of those services.

While higher prices can be an efficient signal where genuine scarcity exists, prices elevated by double counting or over-procurement represent a transfer of costs rather than an efficient market outcome. In this way, ambiguity surrounding demand response eligibility may translate directly into market inefficiencies.

6.2.3 *De minimis* threshold may backfire

Perverse incentives are not limited to demand response arrangements. The proposed *de minimis* threshold may also influence participant behaviour in unintended ways.

The proposed threshold of 500 GWh of aggregate winter load, initially capturing the four large gentailers and the smelter (MBIE, 2026, para. 59) appears to be incorrect. Table 1 shows that nine participants already sit at or above a scale comparable to the threshold, representing approximately 20 TWh of annual winter energy demand across 2024 and 2025.

Table 1 Historical winter energy demand in GWh

Name of participant(s)	2024	2025
Meridian Energy Limited	5,485	5,700
Mercury NZ Limited	3,736	3,736
Genesis Energy Limited	3,399	3,285
Contact Energy Limited	3,051	3,023
New Zealand Aluminium Smelters Limited*	2,182	2,389
Nova Energy Limited	675	657
New Zealand Steel Limited	536	530
Ecotricity Limited Partnership	458	526
Manawa Energy Limited	563	503
Others	1,662	1,493

* Both years impacted by active demand response calls

Source: EMI wholesale reconciled volumes

Ecotricity provides a useful example. If the assessment year had been based on its 2024 realised demand, it would not have qualified under the *de minimis* rule. However, in 2025 it crossed the threshold. This is precisely the outcome that a hard threshold in a growing market can produce, and the same pattern is likely to recur for other participants in similar positions.

In Section 3.3 we raised, as a theoretical matter, the risk that a *de minimis* threshold creates incentives to bunch load just below the qualifying line (Kleven & Waseem, 2013). Ecotricity's trajectory provides a practical illustration of this mechanism. A participant close enough to the threshold may find that ordinary customer growth is sufficient to change its regulatory status within a single year.

This creates a disincentive to customer growth that may be inconsistent with wider policy objectives. The same dynamic could affect any participant approaching the threshold, including large industrial users considering electrification and emerging data-centre developments, both of which are expected to grow rapidly.

Furthermore, winter energy demand varies from year to year because of weather, economic conditions, and changes in customer demand, not solely because of deliberate business decisions. A participant near the threshold may therefore move into and out of the obligated cohort repeatedly across successive years.

Similar concerns have been identified in Australia. AEMO noted the risk that liable retailers facing a binding compliance obligation could respond by dropping large commercial and industrial load to reduce their measured exposure, potentially leaving those customers unable to obtain acceptable retail offers (AEMO, 2023, p. 2). This illustrates that participants facing a binding quantity obligation have more than one way to reduce their measured obligation, and not all responses involve procuring additional genuine reliability.

These issues suggest that the proposed *de minimis* threshold is likely to shape participant growth decisions, customer acquisition strategies, and load management behaviour in ways that the consultation paper does not appear to have anticipated. The result is unlikely to be a more efficient market and may instead create additional distortions that weaken the effectiveness of the proposed obligation.

6.3 SOSA sets up a trajectory that should not be used for this policy

As established in Section 3.2, a forecast that is repurposed as a compliance trigger is subject to two well-known limitations: the Lucas critique, because parties will adjust their behaviour once they understand the rule that is being applied to them, and Goodhart's law, because a measure that becomes a target gives those who supply its inputs an incentive to manage those inputs rather than report them neutrally.

The SOSA forecast, as it stands, probably highlights several further weaknesses. Assessing the capacity required to maintain security of supply is inherently an exercise in planning under uncertainty, much like determining the need for investment in the transmission network. The assessment must therefore reflect the information available when it is prepared and allow an appropriate margin for unforeseen conditions.

