21 July 2026

Electricity Markets Policy

Building, Resources and Markets

Ministry of Business, Innovation and Employment

By email to: electricitymarkets@mbie.govt.nz

Tēnā koe

Response to "A Proposed Reliability Obligation to Manage Dry-Year Risk"

Contact Energy would like to thank the Ministry of Business Innovation and Employment for providing the opportunity to comment on the proposed Winter Energy Reliability Obligation (WERO). Following this short introduction we have appended responses to the consultation questions.

We have also contributed to the submission from the Electricity Retailers and Generators Association of New Zealand (ERGANZ), including the expert report from Concept Consulting that is referenced throughout this submission.

Electricity plays a crucial role in the operation of our economy, and in every Kiwi home. Our focus is in delivering the most robust system possible so New Zealand can thrive.

Over the 30 years of its operation, the electricity market has performed exceptionally well in serving the needs of New Zealanders. We have never had an energy shortfall in that time (a not uncommon occurrence under government administered control), and have not required a conservation campaign for almost two decades (since 2008). We continue to have among the cheapest electricity rates in the OECD for both homes and businesses,[1] and have consistently appeared in the top 10 in the World Energy Council's trilemma index.

However, it is also true that the electricity market has faced a challenging few years, and we recognise that confidence in the market has been eroded, and desire for change has increased. But it is important to recognise that the circumstances that led to these challenges were unique to the time, rather than an indication of an underlying weakness in the market structure.

[1] https://web-assets.bcg.com/27/08/7fcb68024dcc92f2ba01527e8623/energy-to-grow-full-report.pdf, p75-76

The challenges first began back in 2018 with the outage at the Pohokura gas field. At the time this was the largest gas production field in the country, and it suffered an extended unplanned outage and never recovered to its previous output. Since then, we have had failure after failure in the gas industry, with output declining by around 50% since 2017.[2] This has placed extreme pressure on all gas users, including the electricity industry.

This unprecedented decline in fuel occurred at the same time as the market was thrown into uncertainty due to the planned closure of New Zealand Aluminium Smelter (NZAS). It is hard to overstate the size of this effect. Without NZAS there would have been no need for additional generation for at least a decade, and likely more. Any investment during this uncertainty would have been reckless and would have likely breached our Board's obligations to shareholders. In short, it was the most important risk considered by our Board from 2020 when NZAS announced it planned to close, right up to when the contract was signed in early 2024.

These twin pressures would have put any market construct under extreme pressure – including the proposed WERO scheme. We do not consider it appropriate to assess 30 years of market success against five years of extreme and unique market challenge.

But the good news is that almost immediately after the gas market and NZAS uncertainty resolved the existing market signals have done a remarkable job in improving energy security and affordability. As shown by Boston Consulting Group (BCG), 2.3TWh of new generation was added in 2024 alone following certainty on NZAS, with a further 4.1TWh planned before 2027. As a result, futures prices have dropped by around 40% since their peak, and now sit at the bottom of the Electricity Authority's estimate of the cost to build. The Sense Partners report commissioned by the government shows that this could result in a $10.3b boost to GDP by 2030,[3] as companies resign contracts at a materially lower cost in the coming years.

Setting a robust security standard

We recognise that government has a role to play in energy security, and accept that it may be appropriate for it to set a security standard for the electricity industry. We are willing to work with the government in identifying such a standard and developing measures so that there is confidence the standard will be met. We consider that this should complement the success of the existing market rather than seeking to fundamentally alter it.

However, we do not support the proposed WERO. As shown by Concept Consulting, it could increase electricity generation costs by up to 40%, which

[2] https://web-assets.bcg.com/27/08/7fcb68024dcc92f2ba01527e8623/energy-to-grow-full-report.pdf, p48-63.
[3] https://www.mbie.govt.nz/dmsdocument/31690-sense-partners-economic-and-industry-impacts-of-alternative-future-electricity-price-paths This report shows a 'low' scenario where electricity prices are $133/MWh on average. Current ASX prices are below this level, indicating that we are on track to achieve or exceed the estimated $10.3b GDP increase compared to the counterfactual.

would add around $375 per year to the average customer bill. This puts at risk the $10.3b GDP uplift forecast by Sense Partners, for little identifiable benefit.

Fundamentally this uplift occurs because the regime seeks to put in place insurance cover to eliminate physical market risks at any cost. As expressed by Concept Consulting "it is prohibitively expensive to build a level of supply that would eliminate all risk".[4] It is the sort of well-meaning government conservatism that led to a proliferation of road cones, or earthquake standards that drove many building owners out of business, with consequential impacts on business costs.

