Via email: electricitymarkets@mbie.govt.nz

A proposed reliability obligation to manage dry-year risk

Mercury welcomes the opportunity to provide feedback on the Ministry of Business, Innovation and Employment's (MBIE) proposal to implement a new reliability obligation to manage dry-year risk. Mercury's submission comprises this cover letter, responses to MBIE's specific consultation questions in Appendix One, and an expert report by the Lantau Group.[1] In addition, we reference the expert report prepared by Concept Consulting for the Electricity Retailers and Generators Association of New Zealand (ERGANZ).[2]

Mercury key messages

- New Zealand's security of supply framework ultimately needs to balance delivering the level of security consumers seek with the costs of achieving this; additional insurance is not free and will ultimately flow through to end-users and the wider economy.
- The security challenge has diminished markedly since Winter 2024, driven by record levels of renewable investment; any adjustments to the regulatory framework need to be based on current and future system dynamics rather than focussed on those of the past.
- Establishing an enduring security framework requires careful consideration given complex interactions with market price signals and investment incentives; we recommend MBIE take the time to properly assess the objectives, options and implications of further intervention before progressing its proposal, particularly given the simultaneous workstream on a physical dry-year solution.
- Mercury remains open to a reliability mechanism along the lines of the long-term obligation where a comprehensive assessment identifies a clear and intolerable risk of a future winter energy shortfall that the market alone will not meet; but further policy development work is needed to ensure such a mechanism meets its objectives without undue risk of unintended consequences.
- We do not support introducing the proposed short-term obligation; it risks driving significant and unnecessary costs and distorting operating decisions, both of which will be to the detriment of New Zealand consumers.

[1] The Lantau Group provide consultancy and advisory services on energy markets across the Asia-Pacific region, drawing on extensive experience and deep involvement in market development, design, and reform.
[2] Concept Consulting are New Zealand-based energy sector specialists providing expert advice on policy, regulation, strategy and economics. Concept was engaged by Contact, Genesis, Mercury and Meridian to test the diagnoses and prescriptions in the Government's consultation on a proposed reliability obligation to manage dry-year risk.

Overall dry-year framework needs to balance security and cost

Mercury supports the Government's objective of an electricity system that is abundant, renewable, reliable, and affordable, supporting economic growth, stronger businesses, and higher living standards for New Zealanders.

To achieve this, the system needs to strike a balance between the reliability and affordability limbs of the energy trilemma. While gold-plating security may be tempting, additional insurance is not free. The costs of new infrastructure, contracting and compliance will ultimately flow through to consumers and the wider economy.[3]

Any new dry-year framework needs to be well-integrated with wider market and security incentives, proportionate to the challenge at hand, carefully calibrated so New Zealanders do not end up paying more than necessary, and future-proofed so that it is adaptable to changing system dynamics.

In Mercury's view, there is a significant risk that the winter reliability obligation, as proposed, will fall short of delivering on these objectives.

The reliability challenge has changed since 2024

The security outlook has strengthened materially since the security-of-supply challenges experienced in 2024:

- Government interventions and market participant actions have improved system resilience.[4]
- Significant new renewable generation has been commissioned and is under development, reducing the need for thermal support.[5]
- As a result, forward electricity prices are indicating expectations of a more balanced supply-demand position.[6]

Our view is that the proposed winter reliability obligation risks being hastily developed in response to issues that the market has already substantially resolved and is not appropriately calibrated to address the risks the system will face going forward.

As renewable penetration increases, the nature of dry-year risk is changing: the overall need for thermal generation to provide for medium to long-duration flexibility is falling, and from 2030 the more prominent risk is likely to be short, sharp winter capacity shortfalls rather than prolonged hydrological dry years.[7]

While there may be debate over the exact nature of this shift, in our view these changing dynamics call into question the overall need for a new reliability obligation at this point in time. At a minimum, a clear, quantified, forward-looking problem definition is needed before progressing significant changes to a market that is currently delivering record levels of investment.

An enduring security framework requires a robust policy development process

Mercury supports work underway to establish an enduring dry-year security framework, including improvements to information provision, stress testing arrangements, etc. We remain open to this including a provision to encourage additional investment where an objective assessment identifies a future winter energy adequacy shortfall that the market alone will not meet. Where such a need is identified, a mechanism such as the long-term obligation proposed by MBIE could play a role. However,

[3] Concept Consulting's analysis indicates the average wholesale component of prices to consumers would rise by $15 to $50/MWh – an increase of roughly 13% to 42% - if the proposed reliability obligation is adopted.
[4] Actions include release of the October 2025 Energy Package, finalisation of the Huntly Firming Option arrangements, an increase to Ahuroa gas storage, advancing contracting arrangements with Methanex for gas diversion, and improving access to contingent hydro storage.
[5] As identified in Concept Consulting's expert report, by the start of 2026, mean hydrology need for thermal had dropped by 40% relative to the start of 2024. By 2028, it is likely to have dropped by more than 70%.
[6] Concept notes since the start of this year, ASX forward prices for the calendar strips 2027, 2028, and 2029 have fallen by 34%, 29%, and 25%, respectively, while the EA's latest Hedge Market Summary report shows that longer term OTC contract prices are falling in line with LRMC estimates from around 2030.
[7] Concept Consulting, *Review of proposed dry-year reliability obligation*, 21 July 2021, pg11. Modelling indicates a key risk from 2030 onwards is likely to be winter capacity margin. This is driven by the risk associated with multi-day lull in wind and sunshine drawing down energy stored in batteries.

as pointed out by the Parliamentary Commissioner for the Environment in his recent letter to the Minister of Energy, such mechanisms are inherently complex and need careful policy work to get right.[8]

The measures taken by market participants since Winter 2024 and the resulting changes in the supply-demand balance mean that Government and the sector now have time to work through any further regulatory changes carefully and prudently. Ultimately, the Government should only pursue regulatory changes where it has a high degree of confidence that they will deliver better outcomes for consumers. As it stands, we do not believe that the current proposal would meet this test.

The current policy development process is further complicated by the fact that the Government is simultaneously progressing other measures which will significantly impact on security of supply settings, most notably the ongoing procurement processes for New Zealand's first LNG import terminal.[9] Without careful consideration of the interactions between these potential changes, there is a real risk that New Zealand will over-procure dry-year insurance, driving greater costs for consumers and the economy.

International experience shows that reliability mechanisms are highly sensitive to design choices, while their complex interactions with underlying market and regulatory arrangements also mean that they carry potential for unintended consequences. The Lantau Group has expanded on a number of these risks in their expert report, including the potential for market power issues, free rider problems, and perverse incentives:

> *"If the qualifying resources for dry-year cover are concentrated in a small number of portfolios, particularly thermal generation, fuel contracts, coal stockpiles, hydro storage and demand response arrangements, then parties needing to secure cover may have limited practical alternatives. This is particularly relevant for highly renewable gentailers, and any independent retailers or large users above the de minimis level, that may need to buy firming cover from the same parties with whom they compete in retail, contract or generation markets. The proposed obligation could therefore create a compliance-driven demand for a very narrow class of products (or a single product). If the supply of those products (or product) is concentrated, the regime may increase the value of scarce firming resources and create opportunities to withhold, ration or price compliance cover strategically."* [10]

> *"[The proposed de-minimis] threshold is also materially higher than the equivalent threshold used in the Australian [Retailer Reliability Obligation], being approximately 100 times larger. That comparison reinforces the extent to which the proposed New Zealand obligation would be concentrated on a very small number of large participants. That may reduce compliance costs for smaller participants, but it also means that the full forecast shortfall would be met by a very small number of parties. Smaller retailers and purchasers below the threshold would continue to benefit from the resulting improvement in system reliability without directly carrying the obligation. This creates an obvious free-rider issue. The threshold could also create perverse incentives. Retailers or large users approaching the threshold may have an incentive to manage their position so as to remain outside the regime."* [11]

Taking the time to properly assess what any arrangement is trying to achieve, how it should be targeted, what the alternative options might be, and the wider consequences of any changes, will help ensure an enduring framework that appropriately manages the balance between reliability and system cost without driving unintended consequences in other parts of the system.

We ultimately agree with the conclusion by the Lantau Group that "the greatest risk is…not failing to introduce a Winter Energy Reliability Obligation—it is introducing one that is poorly designed".[12]

[8] Parliamentary Commissioner for the Environment letter to Minister Brown, 18 June 2026.
[9] We note that the LNG proposal comes with its own risks and challenges, some of which are detailed in Section 2.5 of the Lantau Group's expert report.
[10] The Lantau Group, *Winter Reliability Obligation*, 21 July 2026, p50.
[11] The Lantau Group, *Winter Reliability Obligation*, 21 July 2026, p46.
[12] The Lantau Group, *Winter Reliability Obligation*, 21 July 2026, p7.

The short-term obligation should not proceed at this stage

Mercury does not support introducing the proposed short-term fuel obligation. The financial incentives established by the short-term obligation would sit on top of wholesale market price signals (including scarcity prices and Customer Compensation Scheme obligations) and may be in addition to both a long-term obligation and a physical dry-year solution in the form of an LNG import terminal.

This overlap is important. A physical LNG solution is intended to provide insurance against a severe dry year. A long-term obligation would require participants to secure dependable, firm winter cover ahead of an identified future shortfall (additional to the physical LNG solution). Adding a separate in-year fuel obligation would require substantially the same group of participants to procure three layers of cover for overlapping purposes with arguably little corresponding improvement in reliability. The overlap between the short and long-term obligation was further described by the Lantau Group in their expert report:

> *"The short-term obligation therefore risks becoming a patch on a patch. If a generator has already entered into a qualifying long-term arrangement, the short-term obligation may either duplicate those obligations or second-guess them. If the long-term arrangement is not firm enough to survive a deteriorating winter position, then it is not clear why it should have counted as firm cover in the first place. If it is firm enough, it is not clear what additional problem the short-term obligation solves."* [13]

This multi-layered approach to dry-year insurance risks driving significant and unnecessary costs into the system, which will be to the detriment of consumers.

A conservative short-term trigger could also distort operational decisions. Participants may hold hydro storage higher or contract additional thermal fuel primarily to avoid compliance risk, increasing spill, thermal generation and system costs. The Electricity Authority, in administering the regime, would face strong incentives to err on the side of requiring more cover, while consumers would bear the cost of any over-procurement.

We recommend that any physical solution and long-term obligation is agreed upon first, then an assessment undertaken of whether any material near-term gap could still likely emerge. A tightly targeted short-term backstop could be retained as a future option if evidence demonstrates that it is necessary and provides net consumer benefits.

Conclusion

Mercury supports the Government's objective of developing appropriate arrangements for dry-year reliability to ensure abundant energy and support economic growth.

Given the wide-ranging and long-lasting implications of getting the right balance between reliability and affordability of the system, any decisions need to be carefully considered, future focussed, and take full account of existing market incentives and wider developments underway.

This will ensure fit-for-purpose, enduring dry-year arrangements are established, and will minimise the risk that consumers pay for more insurance than the system needs.

Further details are set out in our responses to individual consultation questions in Appendix One and our accompanying expert report.

Yours sincerely

Privacy of natural persons

Tim Thompson
Executive General Manager Wholesale Markets

[13] The Lantau Group, *Winter Reliability Obligation*, 21 July 2026, p53.

Appendix One Consultation Questions

Consultation Question	Mercury Response
1. 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?	While we agree that dry-year risk needs to be managed, we are concerned this chapter confuses physical security with higher prices, overstates the events of Winter 2024, and doesn't adequately consider the ability of wholesale purchasers to hedge against high spot prices. In addition, the sector is now significantly more prepared than it was in 2024 when it was surprised by declining gas supply. The various actions taken by market participants since that time suggest effective incentives are already in place to support the management of dry-year risk.
2. 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)?	We consider the principal remaining barriers are policy uncertainty, fuel availability, and the difficulty of supporting long-lived firming investment during the transition to a more renewable system.
3. 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?	New Zealand's electricity system has changed materially since Winter 2024. New Zealand's dry-year risk is receding as the renewables build accelerates and demand flexibility matures. Concept Consulting's modelling finds that the mean-hydrology need for thermal generation fell by around 40% between early 2024 and early 2026 and is likely to fall by more than 70% by 2028. Forward prices for the 2027 to 2029 calendar years have fallen by 25% to 34% since the start of this year.[14] These metrics are a strong indication that the market is finding a new equilibrium with less gas and more renewable supply rather than one pricing in a sustained dry-year premium. Mercury considers there is not sufficient evidence to suggest there is an additional need for further measures to strengthen incentives to invest in dry-year firming. Before imposing substantial new obligations on market participants, MBIE should re-assess the residual dry-year risk on a forward-looking basis and take account of policy and market measures already underway.
4. Do you agree that there is value in building new measures on existing regulatory architecture, rather than creating an entirely	Yes, in principle. Multiple reviews of the New Zealand market have concluded that the market is generally working well. Building on existing architecture is therefore preferable to creating an entirely new regime. However, existing tools should not be repurposed for binding regulatory obligations without first fully testing whether they are fit for that purpose e.g. the SOSA.

[14] Concept Consulting, *Review of proposed dry-year reliability obligation*, 21 July 2021, p5.

new regime from first principles? Why or why not?	
Long-term obligation	
5. 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?	Not currently. We remain open to a mechanism such as the long-term obligation where an objective assessment identifies a future winter energy adequacy shortfall that the market alone will not meet. But based on the evidence provided, we consider it would be premature to advance such an option at this stage. If a clear need for such a mechanism is identified, a comprehensive policy development process should then be undertaken, beginning with identifying and sizing the problem and exploring what other options may be available to address it. MBIE has not yet sufficiently demonstrated the specific market failure being addressed, why a long-term mechanism is superior to less intrusive alternatives, or how the material design risks — including SOSA reliance, allocation, qualifying cover, market power, penalty calibration and interaction with LNG and existing reserve arrangements — would be resolved. These challenges are discussed further in section 4 of the Lantau Group's expert report.
6. 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?	We agree that, where such mechanisms are adopted, they generally place an obligation on wholesale purchasers. However, the detailed allocation rules matter as they will determine not only who pays for additional cover, but also how the regime affects retail competition, contracting incentives and willingness of new loads to enter the system. The de minimis threshold is particularly important. If the obligation is concentrated on a very small number of large participants that may reduce compliance costs for smaller participants but also means market participants below the threshold would continue to benefit from the resulting improvement in system reliability, creating a free rider issue. The threshold could also create perverse incentives. Retailers or large users approaching the threshold may have an incentive to manage their position so as to remain outside the regime. This would also apply to new entrants including data centres or other electrification-driven demand growth. This issue is discussed further in section 4.5 of the Lantau Group's expert report.
7. 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	We do not consider the proposed de minimis threshold is appropriate. It is 100 times that used for the Australian Retailer Reliability Obligation (RRO). As proposed, it would create free riding issues, perverse incentives, gaming issues, and would potentially create market power issues. Refer to section 4.5 of the Lantau Group's expert report for further discussion on this.

should it be measured by reference to aggregate load over the winter period?	
8. 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?	If adopted, the proposed staged approach would create significant uncertainty due to the variability of SOSA modelling outcomes from year to year. This uncertainty would significantly undermine any investment incentives a long-term obligation creates. However, we generally consider it is too early to comment on the specific design parameters of a long-term obligation as the need for such a mechanism has not been clearly established and a robust exploration of alternative options has not been undertaken.
9. 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?	As above, we generally consider it is too early to comment on the specific design parameters of a long-term obligation as the need for such a mechanism has not been clearly established and a robust exploration of alternative options has not been undertaken.
10. What forms of cover should be eligible to meet the long-term obligation?	Eligible cover should be defined by attributes rather than prescribed technologies. If adopted, the obligation should specify the characteristics required — firmness, duration, deliverability, availability, verifiability and non-duplication — and allow the market to identify the most efficient combination of generation, storage, fuel arrangements, hydro flexibility and demand response to meet the requirement.
11. 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?	As above, we generally consider it is too early to comment on the specific design parameters of a long-term obligation as the need for such a mechanism has not been clearly established and a robust exploration of alternative options has not been undertaken.
12. 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?	As above, we generally consider it is too early to comment on the specific design parameters of a long-term obligation as the need for such a mechanism has not been clearly established and a robust exploration of alternative options has not been undertaken.
13. Should penalties for non-compliance be designed and calibrated to tilt investments to comply without overly encouraging inefficient	As above, we generally consider it is too early to comment on the specific design parameters of a long-term obligation as the need for such a mechanism has not been clearly established and a robust exploration of alternative options has not been undertaken.

over-procurement? Please explain your reasoning.	
14. 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?	As above, we generally consider it is too early to comment on the specific design parameters of a long-term obligation as the need for such a mechanism has not been clearly established and a robust exploration of alternative options has not been undertaken.
Short term obligation	
15. 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?	No. In Mercury's view, the short-term obligation is not a necessary or proportionate measure. If some form of long-term obligation is ultimately adopted, it would already require sufficient firm dry-year cover. If that cover is not genuinely firm, the better response is to improve the long-term qualification rules, rather than add a second short-term regulatory overlay shortly before winter. The proposed short-term obligation also raises separate concerns around incentive compatibility, maintenance decisions, fuel procurement, market power, penalty calibration and the extent of regulatory judgement required. MBIE should first demonstrate the specific market failure the short-term mechanism is intended to solve, why existing market and emergency arrangements are insufficient, and why this intervention is preferable to less intrusive alternatives. Further discussion of the short-term obligation is included in section 5 of the Lantau Group's expert report.
16. 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.	As with the long-term obligation, we consider that the proposed de minimis threshold for the short-term obligation is excessively high: in this case 250 times that used for the Australian RRO equivalent.
17. 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?	No. Such a trigger would be highly dependent on assumptions about hydro storage decline, the Watch Curve and the timing of assessment. It should not become a binding compliance trigger. At most, the trigger may be useful as an information signal to support market and System Operator responses, as occurred ahead of Winter 2024.