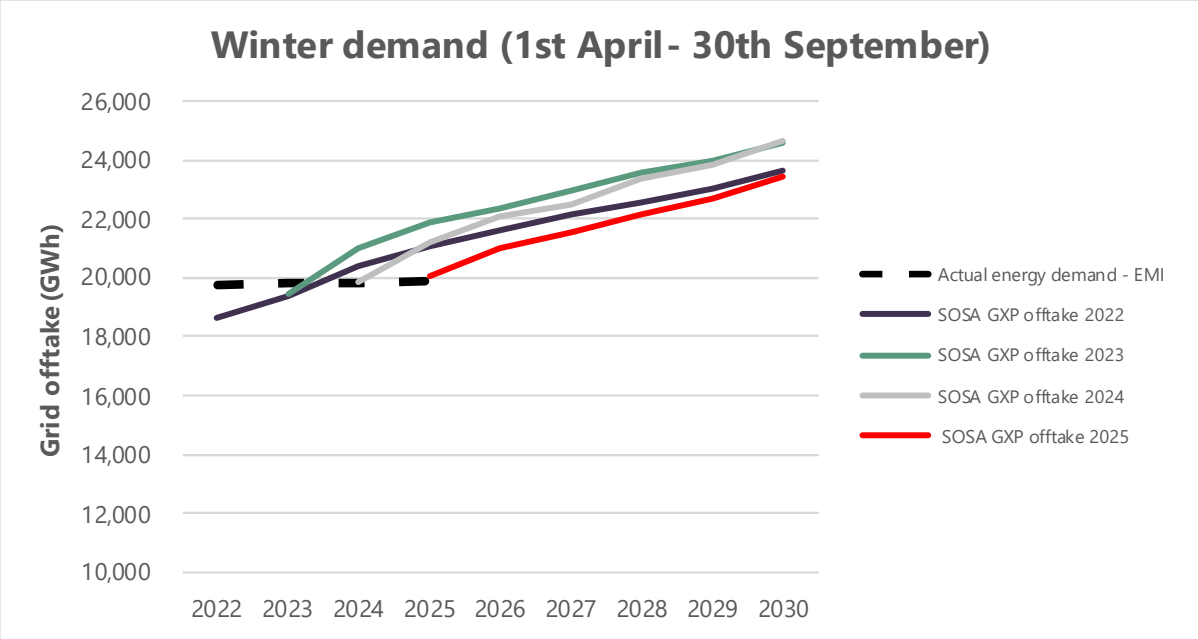
The difficulty with the current SOSA is that it relies on a single, fixed view of the future that may no longer reflect prevailing conditions. This limits its ability to accommodate shifts and fluctuations on either side of the supply-demand balance. Those shortcomings become particularly significant when the forecast is used for compliance purposes, because they risk converting uncertainty in planning judgement into a definitive regulatory threshold.

6.3.1 SOSA is regarded as a prudent forecast

The evidence below suggests the prediction is already visible in the SOSA's track record, independent of any obligation being in place. If the forecast is systematically prudent (e.g., has a tendency to overshoot) even before it carries legal and financial consequences, attaching a penalty-backed obligation to it is likely to widen that prudency. This is because the institutional incentives that exist there are asymmetric which means the consequences of underestimating a shortfall are likely to be more visible and damaging than the consequences of overestimating one, creating a natural tendency toward conservative assessments and over-procurement.

Figure 1 below plots winter energy demand (1 April–30 September) as forecast in each of the last four SOSA (2022–2025), against actual winter energy demand as recorded by EMI over the same period.

Figure 1 Comparison of national level realised winter energy demand and SOSA forecast demand by grid offtake (GWh)



Source: EMI and Transpower SOSA

Every year, the forecast projects materially steeper growth than what has occurred. This is not a one-off forecasting error that has since been corrected. It is a pattern that recurs across four consecutive annual winter demand forecasts.

Each year the SOSA series embeds a growth assumption of at least 3 per cent per annum, on average, across its available time series to 2033. Nevertheless, realised winter demand over the 2022–2025 period grew at approximately 0.2 per cent per annum, on average. This substantial gap warrants an

investigation of both the assumptions and approaches used in forecasting demand, particularly when each variant will trigger penalty to market participants.

6.3.2 Forecast revisions carry more weight than before

Further, the series displays a downward revision for the 2025 series. The corresponding SOSA Final Appendix 2.2 explained that there was a material change in how step loads[8] were treated. Rather than including all step loads across every demand scenario, as in previous years, only step loads assessed as likely, certain, or committed are now carried into the forecast. This revision was prompted by industrial parties backtracking on previously flagged electrification investment. Hence, we see a downward revision in 2025 series. This is a serious problem with SOSA if used for the reliability obligation policy as the penalties would be applied without addressing the actual risks.