We recommend that government take a step back from this proposal, work with the industry to develop a robust security standard measure, and gain an understanding of the cost/risk trade-off in the best interests of New Zealanders. A national conversation is required to determine the level of insurance consumers are willing to bear. Do consumers want assurance that there will be no energy shortfall more than once every 50 years, 100 years, or longer? Is there an appetite for higher prices every 10 years, provided that prices on average are consistent with the long-term cost to build? Or do consumers prefer to place less focus on 'in market hedging' and desire a higher average price to support greater spot market stability across years? These are the judgements government must make, and it should be transparent as to how it is making them, and the consequential impact on consumers so that the public can consider and comment.

[4] Concept Consulting: 'Review of proposed dry-year reliability obligation', 20 July 2026, P19

Response to consultation questions

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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 agree that financing constraints, 'investment timing', and fuel availability make it challenging to invest in assets intended to only provide dry-year support.

However, we are concerned that the government's broader understanding of the challenges in the electricity sector in recent years has been mis-guided by a number of questionable pieces of analysis.

The first piece of analysis that appears to be driving government thinking is the findings of PWC's Gas Supply and Demand Study[5] This report indicated that the exit of Methanex would make the electricity market more vulnerable to dry years because there is no last resort fuel supply. This finding is deeply flawed for three reasons:

- It takes no account of renewable investment that has occurred that reduces the system's reliance on gas. As shown by Concept Consulting "By the start of 2026 the mean need for thermal generation to cover hydrological variation had fallen by around 40% relative to the start of 2024, and is likely to fall by more than 70% by 2028"[6] BCG showed that this meant there was around 300GWh of renewable spill that could be turned into energy generation in a dry year.[7]
- It does not consider the Huntly Strategic Reserve, which in effect replaced the role of Methanex as callable fuel for a dry year.
- It did not consider the potential for other strategic fuel to be used in greater quantities during a dry year, including contingent hydro, diesel and demand response.

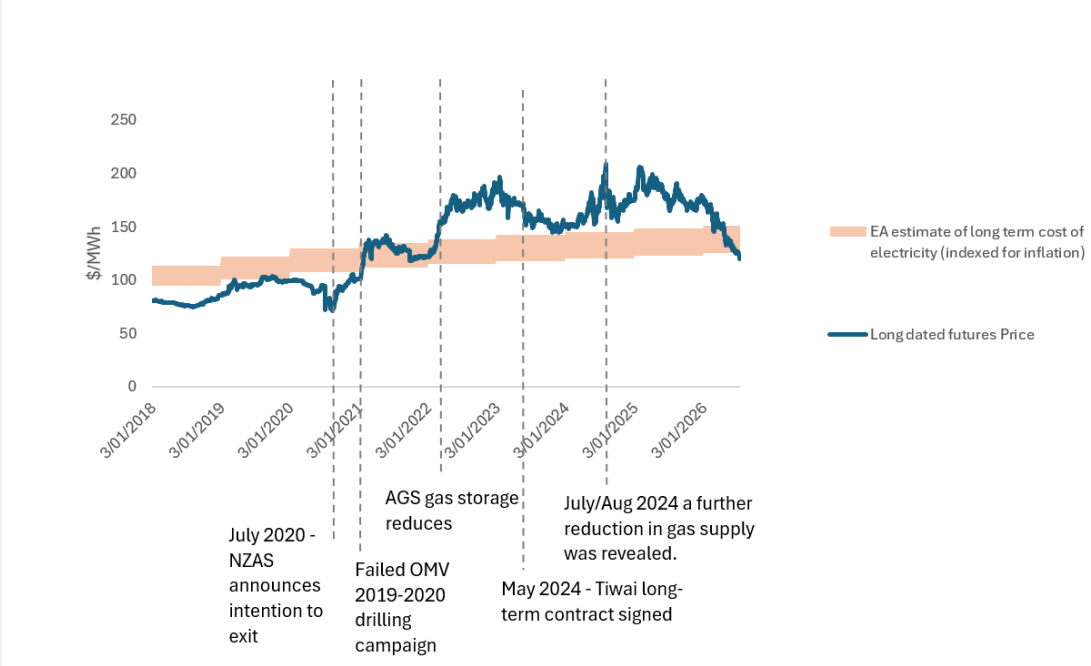
Overall the paper appeared to only optimise within the gas sector, rather than considering the wider fuel sources available to the electricity sector, and the wider economic impact of a 'gas only' solution.