18. 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?	No. The proposed monitoring and response process appears too dependent on administrative judgement and too compressed to support efficient market responses. A three-week response window may force parties into defensive fuel procurement or contracting decisions, particularly where qualifying cover is scarce. The process should remain focussed on providing information to the market until MBIE demonstrates that a binding short-term obligation is necessary and workable.
19. 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?	We consider it is premature to provide a view on such detailed design parameters at this stage given the case for a short-term obligation has not been clearly made.
20. 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?	The treatment of hydro is particularly difficult. Existing stored water may be physically capable of supporting winter adequacy but allowing it to count toward compliance may create incentives to hold water inefficiently. Conversely, excluding it may understate the actual resources available to the system. This further illustrates why the short-term obligation is heavily dependent on regulatory judgement and may distort operational decisions. This challenge is discussed further in section 5.3 of the Lantau Group's expert report.
21. 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).	Compliance would be difficult to assess objectively. The EA would need to form views on firmness, attribution, double counting, hydro storage, fuel availability, maintenance, outage risk, third-party arrangements and counterparty performance. Unless these requirements are specified with considerable precision, this will only increase the risk that the regime will become uncertain, costly and prone to dispute.
22. 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?	The regime should not impose penalties where apparent non-compliance results from genuine upstream supply failure, transport disruption, force majeure or counterparty failure outside the participant's control. However, distinguishing those cases from ordinary commercial risk would itself require difficult regulatory judgements. This further demonstrates the challenges in establishing a workable short-term obligation along the lines of what MBIE has proposed.

23. 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?	Penalty calibration is especially difficult for the short-term obligation. High penalties may encourage defensive over-procurement of fuel or firming cover, while low penalties may not change behaviour. Because the obligation would be triggered in stressed conditions, penalties may also create penalty-backed demand for scarce resources, increasing market power risks. These issues are discussed further in sections 5.4 and 5.5 of the Lantau Group's expert report.
24. 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?	As noted above, Mercury does not support progressing a short-term obligation as it overlaps with other existing and proposed incentives and risks driving additional costs for consumers. If the Government ultimately chooses to proceed with a short-term obligation, it should include clear objective triggers, narrow application, market-power protections, transparent treatment of hydro and fuel cover, and a mandatory post-event review. Each activation should be reviewed against a counterfactual to assess whether the mechanism reduced costs or improved reliability compared with a market-led response.

Appendix 2 Lantau Report

THE LANTAU GROUP

Winter Reliability Obligation

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1. EXECUTIVE SUMMARY

MBIE's proposed Winter Energy Reliability Obligation (WERO) represents one of the most significant proposed interventions in New Zealand's electricity market since the establishment of the energy-only market. The proposal seeks to strengthen security of supply by requiring large wholesale purchasers to secure sufficient long-duration firm energy to manage future dry-year risks. The Government's objective—to maintain electricity security while supporting the transition to an increasingly renewable electricity system—is both legitimate and important.

There is broad agreement that New Zealand requires an enduring framework that provides confidence in dry-year security, supports investment in firming resources, and reduces uncertainty as domestic gas production declines. However, supporting these objectives should not automatically be interpreted as supporting the specific mechanism proposed by MBIE.

The consultation material raises several significant concerns regarding the justification, design, timing and implementation of the proposed obligation. While many of the underlying policy goals are sound, the analysis supporting the preferred solution remains incomplete, several critical assumptions have not been adequately tested, and insufficient consideration has been given to alternative approaches.

The greatest risk is therefore not failing to introduce a Winter Energy Reliability Obligation—it is introducing one that is poorly designed.

Several recurring themes emerge:

- the events of Winter 2024 appear to have become the primary justification for a major market intervention despite substantial improvements already made since then;
- market mechanisms, including contracting and hedging arrangements already in place, appear to have received insufficient recognition;
- the proposal risks confusing fuel security with electricity security;
- reliance on the Security of Supply Assessment (SOSA) as a regulatory trigger may be inappropriate without significant reform;
- the proposed obligations may create or intensify market power issues where the resources needed for compliance are concentrated in one or two portfolios; and
- insufficient analysis has been undertaken to demonstrate that the proposed obligation is preferable to less intrusive alternatives.

Collectively these issues suggest that further work is required before such a regulatory obligation is implemented.

1.1. THE PROPOSAL SHOULD BE VIEWED AS AN INSURANCE PROBLEM

Managing dry-year risk is fundamentally an exercise in purchasing insurance.

Like any insurance policy, greater protection comes at a cost. The central challenge is therefore determining:

- how much insurance is actually required;
- what form that insurance should take;
- who should initially pay for it (ultimately all costs are borne by the consumer); and
- whether the insurance purchased represents the least-cost solution.

These questions remain only partially answered.

The current proposal risks over-insuring the electricity system by embedding conservative assumptions within forecasting methodologies and potentially requiring participants to procure more firming capacity than is economically justified. Over-insurance would increase electricity costs, distort investment signals and potentially crowd out more efficient solutions such as renewable generation, storage and demand response.

Conversely, under-insurance exposes consumers to unacceptable supply risks.

Finding the correct balance therefore requires considerably more detailed analysis than currently presented.

1.2. FUEL SECURITY SHOULD NOT BE CONFUSED WITH ELECTRICITY SECURITY

A recurring issue throughout the consultation is the tendency to treat fuel availability and electricity reliability as though they are the same problem.

They are not.

Electricity security depends on sufficient dispatchable generation being available to meet demand during stressed conditions.

Fuel availability is simply one constraint affecting some generation technologies.

Government policy should focus on maintaining sufficient firm generation capability rather than favouring any particular fuel source. This distinction becomes particularly important when considering the Government's parallel proposal to develop an LNG import terminal.

LNG may provide insurance against declining domestic gas supply, but it should not automatically be assumed to be the preferred solution to dry-year electricity risk. Instead, LNG should be assessed alongside alternative options including:

- additional hydro flexibility;
- coal stockpiles;

- demand response;
- diesel generation;
- contractual arrangements; and
- further renewable generation.

Only after these alternatives have been evaluated should decisions be made regarding the appropriate scale—and indeed necessity—of LNG investment.

1.3. THE BEST PATH FORWARD

While we endorse the objective of improving dry-year reliability we are highly concerned about the apparent level of pressure to implement a proposal before its design has been fully developed, assessed and compared with other alternatives.

New Zealand should not be introducing a complex regulatory mechanism before the supporting analysis is sufficiently developed. The current timetable creates a significant risk that the cure becomes more costly than the disease.

The proposed obligation seeks to reduce dry-year reliability risk. However, if poorly designed it could introduce a range of unintended market risks that ultimately outweigh its intended benefits. These include:

- over-procurement of dry-year cover;
- higher electricity prices for consumers;
- distortion of wholesale price signals;
- reduced hedge market liquidity;
- market power over scarce firming, fuel or compliance products and increased opportunities for gaming;
- wealth transfers;[1]
- inefficient hydro storage decisions;
- barriers to retail competition and new entrants; and
- investment signals that favour compliance over efficient resource management and development.

1 A particular concern is that the proposed obligations may not affect all participants equally. Participants that already control thermal generation, fuel contracts, coal stockpiles, hydro flexibility or demand response arrangements may be materially better placed than participants that must acquire qualifying cover from others. If the regime creates a penalty-backed requirement to obtain cover from a small number of counterparties, it may transfer value to holders of existing firming resources without necessarily creating additional physical reliability.

These risks are amplified because the proposed framework would fundamentally alter the operation of New Zealand's energy-only market. Rather than relying primarily on market signals, the proposal introduces a parallel administrative framework responsible for determining:

- when intervention occurs;
- how much firm energy is required;
- which resources qualify;
- how obligations are allocated; and
- when substantial financial penalties apply.

These are not implementation details—they are central features of electricity market design that will influence investment behaviour for decades.

Our report therefore concludes that considerably more design work is required before such powers are embedded within regulatory frameworks.

1.4. INTEGRATION WITH WIDER MARKET REFORMS

An equally important issue is timing and sequencing.

The proposed obligation is being developed simultaneously with several other major reforms targeted at helping to mitigate dry-year risk, including:

- expanded responsibilities for the Electricity Authority;
- improvements to security-of-supply forecasting;
- revisions to stress-testing arrangements;
- development of longer-duration hedge products;
- improvements to hedge market liquidity;
- market-making initiatives; and
- Government consideration of LNG infrastructure.

Each of these initiatives has the potential either to reduce the need for a reliability obligation or significantly alter its design.

Implementing a mandatory obligation before these complementary reforms are complete, or at least significantly designed, risks locking New Zealand into a framework that may quickly become obsolete or inconsistent with future market arrangements.

We therefore recommend integrating these reforms into a single coherent resource adequacy strategy under the expanded responsibilities of the Electricity Authority, rather than progressing individual initiatives independently.

1.5. BETTER DEFINITION OF THE PROBLEM

The first priority should not be designing obligations but defining the problem they are intended to solve. Before imposing mandatory requirements on market participants there should be broad agreement regarding:

- the actual level of dry-year risk;
- the reliability standard being targeted;
- the appropriate contribution of thermal generation;
- the future role of demand response;
- expected renewable development;
- the contribution of existing firming resources; and
- the amount of additional cover genuinely required.

Without this shared understanding there is a significant danger that regulatory obligations become detached from the physical reliability challenge they are intended to address.

1.6. TEST ALTERNATIVES BEFORE REGULATION

Section 2.8 also stresses that mandatory obligations should only be adopted after demonstrating that less intrusive alternatives cannot achieve comparable outcomes.

Potential alternatives include:

- stronger market stress testing;
- improved transparency of gas and fuel availability;
- enhanced Security of Supply Assessments;
- standardised long-duration hedge products;
- expanded market-making obligations;
- targeted support for existing thermal generation;
- greater use of demand response; and
- better governance of security forecasting.

Some of these initiatives are already underway through the Electricity Authority.

Allowing those reforms to mature before imposing a new regulatory obligation would reduce implementation risk while potentially achieving many of the same policy objectives.

1.7. REVIEW SOSA BEFORE RELYING ON IT

One of the most significant recommendations concerns the proposed reliance on Transpower's Security of Supply Assessment (SOSA). The consultation would transform SOSA from an advisory planning document into the trigger for mandatory commercial obligations carrying potentially severe financial penalties.

This represents a fundamental change in purpose.

Before SOSA assumes such a regulatory role its forecasting methodology, governance arrangements, assumptions and sensitivity testing should be comprehensively reviewed.

Forecasts originally designed for planning should not automatically become legally binding regulatory triggers without demonstrating that they are sufficiently robust for that purpose.

1.8. RECOMMENDED PATH FORWARD

We conclude that the most credible policy pathway is one that separates agreement on policy objectives from premature agreement on implementation.

Government should:

- reaffirm that improving dry-year reliability is an important national objective;
- acknowledge that a reliability obligation may ultimately form part of the solution;
- allow the Electricity Authority, with support from industry working groups, to undertake a comprehensive market design process;
- fully evaluate alternative mechanisms;
- improve the supporting analytical framework, including SOSA; and
- only then determine whether a mandatory Winter Energy Reliability Obligation remains necessary and, if so, what form it should take.

This approach preserves the intent of the proposal while substantially reducing the likelihood of costly unintended consequences.

1.9. OVERALL CONCLUSION

While we ultimately support the policy objective of improving New Zealand's long-term electricity security, we question whether the current proposal represents the best means of achieving that objective.

The evidence (or lack thereof) presented suggests that New Zealand should resist the temptation to move quickly simply because recent dry-year events have elevated political concern. The electricity market is undergoing significant structural change, and the decisions made now will shape investment, competition and security of supply for decades.

Accordingly, the preferred path is one of deliberate design rather than rapid implementation.

A well-designed reliability framework has the potential to strengthen confidence, support renewable investment and improve dry-year resilience. A rushed framework risks embedding unnecessary costs, distorting efficient market behaviour and reducing flexibility just as the electricity system is undergoing its most significant transformation in a generation.

Our central message is therefore clear: support the objective, strengthen the analysis, evaluate the alternatives, integrate the wider reforms, and only then implement a durable and proportionate Winter Energy Reliability Obligation.

2. OVERVIEW

On 9 June 2026, MBIE began consulting on a new two-layer winter energy reliability obligation with the intent to strengthen the electricity sector to secure enough long-duration firm generation to efficiently get the system through a dry winter.

The consultation[2] sets out a proposed new two-layer reliability obligation that (according to MBIE[3]) will ensure the market invests in the firming capacity and fuel the system requires. It aims to boost winter energy investment and prevent shortages that cause extreme power spikes, like the ones we saw in winter 2024.

MBIE go on to state that the new obligation will work alongside an LNG import terminal. The two-layer winter energy reliability obligation forms part of a new regulatory framework for dry year risk. Other changes the Government has agreed to include:

- Giving the Electricity Authority a stronger role in monitoring and responding to dry year risk. The Authority will be responsible for making sure the industry has the right information, tools and incentives to invest in reliable dry year cover[4].
- Improving available information and reporting on dry year risk so the Government and the sector can better identify and understand evolving risks.
- Updating existing risk management tools relating to dry year cover.

2 MBIE, A proposed reliability obligation to manage dry-year risk, 9 June 2026

3 MBIE website - https://www.mbie.govt.nz/about/news/mbie-launches-consultation-on-a-new-winter-energy-reliability-obligation

4 We question the efficacy of placing responsibility on the Electricity Authority for ensuring the industry invest in reliable dry-year cover, while prescribing the primary solution (a winter reliability obligation) for the Electricity Authority to use rather than letting the Authority consider and develop the most appropriate and effective package of solutions. We discuss this more in Section 4.8

The proposal argues that market incentives alone are not delivering enough long-duration firm energy to manage New Zealand's increasing dry-year electricity risks. According to MBIE, a two-layer winter energy reliability obligation would provide stronger, forward-looking investment signals while allowing the market to determine the most efficient mix of generation, storage, demand response and other solutions. The ultimate goal is to deliver a more reliable, renewable and affordable electricity system by reducing the frequency and impact of dry-year shortages.

2.1. A BETTER UNDERSTANDING OF WINTER 2024 IS REQUIRED

The proposal repeatedly cites the events that took place in the Winter of 2024 when average daily wholesale price exceeded $820 per MWh on 7 August due to the confluence of an extreme hydrological dry-year and problematic gas supply. This appears to be a key motivator for the proposed winter obligation.

The carry over from the events of Winter 2024, despite significant industry action prior to the Winter of 2025, is expressed in MBIE's consultation document as:

> *"However, the current system appears to operate with very limited buffer which risks underestimating the asymmetric cost of supply shortfalls and the wider impacts of scarcity. In particular: (1) the economic and social costs of supply shortfalls are significantly greater than the costs of maintaining a modest level of surplus capacity; (2) scarcity events have economy- wide impacts that extend well beyond the electricity sector; and (3) improved access to firming capacity can have dynamic benefits by supporting renewable investment, competition, and electrification over time. In short, more firming generation is the key to more renewable, reliable and affordable electricity".*[5]

Concern expressed over high wholesale spot prices and "the economic and social costs of supply" don't seem to acknowledge that "most electricity consumers, including all residential households, were sheltered from these high prices through retailer hedging," as stated by the Electricity Authority[6]. Notably, three forest-based industrial electricity users did suffer financially but analysis from the Electricity Authority "found that all three of these industrials … had access to enough hedges ahead of time to be fully hedged for July-September 2024"[7]. The stress test regime also ensures that market participants and large consumers understand and consider their exposure to volatile spot prices ahead of time.

5 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, paragraph 37

6 Review of winter 2024, Electricity Authority, 8 April 2025

7 Also as noted in Concept Consulting's "Various analyses of current electricity and gas market dynamics", 4 May 2025, "only the wood processing sector appears to have materially reduced electricity demand through exiting New Zealand production as a result of high electricity prices – accelerating a process that had started prior to electricity prices increasing from 2018 • the worst of these electricity-price-driven closures for the wood processing sector appear to be over".

Following the Winter of 2024 industries' resilience to dry-year risk was significantly boosted by an increase in coal reserves, acceleration of renewables, prior redirection of Methanex gas and an increase in gas storage at Ahuroa...

Further, given the high levels of hedging in place (as stated by the Electricity Authority) it is not evident to us that:

- "the economic and social costs of supply shortfalls are significantly greater than the costs of maintaining a modest level of surplus capacity", or
- "scarcity events have economy- wide impacts that extend well beyond the electricity sector".

If parties elect not to hedge, despite hedges being available and undergoing stress tests that highlight the potential impact of being unhedged, then recourse should not lie with the market. This is explicitly stated in Government's policy statement:

> *"Neither the Government nor the Electricity Authority nor the System Operator will step in to insulate wholesale market participants from risk or to protect them from their failure to manage their own energy supply risks. To do so would only increase the risk of shortage. Such interventions can cause a vicious circle because they can undermine incentives on market participants to manage their own risks properly, chilling hedging and new investment leading to increased scarcity, more periods of high prices and reduced security"*[8].

2.2. LACK OF CERTAINTY AND AN AVERSION FOR HIGH PRICE SIGNALS

While the recently released government policy statement is supportive of markets and not in favour of government intervention (refer section 4.7), uncertainty about whether the market can reliably meet the necessary levels of dry-year firming appears to be a further driver for the proposed winter reliability obligation (as well as for building an LNG receiving terminal).

> *"…we remain concerned that the market may still fall short from a system- wide perspective. Individual participants, acting rationally, may have weaker incentives to secure sufficient long-duration firm energy in advance than desired by consumers. Put simply, they may invest in too little long-duration firm energy or do so too late. This may be the case whether the response takes the form of new firming investment, demand response, fuel procurement, storage, or another dependable arrangement capable of reducing the risk and consequences of a dry year."*[9]

The proposed reliability obligation to manage dry-year risk is very much tenanted on the assertion that:

8 Paragraph 21, Statement of Government Policy to the Electricity Authority Under Section 17 of the Electricity Industry Act 2010: New Zealand Electricity Industry; 9 June 2026.

9 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, paragraph 48

"In practice, the market has not delivered enough certainty that long-duration firm generation will be delivered".[10]

There is also a sentiment that while a market approach is preferred, a market signalling scarcity through higher prices is not an acceptable part of a firming solution. This position runs contrary to how markets work, especially in the case of energy-only markets as adopted by New Zealand. Spot market prices signal how to efficiently allocate resources and when investment is required. And, spot markets work hand-in-hand with future (hedge) markets to allow parties to manage the risk of being exposed to these sometimes high prices,

"The aim is not to displace the market or prescribe a particular solution…"[11]

"…lessen reliance on sharply elevated wholesale pricing in stressed periods…"[12]

While managing energy security during dry years is the often-stated problem to solve, much focus and headlines is also targeted at price risk. Security risk is solved through ensuring supply is greater than demand under normal, contingent and extreme events. Markets achieve this through a combination of:

- allocative efficient price signalling - to bring more expensive generation sources on, or curtail willing and flexible demand, as it is required, and
- dynamic efficient price signalling – to bring on new investment as it is needed (but can result in periods of sustained higher wholesale prices due to time to build).