A forecasting model that carries consequences of this magnitude for market participants should be designed specifically for that regulatory purpose, rather than adapted from a planning forecast. Its methodology, input requirements and decision rules should be clearly specified in advance, while still allowing uncertainty and volatility to be represented appropriately. Any subsequent methodological or input changes should be subject to transparent change-control arrangements, including clear justification, consultation and their implications for affected parties. This is particularly important where forecast revisions could alter participants' obligations or expose them to penalties.

6.3.3 Forecasts should be created independently

The proposed reliability obligation policy extends the SOSA function into a compliance and enforcement role without addressing the mismatch between the forecast's original purpose and this proposed policy. SOSA forecasts are disclosed and understood as investment and risk-planning tools.

In this section, we have demonstrated, empirically, the problems that SOSA forecasts have at the present stage, i.e., they tend to overshoot the winter energy demand forecast. As it stands, the current approach of constructing a SOSA forecast is not fit for a national policy obligation that risks embedding a forecast that did not previously carry legal consequences[9]. In our opinion, a forecast built on independence that is not influenced by other incentives should be proposed in this policy context.

6.3.4 Inputs into the demand forecasts will be contestable

There does not appear to be a single, consistently applied definition of winter across the sector. Even within Transpower, different analysis frameworks use different periods depending on their purpose. For example, transmission planning and grid investment assessments focus on a winter period

[8] Step loads are new demand that might appear in the future from new developments, such as new commercial and residential developments and informed by feedback from electricity distribution businesses (EDBs).

[9] This is in contrast to the AEMO's demand forecast used in the RRO. Such forecasts are legally binding and have put under a lot of scrutiny, particularly in their assumptions.

extending from approximately 10 May to 19 October[10], whereas the Security of Supply Assessment (SOSA) uses a winter period of 1 April to 30 September[11].

This choice of assessment period can materially affect demand forecasts, expected renewable generation output, hydro storage assumptions and measured energy margins which ultimately determines whether a reliability obligation is triggered as well as the size of any resulting obligation. The risk is obviously exposing qualified participants to significant compliance costs based on what is effectively an assumption choice. This issue might be immaterial at the aggregate level but substantial at the customer level.

In Table 2 below, we present the differences in winter energy demand between the two winter definitions for 2024 and 2025. One winter period spans 183 days while the other is 163 days which is shorter in duration. Effectively, this means that there is less energy needed in the shorter winter window.

Table 2 Winter energy demand 2025 in GWh between the two winter periods

Name of participant(s)	Winter demand: 1 April - 30 Sept	Winter demand: 10 May - 19 October	Difference (GWh)
Meridian Energy Limited	5,700	5,177	523
Mercury NZ Limited	3,736	3,397	339
Genesis Energy Limited	3,285	2,968	317
Contact Energy Limited	3,023	2,773	250
New Zealand Aluminium Smelters Limited*	2,389	2,157	232
Nova Energy Limited	657	593	64
New Zealand Steel Limited	530	475	55
Ecotricity Limited Partnership	526	475	50
Manawa Energy Limited	503	422	81
Others	1,662	1,326	336
Total	**21,840**	**19,764**	**2,076**

* Both estimates impacted by active demand response calls

Source: EMI wholesale reconciled volumes

[10] 2025 Transmission Planning Report (TPR), page 21 in footnote 12.
[11] 2026 SOSA – Final Appendices, page 2.

The numbers in Table 2 show that the winter definition 1 April – 30 September always have higher demand than the other[12]. This is to be expected due to the longer window.

The point connects to two issues raised earlier in this review. Section 2.1 noted, as one of the matters the consultation paper does at least acknowledge, 'forecast fragility' as a live concern, but without working through what that fragility consists of in practice. Section 3.2 established that the obligation uses a single forecast scenario whose parameters are neither fixed nor uniformly defined. In our opinion, an obligation with binding financial consequences should not rest on a parameter that have tendency to vary.