The second incorrect conclusion is that there is a 'dry year premium' in futures prices, which therefore flows through to consumer prices. This is not supported by the most recent evidence. While the ASX futures prices have been elevated in recent years, this was driven by market uncertainty due to the potential exit of NZAS, and an unpredicted decline in gas supply. As

[5] https://www.pwc.co.nz/insights-and-publications/2026-publications/gas-supply-and-demand-study.html
[6] Concept Consulting: 'Review of proposed dry-year reliability obligation', 20 July 2026, P5
[7] https://web-assets.bcg.com/27/08/7fcb68024dcc92f2ba01527e8623/energy-to-grow-full-report.pdf, p98.

these uncertainties have been resolved the existing market signals have incentivised substantial new investment, resulting in a sharp decline this year. This is shown in figure 1 below, which shows the long-dated futures contracts compared to the Electricity Authority's estimate of the cost of building new generation. Where the futures price is above the cost of generation it encourages new entry, which in turn depresses the forward prices.

Figure 1: NZ Electricity Long Dated Futures Compared to the Cost to Build new Generation



This figure shows that prices were elevated from about 2021 due to increasingly scarce access to gas resources. Prices continued upwards until about the end of 2023 due to uncertainty about whether NZAS would exit the market. No additional build would have been necessary if it did, placing material uncertainty on the market. After the agreement was signed prices began to fall down to near the long-term cost of build, but then elevated again in the second half of 2024, as gas supply again came up short of expectations. Since then price has fallen sharply due to the large amount of renewable generation that has been committed to.

We note the conclusion from Concept Consulting regarding the reasons for the large drop this year:

> since the start of this year, the forward prices for the calendar strips 2027, 2028, and 2029 have fallen by 34%, 29%, and 25%, respectively. The fact that 2027 prices have fallen so strongly is a clear indication that the prospect of LNG supply is not driving this outcome – ie, because indications from MBIE are that an LNG import facility "could be operational by 2028", but certainly not for 2027.[8]

[8] Concept Consulting: 'Review of proposed dry-year reliability obligation', 20 July 2026, p11.

The third piece of questionable analysis is the finding from Sense Partners that elevated prices resulted in $5.2b reduction in GDP.[9] We do not consider this finding to be robust for a number of reasons:

- It uses un unrealistic cost to build new generation of $105/MWh, materially below the Electricity authorities estimate of $115-135/MWh ($2024).[10] The report itself notes that the estimated savings would only occur due to efficiencies in the electricity sector, not by assuming costs below an efficient level.
- It applies changes in the spot market to the economy in an unrealistic way. The paper states that "we did not analyse the extent to which specific industries were hedged against spot price increases in any given year.". This led to a material over-estimate of the impact of higher prices on industry, and especially for residential consumers. They state that this finding is reasonable as hedges contracts can only shield price changes for a limited amount of time. However, this ignores the dynamic nature of the market, and the reality that prices have since reduced, ie the elevated prices were not a new long-term equilibrium. This was expected by the industry, and long -term sales (including to residential customers) tended to reflect this expectation. In other words the elevated prices from 2021-2025 did not flow through to the economy in the way assumed.
- A material part of the finding is due to lower gas availability and higher gas prices for industrial gas users. This has been conflated together with increases in electricity prices, but are distinctly different effects.

Overall we consider that these questionable pieces of analysis have materially mis-led the Government as to the nature and severity of the problem. We consider that if a more robust process were followed to test these conclusions with interested parties then government may have developed a better understanding of the challenges it is trying to address.

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.

The material increase in renewable generation investment in recent years has reduced the electricity sector's reliance on thermal generation in normal years. This is shown in figure 2 below, which shows there is material unused thermal capacity in a normal year that can be deployed to meet dry year cover.