Addressing price risk can run contrary to addressing security risk, but it is important to note:

- Focus often falls on wholesale electricity prices despite most market participants and consumers being hedged. The stress test regime ensures participants and large consumers understand and consider their exposure to volatile spot prices ahead of time[13]. The impact of sustained higher winter dry-year wholesale prices on retail prices and the contracts market warrants greater focus and clarity.
- Understanding of the marginal (price setting) generation unit becomes more important as NZ's generation mix, impact of the New Zealand Emissions Trading Scheme (NZ ETS) and fuel availability changes in coming years.
- Dry years will put the focus back on thermal fuelled units being the predominant price setters. Here the differences between domestic gas price (subject to availability), coal and the potential move to LNG gas (exposure to global markets) is important to understand.

10 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, page 8

11 Ibid, paragraph 49

12 Ibid, paragraph 50

13 The Government Policy Statement (refer section 4.7) states that "Individual wholesale market participants are responsible for managing their own supply risks in response to efficient price signals"

The proposal goes on to highlight several key challenges to delivering enough certainty that long-duration firm energy will be delivered on time:

- ***Tenor gap*** - plant built for dry years may run only occasionally, so contracts of 10 to 15 years, or more, may be needed to recover costs with confidence. But most buyers are understandably reluctant to commit for that long. The result is too much reliance on occasional very high wholesale prices in dry years, which is not a dependable basis on which to build new plant.[14]
- ***Investment timing problem*** - Huntly's Rankine units can still provide a large amount of long-duration firm energy from plant and fuel already in place. That weakens the case for investing in replacement generation plants while those existing units remain available.
- ***Fuel availability*** - long-duration firm energy depends not only on plant existing, but on fuel being available for the plant to run when needed.

This last point highlights that fuel is not strictly a firming option, it is a constraint to generation being able to provide firming. It is this point that often gets lost or confused when setting policy and regulation for managing dry-year risk and also appears to take primacy when proposing the short-term reliability obligation (refer section 5).

2.3. BUYING INSURANCE

Thinking about the management of dry-year risk in terms of purchasing insurance can be useful to highlight some of the critical factors that are at play. MBIE do this nicely in their consultation proposal:

> *"Both layers can be understood as forms of insurance against dry-year risk. In each case, the obligated parties would be required to put arrangements in place to reduce the likelihood and consequences of the system entering a materially stressed winter position without sufficient dependable contracts for, or own, long-duration firm generation. As with any insurance arrangement, that protection would come at a cost, and in some cases that outlay may be incurred even though the feared dry-year conditions do not ultimately arise. But that does not make the expenditure unnecessary or wasteful. The fact that an insured event does not occur does not mean it was imprudent to guard against it. The value lies both in the protection available if the risk eventuates and in the greater confidence and resilience that comes from knowing it is in place."*[15]

Similarly, the insurance analogy can be applied to the proposed LNG terminal:

14 We note that the investment case for peaking plant often works on the basis of "reliance on occasional very high wholesale prices." The 'tenor gap' for dry year firming may be more the case of a 'transitional gap' where thermal plant is important for supporting the transition to a low carbon future but may not have a role once the transition is complete.

15 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, paragraph 41

> *"LNG represents an insurance policy for New Zealand to ensure the availability of gas resources into the future. Over a 15-year duration, the annualised cost of the infrastructure to provide this certainty is in the region of NZ$170–210 million, this excludes the cost of the LNG. However, LNG demand is uncertain, and it is recognised that in some years demand could be zero. In this case, fixed infrastructure costs will still need to be recovered."*[16]

MBIE's proposal notes that:

> *"The risk of scarcity during dry-year conditions introduces a risk premium into contract markets, which flows through to retail prices even in average hydrological conditions. By reducing the likelihood and severity of scarcity events, a reliability obligation would be expected to reduce this risk premium and place downward pressure on electricity prices".*[17]

From the above statement, there appears to be recognition that the market already prices a risk premium for firmness and dry year risk into future hedging contracts. It is notable that winter quarter contracts are more expensive than summer quarter contracts (although other factors will also be at play here including higher winter demand). And yes, you do pay this whether it's a dry year or not – exactly the same as you pay an insurance premium whether or not your house burns down that year or not. Also, assuming that the reliability obligation works as intended (we are not convinced this is so) then there should be a reduction in the risk premium being priced into future contracts.

What seems to be missing from this argument is that the reliability obligation also will place a cost on the market. A key question to ask is ***will a regulatory obligation, combined with a decision to build an LNG receiving terminal, price the risk of a dry-year more efficiently than the futures market is currently doing?***

Continuing this insurance analogy leads to a number of other critical concerns that need to be correctly managed before moving ahead with any proposed obligation to manage dry-year:

- Need to ***get your cover right*** – what is the size of cover needed to insure against a dry-year? We highly question using the existing SOSA methodology, as is being proposed, where every assumption and process is likely to have a level of conservatism built in, with highly optimistic demand growth repeated year-on-year (refer section 4.3).

16 NZ LNG Import Feasibility Assessment Public Release Summary, Gas Strategies, 20 December 2024, Public release version released 25 June 2025

17 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, paragraph 35

- The ***shape of the cover*** required will vary as not all dry-years come on and last the same. Also, the shape is likely to change over time as more renewables enter the system. There may be a need for flexibility in the cover provided or some kind of staggered approach as used in managing electricity reserves (e.g. a more instant but short-lasting type of coverage combined with coverage that has a longer lead time but can be sustained over a longer duration).
- ***Over insuring*** doesn't help anyone – ultimately will result in higher costs to the customer and to potential investors - can crowd out other investment that may have been more sensible (e.g. non-firm renewables). Also, can provide perverse incentives on industry to avoid falling into the regime (such as an independent retailer or new entrant data centre placing an artificial cap on their total load to stay under the de minimis).
- ***Physical cover through infrastructure*** (like LNG) creates a burden for the future vs more flexible temporary approaches – such as sweating existing infrastructure, fuel options rather than fixed delivery far in advance, and demand response.
- What is the ***most efficient price for cover*** –there is inevitably a trade-off between the level of security and price paid.

We discuss these critical concerns in the remainder of this paper.

The above is incredibly complicated but vital to get right. This will take both time and a more thorough analysis. This message is nicely reinforced in the recent letter from the Rt Hon Simon Upton, Parliamentary Commissioner.

> *"In the spirit of supporting an informed debate about an issue with ramifications that will extend far into the future, I am setting out some questions that I think should be answered if consultation is to be meaningful. They fall under three headings:*
>
> *1. Risk tolerance* – **how much dry-year cover is needed***?*
>
> *2. One policy or two* – **why is public procurement of LNG infrastructure necessary** *if a winter fuel obligation is in place?*
>
> *3. Options analysis – has the proposed winter energy obligation been* **adequately evaluated against the alternatives***?*
>
> *The public needs further information about the assumptions that underlie the Government's proposals. Without them, the message of this letter is simple: the information supplied alongside this consultation is insufficient to support an informed debate"*[18]*.*

[18] Letter to Hon Simeon Brown, Minister for Energy from Rt Hon Simon Upton, Parliamentary Commissioner for the Environment, 18 June 2026 (emphasis added)

2.4. FUEL AVAILABILITY

A critical part of MBIE's proposal (and the justification behind the proposed LNG terminal) is aimed at ensuring there is sufficient fuel available during dry-years. However, it is important to remember that given New Zealand is undergoing a shift to low carbon electricity generation[19], the life of thermal plant is finite. It is unlikely that any new thermal investment of any significance, especially baseload, will enter the system due to this shift, however, thermal generation still plays a vital role in supporting the transition. The challenge thus becomes keeping the remaining (and aging) thermal generation viable in the system and with sufficient fuel to run when needed.

The level of thermal generation available in New Zealand has reduced following the retirement of Contact's 330 MW Taranaki Combined Cycle (TCC) at the end of 2025. The thermal generation remaining on the system is shown in Table 1 below.

Table 1: Thermal plant remaining on the system

Unit	Owner	Size	Fuel Situation (from public information available)	
Strategic baseload and dry-year reserves:				
Huntly 5 – combined cycle	Genesis	400 MW	Gas	Offline till 31 December 2026 with a three-to-five day call back period. Supported in the past by Methanex gas diversion.
Huntly Rankine Units	Genesis	3 x 250 MW	Coal or gas fired	Contracted to operate as a strategic national reserve through to at least 2035 (Huntly Heads of Agreement)[20]. Also offering HFO[21] (Huntly firming option) hedge instruments to support ongoing operations.
Peaking Plant:				
Stratford	Contact	2 x 100 MW	Gas	Access to Ahuroa gas storage.[22]

19 Zero Carbon Act (Climate Change Response Act)

20 1.169 million tonnes at 31 May 2026 (as winter reserve and to cover generation for own customers)

21 Huntly Firming Options (HFOs) are structured electricity swaptions offered by Genesis Energy to back up New Zealand's national grid during periods of dry winters, low gas supplies, or low renewable generation

22 Ahuroa gas storage at 7.079 PJ at 28 June 2026 – 3.66 PJ Contact, 3.43 PJ Nova

Unit	Owner	Size	Fuel Situation (from public information available)	
				7-year gas supply agreement with Greymouth gas for supply of up to 7PJ of gas per annum from 1 October 2025, with an option to extend for a further three years from October 2032.
Huntly 6 open-cycle peaker	Genesis	50.8 MW	Gas or diesel	
Whirinaki	Contact	155 MW	Diesel	
Mckee	Nova	100 MW	Gas	Access to Ahuroa gas storage.
Junction Road	Nova	100 MW	Gas	Access to Ahuroa gas storage.

Additionally, there are two gas fired co-generation plants at Glenbrook (NZ Steel, 74MW) and Whareroa (Nova/Fonterra, 65MW) that could potentially provide generation (subject to meeting their own requirements) to the grid.

While modelling future dry year mitigation is outside of our scope of work, we have previously commented that to ensure 'sufficient' gas generation capacity[23]:

- From a ***power system perspective*** there is little value in creating a more available and certain gas supply if there is ***insufficient gas generation capacity*** available to use it.
- If it is no longer commercially viable in the current market setting for participants to either defer retirement of their existing gas fleet or to invest in new gas generation and gas generation is a necessary or favourable option to meet dry year risk, then some additional action is required:
    - Allow market prices to truly reflect this investment shortfall, or
    - Work with industry to come up with a collective response akin to that used for ensuring a ready supply of coal (Huntly heads of agreement), or
    - Look to some form of market intervention (noting that Government has already rejected the highly interventionist "new-co" option). Bushnell, Daglish, Leslie, and Borenstein have noted that other alternatives to those raised by Frontier are reliability must-run (RMR) contracts and placing forward purchasing requirements on retailers.

23 Government Review of Electricity Market Performance – Dry Year and Firming, Recommended approach – ERGANZ Presentation and Discussion, TLG, 16 December 2025

- In undertaking market intervention measures the following general principles should apply:
    - Limited and targeted to minimise market disruption (foreclosure of other investment options),
    - Minimise or avoid free-riding, and
    - Highly transparent in workings, tenure, scope and on/off triggers to allow investors to assess and plan around.

Generally, we would advise against prescribed fuels/technologies – don't pick winners. Rather increase investment environment certainty where possible.

As gas supply continues to decline, we note that:

- electricity usage is not the main use of gas in New Zealand,
- other users of gas will be affected, and electrification will be necessary both from a supply point of view but also to meet the transition to a low carbon future, and
- reducing supply creates a substantive incentive for electrification.

However, if a more gradual and managed transition is needed then the LNG terminal can be assessed on this basis – its role becoming less about dry-year risk management and more about supporting electrification.

2.5. INTEGRATING AN LNG TERMINAL AS PART OF THE SOLUTION

However, assuming an LNG terminal proceeds, it will be important to understand how it will interact with the electricity market and how the LNG could contribute to helping (or hindering) dry-year risk. Some of this will depend on whether a large-scale or small-scale solution is adopted.

We base the following comparison (refer Table 2 below) from the public release summaries of assessments from Gas Strategies[24] with our own additional insights.

Table 2: Comparison of large scale and small scale LNG terminal options

	Large scale	Small scale
Vessel Size	180,000m3 (equivalent to 4.5 PJ)	15,000m^3 (equivalent to 330 TJ)
LNG source	The volume and quality of LNG required by New Zealand should be readily obtainable in the global market.	Limit to Australia? Anyone else nearby doing break bulking?

24 New Zealand LNG Import Feasibility Assessment, Public Release Summary, 25 June and New Zealand LNG Import Feasibility Assessment Addendum on Small-scale LNG, Public Release Summary, 25 June 2025

	Large scale	Small scale
Shipping Cost		Smaller vessels require more handling cost, create more jetty disruption, and will be more expensive to ship volumes. Small scale landed LNG ~25% more expensive (based on 2024 JKM)
LNG Purchase basis	Flexible as needed cargos Given the scale and uncertainty of LNG demand, the expectation of this Assessment is that LNG will be sourced under short-term or spot deals	Term obligation required
Storage – option 1	Large scale cryogenic required (single or dual tanks for redundancy?)	Small scale cryogenic
Storage – option 2 (if Taranaki based)	Too big (lumpy) for Ahuroa (?) but could use to manage boil off	Use Ahuroa Gas Storage site (max 10-12 PJ although typically <8PJ)
Annual capacity	The number of cargoes required each year could vary between zero and three (13.5PJ) up to 2030 (to cover dr-year scenarios), and perhaps up to seven cargoes (31.5PJ) per year post 2030 (structural demand).	9PJ of gas (~100GWh) using 15,000m^3 vessels Potentially scalable to 12PJ with larger vessels Falls short of meeting demand in post 2030 structure demand scenarios.
Vulnerable to	Swings in LNG spot prices for when occasional loads are required Availability when called upon if the market is distressed (e.g. Fukushima, Ukraine, Hormuz)	More vulnerable to port/sea conditions for unloading Reliant primarily on Australian LNG

2.5.1. Long lead time

Assessments we have seen on the likely lead time for LNG to be available in New Zealand is 3-4 years, all going optimally (inclusive of fast-tracking consents).

> *"No single location has a good combination of sufficient water depth, favourable metocean (wind and wave) conditions and existing gas pipeline capacity. All locations will need some form of development and investment in both new and existing facilities. Given this requirement, and the limited availability of existing FSRUs, it is not possible for New Zealand to implement an LNG solution in the rapid timelines achieved in other countries.*
>
> *The time required to obtain permits and consents drive the pre-FID schedule for all the Preferred Concepts. There is the potential opportunity to accelerate this critical path item through Government intervention and support (see below). The specifics and impact of this intervention need to be explored and agreed with the Government.*

Fabrication of regasification equipment, conversion/construction of an FSU/FSRU and/or construction of onshore pipelines are likely to control the post-FID schedule (Concept dependent). There is a potential opportunity to expedite by ordering long-lead items ("LLIs"), however there is a risk associated with this approach depending on how early LLIs are committed to.

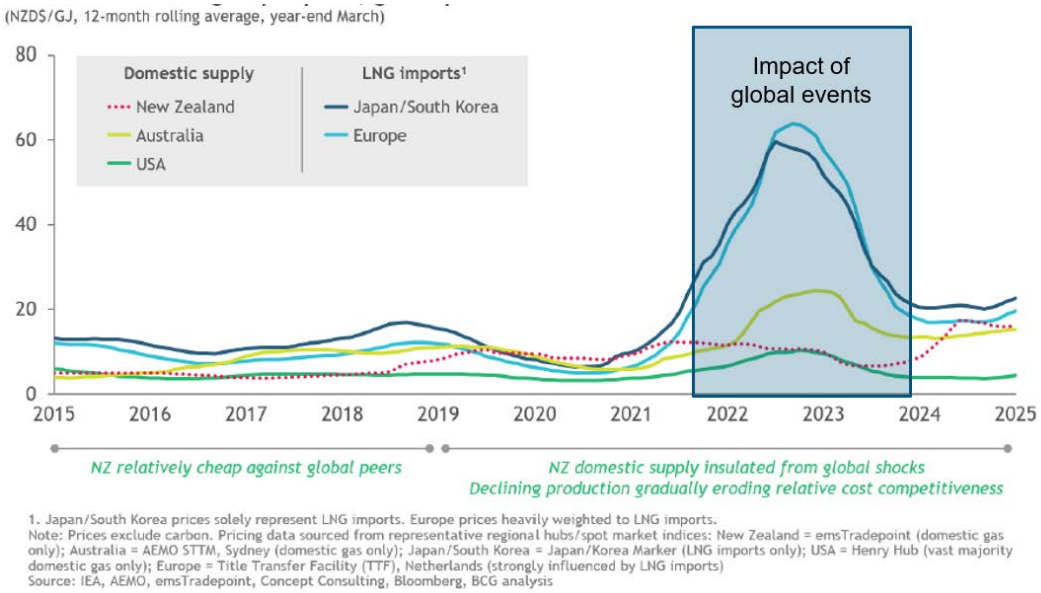
Implementing both the fast-tracking permitting /consenting process and early commitment to long-lead items, could reduce the time to first gas by approximately one year, possibly more. This could result in first LNG in three years in Location 3, or four years elsewhere".[25]

2.5.2. Linking the New Zealand electricity market to global gas prices

If future dry years coincide with times when global LNG markets are under stress (refer Figure 1) then there is the possibility that global LNG prices will fuel the marginal price setting generation unit, thus exposing the domestic electricity market to global LNG market prices. Hedging against these international LNG prices will be problematic on a fixed price, variable (uncertain) volume basis.

Even without global shocks, the price of LNG could still be the most expensive marginal fuel used when taking into account the relatively high costs of building and operating the terminal in relation to a potentially low through-put volume.

Figure 1: Nominal wholesale gas spot price, global peer liberalised markets



25 New Zealand LNG Import Feasibility Assessment, Public Release Summary, Gas Strategies, 25 June 2025

We do however note that the escalation of LNG global prices coinciding with the current disruption of shipping through the straits of Hormuz, while present, has not been as extreme.

2.5.3. How to incorporate LNG into the portfolio of dry-year solutions

Ultimately, we believe integrating LNG as part of the dry-year solution breaks down to better understanding the trade-off between building LNG infrastructure, determining when to use it, and balancing reliability against cost.

LNG cannot be viewed in isolation

LNG should not be viewed in isolation. Instead, it should complement other reliability measures including:

- hydro storage,
- coal reserves,
- demand response,
- diesel generation, and
- contractual supply arrangements.

Different combinations may be appropriate depending on the nature of the emerging dry-year risk as noted earlier.

LNG is an insurance product

LNG acts as an insurance product rather than an everyday fuel - its primary value is providing insurance against severe dry-year electricity shortages rather than being used routinely. Like insurance, using LNG too early may prove unnecessary if hydrology recovers; using it too late means it cannot prevent shortages because LNG supply chains require significant lead time. The challenge is finding the optimal balance between these two risks – trigger timing is critical.