If the reliability obligation is intended to impose binding obligations and potentially substantial penalties, the underlying assessment methodology must be clear, stable and widely accepted by market participants. Otherwise, considerable resources may be devoted to debating assumptions, time horizons and modelling parameters rather than addressing the underlying reliability issue.

[12] Note that the numbers in Table 2 are sourced from the reconciled data which means that they are inclusive of demand response.

7. Conclusions

Dry-year risk is real, and the case for the Government satisfying itself that the system can meet it is unarguable. However, the consultation paper falls short on the analysis required to justify the structural, behaviour-changing intervention that would result from the long-term reliability obligation scheme. The case for intervention has not been made. The paper does not define its problem - 'additional incentives are required' names a remedy, not a cause - and never tests it against recognised sources of market failure. It is internally inconsistent, describing the security standard as cost-benefit optimised while asserting that the system carries too little buffer; those claims have different remedies. The options analysis forecloses rather than tests and government-failure risk is not unexamined.

The claimed benefits are stated against the wrong baseline. The correct counterfactual is the system after the approved Energy Package takes effect: on the paper's own account fuel shortage is the most immediate constraint on dry-year security, and an LNG import capability addresses that failure mode directly. Whether a material residual problem persists is the question the paper needed to answer and did not do so satisfactorily.

The instrument would work against its own objectives. A penalty-backed quantity obligation substitutes an administrative target for the price signal. The trigger creates timing distortions; the de minimis creates notch effects, deters scaling and invites free-riding; revision uncertainty raises hurdle rates on exactly the long-lived commitments sought; and a compliance test that is narrow, state-contingent and discontinuous tilts contracting away from the efficient form on four margins. The NZAS contracts make this concrete: an obligation that rewards flexibility retained over flexibility committed gives the country's largest demand-response provider a reason to withhold arrangements it currently maintains.

The mechanism will face implementation difficulties. Compliance and reliability are not the same thing: the problem is physical, the test contractual, and where qualifying cover is scarce the obligation will bid up prices. Nor can a planning forecast bear the weight of a compliance trigger: an obligation with binding financial consequences cannot rest on parameters that are contestable, revisable and undefined; if it does, resources will be devoted to litigating assumptions rather than to reliability.

We recommend that the Government return to problem definition, specify the evolved counterfactual, and assess all options on a like-for-like basis involving an industry working group with relevant specialised knowledge and experience.

References

Australian Energy Market Operator. (2023). *Submission to AEMC Review of the Operation of the Retailer Reliability Obligation: Draft report* (2 November 2023). https://www.aemc.gov.au/sites/default/files/2023-11/AEMO%20submission%20-%20RRO%20Review%20Draft%20Report.pdf

Arrow, K. J. (1964). The role of securities in the optimal allocation of risk-bearing. The Review of Economic Studies, 31(2), 91–96.

ASX Energy. (2024). New Zealand electricity derivatives. https://www.asxenergy.com.au/products/nz_electricity

Bessembinder, H., & Lemmon, M. L. (2002). Equilibrium pricing and optimal hedging in electricity forward markets. The Journal of Finance, 57(3), 1347–1382.

Coase, R. H. (1937). The nature of the firm. Economica, 4(16), 386–405.

Debreu, G. (1959). Theory of value: An axiomatic analysis of economic equilibrium. Yale University Press.

Dixit, A. K., & Pindyck, R. S. (1994). Investment under Uncertainty. Princeton University Press.

Electricity Authority. (2024). The Tiwai Point smelter demand response in winter 2024 https://www.ea.govt.nz/news/eye-on-electricity/the-tiwai-point-smelter-demand-response-in-winter-2024/

Goodhart, C. A. E. (1984). Problems of monetary management: the U.K. experience. In Monetary Theory and Practice (pp. 91–121). London: Macmillan.

Grossman, S. J., & Hart, O. D. (1986). The costs and benefits of ownership: a theory of vertical and lateral integration. Journal of Political Economy, 94(4), 691–719.

Hart, O., & Moore, J. (1990). Property rights and the nature of the firm. Journal of Political Economy, 98(6), 1119–1158.

Hogan, W. W. (2005). On an "energy-only" electricity market design for resource adequacy. Cambridge, MA: Harvard University.

