



Supporting resource adequacy in a highly renewable, islanded power system

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Transpower in its role as System Operator is responsible for providing information and forecasting on all aspects of electricity security of supply as well as managing any electricity supply emergencies. The Electricity Authority (Authority) sets the electricity market design and the rules and frameworks the System Operator must follow in performing its security of supply functions. These frameworks are designed to support the market to coordinate resources and maintain reliable power supply to Aotearoa New Zealand electricity consumers at all times. In other words, to prioritise a market-led approach that protects security of supply and resource adequacy.

Contingent storage access arrangements are a key part of the arrangements that are currently used to protect resource adequacy. Reconsenting processes are currently considering proposals by generators to introduce more flexibility into those arrangements. This paper sets out our analysis of the potential benefits and costs of easing restrictions on access to contingent storage, to inform any decision to do so. Those decisions sit with other parties such as government, consenting agencies and the Electricity Authority.

This thought piece discusses a range of issues that impact resource adequacy in New Zealand, and therefore security of supply. We discuss changes to the New Zealand security of supply framework that could be considered to both better articulate security of supply risks as well as suggested next steps on mechanisms to address those risks. It is designed to support a range of discussions that are currently underway about Aotearoa's energy security. We are happy to discuss any of the material with interested stakeholders.

1 Resource adequacy and its importance

1. New Zealand's electricity system faces **energy adequacy** ("dry year") and **capacity adequacy** ("peak demand") challenges. Electricity demand is at its highest during the winter months for both peaks and seasonal energy.¹
2. While a high proportion of our total generation comes from hydropower, our hydro lakes have relatively limited storage capability. This means our hydro generation is energy constrained, particularly during extended periods of low inflows when greater output from non-hydro generators is required, particularly thermal generation². With no international interconnections, energy adequacy must be ensured through domestic reserve generation and demand response. This is what gives rise to our recurring "dry year" challenge.
3. New Zealand's energy security of supply standards assess whether there is an efficient level of generation and inter-island transmission to manage the uncertainties associated with extended dry hydro sequences. The standards are assessed at the national level and for the South Island separately, given the latter's greater dependency on hydro generation and limited transmission capability from the North Island to the South Island. The two energy adequacy standards, defined in the Electricity Industry Participation Code (**the Code**) are:³
 - The New Zealand Winter Energy Margin (**NZ-WEM**) of 14% to 16%
 - The South Island Winter Energy Margin (**SI-WEM**) of 25.5% to 30%
4. The winter energy margins represent the difference between the expected amount of energy that can be supplied and expected demand during the winter period 1 April to 30 September, expressed as a percentage of expected demand.
5. The midpoint of the NZ-WEM corresponds to 0.06% of energy shortfall per annum. This equates to roughly 24 GWh of shortfall per annum, or about the average energy consumption of 100,000 homes over 12 days.
6. The NZ-WEM's 0.06% energy shortfall benchmark is set in the Electricity Authority's (**Authority's**) Security Standards Assumptions Document (**SSAD**),⁴ which specifies the assumptions and methodology to be used by the System Operator in determining the winter energy margins. The SSAD arrived at the 0.06% mark through analysis that sought to find the "optimal" level for the NZ-WEM that minimises the expected sum of energy shortage costs and generation costs (in backing up reduced hydropower output) during extended dry sequences.
7. The SSAD and the security standards were last updated in 2012. The Authority reviewed these in 2017 and found that, while changes to the 2012 work may be warranted, the benefits of making changes at that time would be minor. As such, the 2012 SSAD and standards remain in effect.
8. The System Operator produces an annual 10-year forward-looking assessment of New Zealand's winter energy margins through the Security of Supply Assessment (**SOSA**). This annual reporting informs risk management and investment decisions by market participants, policy

1 Peak demand is the highest point of electricity demand on any given day and energy demand is the electricity need over time (i.e. across the winter months).

2 Long-duration demand response such as that between New Zealand Aluminium Smelters and the major gentailers is now also an important "dry year" risk management resource.

3 The Code clause 7.3(2)(a)

4 [Security Standards Assumptions Document](#)

makers, and other stakeholders by showing the margins relative to the standard under different future scenarios. It is the role of market participants (including potential new participants), responding to price signals and market incentives, to ensure sufficient investment is made to maintain margins above the standards.

9. The System Operator also has several processes designed to monitor, report on and respond to emerging security of supply risks closer to real-time, as shown in the Figure 1 below. These include:
 - Monthly Energy Security Outlook which comprises the Electricity Risk Curves (**ERCs**)⁵ and Simulated Storage Trajectories (**SSTs**)
 - New Zealand Generation Balance (**NZGB**) updated daily which provides a capacity margin outlook for the next 200 days
 - Quarterly Security of Supply Outlooks, which provide a summary of the energy and capacity outlook using the latest ERC, SST and NZGB analysis together with other market updates.
 - Market schedules (available within a week of real-time) which are used to signal resource adequacy risks through spot market prices and market notices.⁶

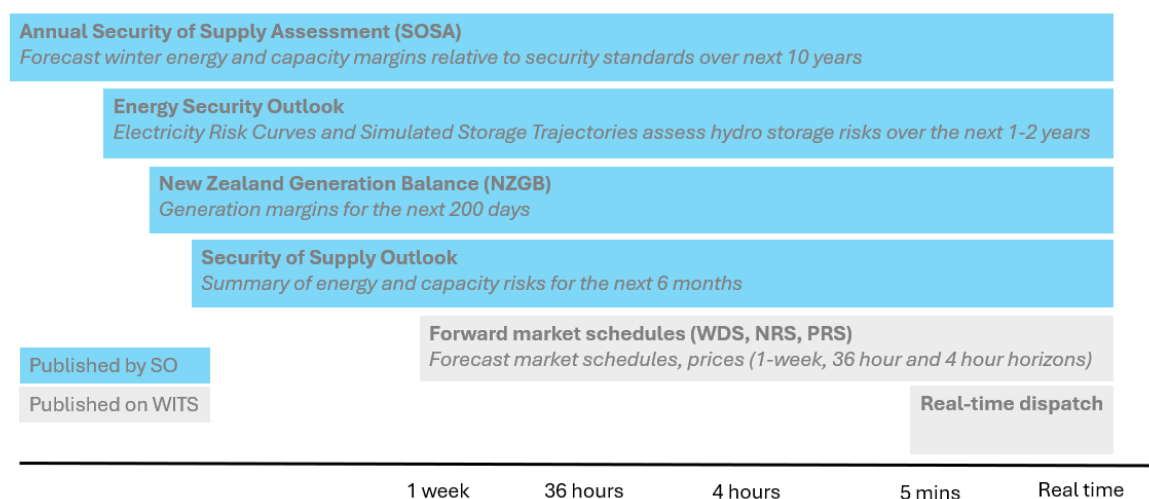


Figure 1: System Operator security of supply reporting to industry

10. New Zealand's thermal power plants have aged and risks to the availability of domestic natural gas supplies for thermal power plants to substitute for hydro generation during extended dry periods have since increased significantly.
11. Meanwhile, in the transition to a highly renewable power system, thermal power plants face an increasingly uncertain future. Increasing quantities of low short run marginal cost (SRMC) intermittent (wind and solar) generation entering the market will tend to reduce average spot prices and increase spot price volatility.

5 The Electricity Risk Curves provide an estimate of the risk of hydro storage running out over the next 12 months assuming market participants respond as if their primary objective is to minimise the use of hydro generation. The SSTs are a market simulation which provides a range of future storage scenarios, based on historic inflows and present-day market behaviour, to assess the likelihood of hydro storage reaching a risk level. See Appendix E for further details.

6 See here for further details: [Process for notifying and managing energy or reserve shortfalls | Transpower](#). A description of these is provided in Appendix E.

12. At times of abundant intermittent renewable power, these resources will displace higher SRMC thermal generation. Price volatility caused by more intermittent renewables will also reduce the incentives for inflexible thermal generation to commit generating units in the wholesale market as there would be guaranteed costs (e.g., in starting up the unit) but more uncertain revenues. This may create capacity risks.
13. In addition, revenue uncertainty could ultimately reduce the availability of thermal generation units going forward, either through retirement or by them being placed into long-term storage. Consequences would include erosion of the electricity system's energy adequacy and its ability to weather dry years.
14. Long-term industry arrangements for thermal back-up energy in dry years are also still emerging – such as the recent agreement between the four large electricity generator-retailers to support the third Rankine generator at Huntly power station remaining operational until at least 2035. The agreement includes holding an initial reserve coal stockpile of at least 600 kilo tonnes ahead of winter each year (in addition to coal stockpile Genesis holds for its own needs).⁷ Despite this, delivery lead times for additional coal (and, potentially, alternatives like biomass) remain long.
15. New Zealand's hydro-dominated system with no overseas interconnections is also quite unique globally, as shown in Figure 2. Few countries have a power system dominated by hydroelectricity, relatively limited hydro storage capability and no (or limited) interconnectivity with other jurisdictions.
16. In other words, periods of low hydro inflows in New Zealand cannot be firmed through power imports. This places extra emphasis on prudent management of hydro storage and availability of dry year reserves, which are currently largely provided by thermal generation. Consequently, a strong focus on energy adequacy is required.
17. Contingent hydro lake storage access arrangements are also one of the ways in which the electricity industry can support energy adequacy for dry years. Resource consents, set by local authorities, hold back access to contingent lake storage until there is an electricity supply emergency.
18. Reconsenting processes are currently considering proposals by electricity generators to introduce more flexibility into contingent storage arrangements. This paper sets out our analysis of the potential benefits and costs of easing restrictions on access to contingent storage, to inform any decision to do so.