LNG infrastructure size changes operating strategy

As noted earlier there are two broad approaches to developing LNG infrastructure:

- Small Scale LNG facility;
  - Lower capital cost,
  - Must be triggered earlier,
  - More likely to be used in years when it ultimately proves unnecessary, and
  - Functions as ongoing insurance.

- Larger Scale LNG facility;
  - Higher capital cost,
  - Can respond later because it delivers much larger volumes,
  - Less likely to be used, and
  - Provides greater operational flexibility.

The exact dynamics of deciding between the two approaches is outside the scope of this paper.

Different dry years require different responses

Not all dry years are alike. Examples include:

- steadily worsening ("linear") dry years,
- sudden late-emerging droughts, and
- uncertain years where conditions remain marginal for extended periods.

Each may require different combinations of LNG, hydro storage, coal, demand response, diesel generation. Therefore, reliability mechanisms should recognise different drought profiles rather than assuming every dry year is the same.

Insurance has an economic value

LNG should be evaluated as:

Infrastructure cost + fuel cost[26] − insurance value

However, once the terminal is constructed, the infrastructure cost is effectively sunk (potentially for future stranding) and the cost of using LNG simply becomes:

Fuel cost − insurance value

The greater the value placed on avoiding electricity shortages, the earlier and more frequently LNG becomes economically justified. Rather than viewing LNG purely as an expensive fuel, it should be valued according to the reliability benefits it provides.

However, overall there is no perfect LNG solution. The key challenge is balancing:

- capital investment,
- operating costs,
- supply chain constraints,

26 Inclusive of terminal throughput costs.

- uncertain hydrology, and
- the high economic value of avoiding electricity shortages.

The value of LNG lies not simply in the energy it provides, but in the insurance it offers against severe dry-year risks. Determining the right size of LNG infrastructure, the timing of deployment, and the interaction with other firming resources is therefore central to designing an effective electricity security strategy. And of course, this all depends on whether LNG is necessary at all.

2.6. ALTERNATIVE OPTIONS

While developing a full alternative mechanism falls outside the scope of this paper, the absence of a sufficiently developed options analysis is itself one of the weaknesses of the current proposal. If Government is minded to move beyond the existing energy-only market framework, then the relevant question should not be limited to whether the particular reliability obligation design proposed by MBIE can be made workable. The prior question is whether there are other ways of achieving the same dry-year reliability objective with fewer distortions, lower implementation risk and better alignment with existing market arrangements. We have noted that the Electricity Authority has been given responsibility to ensure that industry invests in dry-year solutions and the Authority have already begun work in this area (refer section 4.8). We thus question whether presenting them with a proposed and rushed winter obligation tool (which MBIE note is not intended to be a full solution to dry year risk) will help or hinder them in coming up with a cohesive and coordinated response to meet their new responsibilities.

At a minimum, any alternative should be assessed against a number of basic principles. It should:

- be technology-neutral,
- be capable of recognising the contribution of generation, storage, fuel availability, hydro flexibility and demand response,
- be targeted to the actual reliability problem, rather than creating a broad compliance overlay that incidentally reshapes the whole market,
- avoid unnecessary reliance on administrative judgement about future need, eligible resources and participant-specific obligations, and
- preserve, as far as possible, incentives for efficient contracting, new entry, retail competition and demand-side participation.

One possible approach, for example, would be to define a form of dry-year energy credit. Under such a model, participants taking electricity from the grid during the defined winter period could be required to support that load with an equivalent quantity of qualifying dry-year energy cover. Generators and demand-side providers would be assessed as being able to create dry-year energy credits according to their dependable contribution to winter energy adequacy.

Those credits could then be tradable. Retailers, large users and other wholesale purchasers could meet their obligation either through their own resources, bilateral contracts, or purchase of dry-year energy credits from others. A centralised auction or trading platform could also be used to help smaller participants match their winter load requirements and reduce transaction costs. Compliance could then be assessed by reference to whether participants had sufficient qualifying dry-year cover to support the load they served during the relevant period.

This type of mechanism would not be free of difficulty. Indeed, it would raise many of the same design issues seen in capacity markets and other resource adequacy mechanisms internationally. It would require careful treatment of market power, gaming, double counting, credit certification, liquidity, penalty design and the treatment of intermittent generation and hydro. It may also have different portfolio impacts across participants, including those with high renewable or high hydro exposure. Those issues should not be understated.

However, the example illustrates an important point. There are ways of designing a reliability mechanism that may place less reliance on the administrated Security of Supply Assessment, SOSA (refer section 4.3) as the binding trigger for intervention, and more reliance on a market for compliance products. Rather than the regulator determining the amount of additional cover required and allocating obligations through a bespoke administrative process, the obligation could follow load more directly, while the supply of qualifying credits would be created by resources capable of supporting dry-year adequacy. This would not remove the need for regulatory oversight, but it may reduce the extent to which the regulator is required to substitute its judgement for the market's judgement on every material element of the regime.

Other options could also be developed. These include:

- strengthening existing stress testing and disclosure obligations;
- improving the transparency of gas and fuel availability;
- developing standardised long-duration hedge products;
- requiring market making in firming products;
- creating targeted arrangements for existing thermal availability;
- expanding and formalising demand response; and
- improving the governance, methodology and transparency of the security of supply framework.

Some of these measures are already being considered or are underway by the Electricity Authority. The key point is that they should be assessed as part of an integrated reliability framework, rather than treated as peripheral workstreams around a pre-determined reliability obligation design.

The key point is not that any one of these alternatives is necessarily superior to the proposed reliability obligation. Rather, it is that the consultation material does not demonstrate that the proposed obligation has been robustly tested against a sufficiently broad set of less-intrusive, more market-compatible options. That matters because once a reliability obligation is introduced, it may materially alter investment, contracting and risk-management incentives across the market.

2.7. WHAT IS THE BEST PATH FORWARD?

The best path forward is not to reject the underlying objectives of the proposed Winter Energy Reliability Obligation. The objectives have validity. New Zealand does need to manage dry-year risk, maintain confidence in security of supply, support investment in firming resources, and ensure that the transition to a more renewable electricity system remains credible and affordable.

While we can accept the objective of MBIE's proposal we do not believe that the proposed mechanism, the proposed timetable, or the current level of analysis supporting the proposal is equally valid. We would caution strongly against moving too quickly to implement a novel and complex regulatory obligation before the design issues have been worked through properly.

The central issue is one of risk. The proposed obligation is intended to reduce dry-year reliability risk. But if poorly designed, it could introduce new and potentially larger risks into the electricity market. In the current timeframe, the risk-adjusted cost of getting the regime wrong may well exceed the risk-adjusted benefit of getting it right.

Those downside risks are not theoretical. A poorly calibrated obligation could create incentives that operate in the opposite direction to those intended. It could encourage over-procurement of dry-year cover, increase costs to consumers, weaken normal market price signals, distort hydro storage decisions, reduce hedge and retail market liquidity, create opportunities for gaming, and discourage independent generation or retail entry. It could also embed a costly compliance overlay that does not in fact deliver the additional physical reliability it is intended to secure.

These risks are heightened because the proposed regime is attempting to do something that is difficult, and for which there is limited direct international precedent. The proposal is not simply a minor adjustment to existing market arrangements. It would create a parallel administrative framework for determining when additional energy adequacy is required, how much is required, who must provide it, what forms of cover qualify, and what penalties apply if parties fail to comply. Those are not small matters of implementation detail. They go to the heart of how an energy-only market allocates risk, signals investment, and prices scarcity.

As mentioned above, the proposal is also being developed alongside several other significant workstreams. These include changes to the role of the Electricity Authority, improvements to security of supply information, potential changes to stress testing, development of standardised long-duration risk management products, improvements to market making and hedge liquidity, and the Government's proposed LNG import facility. Each of these has the potential to affect the need for, and design of, any reliability obligation. It would be undesirable to lock in a major new obligation before these related measures have been properly integrated into a coherent overall framework.

In particular, if the proposed obligation is to proceed, it needs to be designed as part of a broader resource adequacy framework, rather than as a rushed add-on to the current arrangements. That does not mean New Zealand should adopt a conventional capacity market. Indeed, the language of capacity markets is politically and commercially difficult, and the proposed obligation is directed at energy adequacy rather than peak capacity adequacy. But it would be equally wrong to ignore the lessons from international capacity and reliability mechanisms merely because the label is uncomfortable.

International experience shows that these regimes are highly sensitive to design. Key questions include:

- how the reliability standard is defined;
- who produces and governs the forecast; how the size of the obligation is calculated;
- how obligations are allocated;
- what products or resources qualify; how double counting is avoided;
- whether there is a secondary market for compliance products[27];
- how market power is mitigated;
- how costs are passed through to consumers; and
- how the regime interacts with existing hedge and spot markets.

These issues need careful design, not just high-level consultation. And then there is the crucial issue of if they can even really make a material impact as intended with regards to investment signals. A 1, 3 or even 5-year forward market signal of impending resource scarcity is still only one year in the financial model of a project with 30 to 40-year asset life.

27 Compliance products are those products that are defined or sanctioned to meet a regulatory requirement. We discuss this in Section 4.10

A more credible path would therefore be to separate the principle from the implementation timetable. The Government could confirm that it considers dry-year reliability to be a legitimate policy priority, and that a reliability obligation remains one possible tool. However, rather than immediately committing to the current design, it should require a fuller design process led by the Electricity Authority, supported by the System Operator and MBIE, with genuine industry engagement and proper modelling of alternative options.

That process should begin with a more precise definition of the problem. There needs to be a shared view of the level of dry-year cover that is actually required, the security standard being targeted, the expected role of demand response, the likely future role of thermal generation, and the extent to which existing and planned resources already cover the relevant risk. Without that foundation, there is a material risk of over-insuring the system and imposing costs that consumers ultimately bear.

The process should also test whether less intrusive measures could achieve the same objective. These may include improvements to information, more robust and regularly updated security of supply assessments, better gas and fuel market transparency, targeted arrangements for existing thermal availability, stronger stress testing, standardised long-duration hedge products, enhanced market making, clearer demand response arrangements and identifying the right level of LNG investment that may (or may not) be required. If these measures are capable of addressing the identified gap, then a more intrusive mandatory obligation may not be required. If they are not sufficient, they would still provide an important foundation for any obligation that follows.

The SOSA methodology also needs to be reviewed before it is used as a binding trigger for major commercial obligations and potentially very large penalties. A forecast that was originally designed as an informational planning tool should not be converted into the central trigger for regulatory intervention without first ensuring that its assumptions, governance, review process and sensitivity analysis are fit for that purpose.

Thus, while we can support the objective of what MBIE are trying to achieve we do not support the current rushed implementation path. The Government should slow down, define the problem more carefully, complete the related market design work, and then decide whether a reliability obligation is still necessary and, if so, what form it should take.

That approach would preserve the principles behind the proposed Winter Reliability Obligation while reducing the risk of unintended consequences. It would also give investors, retailers, large users and consumers greater confidence that any new mechanism is durable, proportionate, and consistent with the long-term evolution of the New Zealand electricity market.

3. AUSTRALIAN NEM RETAIL RELIABILITY OBLIGATION (RRO)

As noted in the MBIE consultation paper, Australia's Retailer Reliability Obligation (RRO), is a comparator scheme to the one being proposed for New Zealand. Both schemes are targeted at ensuring that any shortfall in forecast firm generation will be met through placing obligations on liable parties ahead of time, encouraging investment in dispatchable generation (or demand response), to prevent the shortfall from arising. The two schemes have some differences in objectives – some material, some nuanced. As noted by MBIE:

> *"The Australian RRO is fundamentally a capacity adequacy mechanism, focused on ensuring that sufficient firm capacity is available to meet peak demand. It does not address energy adequacy or longer-duration supply risk in the way envisaged by the obligation proposed here".* [28]

However, they are sufficiently similar to warrant a closer look at the Australian scheme, especially since it has been operating for almost 7 years, undergone a number of reviews to help improve from problems observed and trying to keep it relevant to any changes in market dynamics.

A review of the Australian RRO is summarised below with full details provided in Appendix A.

The table below shows how the process followed by MBIE's proposed long term obligation broadly follows the same process as that used in Australia's RRO.

Table 3: Comparison of proposed NZ Winter Electricity Reliability Obligation with Australian Retail Reliability Obligation

Scheme Outline	Australian NEMS RRO	NZEM Proposed Long-term Obligation
Scheme Overview	• Forecast based ex-ante mechanism	• Forecast based ex-ante mechanism
	• capacity adequacy mechanism, focused on ensuring that sufficient firm capacity is available to meet peak demand.	• energy adequacy mechanism, focused on ensuring that sufficient firm capacity is available to meet peak demand.
	• Liable entities are energy retailers and market customers (entities purchasing wholesale electricity)	• Liable entities are energy retailers and market customers (entities purchasing wholesale electricity)
	• Looks at general adequacy throughout the forecast horizon	• Targeted on dry-year risk during 4 months of the year (winter)

28 Paragraph 107, A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026

Scheme Outline	Australian NEMS RRO	NZEM Proposed Long-term Obligation
The Forecasting Phase	• The Australian Energy Market Operator (AEMO) publishes an annual Electricity Statement of Opportunities (ESOO), which includes a 5-year outlook of system reliability.	• System Operator identifies expected risk to winter energy security standards - based on the New Zealand Winter Energy Margin, assessed through the SOSA's Expected Future Scenario and approved by the Electricity Authority. Process begins with 5-year outlook forecast.
	• If AEMO identifies a "material reliability gap" in a NEM region, they request a reliability instrument. This typically happens if the forecast unserved energy exceeds the NEM standard	• If the SOSA shows that existing and planned physical cover is likely to be insufficient, it would identify the forecast shortfall and require large wholesale purchasers to secure additional dependable winter cover ahead of time to meet their respective load requirements
	• A 3-year trigger (T-3) is used, giving the market three years to secure new supply or demand response before the gap begins.	• A 3-year trigger is used
The Contracting Phase	• Once the RRO is triggered, electricity retailers and certain large commercial electricity users become "liable entities".	• EA assigns winter energy obligation to wholesale purchasers. Obligation is allocated based on each party's share of expected winter demand.
	• Applies to entities over a de minimis threshold being …	• Applies to entities over a de minimis threshold (initially proposed at 500GWh of aggregate load over a 6 month winter period (1 April to 30 September)
	• These liable entities must enter into qualifying contracts with power generators or demand-response providers.	• Wholesale purchasers secure contracts, invest and/or build additional winter cover
	• These contracts must cover their proportional share of the region's 1-in-2 year peak demand forecast during the gap period.	• Verifiable winter energy cover may include existing generation plant, generation under contract, contracted demand response, or other dependable arrangements that qualify under the regime.
	• To ensure smaller retailers can actually buy these contracts, a Market Liquidity Obligation (MLO) may be activated. This forces major generators to offer standard small-volume contracts on the market.	• The Electricity Authority is currently looking at firmness liquidity in the hedge markets[29]. MBIE further note that "if a long-term obligation is introduced, it will likely also need to sit alongside other complementary measures, rather than be expected to solve the dry-year problem on its own"[30].
	• Liable entities must report their Net Contract Position to the Australian Energy Regulator (AER) at the T-1 mark (one year before the gap period).	

29 Paragraph 28, The Electricity Authority is currently progressing several initiatives in this area, including improvements in the market stress-testing framework, investigating standardisation of long- duration risk management products and enhancement of market-making settings.

30 Paragraph 109, A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026

Scheme Outline	Australian NEMS RRO	NZEM Proposed Long-term Obligation
The Compliance & Penalty Phase	• If a liable entity cannot demonstrate they are sufficiently contracted by the T-1 deadline, the RRO remains active and they risk heavy penalties	• The EA assesses obligation compliance 12 months from relevant winter
	• If a shortfall in electricity supply still occurs, the AER will verify if a liable entity's under-contracting contributed to the problem.	• A penalty is triggered if the obligated party fails to secure sufficient qualifying cover to meet the purchaser's allocated obligation.
	• Under-contracted entities face substantial civil penalties, potentially ranging from $1 million to $10 million, and are required to cover the costs of emergency reserve measures initiated by AEMO	• The penalty for parties breaching their obligations could be the higher of up to $10 million, or three times the commercial gain, or 10% of a company's turnover. Although, MBIE have noted that "the penalty framework should support the credibility of the scheme without making it unduly rigid or punitive".[31]

A fundamental difference between the Australian RRO and the NZ proposed arrangements is the requirement for a second layer short-term scheme in NZ.

The Retailer Reliability Obligation (RRO) was introduced in October 2019 with the intent to improve reliability in Australia's National Electricity Market (NEM) by requiring retailers and large electricity users to hold sufficient contracts or invest in dispatchable capacity to cover forecast peak demand. However, its effectiveness and ongoing relevance have increasingly been questioned as the electricity system transitions toward renewable generation, storage and demand-side participation.

Critics argue that the RRO has become an expensive and complex regulatory layer that does not necessarily improve physical reliability.

The ***Australian Energy Market Commission (AEMC) reviewed*** the operation of the RRO in 2023–24. Rather than assessing whether the RRO itself remained necessary, the review focused on reducing compliance costs and improving administration. The AEMC proposed reforms including:

- Moving retailer compliance obligations from T-1 to the start of the reliability period (T) to reduce unnecessary over-contracting.
- Allowing newly commissioned projects to contribute toward compliance.
- Giving AEMO greater flexibility in requesting reliability instruments.
- Strengthening the Market Liquidity Obligation (MLO).

31 Paragraph 96, A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026

- Expanding eligible contracts, including demand-side response and storage products.
- Simplifying auditing and compliance requirements.

However, many stakeholders argued that the review should have considered whether the RRO should exist at all, particularly given newer investment mechanisms such as the Capacity Investment Scheme (CIS).

The later ***Nelson Review*** took a broader view of the NEM and concluded that the energy-only market is fundamentally sound but needs additional mechanisms to support investment, risk management and reliability in a renewable-dominated system.

Two new investment mechanisms were proposed to replace temporary schemes such as the CIS (due to complete in 2030).

1. The ***Electricity Services Entry Mechanism (ESEM)*** would:
    - Procure long-term contracts for key electricity services:
        - bulk renewable energy;
        - shaping;
        - firming capacity.
    - Provide investors with revenue certainty.
    - Use competitive auctions.
    - Return contracts to the market over time to maintain competition.
    - Support technologies including renewable generation, storage, demand response and aggregators.
2. ***Market Making Obligation (MMO***)

    An obligation requiring major participants to support liquidity in electricity derivatives markets. The MMO would:

    - Apply initially to key contracts such as caps and baseload swaps.
    - Require certain large participants to provide trading liquidity.
    - Establish minimum trading volumes and maximum bid-offer spreads.
    - Be overseen by the AER.