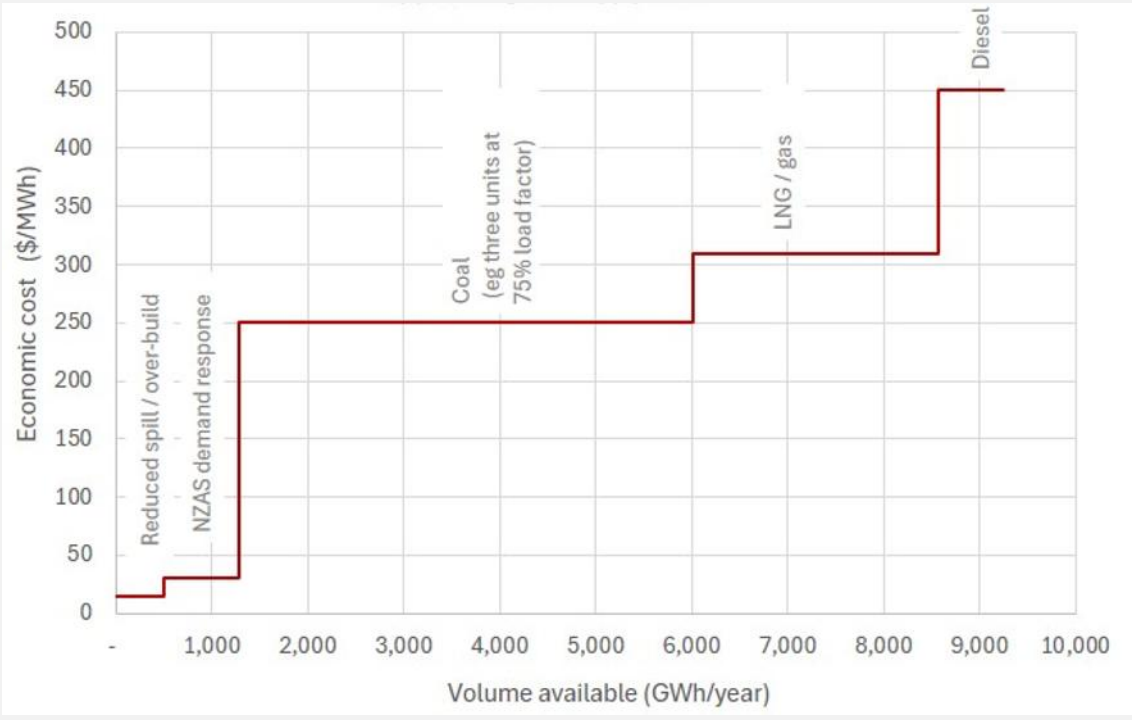
[9] https://www.mbie.govt.nz/dmsdocument/31691-sense-partners-historical-impacts-of-high-electricity-and-gas-prices-on-the-new-zealand-economy-and-industries
[10] https://www.ea.govt.nz/news/eye-on-electricity/electricity-hedge-prices-compared-to-new-estimate-of-the-lcoe/

Figure 2: change in committed and spare thermal capacity as renewable generation increases



The type of dry year cover available to the market is shown in figure 3 below. This is based on existing plant only.

Figure 3: Dry year mitigation supply curve



Currently not all of this plant can be fuelled due to the failure of the gas market in New Zealand. This can only be met by finding new sources of fuel, such as the government's proposed LNG import facility.

We consider that the proposed regime is poorly targeted to resolve a fuel supply problem. The proposed penalty regime does nothing to incentivise greater supply of fuel from providers outside the regime. In fact it creates a perverse opportunity for the providers of fuel to increase their prices, as there would be a clear and transparent increase in the willingness to pay for obligated parties. That would mean gas costs would increase, and have a resulting impact on wholesale electricity prices. This was one of the conclusions reached by Concept Consulting, who found:

> *gas suppliers are able to increase prices to levels that reflect a complex interplay between obligation penalty rates, the (elevated) cost of coal and diesel alternatives, the willingness for non-generation gas consumers to pay for gas*[11]

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.

As shown above, there is a material amount of unused gas generation capacity in New Zealand. If sufficient fuel for these plant becomes available, then we do not consider further measures are required.

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.

In general we support using existing regulatory mechanisms where possible. However, in this case we do not consider that there are any existing mechanism that meet the needs of this regime.

The SOSA is intended to be a cross-check if market incentives are working as intended. They are not designed to dictate market actions, and trying to force them into that role will have material adverse effects as we cover in this submission.

The winter energy margin was set in 2012[12] as an estimate of the optimal margin to cover for system stress, including dry years and plant outages. It

[11] Concept Consulting: 'Review of proposed dry-year reliability obligation', 20 July 2026 p24

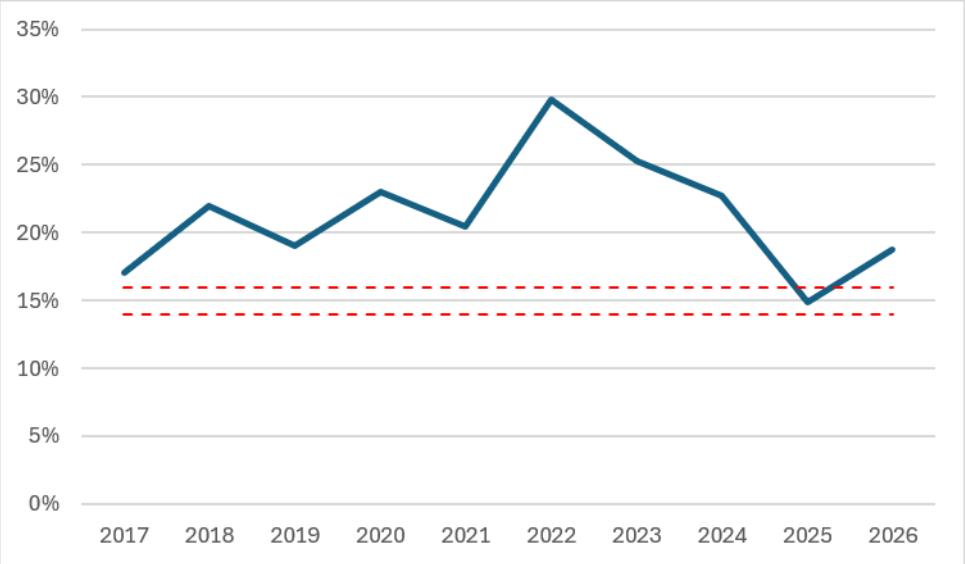
[12] The current winter energy margins are materially out of date. The Authority had an abandoned project to re-estimate them in 2018, where they were going to propose that the margins be extended to 12-19%