7 The Commerce Commission has authorised the agreement between Genesis, Meridian, Mercury and Contact to keep the third Rankine unit (HLY2) in service with a strategic coal stockpile level ahead of each winter to reduce security of supply risks. The stockpile level will initially be set to 600 kT. [Genesis Energy Limited, Contact Energy Limited, Meridian Energy Limited, and Mercury NZ Limited \(the Gentailers\) | Commerce Commission](#)

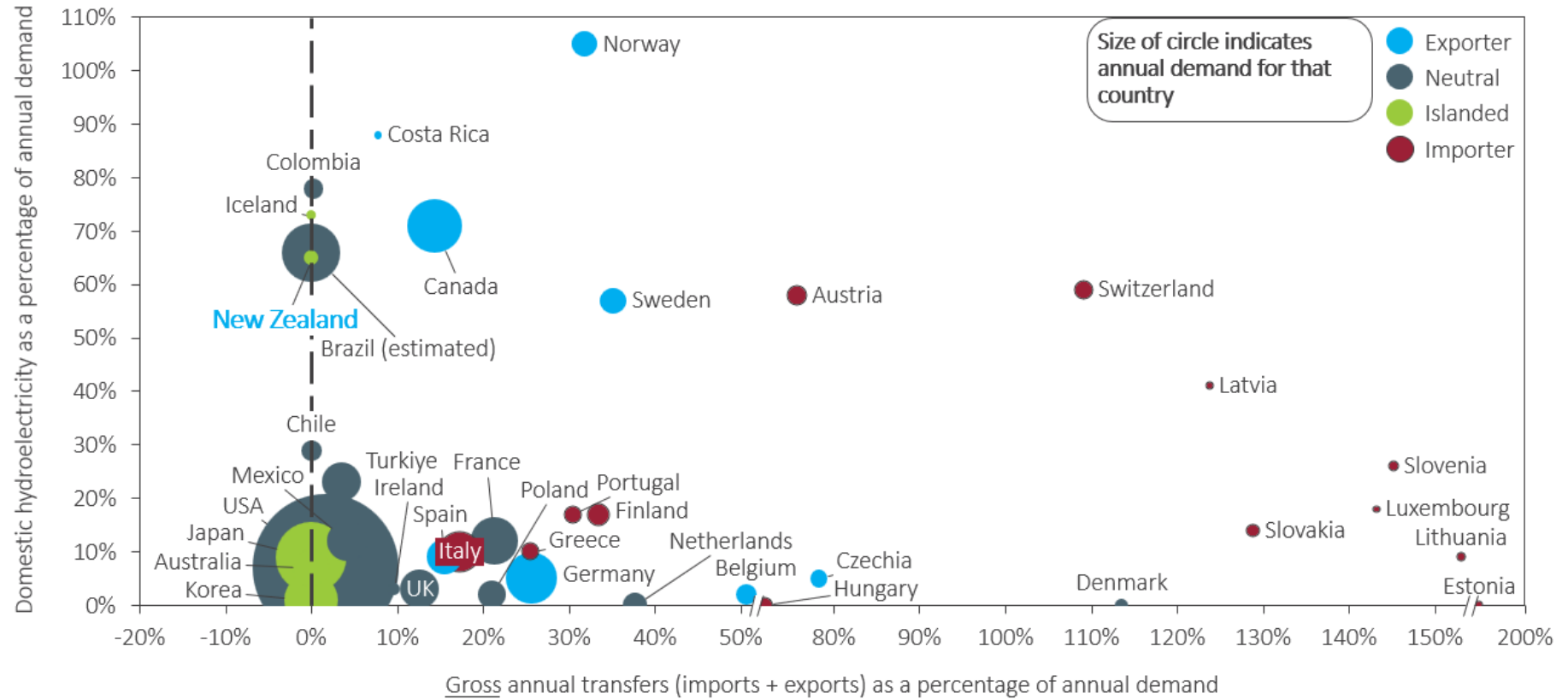


Figure 2: Level of hydroelectricity dominance and power imports/exports by country (IEA data, 2022)

2 Identifying resource adequacy challenges

2.1 The current approach in New Zealand

19. The first step in managing resource adequacy is having an effective way to assess any potential for there to be insufficient energy or capacity in the power system. The Security Standards Assumptions Document (**SSAD**) is the primary instrument that informs the assessment of New Zealand's resource adequacy in the longer-term against security standards that are set in the Code.
20. The SSAD outlines three security of supply margins that must be assessed. These margins are considered the key areas of risk for the electricity system. The North Island and South Island are treated differently because around two thirds of installed hydro generation capacity and around 90% of controlled hydro storage are in the South Island. The margins that are assessed are the:
 - New Zealand Winter Energy Margin (**NZ-WEM**): Adequacy of generation to meet expected national electricity demand under extended dry periods across the winter⁸ months.
 - South Island Winter Energy Margin (**SI-WEM**): Adequacy of generation and north-to-south transmission capacity to meet expected South Island electricity demand under extended dry periods across the winter months, and
 - North Island Winter Capacity Margin (**NI-WCM**): Adequacy of peaking generation and south-to-north transmission capacity to meet peak winter⁹ demand.
21. Each of the margins is assessed against the security standards, which are defined as a range between higher and lower security standards. These are:
 - NZ-WEM: 14-16%
 - SI-WEM: 25.5-30%
 - NI-WCM: 630-780 MW
22. The standards represent an efficient level of reliability - that is, a range where the expected cost of shortage is estimated to be equal to the expected cost of new generation.¹⁰ As an example, the national cost-benefit analysis conducted by the Authority when producing the current NI-WCM security standards determined that up to 22 hours per annum of shortfall (i.e. insufficient capacity to supply the reserve requirements and sometimes the actual load on the system) is economic before additional investment in peaking generation is warranted.⁴
23. Falling below the lower security standards does not equate to electricity shortage. Rather, it implies that investment in new generation would result in an efficient increase in reliability. It can also be interpreted as representing the likelihood of electricity shortage - the higher the actual margin observed the less likely electricity shortage will be, all things being equal.
24. The SSAD therefore sets how the margins (WCM and WEM) are calculated in a way that is consistent with the derivation of the standards and requires that sufficient information about the methodology and input assumptions is provided for the Authority and other stakeholders to have confidence that WCM and WEM are being calculated appropriately. The document sets

⁸ Winter is defined as the period from April to September.

⁹ For the purpose of the WCM, winter is defined as the period between April to October.

¹⁰ The range represents the fact that this efficient level should not be considered as a single number due to uncertainties in key assumptions when determining these standards.

out: (a) the formulae to be used to calculate WCM and WEM, (b) some key assumptions relating to generation, demand, and transmission, and (c) the relationships between the levels of WEM and WCM and measures such as the expected amount of shortage or the cost-benefit of new generation investment.

25. The SSAD was last updated in 2012. It was reviewed in 2017, but with no amendments made. The Authority has agreed that a full review of the SSAD is warranted to ensure that it remains fit for purpose. This had been scheduled for the end of 2025 but we now understand this review will occur in 2026¹¹.
26. Part 7 of the Code then requires the System Operator to prepare and publish a security of supply forecasting and information policy (**SOSFIP**). The SOSFIP sets out that the System Operator will prepare and publish an annual security assessment (known as the Security of Supply Assessment or **SOSA**). The purpose of the SOSA is to inform risk management and investment decisions by market participants, policy makers and other stakeholders. The SOSA provides a ten-year assessment of the balance between supply and demand in the Aotearoa New Zealand electricity system against the standards outlined above.
27. The key inputs into the SOSA are information about generation availability (existing and the new supply pipeline) provided by participants, Transpower forecasts of demand, assumptions specified by the Authority in the SSAD and other assumptions and information not specified in the SSAD.¹² The margins are assessed under a reference case and plausible variations from the reference case (sensitivities) that could occur over the 10-year assessment horizon.
28. Another key role of the SOSFIP is to define how resource adequacy risks to the system in the medium-term are quantified and monitored. The SOSFIP defines the primary tools utilised by the System Operator for this purpose, which is the interaction of Electricity Risk Curves (**ERCs**) and Simulated Storage Trajectories (**SSTs**). Together these show how actual hydro storage, and projected hydro storage (simulated as SSTs), are tracking relative to a calculated risk of energy shortage (modelled as ERCs). The risk of energy shortage is considered to be the risk of running out of controlled hydro storage in the next 12 months, inclusive of contingent storage.
29. The System Operator also has several processes designed to monitor, report on and respond to emerging security of supply risks closer to real-time, as shown in Figure 1 above.

2.2 Evolving the approach to understanding resource adequacy risks

30. The SOSA and Energy Security Outlooks (ERCs and SSTs) are key industry risk indicators that could be developed further to both better inform industry and stakeholders of the risks on the system and also trigger requirements to address that risk.
31. Transpower recently consulted on changes to the SOSFIP including key assumptions used in the development of the ERCs and SSTs, the link between energy and capacity risks, and contingent storage buffer arrangements. We believe these are no regrets changes that are compatible with the current approach to coordinating security of supply in New Zealand's energy-only market. A full overview of this consultation can be found here [Invitation To Comment: SOSFIP Consultation 2025 - Draft amendment proposal | Transpower](#). We are currently considering the

11 The Code (clause 7.3(2)(2C)) provides that the System Operator may use different assumptions than those set in the SSAD in certain circumstances.

12 An example of this is the contribution of batteries and solar to the security margins.

feedback we received. We expect to complete our final SOSFIP amendment proposal in the coming weeks and will publish it once we have provided it to the Authority.