The objective is to ensure retailers and generators can continue accessing affordable risk-management products as traditional thermal generators retire.

The Nelson Review concluded that once the ESEM and MMO are operating effectively, governments should **phase out the RRO**. Reliability policy should move away from mandatory retailer contracting toward mechanisms that directly support investment, liquidity and market functioning.

The RRO was introduced as a safeguard against reliability risks by forcing retailers to contract for future demand. However, experience has shown that it is complex, costly and only indirectly linked to physical reliability. The emerging consensus is that reliability challenges in a renewable-based electricity system are better addressed through:

1. **Investment mechanisms** (such as ESEM) to encourage new firmed renewable capacity;
2. **Strong derivatives markets** supported by market-making obligations; and
3. **Improved forecasting, transparency and system visibility**.

Under the proposed future NEM design, the RRO mechanism is expected to be retired once these broader reforms are established.

3.1. KEY LESSONS FOR NEW ZEALAND

Australia's experience with the Retailer Reliability Obligation (RRO) offers a number of important lessons for New Zealand as it considers its proposed Winter Electricity Reliability Obligation. The most important lesson is not that the RRO failed—it largely achieved its immediate objective of encouraging retailers to contract ahead—but that it has proven to be an expensive and increasingly indirect way of achieving reliability in a rapidly changing electricity market.

The key lessons for New Zealand are shown in the table below.

Table 4: Key lessons for New Zealand from the Australian RRO

Lesson	Australian experience	Implication for New Zealand
Don't expect the obligation to solve the problem on its own	The RRO became only one part of Australia's reliability framework and required complementary reforms.	The NZ obligation should be viewed as one component of a broader energy security package, not a complete solution to dry-year risk.
Investment matters more than contracting	Australia has shifted its focus toward mechanisms that directly encourage investment in firming capacity rather than simply requiring retailers to contract.	NZ should ensure the obligation actually results in new physical winter energy resources, not simply redistribution of existing contracts

Liquidity is critical	Australia found retailers cannot comply efficiently without liquid hedge markets, leading to the Market Liquidity Obligation (MLO) and later proposals for a permanent Market Making Obligation (MMO).	NZ's obligation is likely to require complementary measures to improve firmness and hedge market liquidity.
Minimise compliance costs	The AEMC review focused heavily on reducing unnecessary compliance costs and over-contracting.	NZ should keep reporting, auditing and contract requirements as simple as possible.
Allow flexibility	Australia progressively expanded eligible compliance products to include storage, demand response and new projects.	NZ should avoid technology-specific rules and recognise all dependable winter energy resources.
Markets evolve	Australia's mechanism required continual amendment as the generation mix changed.	NZ should build in periodic reviews so the obligation remains fit for purpose.

4. LONG-TERM OBLIGATION

MBIE’s consultation paper proposes introducing a two-layer Winter Energy Reliability Obligation to strengthen New Zealand's electricity security by ensuring sufficient long-duration firm energy (such as dispatchable generation, storage, demand response or fuel supply) is available to manage dry winters.

The proposed framework aims to:

- Improve resilience during dry-year electricity shortages.
- Encourage investment in firm generation and other reliability resources.
- Support renewable generation by improving access to firming capacity.
- Increase competition in the electricity market.
- Reduce the risk of extreme wholesale electricity prices and lower long-term retail prices.

The proposal recognises that higher reliability comes at a cost, but argues that the economic and social costs of electricity shortages are much greater than maintaining a modest surplus of reliable capacity. We find the later part of this assertion troublesome to reconcile, when a) there were no electricity shortages (supply always exceeded demand) and b) maintaining a modest surplus of supply is necessary in any market to allow competition to take place (if supply equals demand than all suppliers are pivotal).

MBIE propose a two-layer reliability framework:

1. ***Long-term obligation (investment focus)***

- Triggered 3–5 years before winter if Transpower's Security of Supply Assessment (SOSA) forecasts insufficient winter energy margins.
- Large wholesale electricity purchasers would be required to secure additional dependable winter energy through generation, storage, demand response or other qualifying arrangements.
- The objective is to provide revenue certainty that encourages investment before shortages occur.

2. ***Short-term obligation (operational focus)***

- Activated closer to winter if conditions deteriorate despite the long-term mechanism.
- Addresses unexpected events such as generator outages or reduced gas availability.

Together, these obligations are intended to act as an insurance policy against dry-year electricity shortages.

4.1. HOW THE LONG-TERM OBLIGATION WOULD WORK

The operation of the scheme falls into 3 phases; the forecasting phase; the contracting phase and the compliance/penalty phase. This is shown in the table below.

Table 5: Proposed NZ Winter Electricity Reliability Obligation

Scheme Outline	Proposed Long-term Obligation
Scheme Overview	• Forecast based ex-ante mechanism
	• energy adequacy mechanism, focused on ensuring that sufficient firm capacity is available to meet peak demand.
	• Liable entities are energy retailers and market customers (entities purchasing wholesale electricity)
	• Targeted on dry-year risk during 4 months of the year (winter)
The Forecasting Phase	• System Operator identifies expected risk to winter energy security standards - based on the New Zealand Winter Energy Margin, assessed through the SOSA's Expected Future Scenario and approved by the Electricity Authority. Process begins with 5-year outlook forecast.
	• If the SOSA shows that existing and planned physical cover is likely to be insufficient, it will identify the forecast shortfall and require large wholesale purchasers to secure additional dependable winter cover ahead of time to meet their respective load requirements
	• A 3-year trigger is used

Scheme Outline	Proposed Long-term Obligation
The Contracting Phase	• EA assigns winter energy obligation to wholesale purchasers. Obligation is allocated based on each party's share of expected winter demand.
	• Applies to entities over a de minimis threshold (initially proposed at 500GWh of aggregate load over a 6-month winter period (1 April to 30 September)
	• Wholesale purchasers secure contracts, invest and/or build additional winter cover
	• Verifiable winter energy cover may include existing generation plant, generation under contract, contracted demand response, or other dependable arrangements that qualify under the regime.
	• Expected to sit alongside other complementary measures, rather than be expected to solve the dry-year problem on its own"[32]. The Electricity Authority is currently looking at firmness liquidity in the hedge markets[33].
The Compliance & Penalty Phase	• The EA assesses obligation compliance 12 months from relevant winter
	• A penalty is triggered if the obligated party fails to secure sufficient qualifying cover to meet the purchaser's allocated obligation.
	• The penalty for parties breaching their obligations could be the higher of up to $10 million, or three times the commercial gain, or 10% of a company's turnover. Although, MBIE have noted that "the penalty framework should support the credibility of the scheme without making it unduly rigid or punitive".[34]

While acknowledging the compliance burden and forecasting uncertainty, MBIE conclude that a targeted long-term obligation would strengthen investment incentives, improve winter reliability, and reduce the economic and social costs of prolonged electricity shortages. It also recognises that the obligation should form part of a broader reliability framework—including complementary measures to support contracting, investment and market liquidity—rather than being expected to solve New Zealand's dry-year challenge on its own.

Key features of the scheme include:

- Obligations triggered when SOSA forecasts winter energy margins below the required security standard.
- Responsibility allocated according to each participant's share of expected winter electricity demand.
- Participants can comply through existing generation, new generation, contracted demand response, storage or other qualifying firm energy resources.
- Compliance assessed one year before the relevant winter.

32 Paragraph 109, A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026

33 Paragraph 28, The Electricity Authority is currently progressing several initiatives in this area, including improvements in the market stress-testing framework, investigating standardisation of long- duration risk management products and enhancement of market-making settings.

34 Paragraph 96, A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026

- Significant financial penalties for non-compliance to encourage investment rather than simply paying fines.

Expected benefits

The proposal argues the framework would:

- Increase investment in firm generation and other reliability resources.
- Reduce the likelihood and severity of dry-year electricity shortages.
- Lower wholesale price volatility during stressed periods.
- Reduce reliance on emergency market interventions.
- Improve confidence for renewable energy investment.
- Support electrification and economic growth.
- Reduce risks to businesses, employment and households from electricity shortages.

Challenges and risks

The proposal acknowledges several implementation challenges:

- Forecasting future electricity shortages is inherently uncertain.
- The regime would add compliance and administrative costs.
- Poor design could distort investment decisions or increase costs unnecessarily.
- Careful calibration of penalties and qualifying resources would be required.

The experience of the Australian RRO experiment (refer Table 4) provide a number of cautions for New Zealand:

- Don't expect the obligation to solve the problem on its own
- Investment matters more than contracting
- Liquidity is critical
- Minimise compliance costs
- Allow flexibility
- Markets evolve

However, should such a scheme proceed, we highlight some of the more glaring issues that will need to be addressed. These include:

1. Correct sizing of the dry-year gap that exists (avoid over insuring)
2. Correct allocation of the obligation to liable parties to avoid perverse incentives

3. Maximise the incentive on parties to invest which is one of the primary goals of the scheme, while minimising disincentives for investment
4. Better understanding of the purpose of wholesale markets i.e. to create price signals for efficient allocation of resources in the short term while signalling new investment ahead of time in the longer term
5. Better alignment with the recent Statement of Government Policy
6. Alignment with other work taking place e.g. market stress-testing framework, investigating standardisation of long- duration risk management products and enhancement of market-making settings
7. Setting appropriate timeframes to get it mostly right – what is driving the perceived urgency
8. Is market power present with firming resources and what is to stop it from being exercised.

These are discussed in the following sections.

4.2. SIZING THE GAP

As noted in Section 2.3, the first step to purchasing insurance is to calculate how much cover is actually necessary – i.e. how much firming is required to cover the future risk of dry-years. As we have noted in the past there have been a range of figures postulated (footnote), varying by period of historic look-back, assumptions made and definitions around 'worse case' made. We also noted that a more consistent methodology to quantify dry year risk needs to be agreed, regularly calculated and published[35].

Two recent examples for assessing the size of the dry-year gap include the June 2025 Bushnell Peer Review of Market Performance[36];

> *By our calculations, the most severe quarterly deficit in hydro production, relative to a twenty-year seasonally adjusted average, was about 1675 GWh in the quarter ending September 2001. The coal capacity of Huntly alone, operating at an 80% capacity factor can produce about 1300 GWh quarterly. Other sources, including newly committed renewable energy, demand response, not to mention diesel generation, appear to fill the remaining gap, even if there is a continued decline in gas availability.*

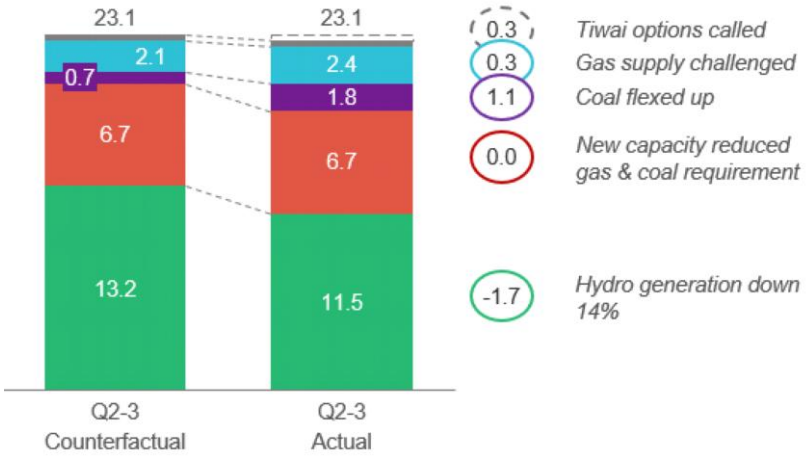
and observing what actually played

35 Government Review of Electricity Market Performance – Dry Year and Firming, Recommended approach – ERGANZ Presentation and Discussion, TLG, 16 December 2025

36 Review of the NZ Electricity Market Performance - Peer Review Evaluation; Bushnell, Daglish, Leslie and Borenstein; June 8, 2025

out in the Winter of 2024 (the reference point for the newly elevated focus on dry-year risk). This was A 1.7 TWh drop in hydro being met by 1.1 TWh of coal, 0.3 TWh of demand response (Tiwai) and 0.3 TWh of gas (Methanex) as shown in Figure 2 below.

Figure 2: Dry year gap observed in Winter 2024 (TWh)



Source: BCG – Energy to Grow, November 2025

Ultimately, there needs to be a shared view of the amount of energy required to cover the risk of dry-years. This figure will change year on year but ideally should be based on an explicit security standard to avoid the risk of over insuring (increasing cost to consumers) or under investing (allowing the system to fall below set reliability levels).

The proposed methodology for achieving this in MBIE's proposal is to use Transpower's Security of Supply Assessment (SOSA).

4.3. Reliance on Security of Supply Assessment (SOSA)

The proposal makes SOSA (Security of Supply Assessment) the foundation of the proposed long-term reliability obligation. SOSA would become the mechanism that determines whether an obligation exists, how large it is, and when participants must act.

4.3.1. SOSA becomes the trigger for the long-term obligation

Currently, SOSA identifies potential future security-of-supply issues but does not require anyone to act. The proposal changes this by making SOSA a regulatory trigger. If the New Zealand Winter Energy Margin (NZ-WEM) in the SOSA Expected Scenario falls below the security standard, a long-term reliability obligation is triggered. In effect, SOSA changes from an advisory forecasting tool into the basis for regulatory intervention.

This is clearly outlined in prior year consultation processes – in 2023 Transpower actually stated that:

> *"Falling below the security standards does not equate to an electricity supply shortfall. Rather, it implies that investment in new generation would result in an efficient increase in reliability".*

The concern here is that the processes that support the development of the SOSA were never intended to have the rigor for it to be the reference tool for setting investment obligations and being the basis for potentially crippling penalties of up to 10% of company turnover being sanctioned.

In some ways, worse than this, is that the industry knows this too – i.e. confidence to act on SOSA out-year forecasts is not high. General commentary from the industry is that SOSA demand forecasts are always wildly optimistic – with back-casting of the low demand cases vs actual, looking like a Harrier jump jet taking off from an aircraft carrier.

4.3.2. The Expected Scenario becomes the reference forecast

The proposal intends to use the SOSA Expected Scenario as the reference forecast. MBIE argue that this provides a transparent methodology, one already familiar to industry, and establishes a clear link between Transpower's forecasting and government intervention. Unfortunately, this transparent methodology uses underlying assumptions and methodologies from the Electricity Authority's Security Standards Assumptions Document (SSAD) that was originally put in place in November 2012 and has never been updated since. In talking with industry on their familiarity with this process, we get the impression that this part of the proposal is indeed SSAD.

4.3.3. SOSA determines the size of the obligation

The proposal doesn't simply ask SOSA whether there is a potential problem. Instead, it goes further to require SOSA to calculate how many GWh of additional winter energy is required to restore the Winter Energy Margin to the security standard. That quantified shortfall becomes the amount that must be secured through the reliability obligation.

4.3.4. SOSA drives a staged process

The proposal suggests using successive SOSAs to progressively increase certainty. If SOSA forecasts show an inadequate Winter Energy Margin 5 years before winter it will trigger issuing a warning that an obligation is likely. Three years before winter it will issue a binding obligation. One year before winter it sets the bar to assess whether obligated parties have secured enough qualifying cover.

This recognises that forecasts become more accurate as the relevant winter approaches.

4.3.5. The proposal acknowledges SOSA forecasts are uncertain

The paper repeatedly notes that SOSA is forecast-based and therefore imperfect. It identifies several uncertainties including:

- future demand growth;
- new generation projects;
- project delays;
- fuel availability;
- hydrology;
- outages.

It recognises a trade-off - acting too early may require investment for a shortfall that never eventuates. Acting too late leaves insufficient time to build or contract new resources.

A simpler way of stating this is that industry cannot wait to respond to a signal until it becomes more accurate. The dilemma they are faced with is how much investment to make on an inaccurate requirement or to assume that SOSA has got it wrong again.

4.3.6. The problem

The real problem we have with this is that SOSA was never intended to fulfil this kind of role. The proposal significantly elevates the importance of SOSA. Instead of simply publishing forecasts of electricity security, SOSA would become the primary decision-making tool for New Zealand's proposed long-term reliability regime. Its forecasts of the New Zealand Winter Energy Margin (NZ-WEM) would determine:

- whether intervention is required;
- the size of any winter energy shortfall;
- when obligations are triggered; and
- how much additional firm energy obligated parties must secure.

In practical terms, the proposal transforms SOSA from an informational planning document into the central mechanism that drives regulatory action on long-term electricity security.

4.4. INCREASED HYDRO STORAGE

Effective 1 May 2026 the Electricity Authority approved changes to the Security of Supply Forecasting and Information Policy (SOSFIP) to improve certainty and better support market participants to ensure security of supply[37].

The changes include an update to the triggers for the access to contingent storage.

> *"The changes will be in place before this winter and will materially improve the contingent storage release boundary buffer. We believe it will address many of the concerns about accessing that storage that were highlighted during the 2024 dry sequence."* [38]

How the Alert Contingent Storage Release Boundary buffer is calculated will change to better reflect the low-range operating characteristics of key hydro catchments to address any resource consent restrictions that could prevent the triggering of hydro storage when required. In practice, this means that the buffer is larger overall, and much larger in winter months than in summer months.

While this change to contingent hydro storage has not been free from opposition, it was approved on 1 July 2026, thus increasing access to an additional 545GWh of capacity for the winters of 2026, 2027 and 2028.

4.5. ALLOCATION OF OBLIGATIONS

The proposed allocation of the long-term obligation also raises important design issues. MBIE proposes that the obligation would be allocated across obligated wholesale purchasers by reference to each purchaser's share of expected winter demand. In principle, allocating responsibility by reference to load has merit, because it links the obligation to the parties whose demand contributes to the need for winter cover. However, the detailed allocation rules will matter. They will determine not only who pays for additional cover, but also how the regime affects retail competition, contracting incentives and the willingness of large new loads to enter the system.

37 Electricity Authority website, https://www.ea.govt.nz/news/general-news/policy-changes-to-strengthen-dry-year-risk-management/

38 Hayden Glass, General Manager, Wholesale and Supply, Electricity Authority

The proposed de minimis threshold is particularly important. MBIE suggests an initial threshold of 500GWh of aggregate load over the six-month winter period. On MBIE's own analysis, this would mean the obligation currently applies only to the four large gentailers and the New Zealand Aluminium Smelter. This threshold is also materially higher than the equivalent threshold used in the Australian RRO, being approximately 100 times larger. That comparison reinforces the extent to which the proposed New Zealand obligation would be concentrated on a very small number of large participants. That may reduce compliance costs for smaller participants, but it also means that the full forecast shortfall would be met by a very small number of parties. Smaller retailers and purchasers below the threshold would continue to benefit from the resulting improvement in system reliability without directly carrying the obligation. This creates an obvious free-rider issue.