optimises the cost of additional energy sources against the cost of the risk of outages. That means any point outside of the upper and lower bound is inefficient:

- A result below the lower bound of the winter energy margin indicates that from an economy-wide perspective it is lower cost to introduce a new energy source.
- A result above the upper bound of the margin indicates that from an economy wide perspective there is too much energy, in effect we are paying more for energy security than the cost savings from reducing security risks.

As shown in figure 4 below, since at least 2017 the SOSA has not shown a margin below the winter energy margin in the year each assessment was released. If we are to believe the SOSA results, it is actually showing an inefficiently high level of winter energy margin in almost every year. While the SOSA has shown a forecast that margins may fall below the thresholds in future years, this is typically out beyond a normal investment horizon, and these gaps have been filled before the year in question. Also, as highlighted by Concept Consulting, the SOSA are prone to forecasting errors, particularly for demand and gas supply, which make the forecast results unreliable.

Figure 4: SOSA Energy Margins assessed at the date of reporting



There are a few things to note about this graph:

- The 2022 result appears to be an outlier due to a change in methodology for gas deratings. There was also dramatic reduction in the estimated demand that year, suggesting a temporary imbalance rather than a desirable margin increase.

(from the current 14-16%). However even this estimate is no longer meaningful as costs for both energy shortfalls (measured as the value of lost load), and the costs of adding more energy have materially increased. However, the consultation paper is drawing its conclusions based on this dated standard, and it is therefore the only measure we have to comment on at this stage.

- The SOSA did not predict any shortfall in 2024, indicating it can have both false positives, as well as false negatives
- The 2025 margin appears to be very narrow, however this should be treated with caution. In that year Transpower did not have good information on gas contracting. This was corrected for the 2026 result, which is more indicative of where the energy margin currently sits.
- In 2025, the output from Contact's geothermal stations was reduced by almost 300GWh. We are discussing with Transpower why this change occurred.

Because the SOSA has not indicated a winter energy problem, the consultation paper is indicating that a new standard is required, and that the sector may not be meeting this as yet undefined standard.

We consider that identifying this standard, and a way to measure performance against it, is a worthwhile undertaking. However, at this stage we cannot comment on the implications of something we haven't yet seen.

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.

We do not support the introduction of this regime as proposed. The current market incentives are operating as intended to ensure that there is sufficient winter energy margin, as shown by the SOSA results in figure 4 above. We support government work to introduce a more fuel via a right-sized LNG import facility, and consider that this alone will be sufficient to address any concerns.

We recognise that it is legitimate for government to identify a security standard that must be met by industry. However, it will require significantly more work to identify the correct standard to apply, and assess the expected impact on the market, and prices paid by consumers of meeting that standard. Further consideration is also required on the means for incentivising the standard to be met. At this stage we consider there may be material perverse effects from the proposed penalty regime.

Concept Consulting found that overall it could increase prices to consumers by $15-50/MWh due to the introduction of a number of inefficiencies:

- Conservatism in the dry year margin increases system costs
- Sub-optimisation and constrained innovation
- Dampened retail and contract competition
- An increase in fuel costs.

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.

Without prejudice to our overall comment that the long-term obligation is not necessary and will harm outcomes for consumers - we agree with placing the obligation on wholesale purchasers. However:

- In response to question 7 we demonstrate the harms caused by the proposed de-minimus thresholds.
- In response to Question 9 we explain why this obligation must also take a 'causer pays' approach, so as it doesn't distort incentives, and reduce the likelihood of more generation being deployed in dry years.

Q7. Do you agree that a de minimis threshold should apply to limit the obligation to wholesale purchasers with a material winter load? If so, is

the 500 GWh threshold appropriate, and should it be measured by reference to aggregate load over the winter period?