32. It is important to note that the SOSFIP consultation does not make any suggested changes to the broader framework and approach to managing security of supply. That is, the security of supply risk management framework currently prioritises a market-based industry response to resource adequacy challenges both in the short and long term. The tools and calculations specified in the SOSFIP define how the System Operator must assess and provide information to support market participants to mitigate security of supply risks by efficiently coordinating market resources over the near and longer-term.
33. The SOSFIP consultation, and the Authority's consideration of the subsequent final SOSFIP amendment proposal, will therefore allow the evolution of some elements of the risk assessment approach currently utilised by the System Operator. Broader changes, including to SOSA, are however dependent on the Authority's review of the security standards and SSAD, other policy changes¹³ to strengthen the current regulatory framework to reduce future "dry year" risks for our increasingly renewable power system.
34. Changes to the way the SOSA is undertaken could provide a more realistic picture of the challenges facing the sector over the long term. It is becoming clear that the current approach to develop the Reference case under the SSAD no longer provides a sufficiently representative baseline against which to track rapidly evolving investment plans, commitments and commissioning activities between annual SOSA updates. It also does not test the most likely future against the reliability margins thereby potentially impacting the resulting conclusions from the analysis.
35. To help address this concern and ensure the SOSA remains highly relevant for industry and stakeholders, we propose to introduce an additional "Expected Future" case for SOSA 2026.¹⁴ This would represent the combination of the Reference case and sensitivities that we consider (at the time of publishing SOSA 2026) reflects the current view of a most likely outcome for the 10-year modelled period (2026-2035). We could then report on how the market is tracking against this Expected Future case through our quarterly Security of Supply Outlook updates.³⁶ Our November 2025 consultation on the reference case assumptions and sensitivities to be used for SOSA 2026 sought feedback on this proposal.
36. In addition, we have previously provided input into considerations for how the SSAD needs to evolve.¹⁵ These changes include consideration of:
 - **Changing risks:** Considering the potential for increasingly correlated risks (such as low wind, solar, hydro), operational constraints (such as unit commitment and plant failure risks), intra-trading period demand variability risks and reduced thermal back-up generation capacity.
 - **Changing economics:** Issues for consideration when assessing the "efficient" trade-off. An example being the increasing role (and as a result value) of electricity in the economy and how this impacts the "efficient" trade-offs when determining the standards. Other considerations include the additional revenue streams earned by last resort plant in reality.
 - **Changing expectations:** Currently assessments of margins against the Authority's security standards provide information about the average outcomes for a given adequacy margin.

13 See [At a Glance - New Zealand's Energy Package.pdf](#)

14 The Expected Future case is in addition to the Reference case.

15 We've previously referenced and highlighted the importance of reviewing the security of supply settings underpinning our Security of Supply Assessment [Transpower Sub Solutions for peak capacity issues 1Mar2024](#)

No visibility of the size, duration, frequency and timing of potential shortfall events is provided. We think these additional dimensions of potential shortfall events are important attributes to convey so that consumers and wider industry stakeholders can better understand the potential system risks implied by the standards. This is especially important given the increasing economic and social consequences of any shortages as additional segments of the economy are being electrified.

37. These changes to the SOSA and current approach to the SSAD would build on the no-regrets changes currently proposed, ensuring the security standards evolve to the changing system conditions and there is a very clear, regular assessment of security of supply challenges. As noted, these changes do not however alter the focus on a market-led industry-based response to any risks. For example, when the SOSA security margins are projected to be below the “efficient” standards, there are little to no consequences or mitigations to help alleviate this risk.
38. The current framework is based on information provision only and no mechanisms currently exist in New Zealand’s security of supply framework to “to ensure that dry year risk will not reemerge in the future”.¹⁶ In other jurisdictions, breaching the equivalent of a SOSA standard has implications as it signals a risk of the system operating below the efficient level of security. Through the energy-only market these risks are realised through elevated spot and contract prices and potentially inefficient demand curtailment and efficiency losses. There are also wider consequences for homes, business, industries, GDP and the economy broadly.
39. The Energy Security Outlook (ERCs and SSTs) and NZGB are nearer-term energy and capacity risk indicators with the ERCs and SSTs signalling energy risks 1-2 years out and NZGB signalling capacity risks 200 days out. These risk indicators provide a more frequent and up-to-date assessment of these risks to inform industry actions.¹⁷
40. The System Operator notes that the Frontier Economics Review of Electricity Market Performance for the Government recommends a review of security of supply standards, which the Government has endorsed. The Government has also decided to work with the System Operator, to ensure its security-of-supply assessments are fit for purpose for our evolving energy system. We will work with the Government and its nominated agencies to respond to this decision. Our view is that the SOSFIP amendment proposals we are consulting on, and progressing our annual SOSA engagement, are consistent with the Government’s expectation.
41. The Government’s review of electricity market performance also recommends that Transpower produce an annual Electricity Opportunities Statement (**EOS**). The EOS is expected to highlight opportunities for market participants, investors and government to invest in new electricity assets and systems to maintain a reliable and secure supply of electricity. There are a range of EOS-type publications produced in other jurisdictions. Table 1 below provides a comparison of different approaches around the world.
42. An EOS-type document is typically prepared by the System Operator entity to provide a whole of system view on different development opportunities available across generation, transmission, distribution and the demand side as well as incorporating the potential for various fuels. It could be a useful addition to the System Operator’s current suite of analysis. Once the SOSA, Energy Security Outlook (ERCs and SSTs) or NZGB identifies a security of supply challenge, an EOS-type document would provide clarity on what investment or actions might be required to address any gap. This would inform generation investors, network operators, industry and governments on next steps and the pace of development and action required.

16 [At a Glance - New Zealand's Energy Package](#)

17 See Appendix E for further details.

43. The System Operator's annual SOSA already informs risk management and investment decisions by market participants, policy makers, and other stakeholders by showing security margins relative to standards under different future scenarios. However, it is currently left to market participants (including potential new investors), responding to price signals and market incentives, to ensure sufficient investment is made to maintain margins above the standards. This is also the case for lower risk ERCs and NZGB.¹⁸
44. While new investment in generation will support resource adequacy over time, the transition to a more stable state will not be linear. We know that new generation projects can get delayed, fuel supply channels can get disrupted and events happen on the power system, particularly with aging generation and grid assets. But we need to be prepared. We will continue to look for opportunities to enhance our existing publications, including the Energy Security Outlook (ERCs and SSTs), NZGB, quarterly Security of Supply Outlook, and SOSA to keep participants and stakeholders informed about evolving security of supply risks.
45. In this section we have:
- discussed our current arrangements for assessing and identifying resource adequacy risks and some of the changes we are considering (through the SOSFIP review and SOSA "expected case" development) to improve security of supply information to stakeholders
 - outlined some wider changes that we believe would help improve the security of supply and resource adequacy risk assessments going forward. We look forward to working with Electricity Authority and MBIE on these.
46. In the next section, we cover the current approach to strategic reserves in New Zealand – contingent storage and some of the trade-offs if this is reduced.

18 The Watch curve triggers increased reporting but no other industry action. NZGB is used to inform SO market notices. The Electricity Authority is consulting on a new Emergency Reserve Scheme which is proposed to trigger off NZGB.

Table 1: Comparison of Electricity Statement of Opportunities approaches

	Australia	Great Britain	Europe	USA
Publisher of the SOO	AEMO – Electricity Statement of Opportunities (ESOO)	National Energy System Operator NESO – Electricity Ten Year Statement (ETYS)	ENTSO-E – Ten-Year Network Development Plan (TYNDP)	NYISO – System and Resource Outlook (2023-2042)
Purpose	Provides a 10-year outlook for investment signals and maintaining reliability for the National Electricity Market (NEM). Informs planning, decision making and opportunities to invest.	Identifies future electricity transmission system requirements over a 10-year horizon, to support network planning and government decarbonization ambitions.	Pan-Europe transmission and generation planning for the European power system covering a 10-year outlook, that links together various national grid development plans.	Identifies long term reliability needs and investment signals for generation and transmission in New York, over a 20-year horizon.
Audience	Market participants, investors, governments and other jurisdictional bodies.	Transmission owners, developers and investors, policy agencies and regulators, industry stakeholders.	Transmission system operators (TSOs), policy agencies, regulators, industry, developers.	Policy agencies, regulators, energy market participants.
Contents	Forecasts of demand, reliability forecasts (includes unserved energy), generation retirements, committed and anticipated generation and transmission developments, demand flexibility, power system issues.	Transmission network assessment and investment requirements by region, system needs including year-round (including winter), identifies constraints and power system challenges, impacts of new generation, alignment with net-zero targets.	List of transmission and storage projects, including cost benefit analysis, system needs assessment, infrastructure gaps (between committed and identified system needs). Various supplementary analysis and documents, including an interactive online platform.	Identifies current grid conditions and planned projects, forecasts energy and peak demand, potential supply resource development and transmission investment opportunities, provides a range of key findings across demand, resources and transmission under various scenarios
Gaps/ opportunities	Firming capacity, renewables, storage, flexible demand. Note, as AEMO publishes the ISP there is less information in the ESOO around transmission planning.	Transmission projects, market-based grid services, demand-side flexibility, offshore wind and other renewables.	Transmission capacity, cross-border renewables, offshore wind hubs, storage, hydrogen, interconnectors, supply chain, workforce.	Identifies opportunities across demand, resources (supply and capacity) and transmission.