The threshold could also create perverse incentives. Retailers or large users approaching the threshold may have an incentive to manage their position so as to remain outside the regime. The same issue could arise for new material load, including data centres or other electrification-driven demand growth. If new load is not brought within the regime in a timely and predictable way, existing obligated parties may be required to procure cover for demand growth they do not control. If it is brought in too abruptly, the regime could become a barrier to entry or expansion.

The allocation framework therefore needs to be developed carefully. It should avoid simply converting a system-wide reliability issue into a compliance burden on the largest gentailers. It also needs to recognise existing arrangements, including demand response embedded in large user contracts, and ensure that obligations are not double counted or misallocated. Without careful design, the allocation rules could undermine the stated objective of the scheme by discouraging retail growth, reducing competitive pressure, and increasing costs for consumers without clearly improving physical reliability.

4.6. PROMOTE INVESTMENT

A central premise of the proposed long-term obligation is that requiring wholesale purchasers to secure dependable winter cover will support investment in the firming resources needed to manage dry-year risk. In principle, this might be correct. A purchaser obligation can create demand for firming contracts, and those contracts may provide the revenue certainty needed to support investment, retention of existing plant, demand response or other qualifying resources.

However, the strength of that investment signal should not be overstated. Investment in long-lived firming resources will only be supported if the obligation creates contracts that are sufficiently bankable, durable and credible beyond a particular compliance year. A one-off or uncertain SOSA-triggered requirement may bring forward some contracting, but it may not be enough to support assets with lives of 30 or 40 years, particularly where future dry-year risk, fuel availability, carbon policy, regulatory policy and technology costs are all uncertain.

This is especially relevant for thermal plant. Assuming New Zealand's long-term direction remains toward a lower-carbon and ever-increasingly renewable system, then the commercial case for new thermal investment will remain difficult even with a reliability obligation. The regime may therefore work less as a broad investment mechanism and more as a compliance pressure on vertically integrated gentailers to retain or contract for existing firming capability. That may have value, but it is different from saying the obligation will efficiently promote new investment.

The design therefore needs to be clear about what kind of investment response is realistically expected. If the objective is to support new firming investment, the regime will need credible qualifying products, sufficient contract tenor, clear treatment of demand response and storage, protections against double counting, and enough liquidity for non-integrated retailers and large users to comply. Without those features and more, the obligation risks becoming a penalty-backed compliance mechanism rather than an efficient investment signal.

4.7. Alignment with Government Policy

The new winter obligation consultation coincides with the gazetting of the new Statement of Government Policy (June 2026). This new policy statement (replacing earlier versions) places a strong emphasis on the need for flexible, dispatchable resources that firm intermittent renewable generation. **The policy statement consistently presents that reliability should be achieved through market incentives.**

A full review of the new policy statement as it pertains to firming electricity is provided in Appendix B and summarised below.

The policy identifies several types of resources that provide firming:

- Hydro storage
- Demand-side response
- Battery storage
- Thermal generation

Rather than directing investment, the Government expects market participants to invest in firming where price signals justify it. A major theme is ***that investment in firming should arise from efficient wholesale markets***.

The Government expects accurate spot prices, strong forward markets, liquid hedging products and clear information about future shortages to encourage investment in flexible resources. Similarly, the Government expects the Authority to develop risk-management products that support investment in flexible generation, storage and other physical resources that reduce supply risk.

The policy is clear that Government, the Electricity Authority and the System Operator should not insulate wholesale market participants from supply risk. The rationale is that protecting participants from market risk would weaken incentives to hedge properly, invest in new firming resources, and maintain security of supply.

The policy avoids favouring any particular firming technology. Instead, it says competition should determine the lowest-cost mix of hydro, batteries, demand response, thermal generation and other flexible technologies.

In short, the GPS presents firming and flexibility as essential to a highly renewable electricity system, but places primary weight on market incentives, participant risk management, technology neutrality and improved information. The proposed reliability obligation is a regulatory intervention that would sit in tension with that framework. MBIE should therefore explain more clearly why a mandatory obligation is required in addition to the market-led measures contemplated by the GPS, and how the obligation would avoid displacing the price signals, contracting incentives and technology-neutral investment decisions that the GPS seeks to preserve.

4.8. COORDINATING OTHER WORK TAKING PLACE

Action 2.5 of the Government's Energy Package is directed at strengthening the regulatory framework for managing dry-year risk over the medium to longer term[39]. To this effect, the Electricity Authority will be given a number of responsibilities and additional enforcement powers through:

- Changes to the Electricity Industry Act 2010 (the Act) to give the Electricity Authority an explicit function to ensure effective management of dry-year risk.
- Updates to the Government Policy Statement for Electricity with clear expectations on the Electricity Authority to increase its focus on the management of dry-year risk. The GPS signals the Electricity Authority should focus on improving the security of supply.

The Electricity Authority is currently progressing several initiatives in this area, including improvements in the market stress-testing framework, investigating standardisation of long-duration risk management products and enhancement of market-making settings.

As noted by MBIE, "if a long-term obligation is introduced, it will likely also need to sit alongside other complementary measures, rather than be expected to solve the dry-year problem on its own."[40]

39 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, Paragraph 19

40 Ibid, Paragraph 109

Given the number of regulatory measures being taken or proposed to support the management of dry-year risk there is a need for tight co-ordination to ensure measures are well aligned. If a single party was given responsibility for bringing all this work together it is much more likely that a more cohesive framework would result. We thus question why the Electricity Authority has not been given the responsibility to assess the proposed winter reliability obligation to determine whether it is an effective and necessary part of the overall framework to manage dry year risk.

We therefore recommend integrating these reforms into a single coherent resource adequacy strategy under the expanded responsibilities of the Electricity Authority, rather than progressing individual initiatives independently.

4.9. APPROPRIATE TIMEFRAMES TO IMPLEMENT

The proposed obligation should not be implemented on a rushed timetable. The design questions are material and go well beyond ordinary Code implementation detail. They include how the relevant reliability standard is defined, how SOSA is used, how the obligation is sized, how qualifying cover is assessed, how obligations are allocated, how market power is managed, and how the obligation interacts with hedge markets, demand response, LNG procurement and existing Electricity Authority work on stress testing and long-duration risk management products.

A useful comparison is the Nelson Review in Australia. That review addressed future wholesale market settings for the NEM and proposed significant new mechanisms, including the Electricity Services Entry Mechanism (ESEM) and a market-making obligation (refer section 3). However, those recommendations were not treated as ready-made instruments for immediate implementation. They are being taken through detailed design, industry taskforce-led implementation and staged reform. That is the right kind of discipline for mechanisms that can materially affect investment incentives, contracting behaviour and consumer costs.

The same discipline should apply here. There does not appear to be sufficient immediacy in the physical security position to justify the Government committing to a novel reliability obligation before the core design questions have been worked through. Nor has a full regulatory impact analysis of the proposed actions been undertaken, again highlighting the need for a more calculated and measured approach. Existing and near-term measures, including higher coal reserves, existing thermal capability, demand response arrangements, improved access to contingent storage, gas storage and the Electricity Authority's wider work programme, provide time to develop a more coherent framework. If a reliability obligation is ultimately required, it should follow that process rather than precede it.

4.10. MARKET POWER

As has been discussed above, a specific and crucial issue that would need to be addressed is market power in firming resources. If the qualifying resources for dry-year cover are concentrated in a small number of portfolios, particularly thermal generation, fuel contracts, coal stockpiles, hydro storage and demand response arrangements, then parties needing to secure cover may have limited practical alternatives. This is particularly relevant for highly renewable gentailers, and any independent retailers or large users above the de minimis level, that may need to buy firming cover from the same parties with whom they compete in retail, contract or generation markets.

The proposed obligation could therefore create a compliance-driven demand for a very narrow class of products (or a single product). If the supply of those products (or product) is concentrated, the regime may increase the value of scarce firming resources and create opportunities to withhold, ration or price compliance cover strategically. This risk is heightened where the alternative to securing cover is exposure to substantial penalties.

This matters because the demand created by the obligation would not be ordinary commercial demand. An obligated party facing a material penalty may have little practical ability to walk away from an offer of qualifying cover, particularly where alternative resources are limited or unavailable. The result could be a form of penalty-backed bargaining power for the holders of scarce qualifying resources. In that situation, the regime could become less about creating new firming capability and more about determining who can monetise existing firming capability.

Any reliability obligation would therefore need explicit market power protections. These could include clear rules on qualifying products, transparency over available firming resources, anti-hoarding and double-counting protections, market-making or standardised product obligations, possibly a requirement for price regulation and/or other market power mitigation mechanisms, and in all cases close monitoring by the Electricity Authority. History and the most relevant international precedent suggest that none of this would be straightforward. Yet without such safeguards, the obligation could improve neither reliability nor competition, but instead transfer value to holders of scarce firming resources while increasing costs for consumers.

Finally, the issue of market power is also entangled with an issue of wealth transfer, with the implication that this is not only a question of protecting consumers and smaller participants. The proposed obligation may create unequal treatment among the obligated parties themselves. Parties that enter the regime with existing firming resources would be structurally advantaged, while parties with more renewable portfolios may be required to procure cover from competitors that already control the relevant resources. That initial endowment position may not change the amount of incremental reliability required, but it could materially affect how value is redistributed through the regime.

5. SHORT-TERM OBLIGATION

As introduced in the beginning of Section 4, the long-term scheme is intended to work in conjunction with a short-term scheme. While the long-term scheme is intended to have an investment focus, the short-term scheme is purely operational (as repeated below for ease of reference:

1. ***Long-term obligation (investment focus)***

- Triggered 3–5 years before winter if Transpower's Security of Supply Assessment (SOSA) forecasts insufficient winter energy margins.
- Large wholesale electricity purchasers would be required to secure additional dependable winter energy through generation, storage, demand response or other qualifying arrangements.
- The objective is to provide revenue certainty that encourages investment before shortages occur.

2. ***Short-term obligation (operational focus)***

- Activated closer to winter if conditions deteriorate despite the long-term mechanism.
- Addresses unexpected events such as generator outages or reduced gas availability.

Together, these obligations are intended to act as an insurance policy against dry-year electricity shortages.

The operation of the short-term obligation is summarised in Table 6.

Table 6: Overview of short-term obligation

Trigger	Activated if projected hydro storage, declining at 18GWh per day, is expected to cross the Watch Curve within the next 90 days
Obligated entities	Large generators whose contribution to winter energy supply exceeds a defined threshold (but set at 2500GWh annually)
Obligation allocation	Based on the winter load each generator's portfolio is expected to support, including its own retail load and relevant contractual commitments.
Qualifying cover	Genuinely firm and deliverable winter energy fuel resources, which may include additional fuel for thermal generation, demand response or other arrangements capable of supporting winter supply – Focus: any action that lowers the Watch Curve.
Compliance assessment	The Electricity Authority would assess whether each obligated generator has secured enough qualifying cover after the response period.
Penalty trigger	Failure to demonstrate sufficient qualifying cover once the obligation has been triggered and the response period has elapsed.

The short-term scheme is intended to act as a backstop to the proposed long-term obligation, requiring major generators to ***quickly secure additional reliable fuel or demand-side resources*** when hydro storage falls to concerning levels.

As set out in Section 4, we do not consider that the long-term obligation should proceed in its currently proposed form. A number of fundamental design issues would need to be resolved first, including ones related to the definition of the problem, the use of SOSA as a binding trigger, the sizing and allocation of obligations, the treatment of qualifying cover, market power, and the interaction with wider reforms. The short-term obligation should therefore not be assessed on the assumption that the long-term obligation is already accepted or settled. Rather, it should be assessed as a second and additional layer of intervention that would sit on top of an already complex and unresolved long-term proposal.

Even if some form of long-term obligation were ultimately justified, the proposed short-term obligation raises distinct concerns. MBIE describes it as an in-year backstop that would apply to large generators, requiring them to demonstrate that they have sufficient genuinely firm fuel cover in place where hydro storage is projected to cross the Watch Curve within the next 90 days if storage continues to decline at an assumed rate of 18 GWh per day.

The objective is understandable. If the system is approaching winter with hydro storage deteriorating, gas availability uncertain, and thermal plant or fuel not clearly available, policy makers will naturally want assurance that something more can be done before the situation becomes critical. No one wants to be standing in front of an empty fuel yard in July explaining that the coal, gas or demand response is “probably on its way”.

However, the short-term obligation is materially different from the long-term obligation. The long-term obligation is at least directed toward creating forward contracting and investment incentives, albeit we have serious concerns about its current design. The short-term obligation is more interventionist again. It would impose a regulatory requirement on generators to procure or demonstrate firm cover in response to an administrative trigger, within a compressed timeframe, with potentially substantial penalties if the EA is not satisfied with the response.

In our view, that raises a number of serious concerns. The short-term obligation risks duplicating, cutting across, or attempting to compensate for unresolved weaknesses in the long-term obligation. It also relies heavily on administrative judgement, creates arbitrary incentives, increases market power risks, and may impose costs on generators in ways that ultimately reduce, rather than increase, the likelihood of efficient firming investment. Each of these points is discussed below.

5.1. WHAT PROBLEM IS IT TRYING TO SOLVE?

The first question we would ask is what market failure is the short-term obligation intended to solve?

If a long-term obligation of some kind is ultimately adopted, it should already require wholesale purchasers to secure sufficient dependable winter cover. Generators providing that cover should already be subject to commercial obligations under the relevant contracts or arrangements. If a thermal generator has contracted to provide dry-year cover, then it will have a natural commercial incentive to secure fuel, maintain plant availability, and manage outage risk. If it fails to do so, the issue is primarily one of contract performance, counterparty risk and the design of the qualifying long-term cover.

That matters because a well-designed long-term regime should already ask the critical questions: is the resource real, is the fuel available, is the plant available, is the demand response callable, and is the cover sufficiently firm? If those questions are not adequately addressed under the long-term regime, the answer should be to improve the long-term qualifying-cover rules, not necessarily to add a second regulatory obligation shortly before winter.

Against this background:

- The short-term obligation therefore risks becoming a patch on a patch. If a generator has already entered into a qualifying long-term arrangement, the short-term obligation may either duplicate those obligations or second-guess them. If the long-term arrangement is not firm enough to survive a deteriorating winter position, then it is not clear why it should have counted as firm cover in the first place. If it is firm enough, it is not clear what additional problem the short-term obligation solves: It does not support revenue adequacy or investment support for firming.
- It seems to be purely a blunt regulatory tool requiring compliance or face a punitive fine – ***do this or else; comply or be punished***.
- It risks incentivising generators to hold lake levels at inefficiently high levels (to avoid penalties) thus locking in dependency on thermal; and increasing chances of hydro spill. Or potentially worse - forcing them to contract for LNG that they don't need at unnecessary cost to consumers.
- It is questionable if needed for physical system security and reliability (refer section 2.1).
- It applies to different parties than the long-term measure (unless you set the de minimus 250x higher than that used in the Australian RRO).

MBIE's stated concern is specific to dry-year conditions. The short-term obligation is framed as a dry-year backstop, triggered where the hydro storage outlook deteriorates to the point that projected storage would cross the Watch Curve within 90 days. Generator outages or lower-than-expected gas availability may be relevant, but principally because they can worsen the system's ability to manage an emerging dry-year position or increase the need for genuinely firm fuel-backed cover. These are indeed potential risks. But the consultation material does not evidence their materiality, particularly within the context of a long-term obligation regime, nor does it demonstrate that the best response to such a dry year backstop risk is to require generators to procure additional cover under threat of regulatory penalties. It also does not show that other options were assessed and rejected against transparent criteria before arriving at this particular mechanism.

Further, MBIE's stated concern isn't consistent with the cause of the problem MBIE gives as an example of what needs to be solved: the sharp price spikes of 2024. If one were to re-examine the events of Winter 2024 it can be seen that the likely cause of the high price spike observed in August was less due to a shortage of generation, or even a shortage of gas, but rather that it reflected the prices needed to secure short-notice demand response from Methanex (i.e. to ***quickly secure additional reliable fuel or demand-side resources).***

At a minimum, before such a short-term regime as that proposed is introduced, MBIE should clearly identify the specific market failure observed, explain why existing market, contractual and emergency mechanisms cannot address it, and show why this proposed intervention is superior to less intrusive alternatives.

5.2. THE SHORT-TERM OBLIGATION IS NOT OBVIOUSLY INCENTIVE-COMPATIBLE

Markets work when participants have incentives to act in ways that also support efficient system outcomes. The mechanisms of such markets are "incentive-compatible". Incentive-compatibility is crucial so that participants can pursue their own commercial interests and, in doing so, contribute to the desired reliability outcome.

The short-term obligation has the opposite flavour. It seeks to require generators to behave in a particular way once an administrative trigger has been met. In effect, it says to generators: you must have sufficient qualifying cover, on terms acceptable to the regulator, by a particular point in time, whether or not your own commercial assessment would lead you to that outcome. That may be a regulatory obligation, but it is not a market incentive in the ordinary sense.

It leads to some uncomfortable practical questions. For example, if a generator intends to take plant out for major maintenance, is that prudent asset management or an attempt to avoid being treated as available for short-term obligation purposes? If a generator says its plant cannot be relied on because major maintenance is required, how is the EA to determine whether that maintenance is appropriate, avoidable, efficient or conveniently timed? Maintenance is not a moral failing. Plant sometimes needs work. Indeed, discouraging maintenance may be one of the fastest ways to make reliability worse over time.

A similar set of uncomfortable questions arises with fuel procurement. A thermal peaking plant might not expect to run much in winter, even in a winter where the short-term Electricity Authority trigger has been pulled – except in extreme circumstances, particularly where its marginal fuel cost is high. In an ordinary market setting, that generator would make a commercial decision about whether to procure fuel in advance by weighing the cost of holding fuel or fuel options against the expected value of being dispatched, or of meeting any contracts it has entered into. However, the short-term obligation would change that calculus. A generator may be required to procure fuel, or fuel options, not because it expects to run, and not because it has voluntarily contracted to provide firm cover, but because it may need to demonstrate compliance with a regulatory obligation. The fuel may never be used. The cost could be material.

This situation is not obviously incentive-compatible. The regime might encourage generators to hold expensive fuel optionality as a compliance matter, rather than because that fuel is expected to be part of the least-cost operational response. The generator's commercial incentive becomes less about efficient dispatch and more about avoiding the risk that the Electricity Authority later concludes it should have had more fuel available. The result is an awkward policy loop. The plant is treated as valuable because it could run in a dry-year event. But if its fuel is expensive, it may only be dispatched in extreme conditions. Yet under the short-term obligation, the generator may still need to procure that expensive fuel in advance so the plant can be counted as firm. That may provide regulatory comfort, but it does not necessarily produce an efficient market outcome and the generator's incentive is tilted towards trying to escape compliance. Worst-case scenario from a system point of view, for example, would be for the generator to conclude it is better off scheduling a major maintenance or some other form of "Electricity Authority-acceptable" unavailability for the dry year period concerned. That, or to accelerate a permanent closure decision.