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

Please explain your views.

We do not support this threshold. It appears arbitrarily high, and will result in many market participants being able to free ride. As noted by Concept Consulting, this will cause wider market distortions, "this should drive up retail margins above expected wholesale prices, while driving down the market share of the four large gentailer and driving down availability of hedge contracts".[13]

The largest participants currently hedge their risk well due to the large financial costs if they do not. Most of the winter energy risk carried in the market sits with industrials, and smaller retailers. Setting the threshold arbitrarily high will mean that their un-hedged risk is not resolved.

This will result in an unlevel playing field in favour of smaller participants. As these participants are less financially secure it will mean the market becomes riskier, and costs will increase as a consequence.

It will also mean that the obligated parties will be unlikely to call on options contracts not needed to secure their own book. The consequences of this need to be better understood, but it may encourage more low fixed cost, and high variable cost generation in the market. We are unsure if this is the intended effect.

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.

This regime will create a barrier to new electricity demand. This would place a handbrake on economic growth in New Zealand, and the decarbonisation of our economy.

This is because under the proposed regime new demand will reduce the SOSA's measure of the energy margin. If the new demand is large enough it may tip the SOSA below the winter energy margin thresholds, and result in a penalty on obligated parties. Because of this, obligated parties may need to build the cost of the penalty into new demand contracts, likely making the new demand uneconomic.

Under the existing market incentives any imbalance between supply and demand will be quickly filled. However, this will be constrained by the time it takes to physically build assets. There will be moments where new demand has a need to come online faster than that.

[13] Concept Consulting: 'Review of proposed dry-year reliability obligation', 20 July 2026, P22.

To avoid disincentivising new demand and economic growth we consider that there must be sufficient warning prior to any enforcement, to allow time for investment decisions and construction to occur. In practice this means that there must be at least 3 years of prior notice before any enforcement. That means:

- Shortfalls identified one, or two years out from real time must not be considered for enforcement penalties.
- If the size of the shortfall increases after the three year obligation point, the additional shortfall should not be considered in any compliance.

These subsequent shortfalls could then be addressed in subsequent years.

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.

We consider that the obligation must be allocated based on a causer pays approach. This would see parties with greater exposure to the spot market in a dry winter face a greater share of the obligation. Broadly there are two groups of wholesale purchasers that this would affect:

- Purchasers who are net short without options cover – ie consume more energy than they have contracts or generation assets to cover.
- Parties who rely on generation assets that may produce less in a dry winter, and have insufficient options cover. This could include generators with a large share of hydro assets, or other parties who buy generation following contracts based on hydro assets.

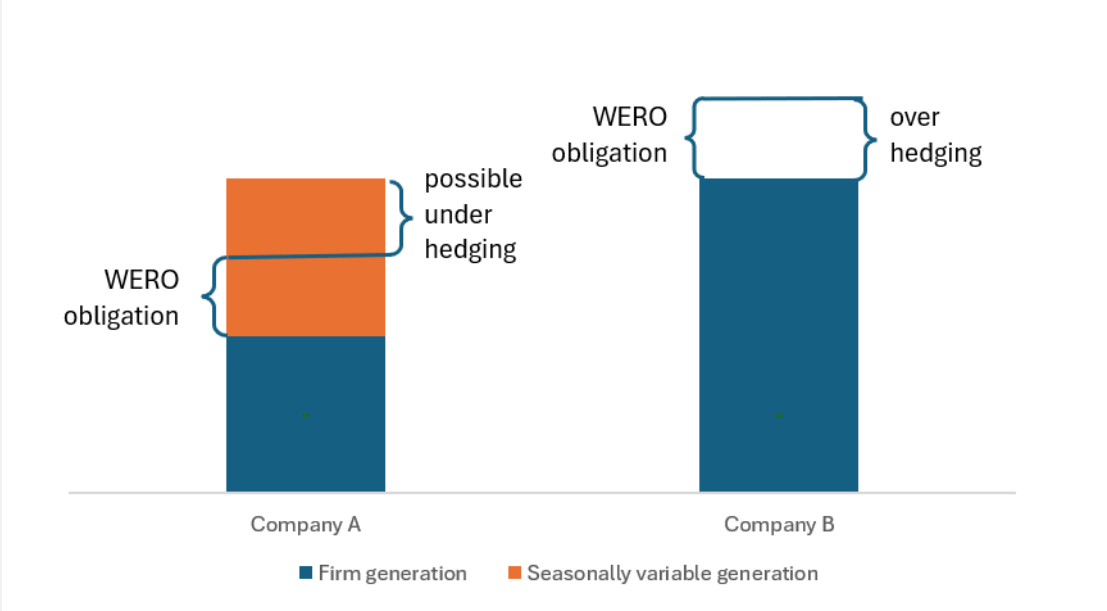
A hypothetical example may help illustrate why a causer pays approach is necessary. Figure 5 below shows a simplified example of a market with two purchasers, one who is fully firmed in their portfolio, and the other that has unhedged winter shortfall risk. The total winter shortfall risk is 100GWh, and both companies purchase the same amount of electricity.