Sources: [AEMO Electricity Statement of Opportunities](#), [National Grid Electricity Ten Year Statement](#), [ENTSO-E Ten Year Network Development Plan](#), [NYISO System and Resource Outlook \(2023-2042\)](#)

3 Understanding the trade-offs made in contingent storage access arrangements

47. New Zealand has a hydro-dominated power system with no overseas interconnections. During periods of low hydro inflows in New Zealand there are limited options available to maintain resource adequacy. As a result, extra emphasis on prudent management of hydro storage and a focus on how access to contingent storage is structured is important. Appendix A: provides background information on current contingent storage access arrangements.
48. Some market participants have requested the ability to utilise the water that is currently set aside as contingent storage in a wider set of security of supply situations. As the electricity system transition progresses and the supply mix evolves, testing the regime around contingent storage access is sensible. As System Operator, our primary focus is on ensuring that the electricity sector can reliably supply New Zealand consumers through all but the most extreme climatic and unplanned events, and participants and stakeholders understand the risks to the system's ability to do so.¹⁹ It is therefore important that decisions made in relation to accessing the country's fuel of last resort are made with a full understanding of both the possible benefits, and the risks and associated potential consequences for consumers.
49. If access to contingent hydro storage were to be eased (perhaps through changes to resource consents or direct legislation) then this would impact the extent to which, and how frequently, contingent storage is used. It could result in contingent storage being used ahead of other generation and demand response resources. As a result of any such increased frequency of access, we should expect flow-on effects on generation dispatch and system costs, and on the system's exposure to uncontrollable, high-impact, low-probability security of supply events. We should also expect changes to incentives to invest/reinvest in any fuel thermal generation assets, which currently are the primary means the electricity system relies on to supplement for low hydro generation during dry sequences.
50. We commissioned JC2 Consulting to undertake independent analysis to assess the implications of changing the way contingent storage is used and the potential trade-offs that arise. This analysis used a market simulation, broadly similar to that used for our Energy Security Outlooks' SSTs, to test book-end scenarios for contingent storage access arrangements and supply pipeline and demand assumptions based on our 2025 Security of Supply Assessment (**SOSA 2025**). JC2 considered a Restricted Access scenario that reflects the regime we have today, and an Unrestricted Access scenario that reflects a hypothetical scenario where contingent storage could be used for generation regardless of the security of supply situation at the time.
51. For both the scenarios the analysis considers different time frames (snap shots in time) covering the short-term (2026 and 2028), mid-term (2030) and longer-term (2035) using simulated cases based on 92 years of historic inflow sequences. For both scenarios we also look at the impact of an uncontrollable high-impact, low-probability security of supply event comprised of a low inflow year and a 28-week outage of the Huntly 5 (E3P) generator (a Stressed case).²⁰
52. The analysis assumes the third Huntly Rankine is retained and considers the impact of one of the Rankines retiring in early 2026, which Genesis indicated would have been the situation if the proposed

19 The regulatory regime against which the System Operator assesses the ability of electricity system to meet consumer demands (near and longer-term) reflects an economic level of investment to provide an efficient level of reliability.

20 The Stressed case uses 1932 inflows and simulates these occurring in parallel with an unplanned outage of Huntly 5 (E3P) similar in duration to what occurred in 2023.

10-year agreement between Contact, Genesis, Meridian and Mercury had not been authorised by the Commerce Commission.²¹

53. This analysis provides an estimate of the likely relative outcomes between the scenarios on aggregate South Island controlled hydro storage levels, and the potential impacts on electricity system costs, which comprise fuel, carbon, demand response and load curtailment costs (but not wider economic implications of electricity for the economy). Potential implications for spot electricity prices are also assessed.
54. It is important to understand that the analysis assumes demand is able to persist through all simulated cases in both scenarios, and none of them (including the Stressed case) result in demand exiting permanently. This assumption likely does not hold for some industries such as those exposed to international competition, as was demonstrated by the contribution of very high wholesale electricity prices to decisions taken by some industrial consumers to permanently exit in 2024.²² It likely does hold better for other consumer demands. Furthermore, the analysis does not attempt to quantify or take into consideration the broader economic impact of electricity supply disruptions on New Zealand's Gross Domestic Product, investor confidence or consumer confidence, which are likely to be much greater than the direct costs of load curtailment.²³
55. The details of the JC2 analysis are included in Appendix B: and summarised in this section.

3.1 Short-term effects of easier access to contingent storage

56. We have modelled a 2026 year to provide an illustration of the potential impacts in the short-term.²⁴ This analysis was undertaken assuming the continued operation of the third Rankine.²⁵ Figure 3 and Figure 4 show the simulations of South Island controlled storage for each of the Restricted Access and Unrestricted Access cases respectively for the 2026 simulated year. The:
 - Blue shaded area is the 5-95 percentile range of simulated storage trajectories
 - Green shaded area represents current contingent storage levels
 - Purple and red dots are weeks where average spot prices exceed \$300/MWh and \$500/MWh respectively. These represent high priced periods.
 - Blue dots are weeks where average spot prices are below \$15/MWh. These represent low priced periods.
 - Red storage trajectory is the Stressed case.

21 The Commerce Commission has recently announced its authorisation of this Huntly agreement. See [here](#).

22 Examples of these include the permanent closure of the Winstone Pulp International mills and Oji's paper recycling plant.

23 Wholesale electricity costs do account for the costs of generator emissions through the effect of the Emissions Trading Scheme.

24 Based on supply and demand conditions from SOSA 2025.

25 The four large gentailers have signed an agreement which, has been authorised by the Commerce Commission. This agreement should see the third Rankine generator remaining until 2035 with a coal stockpile initially of at least 600 kT ahead of winter to support Contact, Mercury and Meridian to cover their dry sequence portfolio risks (~1200 GWh of electrical energy). This will be in addition to Genesis' indicated coal stockpile holding for its own use of ~350-550 kT, bringing the total Huntly stockpile quantity up to ~1.15 MT (~2300 GWh).

Restricted Access

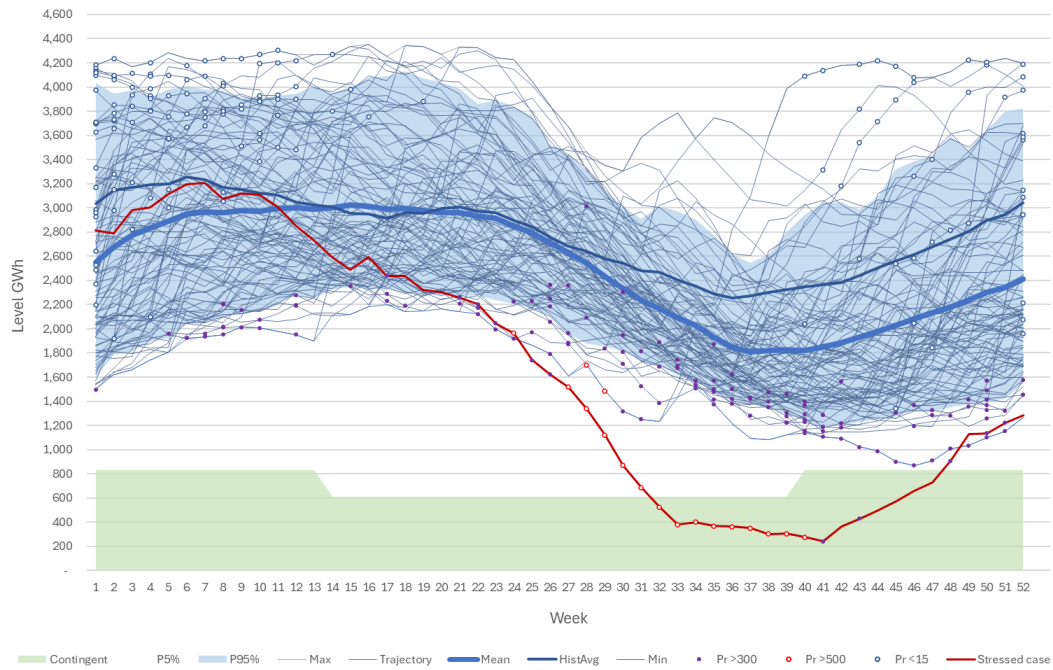


Figure 3: South Island controlled storage with Restricted Access to contingent storage (2026 modelled year)

Unrestricted Access

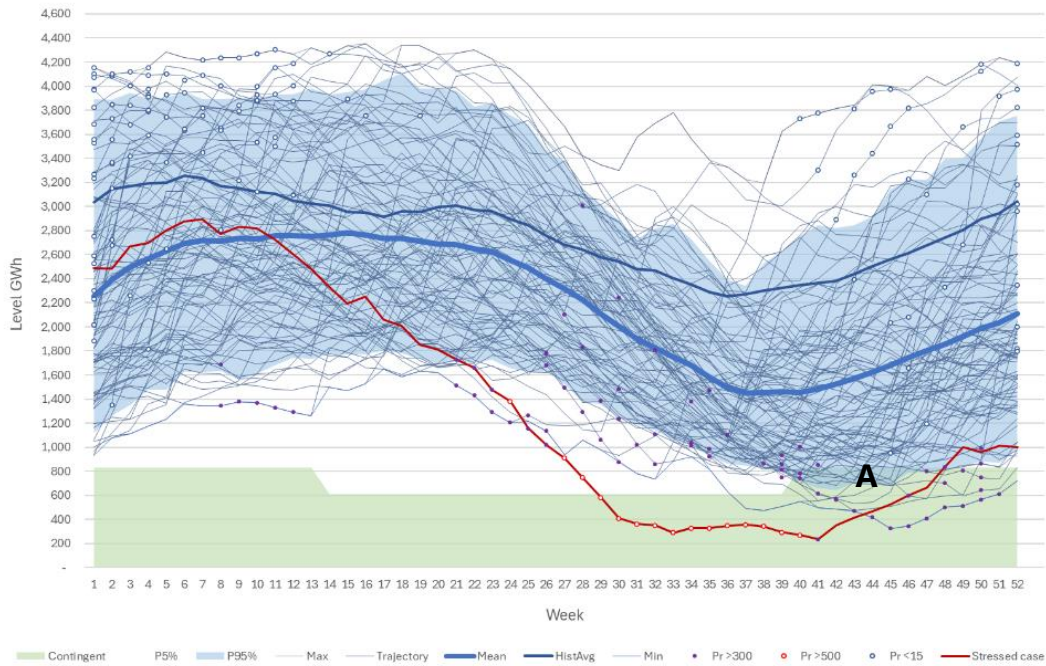


Figure 4: South Island controlled storage with Unrestricted Access to contingent storage (2026 modelled year)