By contrast, if a long-term regime required purchasers to contract with resources capable of providing sufficient dry-year energy capability, then the generator's incentives would be contractual and commercial. The generator would decide when to maintain plant, whether to procure fuel, and how to manage operational risk by reference to the value of meeting its contractual obligations and the cost of failing to do so. That is a more natural incentive structure than asking the Electricity Authority to determine, close to winter, whether the generator has done enough.

5.3. THE SHORT-TERM MECHANISM DEPENDS HEAVILY ON ADMINISTRATIVE JUDGEMENT

The short-term obligation is presented as a targeted operational backstop. In practice, it would require a large number of judgements by the System Operator and the Electricity Authority. These include, at a minimum:

- whether the trigger should be based on a national hydro storage trajectory;
- whether the assumed 18 GWh/day rate of decline is appropriate;
- whether the Watch Curve is the correct reference point;
- when the relevant assessment is made;
- whether the three-week response period is sufficient;
- which generators exceed the threshold;
- what winter load each generator's portfolio is expected to support;
- what contractual commitments should be included;
- what forms of cover qualify;

- how hydro should be treated;
- how much wind or other intermittent generation can be treated as dependable;
- whether demand response is sufficiently firm or “ready”;
- whether fuel arrangements are sufficiently firm;
- whether third-party arrangements can be relied on;
- whether cover has been double counted;
- whether a plant outage is genuine, prudent or avoidable;
- whether a failure was caused by force majeure or ordinary commercial risk; and
- whether a penalty should apply.

No single judgement is necessarily impossible. But taken together, this is a substantial administrative exercise. It is not simply a matter of checking whether a generator has a contract in a drawer. It requires the Electricity Authority to form a view on physical availability, commercial firmness, hydrological risk, fuel logistics, dispatch expectations, counterparty performance and portfolio attribution.

That is a long way from allowing the market to speak through prices, contracts and dispatch. It places the Electricity Authority in the position of deciding whether a generator’s operational and commercial choices were good enough. The consultation paper itself recognises this when it says the Electricity Authority will likely need to make a “judgement” on how much a generator should be able to rely on expected hydro storage and the optimism of generators’ assumptions.[41]

That is a significant warning sign. A mechanism of this kind should be based, as far as possible, on objective data and clearly specified obligations. Where too much turns on regulatory judgement, the regime becomes harder to predict, harder to finance around, and harder to comply with. Participants will then rationally manage not only physical reliability risk, but also regulatory interpretation risk.

5.4. PENALTIES CREATE ARBITRARY INCENTIVES

The short-term obligation would be enforced through penalties. MBIE recognises that penalties must be large enough to change behaviour, but not so large that they encourage inefficient over-procurement or distort investment decisions. That is easy to say and very difficult to calibrate.

41 A proposed reliability obligation to manage dry-year risk, MBIE, 9 June 2026, Paragraph 151

The problem is more acute for the short-term obligation than the long-term obligation. A short-term trigger leaves less time to respond, fewer options to choose from, and greater uncertainty about whether the feared event will actually materialise. A high penalty in that context may create strong incentives to procure cover that is not economically justified. A low penalty may simply be treated as a cost of doing business. There may be no "Goldilocks" penalty that is just right.

This matters because penalties will change behaviour. A risk-averse hydro generator may conserve water more aggressively than is efficient to reduce the chance of being found non-compliant. That may increase scarcity and prices in the near term. A thermal generator may procure fuel options it would not otherwise need, increasing its costs and raising the hurdle rate for future investment as per the example above. A generator may avoid entering certain contracts if doing so increases the winter load it is deemed to support. A participant may seek to structure its portfolio to remain outside the obligation.

Other behavioural responses are also possible. Participants may seek to ensure that any qualifying cover they hold is priced at a premium because others need it for compliance. Generators with scarce resources may become more cautious about selling cover too early if scarcity later increases its value. The regime may therefore create a compliance market, but one in which the value of the product is driven as much by penalty avoidance as by underlying physical reliability.

This is not a theoretical concern. A short-term obligation would be triggered in precisely the conditions where system stress is rising, optionality is valuable, and alternative resources are limited. If the regime creates a legal need to buy cover at that point, it also creates a very strong incentive for holders of scarce cover to price accordingly. The Electricity Authority may then find itself trying to distinguish between efficient scarcity pricing and the exercise of market power. That is not a job for the faint-hearted.

5.5. MARKET POWER CONCERNS ARE PARTICULARLY ACUTE

The market power issue is significant in the long-term obligation regime as set out in section 4.10. The market power issue just touched on is especially important for the short-term regime.

Once the obligation is triggered, the relevant resources may be highly concentrated. The practical options are likely to include additional thermal fuel, coal-backed generation, gas storage, LNG-backed arrangements, hydro conservation, diesel generation or firm demand response. In many cases only one or two parties may control the resources that can materially lower the Watch Curve or provide qualifying cover within the required timeframe.

That creates a penalty-backed demand for scarce resources. An obligated generator that does not control sufficient qualifying resources may have little practical choice but to contract with a competitor that does. The counterparty will know that the buyer faces a regulatory deadline and potentially substantial penalties. That is a poor starting point for a workably competitive market.

This problem is not confined to independent retailers or smaller players. It can arise among the large gentailers themselves. A highly renewable portfolio may need access to thermal firming or fuel-backed cover held by another party. If the holder of that cover can price it strategically, the obligation may transfer value to existing holders of scarce firming resources without creating additional physical reliability.

The short-term obligation may therefore increase the value of incumbency. Parties that already hold fuel, plant, storage or demand response arrangements may be advantaged. Parties that need to buy those arrangements may be disadvantaged. If this is not addressed through market-making, mandatory-offer, non-discrimination or other access rules – any and all of which would be challenging to put it mildly – the short-term obligation could reduce competition and increase costs.

5.6. THE RELATIONSHIP WITH LNG AND HUNTLY IS NOT STRAIGHTFORWARD

MBIE presents the short-term obligation as complementary to the LNG import facility and the Huntly Strategic Energy Reserve. That may be possible, but it is not obvious.

If LNG is intended to provide additional fuel optionality, then the short-term obligation may increase the likelihood that generators procure LNG-backed arrangements before it is clear that LNG is actually needed. That may support LNG utilisation, but it does not necessarily mean the outcome is efficient. LNG has lead times, logistics constraints and exposure to international prices. Requiring generators to secure LNG options under a short-term compliance regime may simply convert system uncertainty into higher private costs, which will ultimately be passed through to consumers.

The relationship with Huntly also needs careful treatment. If the Huntly Strategic Energy Reserve is already intended to provide coal-backed security during dry years, then the short-term obligation may either duplicate that role or create additional obligations around it. If parties are able to rely on Huntly-related arrangements, the Electricity Authority will need to determine how those arrangements are attributed and whether they are being double counted. If they are not able to rely on them, the regime may require additional cover even though a strategic reserve already exists.

There is also a deeper tension. Strategic reserve arrangements usually require careful quarantine from normal market operation. If resources are perceived as likely to be used too early, or used to manage prices rather than genuine scarcity, they may stop providing additional reliability. The short-term obligation risks blurring this line by creating a regulatory mechanism that may cause fuel or reserve-like resources to be procured, attributed and potentially priced into market behaviour before an actual emergency exists.

5.7. THE PROPOSED SHORT-TERM OBLIGATION RESEMBLES OPTIONS MBIE HAS REJECTED

MBIE has considered and rejected wider options such as capacity markets, strategic reserves and public fuel reserves. The reasons given for rejecting those options are instructive.

Capacity markets were criticised for risking damage to well-functioning investment signals in the energy-only spot market, introducing inefficiencies through Government intervention, and potentially resulting in over-investment or undelivered electricity. Strategic reserve schemes were criticised for the risk that system operators or regulators may be tempted to use reserves in non-emergency situations to lower prices, for damaging spot-market investment signals, and for requiring central management over time.

Those concerns apply with some force to the proposed short-term obligation.

The short-term obligation would not be called a capacity market or a strategic reserve. However, labels only get you so far. The mechanism would still require an administrative trigger, administrative judgement about qualifying resources, administrative compliance assessment and penalty-backed procurement of cover. It could still damage spot-market signals, create incentives to over-procure, and place the Electricity Authority in a continuing central role in determining whether market participants have secured enough physical cover.

In some respects, the short-term obligation may be more difficult than the options MBIE rejected. A strategic reserve at least identifies the reserve resource and attempts to quarantine it. A capacity market at least creates a defined capacity or reliability product and a market for that commodity. The short-term obligation appears to create a reserve-like outcome without a reserve, and a compliance product without a fully developed market. That is clever in theory, but it may be too clever by half.

5.8. IS IT NECESSARY AT ALL?

We are not convinced that the short-term obligation should proceed as proposed.

If the concern is that long-term qualifying cover may not be sufficiently firm, then the long-term qualification rules should be strengthened. If the concern is that fuel information is inadequate, then fuel disclosure and transparency should be improved. If the concern is that demand response is not sufficiently available, then demand response products should be developed and standardised. If the concern is that thermal plant or fuel reserves are strategically important, then targeted availability or reserve arrangements should be considered directly and transparently.

What should be avoided is creating a short-term regulatory overlay that attempts to solve all of these problems at once through Electricity Authority judgement and penalties.

Before the short-term obligation is accepted, MBIE should demonstrate:

- the specific market failure the short-term obligation is intended to solve;
- why that market failure is not addressed by the proposed long-term obligation;
- why existing contractual, market and emergency mechanisms are insufficient;

- what alternatives were assessed;
- what criteria were used to compare those alternatives;
- how the regime avoids duplicating LNG and Huntly arrangements;
- how market power and other forms of gaming will be controlled;
- how maintenance, outages and fuel-price risk will be treated;
- how penalties will be calibrated without creating inefficient behaviour
- how the regime will be implemented so that it is incentive-compatible; and
- how the regime will be implemented without undermining energy-only market signals.

In the absence of that analysis, the short-term obligation should not be implemented.

A more proportionate approach would be to focus first on the long-term framework, the firmness of qualifying cover, improved fuel and outage transparency, demand response, market-making for firming products, and clearer emergency arrangements. If, after that work is complete, a genuine short-term residual risk remains, then a targeted backstop could be developed. But it should be developed from first principles, with objective triggers, clear evidence requirements, market-power protections, and a narrow role.

The policy objective is valid. The proposed short-term obligation is not yet demonstrated to be the right way to achieve it.

APPENDIX A: AUSTRALIAN NEM RETAIL RELIABILITY OBLIGATION (RRO)

The Retailer Reliability Obligation (RRO), commencing in October 2019, is aimed at ensuring system stability in Australia's National Electricity Market (NEM). It mandates that energy retailers and large buyers hold sufficient contracts or invest directly in dispatchable capacity (generation or demand response) to cover their share of peak demand, thus preventing forecast supply shortages.

A.1 HOW THE RRO WORKS

The Australian Energy Market Operator (AEMO) assesses forecast demand against anticipated supply. AEMO is required to issue reliability forecasts as part of its annual Electricity Statement of Opportunities (ESOO). If AEMO identifies a forecast reliability gap in electricity supply for a participating region in 3 years' time, it will ask the Australian Energy Regulator (AER) to issue a T-3 (T being the start of the gap period) reliability instrument for that region.

A T-3 reliability instrument puts liable entities on notice to enter into sufficient contracting to cover their share of the peak demand forecast during the forecast gap period.

If the forecast reliability gap is still reported in the ESOO one year out, AEMO will ask the AER to issue a T-1 instrument setting out a contract position day. By the contract position day, liable entities must hold a sufficient Net Contract Position (NCP) for the reliability gap period. The T-1 instrument will also set a contract reporting day, at least 2 months after the contract position day. Liable entities must report their NCPs to the AER by the reporting day.

Trigger

If AEMO identifies a material reliability gap 3 years and 3 months out, it will apply to the AER to trigger the RRO by making a reliability instrument. Each (State) Minister for Energy in a NEM region also has the ability to trigger the RRO (effectively bypassing the AEMO process) by making an instrument directly. Thus the process is directly open to political directive.

Liable Entities

Liable entities are retailers and other parties that purchase electricity directly from the wholesale energy market. Exempt if consumption <10 GWh per annum (i.e. 100 times smaller than the 500 GWh for the 6month winter period proposed by MBIE for the NZ scheme).

Nature of Liability

Where a reliability instrument is made, liable entities are on notice to enter into sufficient qualifying contracts with generators to cover their share of a 1-in-2 year peak demand and report their net contract position (NCP) to the AER.

A.2 HAS THE RRO BEEN EFFECTIVE?

Opponents of the **Retailer Reliability Obligation (RRO)** have argued that the scheme has become an expensive, complex and ineffective regulatory framework that imposes significant compliance costs on Australia's electricity industry without delivering meaningful improvements in power system reliability.

An example of this sentiment come through strongly in the Australian Energy Council's response to the AEMC review conducted in 2023.

The Australian Energy Council (AEC) argues that the Retailer Reliability Obligation (RRO) should be removed, describing it as an unnecessary, complex and costly intervention that no longer serves its original purpose . While the AEC provides recommendations to improve the scheme if it is retained, its overarching position is that the RRO is inefficient and increasingly redundant.

- The RRO is no longer justified. The AEC argues it distorts efficient market outcomes, imposes significant compliance costs, and interferes with normal market contracting without materially improving reliability.
- The policy has changed substantially since introduction. Lower reliability trigger thresholds, expanded ministerial powers to invoke T-3 instruments, and the extension of the Interim Reliability Measure (IRM) and multi-year RERT have fundamentally altered the original design, making the RRO even less necessary.
- The original rationale has weakened. The RRO was largely a response to reliability concerns in South Australia, rather than a systemic National Electricity Market (NEM) issue.
- Other mechanisms now address reliability. The combination of the IRM, RERT and the emerging Capacity Investment Scheme (CIS) means the RRO duplicates other reliability mechanisms and is likely to become redundant.

The submission concludes that the RRO represents an example of unnecessary regulatory intervention in the NEM. In the AEC's view, existing market arrangements and newer reliability mechanisms provide sufficient safeguards, making the RRO an inefficient overlay that increases compliance costs, distorts contracting behaviour, and ultimately raises costs for consumers. If governments nevertheless choose to retain the RRO, the AEC recommends reforms to improve forecast quality, reduce false reliability triggers, and simplify compliance

Other commentators have noted that financial contracts do not necessarily correspond to physical generation capacity. Retailers may appear fully hedged while the counterparties providing those contracts may themselves lack firm capacity, meaning the RRO does not guarantee a reliable electricity system.

- **Purpose of the RRO:** The RRO was designed to ensure electricity retailers are adequately contracted for their customers' demand, based on the idea that widespread financial hedging would encourage sufficient investment in generation and improve reliability.
- **High compliance burden:** The framework requires extensive reporting, auditing and administrative processes involving retailers, generators, large customers, the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO). These costs are ultimately passed on to electricity consumers.
- **Origins driven by politics:** The RRO emerged following concerns over South Australia's electricity market in 2016 and was later incorporated into the proposed National Energy Guarantee (NEG) as a political measure to reassure critics about reliability. Although the NEG collapsed, the RRO remained..
- **Increasing complexity:** Applying the RRO to today's electricity system is difficult because modern generation includes renewables, storage, demand response and diverse contract structures. The RRO attempts to reduce these complex, probabilistic realities into simplified "contracted megawatt" figures.
- **Expanded scope over time:** Changes to the reliability standard and ministerial powers have made it easier to trigger RRO obligations, increasing compliance costs even when reliability risks are relatively low.
- **Weak link between contracts and reliability:** Financial contracts do not necessarily correspond to physical generation capacity. Retailers may appear fully hedged while the counterparties providing those contracts may themselves lack firm capacity, meaning the RRO does not guarantee a reliable electricity system.
- **Other mechanisms have overtaken the RRO:** Confidence in energy-only markets was not restored by the RRO. Instead, governments introduced capacity investment schemes and expanded AEMO's intervention powers, making the RRO largely redundant.

A.3 OVERLAPPING MECHANISMS

Since the introduction of the RRO in 2019, new policy mechanisms have arisen that overlap with the RRO. These mechanisms include the Commonwealth Government’s Capacity Investment Scheme and jurisdictional schemes such as NSW’s Electricity Infrastructure Roadmap.

A further review of the RRO would help understand the overlap with other policy mechanisms and assess the overall policy efficiency of the RRO. The Commission is aware of strong stakeholder support for a further review on the efficacy of the RRO.

In light of stakeholder views, the Commission considers that the Commonwealth should take a holistic view of policy mechanisms that support reliability, including the RRO, as part of its work on the future design of the market. In the Commission's view, the Commonwealth should consider potential overlaps between the RRO and other policy mechanisms it may recommend and evaluate suitability of the RRO as a mechanism to support reliability in the future national electricity market (NEM).

A.3.1 Capacity Investment Scheme (CIS)

The Capacity Investment Scheme (CIS) is an Australian Government initiative designed to encourage investment in clean energy. It aims to support the deployment of 32 GW of new renewable and clean dispatchable capacity by 2030, ensuring grid reliability as ageing coal plants exit and helping the country achieve its target of 82% renewable electricity.

How it works:

- Competitive Tenders: The Australian Government conducts regular competitive tender bids. Developers tender to build large-scale renewable generation and battery storage facilities.
- Revenue Underwriting: The CIS acts as an underwriter. It provides financial agreements to guarantee a floor price for the energy generated, reducing financial risks for developers and encouraging investment.

A.4 AEMC Review of the Operation of the Retailer Reliability Obligation (RRO)

In February 2024, the Australian Energy Market Commission (AEMC) published recommendations to improve the RRO and reduce the regulatory burden on retailers. Rather than questioning whether the RRO should exist, the review focused on making it more efficient and reducing unnecessary compliance costs.

Key findings

- The National Electricity Market (NEM) is transitioning from a thermal generation system to one dominated by renewable energy, storage and demand response, requiring reliability mechanisms to evolve.
- The RRO remains one component of the NEM's reliability framework, alongside market price settings and AEMO's intervention powers.
- Since its introduction in 2019, the RRO has only been fully activated once, during the South Australian T-1 reliability event (January–February 2024). Experience from this event informed the review.

Twelve recommendations

The AEMC made 12 recommendations aimed at reducing regulatory burden while preserving the RRO's role in supporting reliability.