Under the proposed WERO the total winter shortfall would be evenly divided between the two firms as both purchase the same amount over winter. Each would need to buy 50GWh of winter energy cover. For Company A 50GWh of winter energy cover is less than the risk it carries, so it is likely to hedge beyond the requirements up to a prudent level, ie equivalent to the level of hedging under the current market settings.

In other words Company A (who carries all the winter energy risk) is able to continue to operate the same with and without the WERO obligation, so long as it manipulates when it enters into hedging cover to game the regime.

The WERO obligation therefore falls only on Company B, who would need to enter into options contracts for additional supply it knows it doesn't need.

Because this option is not necessary for its portfolio it will never be called, and therefore provide no additional cover during a dry winter. CompanyB will simply be burdened with an ongoing option fee. This in turn may have implications for the type of generation that is built, and the type of contracts available in the market.



While the actual market is not this simple, we note that there is a large disparity in the underlying assets of each of the obligated parties. While we expect each party currently hedges prudently, this regime gives some parties a greater ability to game the regime and shift the obligations on to parties that do not require it for their own portfolio.

We are concerned that this creates a perverse incentive on the market, and opens the regime up to gaming. Participants are incentivised to reduce winter energy volumes at the point of assessment, to limit the impact of the regime on their business, and then reinstate hedging after the fact to meet their obligations. Parties with firmed portfolios will be punished by this behaviour, which may create a perverse incentive on the type of assets built.

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

Please explain your views.

We do not consider that the government should be playing a role in dictating what forms of hedging should be utilised. As noted by Concept Consulting "A central decision maker is not inherently better placed to identify needs or evaluate solutions".[14] They go on to note that administrative decision makers:

[14] Concept Consulting: 'Review of proposed dry-year reliability obligation', 20 July 2026, P17.

- have less information – one party cannot access and make better sense of relevant information than the market as a whole
- are vulnerable to under-funding, which can compound the challenge of accessing and analysing information
- unavoidably have institutional incentives to over-procure – ie, because the cost of over-supply is not transparent whereas shortages are interpreted as failure.

We also note that any government direction on what assets 'qualify' will be a highly subjective judgement that may lead the government of the day dictating investment policy. One government may force greater thermal investment, and the next may then rule that investment out from consideration, and only count renewable sources.

There must be long term consistency, and impartiality in meeting the obligations. Investment decisions cannot be made when it is known the business case may be undone based on the political whims of the day.

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.

We consider that the compliance framework should relate to the as yet undetermined security standard framework. In the abstract we are unable to comment further on how this should work, except to say that actions that change each company's contribution to winter energy reliability should be sufficient to meet compliance requirements.

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.

We consider it inappropriate for government to second guess these matters. These are real risks that occur, and cannot be eliminated by any regime. Obligated parties are already sufficiently incentivised to minimise these risks. Further penalties will lead to greater risk aversion, which will result in higher costs to consumers.

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.

Concept Consulting found that there are "institutional incentives for

administrative decision makers to err on the side of over-estimating the need for supply-side cover for dry years." That means this regime is unlikely to ever land on in an optimal position, and consumers will be burdened with excessive costs.

We consider that a likely outcome is for this regime to encourage increased callable fuel or demand response. However, we are concerned that the price of the penalty will be become baked into the costs of this energy. This is because there will be a clear and transparent change in obligated parties willingness to pay. Providers of gas and demand response that sit outside the regime are likely to respond by pricing the penalty into the cost of the energy.

This will alter the marginal price when discretionary fuels are used. As we have seen since 2021, an increase in the cost of fuel can have a material impact on wholesale electricity prices.

We consider that these effects (and others) need to be well understood before a penalty-based regime is implemented.

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

Please explain your views.

We have a number of concerns and questions that need to be carefully considered before such a regime should be implemented:

- We are concerned with the historical inaccuracy of key parts of the SOSA forecasts. As shown by Concept Consulting, Transpower has systematically over-estimated demand, making the forecast results appear worse than reality. Transpower has also struggled to forecast gas supply correctly, and does not have full visibility of expected generation, including embedded generation that is not in their connection queue. In recent years this has equated to around half of new generation capacity. Fundamentally forecasting the market in this way is very hard, and this regime will be subject to forecast errors as much as any real market results.
- We are concerned about how the regime will react if new spot exposed customers enter the market. This may still result in the SOSA breaching, but there would be no action any obligated party could take to avoid or change this outcome.
- We are concerned that the regime may encourage obligated parties to reduce their sales position to minimise their exposure to this regime. Our sales position is based on a risk test of our assessment of our exposure to costs. This regime would likely materially alter that assessment and would likely show a smaller sales position is optimal.