Impact	Restricted Access	Unrestricted Access
Change in average system cost	-	-\$38M pa
Percentage of weeks in contingent storage	0%	2.1%
Change in Stressed case load curtailment costs	-	+\$440m

Table 2: Comparison of Restricted and Unrestricted Access scenarios (2026 modelled year)

57. The modelling results summarised in Figure 3, Figure 4 and Table 2 show that with the Restricted Access we can expect more use of higher cost resources (like thermal generation and demand response) than with Unrestricted Access. With Restricted Access, hydro storage would be held higher (on average), use of contingent storage would be less likely and there could be more hydro spill (as indicated by the increased likelihood of lower-priced weeks).
58. The net effect is that simulated average system costs are higher for the Restricted Access scenario than for the Unrestricted Access scenario. The JC2 analysis estimates the annual average system cost in the Restricted Access scenario in the short-term to be in the range of ~\$38m more per year.²⁶
59. The trade-off is that under the Unrestricted Access scenario, use of hydro storage is more aggressive and storage levels are drawn lower on average, with an average of ~2.1% of weeks in contingent storage in the simulated 2026 year, as shown by the label marked A in Figure 4.
60. Under the Stressed case (the red line), Unrestricted Access results in hydro storage falling lower with more reliance on demand response (voluntary and involuntary). Curtailment cost for the Stressed case with Unrestricted Access is ~\$440m more than with Restricted Access.²⁷
61. From a cost perspective, easing access to contingent storage such that it can be used ahead of other market resources becomes a trade-off between potentially lower wholesale electricity costs on average during normal conditions, and risking higher costs under lower probability-higher impact system states. These could include the effect of factors such as extended dry sequences, unplanned larger generator outages, thermal fuel supply risks and low solar/wind intermittent generation. As such, consciously utilising the fuel of last resort earlier would inherently increase the vulnerability of the power system to uncontrollable but not unforeseeable events. The power system would become less resilient, and the risks and potential consequences for load curtailment (shortage) would be higher.
62. If the third Rankine was not available, the JC2 analysis shows that the reduction in average system costs will be slightly higher, but the costs of load curtailment are even more in uncontrollable, high-impact, low-probability events (our Stressed case). The results for the 2026 and 2028 modelled years, with and without the third Rankine, are shown in Table 3. The results show the cost impact of the Unrestricted Access scenario relative to the Restricted Access scenario. A negative indicates a cost saving relative to the Restricted Access scenario.

²⁶ System costs include fuel costs, carbon costs, Tiwai demand response costs and shortage costs.

²⁷ Load curtailment costs include demand reduction from \$900/MWh (voluntary) to \$10,000/MWh (involuntary). This excludes broader economic impacts for New Zealand such as industry exit and consequences for the GDP.

Modelled year	Cost impact	Two Rankine	Three Rankine
2026	Change in average system cost	-\$43M pa	-\$38M pa
	Change in Stressed case load curtailment costs	+\$740M	+\$440M
2028	Change in average system cost	-\$42M pa	-\$41M pa
	Change in Stressed case load curtailment costs	+\$337M	+\$119M

Table 3: Comparison of Unrestricted Access relative to Restricted Access (2026 and 2028 modelled years)

63. The benefit from the additional Rankine comes from it being a lower cost option under both normal operation and when responding to Stressed system states. This is because the alternative, without the third Rankine, would be higher-priced thermal generation (gas and diesel) peaking plant running harder. Under the Stressed case the availability of the third Rankine reduces the amount and cost of demand curtailment and improves system resilience.
64. The third Rankine helps reduce system costs and increase resilience, but it too is subject to unplanned outage risks. Given the size of Rankine units, unplanned outages of a single Rankine unit would have a larger impact than an outage of a single hydro generating unit on a river chain. This highlights the importance of diversity in our last resort resources. A more diversified system compared to the status quo both in terms of fuel-type and location makes the system more resilient to uncontrollable, high-impact, low-probability events.
65. While system cost impacts provide an indication of national cost-benefit trade-offs, impacts on spot electricity prices could provide an indication of potential market impacts. The JC2 analysis indicates that the price effects are less certain and relative to the Restricted Access scenario, the Unrestricted Access could result in lower prices under certain conditions and higher in others.
66. In the Restricted Access scenario, to maintain higher storage levels, higher-priced resources are likely to be used more often which results in more higher-priced periods. On the other hand, when lakes are fuller and spill risk is increased the Restricted Access scenario is also more likely to result in lower prices more often (relative to an Unrestricted Access regime). Furthermore, there is likely to be much lower prices under a Stressed Case with Restricted Access than under an Unrestricted Access scenario.²⁸ Therefore, the net price impacts of Restricted Access to contingent storage (versus Unrestricted Access) depends on the balance between those instances that can raise price versus those that can lower prices. Market pricing impacts are also dependent on market participant behaviour including how offers are adjusted to reflect periods of higher spill risk and (during dry periods) higher risk of running out of storage. An illustration of these effects is shown in Figure 5 which shows the simulated price duration curve for the Restricted Access and Unrestricted Access scenarios.

²⁸ As discussed above, the modelled Stressed Case scenario comprised of a low inflow year and a 28-week outage of the Huntly 5 (E3P) generator.

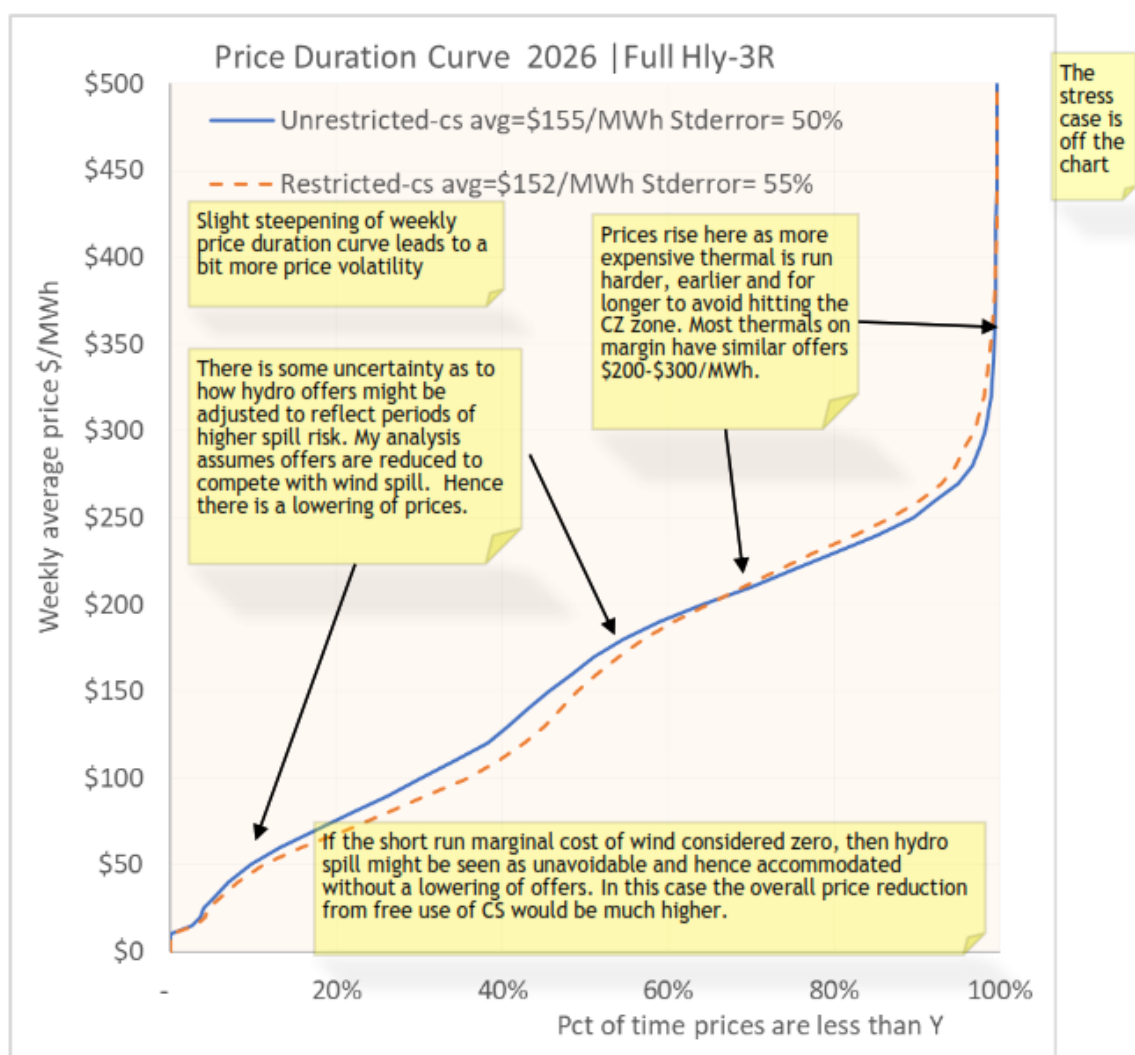


Figure 5: Simulated weekly average prices for the Restricted and Unrestricted Access scenarios over all 92 weather years (2026 modelled year) with 3 Huntly Rankine units (excluding the Stressed Case)