The most significant recommendations include:

- Move the Net Contract Position (NCP) compliance date from one year before the reliability period (T-1) to the start of the period (T).
    - This would reduce over-contracting.
    - Allow retailers to include contracts from newly commissioned projects.
    - Better reflect actual customer demand.
    - Lower compliance costs.
- Give AEMO greater flexibility by allowing it to request a reliability instrument between 3 and 9 months before a potential reliability gap.
- Retain the AER's role in assessing reliability instrument requests.
- Strengthen the Market Liquidity Obligation (MLO) by lowering the threshold for large generators from 15% to 10% market share in affected regions.
- Remove unused features, such as the voluntary book-build mechanism.
- Expand the range of eligible contracts, including greater recognition of demand-side management and adjusting contract guidelines so more contracts qualify.
- Simplify auditing and compliance requirements, particularly for bespoke contracting arrangements.
- Maintain existing arrangements for liable entities, retailer opt-in provisions and procurer of last resort (PoLR) cost arrangements, while recognising battery storage may require future changes.

Stakeholder feedback

- Most stakeholders supported the proposed operational improvements.
- However, many argued the review should have examined whether the RRO itself remains necessary, particularly given newer reliability policies such as the Commonwealth's Capacity Investment Scheme (CIS).
- The AEMC noted these concerns but stated that evaluating the RRO's overall effectiveness was outside the scope of its review.

Areas of disagreement

The AER and AEMO opposed moving the compliance date from T-1 to T, arguing that it could weaken incentives for retailers to contract early.

The AEMC disagreed, concluding that:

- retailers would still have incentives to secure contracts early;
- moving the compliance date would improve efficiency;

- retailers would have more accurate demand forecasts closer to the reliability period; and
- new generation projects completed between T-1 and T could contribute to compliance.

Future of the RRO

The AEMC acknowledged that the Commonwealth Government's broader review of electricity market design beyond 2030 should consider:

- whether the RRO overlaps with newer mechanisms such as the Capacity Investment Scheme and state-based reliability schemes;
- whether the RRO remains an appropriate reliability mechanism in a highly renewable electricity system.

The AEMC concludes that the RRO should continue, but with targeted reforms to make it simpler, cheaper and more flexible.

A.4.1 Nelson Review

The Nelson review was a more comprehensive review of the Australian NEMS market, releasing its final report in December 2025[42]. It took a more holistic view that the spot market, related derivatives markets and long-term investment markets needed to work together in order to meet the needs of both sellers and buyers:

> *"…how to better link these markets and ensure they work together for the end consumer – with the spot market facilitating efficient dispatch, the derivatives market managing risks arising from the spot market and a new Electricity Services Entry Mechanism (ESEM) extending the forward signals from the derivatives market to support longer-term investment."*[43]

The panel was tasked with reviewing the NEM wholesale market settings ***to support investment in firmed renewable generation*** and storage capacity following the conclusion of Capacity Investment Scheme (CIS) in 2027.

The Panel focused on reforms that reinforce the NEM's original architecture and its effectiveness, put the consumer at the centre of the market and uphold the jurisdictional roles of states and territories:

- For sellers including generators, demand response providers and households and businesses participating via aggregators – the reforms aim to provide accurate price signals, improve access to risk management tools and increase investment certainty.

42 National Electricity Market wholesale market settings review, final report, December 2025

43 Ibid, page 10

- For buyers including retailers and commercial and industrial users – the reforms aim to deliver efficient spot prices, stable and transparent contract prices in the derivatives market, and long-term reliable supply.

Key observations and findings from the review (many, if not all, paralleling the situation in New Zealand) were:

- ***Weather dependent and energy constrained*** - VRE generators are central to decarbonising Australia's electricity supply. While VRE generators produce no greenhouse gas emissions, they are inherently weather dependent, introducing greater day-to-day and seasonal variability in supply. The growing reliance on weather-dependent resources increases the risk of periods where the market is energy constrained
- ***Less dispatchable and less scheduled*** - The market is also being shaped by the expanded participation of distributed energy resources. Millions of new, small-scale, price-responsive generators (i.e. batteries) are expected to enter the market. Without reform to make these resources more visible to the market operator and market participants, the market may not be able to function without significant over-investment.
- ***Thermal retirement*** - Coal-fired power stations approach the end of their technical and economic lives in a 'lumpy', non-linear fashion.
- ***"Sharpening" price signals*** -Sharp price signals are a necessary feature of a market responding to changing resource characteristics and the supply-demand balance. They should be seen not as a flaw but as a sign of a market at work. The Panel notes the market will continue to respond to these signals, provided the right financial tools are available to allocate and manage risk effectively.
- ***Energy only market*** - An energy-only, uniform clearing price market can continue to function effectively even as wind and solar, both with near-zero short-run marginal costs, become dominant sources of generation.
- ***Flexible demand*** - Emergence of a growing class of non-scheduled resources that are responding to wholesale prices ('hidden participants') whose behaviour and impact on the system are not directly visible to the Australian Energy Market Operator (AEMO) and market participants in real time. This includes unscheduled consumer energy resources (CER), such as battery storage, electric vehicles and flexible demand. Traditional assumptions of inelastic demand are no longer valid.

Financial markets

The review also took a keen focus on the present state and role of financial markets. While the spot market governs the operation of the power system, it is the derivatives market that provides the scaffolding necessary to manage financial risk. Effective derivatives markets allow participants to transfer risk to those best equipped to manage it, enabling retailers to offer predictable prices to consumers and generators to manage the risk of uncertain spot prices. These markets perform a crucial function in maintaining confidence, enabling competition and supporting the long- term health of the NEM.

price signals are expected to continue to sharpen in the spot market as it becomes more weather dependent and energy constrained. These trends introduce new financial risks that need to be managed and a derivatives market is key.

Without reform, some traditional hedging instruments are likely to become less available as thermal generators exit the market. These generators have historically underpinned supply of baseload swaps and played a key role in energy-related financial markets.

Effective derivatives markets allow participants to transfer risk to those best equipped to manage it, enabling retailers to offer predictable prices to consumers and generators to manage the risk of uncertain spot prices.

The ability of new or smaller retailers to access affordable hedge products is diminishing, exposing them to unacceptable financial risk and reinforcing a trend towards vertical integration. If left unaddressed, this could result in a less dynamic and more concentrated retail sector with opaque prices, reducing choice for consumers and undermining the competitive pressures that help keep prices efficient.

While direct government interventions, such as the CIS, have had the goal of providing revenue certainty for new investments, they typically do not contribute to derivatives market liquidity. Instead, they operate in parallel to the market, potentially crowding out private hedging activity and limiting the development of deeper, more transparent financial markets.

A well-functioning derivatives market is a precondition for a resilient and investable market-based electricity system. Rather than waiting for these issues to escalate, requiring more disruptive interventions as further coal closures occur, the Panel recommends the creation of a permanent market making obligation framework. This market making obligation would be underpinned by the establishment of an industry-led derivative contracts co-design process to ensure contracts available in the market reflect the needs of buyers and sellers. These material recommendations would be complemented by the extension of the generator availability Medium-Term Projected Assessment of System Adequacy projections to ensure sufficient market information is available to support longer term derivatives market liquidity and price discovery. Together, these measures should shield the NEM against future liquidity and access challenges.

Recommendations

Key recommendations of the Panel included the development of two new schemes:

- Electricity Services Entry Mechanism (ESEM)
- Market making obligation (MMO) framework

These are described in the following sections.

Electricity Services Entry Mechanism (ESEM)

Two barriers to long term investment were seen.

- Tenor gap: a mismatch between the long-term contracts needed by sellers to finance capital-intensive assets (often 10 to 30 years) and the short-term contracting of buyers (typically three to seven years). This tenor gap is driven by a broad suite of uncertainties – technological, regulatory and demand-related.
- uncertainties driven by policies to achieve entry before exit. Consumers expect a seamless, uninterrupted transition with new generation capacity and the requisite system services in place before legacy plants retire.

The Panel recommends the creation of a new ESEM that addresses these barriers that investors currently face and that the market, in its current form, is not well placed to resolve. The ESEM would represent an evolution on existing schemes. The ESEM retains the core features of other recent schemes such as the CIS (i.e. reverse auctions for competitive investments, with targets determined by reliability requirements and jurisdictional emissions goals) but with tweaks to ensure it is:

- Enduring: A permanent feature of the NEM, embedded in the NEL
- Efficient: Focused support for the later years of a project's financed life, targeting only those risks the market cannot manage
- Market-linked: Utilising financial derivatives (defined through a contracts co-design process) for contracting new investment and then progressively returning contracts to market to minimise costs to consumers, keep risks in-market and improve derivative market liquidity and access.

They recommended that:

A. The ESEM be created within the National Electricity Law (NEL) and National Electricity Rules (NER) with the following key features:

    - The services initially procured through the ESEM should be; bulk zero emissions energy; shaping; and firming.
    - The ESEM should allow new electricity service providers to compete for standardised, fungible contracts developed through the industry-led co-design process. These contracts would offer stable income streams tied to the delivery of defined electricity services, helping providers finance new projects.
    - The ESEM should not address risks that market participants are able to manage. The ESEM Administrator should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM Administrator should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or commercial and industrial (C&I) users for the period of time that the market can manage risks effectively.
    - The ESEM Administrator should sell the standardised, fungible contracts it has procured back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.

- The ESEM Administrator should be open to all providers of a given service (bulk energy, shaping, firming), including aggregators of consumer and distributed energy resources (CER and DER), and demand response providers, provided these resources will be scheduled for dispatch by the Australian Energy Market Operator (AEMO).
- The ESEM Administrator should seek to procure quantities of each service that achieve the National Electricity Objective (NEO). This includes any electricity-sector specific requirements of state and territory government emissions policies referenced in the Australian Energy Market Commission's (AEMC's) targets statement.
- Where specific technologies are required to be procured by state and territory government policy and these technologies face greater barriers than the standard tenor gap (e.g. offshore wind, pumped hydro) the ESEM Administrator should use an amended approach to facilitate their procurement.

B. Where cost-effective, projects facilitated through the ESEM should also be able to provide essential system services (ESS).

C. The ESEM Administrator should apply market concentration thresholds, independently set by the AER, when setting eligibility criteria for participating in ESEM procurement rounds.

D. The ESEM Administrator should facilitate the procurement of strategic reserves covering high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions on advice from the Reliability Panel

Market making obligation (MMO) framework

They recommended the establishment of a permanent market making obligation (MMO) framework in the National Electricity Law (NEL) and National Electricity Rules (NER) for a small number of key derivative contracts

The MMO framework should include the following key features:

- The MMO framework should apply to contracts for all services (bulk energy, shaping and firming) defined by the industry-led contract co-design process and as designated by the Australian Energy Regulator (AER).
- The AER should have the ability to add and remove designated contracts over time, responding to market developments and the outcomes of the industry-led contract co- design process. Initially, the designated contracts for firming services should be caps, and the designated contracts for combined bulk energy and shaping services should be baseload swaps.
- Once a contract is designated, the AER should be responsible for assessing whether the MMO should be triggered for that contract and in which NEM regions. The AER assessment should be based on pre-determined objective liquidity thresholds developed through consultation with industry.

- The AER's decision-making on designating contracts and objective threshold for triggering the MMO for a contract should be informed by consultation with the industry-led contract co-design group.
- The MMO should be triggered as soon as possible in South Australia. While both caps and baseload swap contracts will be designated, the MMO should initially apply only to cap contracts in South Australia.
- Energy ministers should be able to opt out of the application of the MMO in their region.
- The MMO should cover suppliers of the relevant services in each region that are above a specified threshold, and should set requirements for minimum trading volumes and maximum bid-offer spreads with trading occurring via an AER-approved exchange and/or over-the-counter (OTC) platform.
- Energy trading businesses should also be able to act as voluntary market makers but be required to comply with the same bid-offer spread as obligated mandatory participants if they elect to trade in the MMO windows.

The AER and ESEM Administrator should regularly convene an industry-led co-design process to define a small set of core derivative contracts that underpin trading activities and the MMO and ESEM

The industry-led co-design process should occur on a regular basis (e.g. every four years) and include financial market bodies, project developers, brokers, generators, retailers and consumers. The Clean Energy Finance Corporation (CEFC) should be a standing participant of the group.

The first co-design process should occur as soon as practicable, drawing on the findings from the pilot process conducted by the NEM Review Panel.

The contracts developed through the co-design process:

- should be able to be traded on an exchange platform
- should be the subject of market making obligation
- should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
- should be utilised to contract with projects through the ESEM
- could be used in retail price benchmarking.

Aligning other policy measures

Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs are aligned with the ESEM.

- Governments should clarify how their greenhouse gas emissions targets apply to projects procured to provide firming services, to provide certainty for investors.

- The Australian Government should task the Australian Renewable Energy Agency (ARENA), in collaboration with the Clean Energy Finance Corporation (CEFC) and other financiers, to accelerate the development and deployment of zero emissions technologies that provide firming at scale.
- Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity.
- The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter- regional settlement residue units beyond three years.
- Once energy ministers are satisfied the ESEM and market making obligation (MMO) are working effectively, they should phase out the Retailer Reliability Obligation (RRO).
- Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication.
- Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at the distribution and transmission level, to ensure a level playing field

Stakeholder response

Stakeholder reactions to the Nelson Report have generally been positive and supportive, with broad agreement among industry players on the need to address the "tenor gap" (a lack of long-term investment signals in the current spot and derivative markets).

Specific stakeholder groups have responded to the proposed Electricity Security Entry Mechanism (ESEM) and contract reforms in the following ways:

- Investors and Developers: Generally welcomed the report's focus on creating transparent, long-term investment signals. Developers strongly supported the proposed long-term contracts for electricity services, as they provide revenue certainty needed to fund multi-billion-dollar wind, solar, and storage projects.
- Energy Ministers: The Energy and Climate Change Ministerial Council formally endorsed the final report, recognizing it as a crucial step to replace the temporary federal Capacity Investment Scheme (CIS) with a more permanent, cohesive national structure. However, Queensland (with the most carbon intensive system) withheld support.
- Large Market Participants: Reactions to the proposed Market Making Obligation (MMO)—which requires large participants to trade certain contracts—were mixed. While broadly understood as necessary to increase market liquidity, states and participants pushed back on widespread enforcement; as a result, ministers agreed to confine the initial MMO to "cap" contracts exclusively in South Australia.

- Industry Analysts & Legal Experts: Experts noted that these reforms represent the biggest change to the NEM in 27 years. They have widely praised the panel's conclusion that the current energy-only market is not fundamentally flawed, but rather needs to be extended to better handle the complexities of a weather-dependent energy grid.

Next Steps and broad timetable

Implementation of the Panel's recommendations have already commenced:

- Ministerial Agreement: In December 2025, Energy Ministers (apart from Queensland) agreed in-principle to the core recommendations. By March 2026, all NEM jurisdictions excluding Queensland agreed on the implementation pathways.
- Legislation & Development: In May 2026, participating Ministers agreed to develop a legislative package for the ESEM and MMO, and will continue preparatory planning.
- Taskforce Support: The Department of Climate Change, Energy, the Environment and Water (DCCEEW) established a taskforce to assist with the reforms.
- ESEM: pilot by late 2026; formal commencement by early 2027;
- PRR visibility/dispatch framework: AEMO to develop by December 2026 (defining visibility/participation modes and thresholds), with NEL/NER amendments progressed to enable full implementation by 2030;
- MT PASA: extend and publish generator availability projections from three to five years to support longer-dated liquidity and price discovery; and
- RRO: once ministers are satisfied the ESEM and MMO are working effectively, ***phase out the Retailer Reliability Obligation***

APPENDIX B: GOVERNMENT POLICY STATEMENT ON ELECTRICITY

The new winter obligation consultation coincides with the gazetting of the new Statement of Government Policy (June 2026). This new policy statement (replacing earlier versions) places a strong emphasis on the need for flexible, dispatchable resources that firm intermittent renewable generation. **The policy statement consistently presents that reliability should be achieved through market incentives.**

What it says about firming generation

The policy identifies several types of resources that provide firming:

- Hydro storage
  - States that as wind and solar increase, "hydro generation with storage will become more important in smoothing out electricity supply in periods when wind and solar are low" (para. 11(c)).
- Demand-side response
  - Identifies demand response as a key source of flexibility that becomes increasingly valuable during peak demand and tight supply (paras. 11(d), 20, 34–35).
  - It is treated as equivalent to generation for balancing supply and demand.
- Battery storage
  - Notes that distributed batteries and storage will become increasingly important (11(b)).
  - Refers to "energy storage" throughout as an important source of flexibility.
- Thermal generation
  - Explicitly recognises that thermal generation remains an important source of flexible backup (11(d)).
  - The Government proposes establishing an LNG import terminal to support reliable thermal generation:

    "Access to LNG could give renewable energy investors greater confidence intermittent renewable generation is supported by reliable thermal back-up generation." (para. 10)

Investment in firming

Rather than directing investment, the Government expects market participants to invest in firming where price signals justify it.

Paragraph 17 states reliability requires:

> *"enough investment in power stations, storage devices and demand-side response capability... including a reasonable buffer to insure against variability in hydro, wind and solar generation."*

This recognises that a highly renewable system needs additional flexible resources.

Market incentives, not mandates

A major theme is that investment in firming should arise from efficient wholesale markets.

The Government expects:

- accurate spot prices
- strong forward markets
- liquid hedging products
- clear information about future shortages

to encourage investment in flexible resources.

For example:

- Paragraph 18 calls for wholesale market incentives that encourage participants to manage dry-year and long-duration supply risks.
- Paragraph 22(c) asks the Electricity Authority to improve forward price discovery, particularly for:

> *"flexible supply to cover periods of low wind, sun and/or hydro inflows."*

Similarly, paragraph 32 expects the Authority to develop risk-management products that support investment in:

- flexible generation
- storage
- other physical resources that reduce supply risk.

Government should not replace the market

The policy is clear that Government, the Electricity Authority and the System Operator should not insulate wholesale market participants from supply risk..

Paragraph 21 states:

> *"Neither the Government nor the Electricity Authority nor the System Operator will step in to insulate wholesale market participants from risk..."*

The rationale is that protecting participants from market risk would weaken incentives to:

- hedge properly,
- invest in new firming resources,
- maintain security of supply.

Technology-neutral approach

The policy deliberately avoids favouring any particular firming technology. Instead, it says competition should determine the lowest-cost mix of:

- hydro
- batteries
- demand response
- thermal generation
- other flexible technologies

Paragraph 40(d) explicitly states:

> *"It is not the Electricity Authority's role to prefer one form of supply over any other."*