Joskow, P. L. (2008). Capacity payments in imperfect electricity markets: need and design. Utilities Policy, 16(3), 159–170.

Kleven, H. J. (2016). Bunching. Annual Review of Economics, 8, 435–464.

Kleven, H. J., & Waseem, M. (2013). Using notches to uncover optimization frictions and structural elasticities: theory and evidence from Pakistan. Quarterly Journal of Economics, 128(2), 669–723.

Lucas, R. E. (1976). Econometric policy evaluation: a critique. Carnegie-Rochester Conference Series on Public Policy, 1, 19–46.

Ministry for Regulation. (2026a). Problem definition and options identification - A Resource. Wellington: Ministry for Regulation (May 2026).

Ministry for Regulation. (2026b). Cost-benefit analysis - A Resource. Wellington: Ministry for Regulation (May 2026).

Ministry of Business, Innovation and Employment. (2026). A proposed reliability obligation to manage dry-year risk (Energy Package - Action 2.5). Consultation document, 9 June 2026.

NEM Wholesale Market Settings Review Panel. (2025). *National Electricity Market wholesale market settings review: Final report*. Australian Government, Department of Climate Change, Energy, the Environment and Water. https://www.energy.gov.au/sites/default/files/2025-12/national-electricity-market-wholesale-market-settings-review-final-report.pdf

Newbery, D. M. (2016). Missing money and missing markets: reliability, capacity auctions and interconnectors. Energy Policy, 94, 401–410.

New Zealand Government. (2017). Government expectations for good regulatory practice. Wellington: The Treasury.

O'Mahony, C. (2020, January 13). *South Australia triggers Retailer Reliability Obligation*. Energy Magazine. https://www.energymagazine.com.au/south-australia-triggers-retailer-reliability-obligation/

Slemrod, J. (2013). Buenas notches: lines and notches in tax system design. eJournal of Tax Research, 11(3), 259–283.

Stigler, G. J. (1958). The economies of scale. The Journal of Law and Economics, 1, 54–71.

Transpower. (2024). *Security of supply assessment 2024* (Version 2.0). https://static.transpower.co.nz/public/bulk-upload/documents/2024%20SOSA%20-%20Final%20Report%20-%20Final%20Version.pdf

Transpower. (2026). *Security of supply assessment 2026* (Version 2.0). https://static.transpower.co.nz/public/bulk-upload/documents/2026%20SOSA%20-%20Final%20Report.pdf

Williamson, O. E. (1985). The Economic Institutions of Capitalism: Firms, markets, relational contracting. New York: Free Press.

About Sapere

Sapere is one of the largest expert consulting firms in Australasia, and a leader in the provision of independent economic, forensic accounting and public policy services. We provide independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

'Sapere' comes from Latin (to be wise) and the phrase 'sapere aude' (dare to be wise). The phrase is associated with German philosopher Immanuel Kant, who promoted the use of reason as a tool of thought; an approach that underpins all Sapere's practice groups.

We build and maintain effective relationships as demonstrated by the volume of repeat work. Many of our experts have held leadership and senior management positions and are experienced in navigating complex relationships in government, industry, and academic settings.

We adopt a collaborative approach to our work and routinely partner with specialist firms in other fields, such as social research, IT design and architecture, and survey design. This enables us to deliver a comprehensive product and to ensure value for money.

For more information, please contact:

Eric Hansen

Mobile: +64 21 370 162

Email: ehansen@thinkSapere.com

Wellington	Auckland	Melbourne	Sydney	Canberra	Perth	Brisbane
Level 9 1 Willeston Street PO Box 587 Wellington 6140	Level 20 151 Queen Street PO Box 2475 Shortland Street Auckland 1140	Level 11, North Tower 80 Collins Street Melbourne VIC 3000	Level 18 135 King Street Sydney NSW 2000	GPO Box 252 Canberra City ACT 2601	PO Box 1210 Booragoon WA 6954	Level 18 324 Queen Street Brisbane QLD 4000
+64 4 915 7590	+64 9 909 5810	+61 3 9005 1454	+61 2 9234 0200	+61 2 6100 6363	+61 8 6186 1410	+61 7 2113 4080

www.thinkSapere.com

independence, integrity and objectivity

© 2020 Sapere Research Group