67. Due to the uncertainties in the net price impacts of restricted access relative to unrestricted access, the JC2 analysis estimated ranges for the impact on the average spot electricity prices in the short-term (2026) with 3 Rankine units which are shown in the table below. The lower impact range includes both the higher and lower price effects of restricted access versus unrestricted access averaged over 92 modelled years (as discussed above and shown in Figure 5). The lower impact range indicates a potential for price reduction (-\$3/MWh) under a restricted access regime where the effects that reduce prices (e.g. periods of increased spill risks) exceed those that increase spot prices (e.g. earlier usage thermal generation to hold storage higher). To estimate the upper price impact the assessment only considers the effects that increase spot prices in the restricted access case. This could occur if offers are adjusted to avoid very low prices during periods of increased spill risk. Under these assumptions, the net price increase is +\$7/MWh in the restricted access scenario versus the unrestricted scenario.
68. Under the stressed case scenario, there is a large benefit of having additional hydro storage available and this is reflected in the system cost effects (discussed above) as well as pricing effects. The impact on the 2026 prices could be -\$140/MWh and depending on the level of risk aversion could add -\$1 to

-\$3/MWh to the average price effect (i.e. indicating the net price reduction effect of having additional resources (in this case water available in contingent storage with Restricted access) during stressed system conditions).

Modelled year	Average price impact	Range ²⁹
2026	Excluding Stressed case	-\$3 to +\$7/MWh
	Stressed case only	-\$1 to -\$3/MWh

Table 4: Average spot price impacts of Restricted Access relative to Unrestricted Access (2026 modelled year)

Box 1: Short-term analysis - Key findings

- In the short-term retaining the third Rankine unit allows an increase in the availability of lower cost hydro back-up resources where available alternatives are limited. This reduces system costs (on average) and improves system resilience to uncontrollable, high-impact, low-probability events.
- Any decision to remove restrictions on contingent storage access would need to balance the trade-off of potentially lower system costs (~\$38M pa average) with reduced resilience (load curtailment costs of ~\$440M in uncontrollable, high-impact, low-probability events). These load curtailment costs do not include the consequent wider economic impacts for Aotearoa New Zealand of an outage event, or on the communities and environment local to the lakes with contingent storage.
- While system cost impacts provide an indication of national cost-benefit trade-offs, impacts on spot electricity prices help inform a market impact assessment. The net impact of restricting contingent storage access on average spot electricity prices is less certain and dependent on participant offer behavior. It is also dependent on the scale and duration of higher-priced periods to maintain higher storage levels versus lower-priced periods when there is an increased risk of spill. Prices are expected to be a lot lower during a stressed system state under a restricted access regime reflecting the increased value of last-resort (strategic reserve) resources during periods of increased system stress.
- Diversifying last-resort, strategic reserve holdings (relative to the status quo) across multiple fuel types such as contingent storage and thermal fuels, and multiple generation assets is necessary to increase the resilience of the electricity system to get through uncontrollable, high-impact, low-probability events.

²⁹ Negative indicates where the Restricted access price estimate is lower than Unrestricted access whereas a positive indicates where it is higher.

3.2 Potential longer-term (2035) effects of easier access to contingent storage

69. We need to consider the impact of changing access to contingent storage in both the short and longer term. For this analysis the longer-term is out to 2035 where the system is modelled as in economic equilibrium³⁰ with new generation build, most of which is low short run marginal costs (**SRMC**) renewable generation. The analysis assumes three Huntly Rankines remain available to the electricity system and tests the impact of one Rankine having been retired. The low SRMC generation will sometimes displace hydro generation, which will result in hydro storage being held higher on average. Controlled hydro storage schemes are expected to shift towards becoming the shock-absorber of the system. This is consistent with the Market Development Advisory Group (MDAG) work on price discovery in a renewables-based electricity system.³¹
70. The JC2 analysis uses the 2025 Security of Supply Assessment medium demand forecast³². An additional ~20 TWh of new investment in wind and solar generation could be required by 2035 to get to an economic equilibrium. This outcome could be achieved if (for example) ~75% of the potential wind capacity and ~45% of the solar capacity in the SOSA generation build pipeline were to be commissioned by 2035.

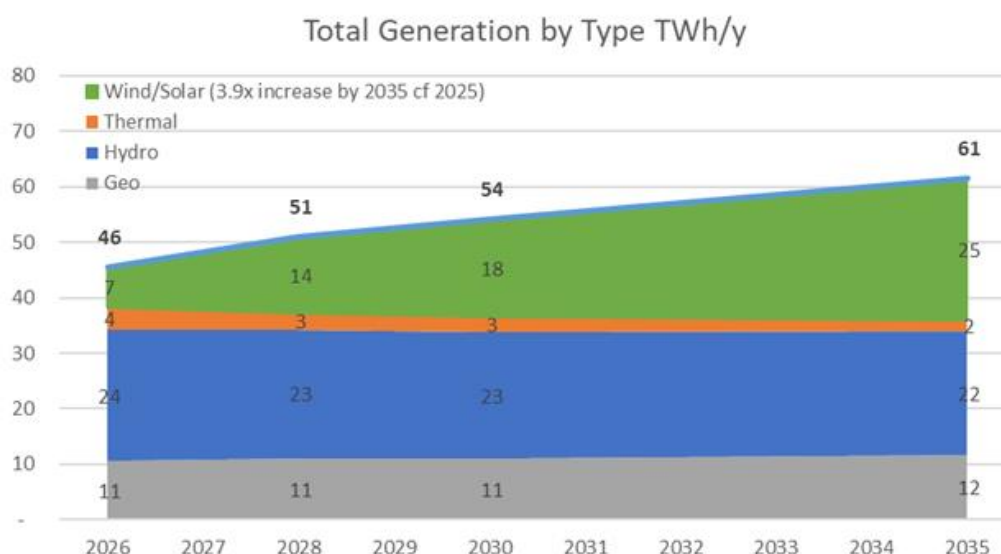


Figure 6: Modelled increase in generation largely due to wind and solar investment

71. Adding more low-SRMC generation to the system reduces the wholesale electricity cost impact of the Restricted Access scenario – including for the Stressed case. This is because in all sequences the new low-SRMC resources are used to limit reliance on stored water, which reduces the need to draw lake levels towards and into contingent storage. This highlights that bringing sufficient new diversely fuelled sources of generation online would help reduce both wholesale electricity costs and the risks and costs of extreme uncontrollable events. Figure 7 and Figure 8 below show the simulated South Island controlled storage trajectories in 2035 under the Restricted Access and Unrestricted Access scenarios. A comparison of the impact on system costs under average conditions and shortage costs under the Stressed case is shown in Table 5.

³⁰ An economic equilibrium is achieved when new entrant generators are able to cover their full investment and operating costs.

³¹ See [Price discovery in a renewables-based electricity system: Final Recommendations PAPER 2023](#)

³² This includes some potential step load increases.

Restricted Access

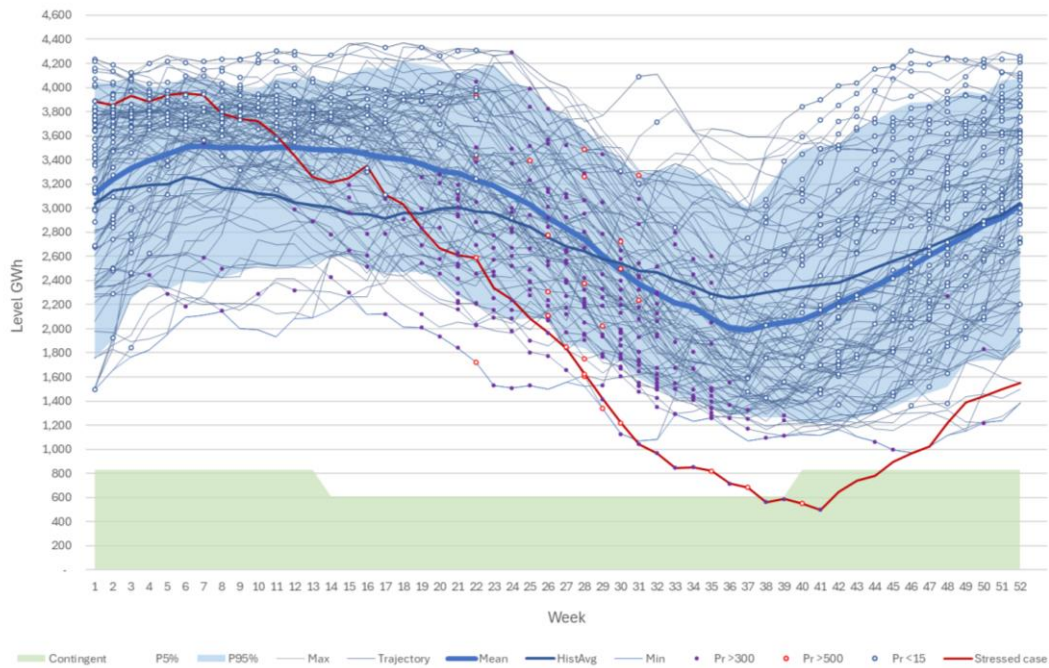


Figure 7: South Island controlled storage in 2035 with Restricted Access to contingent storage