Therefore less contracts will be sold in the market, increasing spot market exposure for other participants.

- We are also concerned about the impact generators outside of this regime could have on the market. In particular, generators with flexible generation such as Nova. These generators could hold the industry to ransom by under-utilising plant and suppressing the SOSA, and only running if paid exorbitant fees.

Short-term Obligation

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

☐ **Yes, I agree** ☒ **No, I don't agree**

Please explain your views.

We are unsure what problem the short-term obligation is intended to address. There has never been an energy shortfall since the market began, and the last time there was a conservation campaign was in 2008 – almost two decades ago.

The elevated prices during 2024 have been a particular concern for the Government. However, the Electricity Authority's review found that during this period 'generation offers reflected underlying costs and supply' and that 'the industry responded in several ways to alleviate this fuel shortage and bring down electricity spot prices'.[15]

As noted by Concept Consulting "on any fair reading, market arrangements coped well with an exceptional set of circumstances." And "the market also self-corrected quickly." We do not consider that this points towards a need for heavy handed intervention from government.

In a dry year, exposed parties are highly motivated to meet the shortfall through whatever means are available. If they do not they will not be able to meet their sales position with hedged load, and will be exposed to very high spot prices. In 2024 this came via the Tiwai demand response agreement, and the gas deal with Methanex. Since then arrangements with Genesis have been entered into to ensure a greater stockpile of coal and generating capacity.

Given the very strong existing incentives and strong market performance, we cannot see a meaningful role for further government intervention. In short, this obligation has material harms (as covered below), and no benefits.

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.

This threshold would exclude the majority of parties that carry dry year risk. We are unsure the purpose of such a poorly targeted obligation.

Q17. Do you consider the proposed trigger – projected hydro storage crossing the Watch Curve within 90 days if it declines at an assumed rate

[15] https://www.ea.govt.nz/documents/7159/Review_of_winter_2024_jnOSQfc.pdf

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.

This is an extremely conservative trigger based on the draw down in one of the dryest sequences on record. It would mean that the short-term obligation would be triggered very frequently, resulting in government interference in the efficient operation of the market every few years.

At this stage we consider the short-term obligation entirely unworkable, so cannot propose an alternative trigger.

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.

We consider further work is required on the need and role of the short-term obligation before considering the details of how it will function.

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.

As covered in response to Question 9, we consider that any obligation created as part of this regime should be on a causer pays basis.

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.

We consider that the generators themselves are better placed to assess the risks in their portfolio than officials. Generators are already highly exposed to costs if they assess their risks incorrectly. Adding in another party to make this same assessment won't improve the quality of the outcome. It will simply introduce conservatism, cause confusion and delay, increase costs, and shift blame for decision making.

As noted by Concept Consulting the electricity system in New Zealand was more prone to energy shortfalls prior to the introduction of the market. It was also more prone to periods of over-build, which created costs ultimately met by consumers (either via electricity charges, or via the general tax base). Re-introducing heavy handed government oversight will likely lead to such inefficient outcomes becoming a feature of the market once again.

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.

Further clarity is required on what this obligation is seeking to achieve before compliance measures can be considered.

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.

In these cases market participants will face the risk of having to purchase off the spot market at an elevated price. Because of this cost parties seek to minimise these risks. We are unsure what additional role this obligation can play to reduce these risks. In all likelihood it will simply introduce conservatism, reduce efficiency, and ultimately drive up costs for consumers.

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.

We consider that the costs of being exposed to the spot market when prices are elevated in a dry year is already sufficiently high. The discussion paper presents no evidence that this incentive isn't already sufficiently strong.

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.

We cannot see any way to make the short-term obligation proportionate, cost effective or beneficial to consumers. In addition to the issues identified above we also have the following concerns with this proposal.

- It incentives parties to keep lake levels very high. That means water values would likely materially increase, and higher cost forms of generation would run more often. This will cause a significant increase in costs for consumers, and significantly increase the carbon intensity of the electricity industry. Both of these outcomes could stall efforts to decarbonise and grow New Zealand's economy.
- The regime would also likely cause the costs of firming generation to materially increase. This would make it harder for new entrants, and reduce the value of intermittent generation, such as wind and solar.