Unrestricted Access

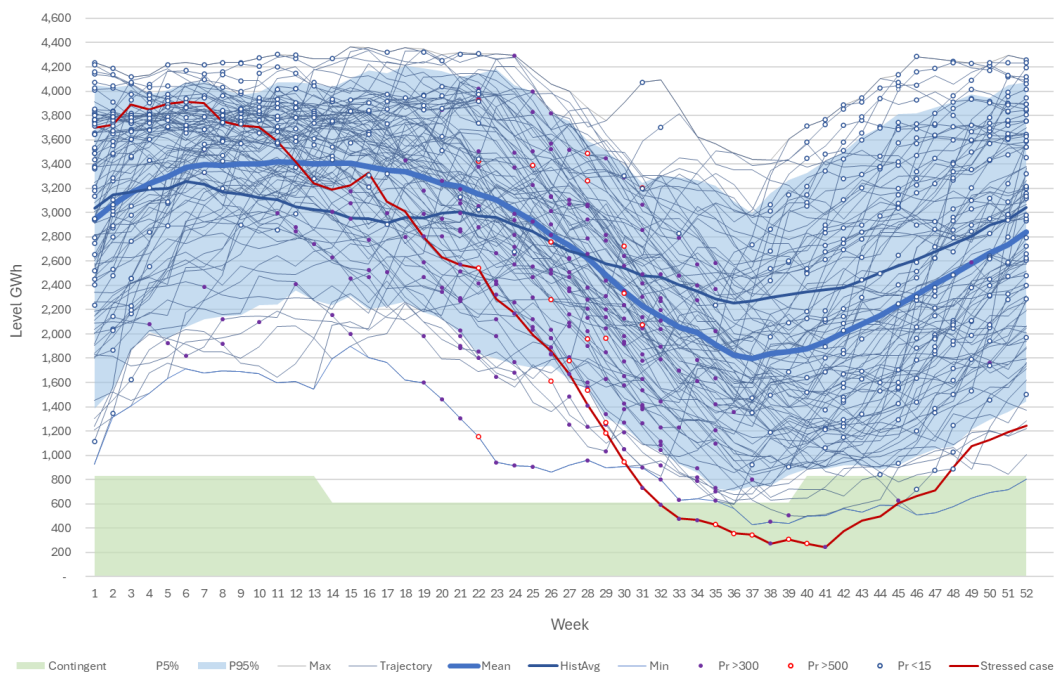


Figure 8: South Island controlled storage in 2035 with Unrestricted Access to contingent storage

Impact	Restricted Access	Unrestricted Access
Change in average system cost	-	-\$28M pa
Percentage of weeks in contingent storage	0%	0.8%
Change in Stressed case load curtailment costs	-	+\$9m

Table 5: Comparison of Restricted and Unrestricted Access scenarios (2035 modelled year)

72. This indicates that in the longer-term (2035), provided there is sufficient new investment, the impact on system costs of Restricted Access to contingent storage should reduce over time. Hydro storage will be held higher, acting more often as the power system's "shock absorber", providing flexibility with increasing intermittent generation.
73. Maintaining the third Rankine unit with sufficient fuel out to 2035, together with new generation build, increases the system's resilience to uncontrollable, high-impact, low-probability events and reduces load curtailment costs (risks) but the impacts are less (as shown in Table 6 below).

Modelled year	Cost impact	Two Rankine	Three Rankine
2035	Change in average system cost	-\$29M pa	-\$28M pa
	Change in Stressed case load curtailment costs	+\$56M	+\$9M

Table 6: Comparison of Unrestricted relative to Restricted Access scenario (2035 modelled year)

74. One of the other impacts of easier access to contingent storage is on incentives for other generation. The impact on the viability of the third Rankine is particularly important because, as noted, it reduces costs by providing lower cost back-up generation but also provides fuel and locational diversity that reduces vulnerability to more extreme events including asset failures.
75. The JC2 analysis found that in the short-term (next 1-3 years), the price signals as reflected through simulated and actual forward prices exceed the marginal cost of new investment. This means there should be an incentive for new investment to enter the market as the expected price received by generation is expected to be higher than the cost of building it. While new investment is being made, the rate of entry is limited by how quickly these new projects can get consented, constructed, commissioned and operating in the market.
76. In the longer-term the entry of these largely low-SRMC generators will reduce prices (gross margins) thus reducing incentives for further investment. This will also reduce the incentives on back-up thermal generation (such as the third Rankine unit and the level of backup fuel).
77. With unrestricted access to contingent storage this is likely to reduce gross margins for the key thermal back-up generators such as the Rankines by up to \$5-20/kW/y. This may be enough to affect the financial viability of retaining the third Rankine unit from as early as 2028 and so could mean it is retired

or less coal is held to be able to fuel the third Rankine. This is highlighted in red in Figure 9 below.³³ The consequence of this would be an electricity system that is less resilient to uncontrollable, high-impact, low-probability events.

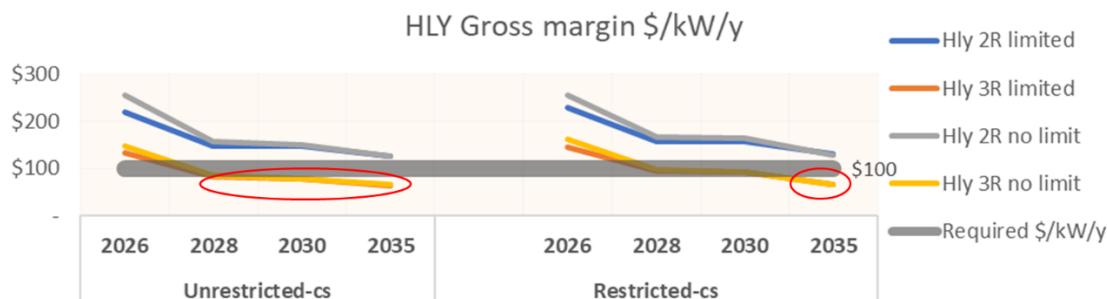


Figure 9: Simulated gross and required margin for 2026, 2028, 2030 and 2035

78. To ensure sufficient resilience against uncontrollable, high-impact, low-probability events going forward, there may be a need to strengthen incentives and/or requirements to maintain sufficient back-up thermal fuel and plant levels. Any change that results in easing access arrangements for contingent storage will bring this need forward.
79. The JC2 analysis also finds that the impact on spot electricity prices of restricting access to contingent storage in the longer term is likely to be small (+/- \$1/MWh) with the system expected to be closer to equilibrium.

33 "Limited" represents a case where Huntly has 400kT of coal with 2 units and 600kT of coal with 3 units over winter. "No limit" represents a case where the stockpile and replenishment rates mean Huntly generation can run without constraints.

Box 2: Long-term analysis - Key findings

- In the longer term, the impact on system costs of ongoing restricted access to contingent storage is expected to reduce provided more low-SRMC energy resources are built and hydro storage increasingly acts to flex in response to fluctuations in solar and wind generation.
- Restricted access with a fueled third Rankine mitigates the risks of uncontrollable, high-impact, low-probability events by reducing demand curtailment costs relative to unrestricted access, but the impacts of easing access are lower than in the short term as a result of increased generation build and the availability of the third Rankine.
- However, as more low-SRMC renewable generation is built and wholesale electricity prices are reduced, incentives to invest in maintaining and fueling thermal back-up generation that provide resilience will reduce. This is expected towards 2035 and will remain a challenge while these assets are needed to ensure resilience of the power system to uncontrollable high-impact, low probability events.
- Unrestricted access to contingent storage will bring this forward (potentially to ~2028).
- Stronger market incentives or other funding mechanisms may be needed while thermal generation continues to be needed as part of the power system.
- Market price impacts of restricted access versus unrestricted access are likely to reduce as additional lower-priced SRMC renewable generation come online which helps hold hydro storage higher at lower prices.

4 The role of strategic reserves in resource adequacy

80. This section explores the role that a “strategic reserve” concept can play in supporting resource adequacy within an electricity market’s design. While more foundational market design features can contribute to supporting resource adequacy, strategic reserves are sometimes used as a complement to a market’s design by addressing resource adequacy gaps in a targeted fashion.

4.1 The energy-only market and the approach to resource adequacy

81. In electricity markets, strategic reserves – and the related concept of a capacity market – primarily exist to address lack of investment in sufficiently firm generation and/or flexible demand to maintain resource adequacy as mandated by security of supply standards. There is some debate in the literature³⁴ as to:
- The extent to which strategic reserves or capacity markets are strictly necessary.
 - Whether strategic reserves may be a stepping stone to or complement to a capacity market.
 - Whether strategic reserves could/should exist standalone absent a capacity market.
82. Such debate exists because the cornerstone of a competitive, liberalised electricity market is the “energy-only market,” which typically exists as a “spot market” and/or “day-ahead market” cleared in \$/MWh half hourly for buyers and sellers of wholesale electricity. Forward contracts (be they exchange traded or “over the counter”) usually exist to complement the energy-only market, reflecting market expectations on prices into the future and providing market participants with opportunities to hedge forward.

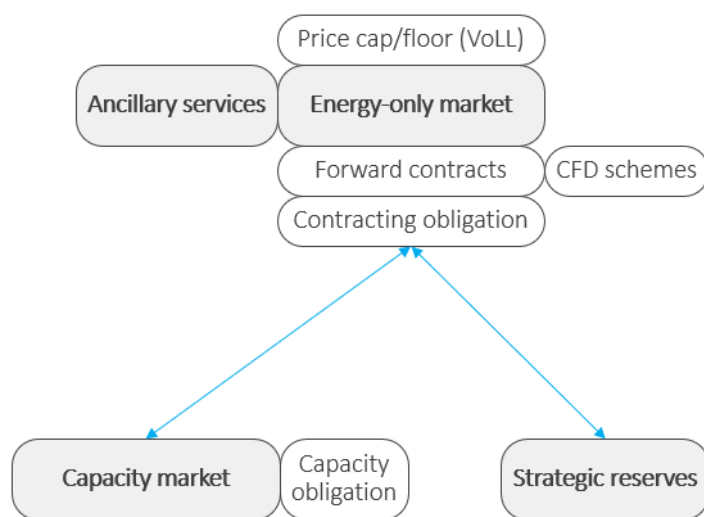


Figure 10: Common features of electricity market designs

34 Refer working paper by Holmberg and Tangeras on “Strategic Reserves versus Market-wide Capacity Mechanisms”: [wp1387.pdf](#)

83. Sustained growth in energy-only market prices (be it day-ahead, spot and/or forward pricing) when demand starts to outstrip supply provides signals for market participants to invest in new generation and/or flexible demand.
84. The academic literature is clear that purely energy-only market designs can deliver security of supply efficiently *in the long run* assuming energy-only market prices are not capped any lower than value of lost load (**VoLL**).³⁵ In practice, relying solely on an “energy-only” market can prove problematic. Firstly, high prices – be they periods of “elevated” pricing or shorter, sharper price “spikes” – inevitably prove controversial, even if they only occur at relatively rare times of resource scarcity and signal the need for new investment. Industry participants, especially those most exposed to high prices, may ask regulators to introduce energy-only market price caps or place pressure on the System Operator and other industry participants to act (for example, through load management or release of energy reserves before triggers are hit) to attenuate what are deemed “unacceptably high” prices. High prices may become particularly unpalatable when industry stakeholders (rightly or wrongly) suspect that market power may also be a driving factor behind high prices.
85. As a result, if prices do not rise sufficiently often towards VoLL due to various interventions, a lack of generation investment may occur due to “missing money” in the energy-only market, placing resource adequacy and security of supply at risk. For example, the investment cases for certain assets that run at low-capacity factors but bolster capacity adequacy often rest on market price volatility. Examples of such assets include gas or diesel peaking plant, batteries, and industrial demand flexibility.
86. Conversely, setting the energy-only market price cap appropriately at VoLL can be difficult to implement. This is simply because estimating VoLL is an inexact science, no matter the jurisdiction. VoLL will inevitably vary by classes of consumer (e.g., residential vs. commercial and industrial), by region, by time of day/week/year and with time as use cases for and alternatives to grid-supplied electricity vary and evolve.
87. Finally, even when an energy-only market is established under ideal conditions, investment in generation and flexibility to support resource adequacy in a timely fashion can fluctuate for a variety of reasons external to the electricity market. Examples of such factors include:
- Regulatory constraints (e.g., delays in working through permitting regimes like the Resource Management Act).
 - Lead times associated with financing, designing, procuring, constructing and commissioning generation (e.g., challenges with global supply chains that were prominent following the Covid-19 pandemic and delays associated with securing grid connections/necessary grid upgrades).
 - Regulatory uncertainty (e.g., uncertainty concerning carbon market pricing and other policy support for moving away from fossil fuels could weigh on the outlook for electricity demand and thus deter generation investment).
 - Economic uncertainty may affect the electricity demand outlook, especially decisions concerning the expansion or contraction of major industrial users.
 - On the consumption side, buyers might not be willing or able to contract too far into the future due to uncertainties and constraints in their own industries.³⁶
 - Fuel constraints may deter investment in, or precipitate the retirement of, certain forms of generation (e.g., consider the current poor outlook for domestic gas production in New Zealand, or the impacts of Russian gas supplies to Europe being curtailed at the start of the invasion of Ukraine in early 2022).

35 Refer working paper by Holmberg and Tangeras on “Strategic Reserves versus Market-wide Capacity Mechanisms”: [wp1387.pdf](#)

36 The recent NEM review highlighted this tenor gap between what buyers are able/willing to contract versus what investors/sellers might be seeking to invest in generation projects. See [National Electricity Market wholesale market settings review](#)

- Technological shifts, such as the rapid improvement in the economics of batteries, wind generation and solar generation, may (somewhat counterintuitively) cause investors to pause and reevaluate their options.
88. The aforementioned factors can exacerbate cyclical mismatches between supply and demand in the electricity market. Where supply-side investment is lagging in the cycle, this can contribute to extended periods of elevated energy-only market and forward contract pricing. This is particularly challenging on the cashflows of market participants that are exposed to the energy-only market price and/or short-term forward contracts.
 89. The unique features of New Zealand's electricity market (a hydro-dominant system, no international power interconnections and an isolated domestic gas market) have the potential to exacerbate supply/demand imbalances further, as seen in the dry winter of 2024 when low hydroelectricity output (due to poor hydrology in a "dry winter") coincided with unexpectedly low gas production. The low gas production during this event resulted in the unavailability of reasonably priced flexible gas for increased gas-fired power generation to offset low hydropower generation.
 90. There are a number of options that could be considered to address these challenges with energy-only markets. The table below provides a summary of current approaches in a range of different jurisdictions.

Table 7: Strategic reserves – summary of case studies

	Sweden	Belgium	Australia (RERT)	New Zealand
Date of strategic reserve introduction	Late 1990s / early 2000s	2014/15	1998	2004
Reasons for introduction	Nuclear plant closures, intended to be transitional	Plant closures	Transitional measure at commencement of the NEM	Dry winters requiring public conservation in 2001 and 2003
Date of strategic reserve retirement	-	2018 (effectively)	-	circa 2010
Primary purpose	Winter energy and capacity adequacy	Winter capacity adequacy	Summer capacity adequacy	Winter energy adequacy
Procurement window	Six months ahead of each winter	Ahead of each winter	Long, medium and short notice rolling windows	Variable, triggered by the “minzone” hydro risk curve rising above set levels
Procurement method	Auction (pay as bid) for capacity payments and variable compensation	Tender – availability and event payments	Tender, with panellists in place for short- and medium-term procurement; pre-activation and activation payments per incident ³⁷	Tender – availability and variable payments, although no contracts were awarded other than for the Whirinaki peaking plant
Quantities procured historically	Between 1% and 6% of installed capacity	4% to 8% of installed capacity	As much as 1% to 4% of installed capacity	Circa 2% of installed capacity (Whirinaki peaking plant)
Participating assets	Generation and load	Generation and load	Generation and load	Generation and load, although no load was ever procured
Notable constraints on participating assets	Generators in the reserve cannot participate in the market over winter	Capacities contracted for the reserve were not permitted to receive any revenues from the energy-only and ancillary service markets	Dispatchable assets cannot participate in the RERT if they have operated in the NEM 12 months prior to being contracted	The reserve operated with a 1,200 GWh cap on energy provision in any four-month period and generation assets were expected to be high variable cost plant “additional” to normal market investment decisions

37

IRR participants are paid longer term availability payments.

	Sweden	Belgium	Australia (RERT)	New Zealand
Trigger mechanism	Lack of reserve conditions – likelihood of “balance resources” being exhausted to maintain a supply and demand balance.	If shortfalls are indicated in the day ahead market or if the TSO deems there to be sufficient risk of shortage day ahead/intraday, reserve participants may be instructed to “warm up.”	Lack of Reserve (LOR) conditions 2 (insufficient reserves to cover the largest source of supply within a state) or 3 (supply deficit)	The Whirinaki peaking plant operated on price-based triggers, with offers made to the market in line with its offer policy
Interaction with energy-only market pricing	Energy price is set to the market price cap if the reserve is activated	Energy price is set to the Administrative Imbalance Price if the reserve is activated	No specific measures	No specific measures
Cost recovery	From balancing “responsible parties” – i.e., electricity suppliers or third parties that undertake balancing on behalf of them	Recovered through transmission tariffs	From NEM purchasers in the regions where costs are incurred	Net costs recovered by levy on wholesale market purchasers

Box 4: Strategic reserves in Sweden

Sweden's electricity system is heavily reliant on hydropower, which accounts for about 60% of annual generation, so its strategic reserve addresses both energy and capacity challenges. The reserve was introduced in the late 1990s and early 2000s following nuclear plant closures that created winter shortage risks. Initially small (around 400–600 MW or 1–2% of installed capacity), it expanded to 2 GW by 2003 before being scaled back to 750 MW between 2011 and 2017 as market design improvements and cross-border interconnections reduced the need for such reserves. Although intended as a temporary measure, the reserve remains in place today and has been activated roughly ten times, with peak deployment reaching 826 MW.

Reserve suppliers must maintain 95% availability, and while regulations aimed for demand response to make up at least 25% of the reserve, this has proven difficult to achieve for extended periods. Capacity is procured ahead of winter through auctions held six months prior, with bids assessed on price, technical performance, environmental criteria, and activation payment terms. Activation occurs when the transmission system operator (TSO) anticipates that balancing resources will be exhausted, making the trigger primarily capacity-driven, though it also supports energy adequacy during poor hydrology. When activated, spot prices are set to the market cap, and reserve generators are excluded from the market during winter. Experimentation with reserve size, duration, and environmental requirements has introduced political uncertainty and raised investment costs. The costs of maintaining the reserve are recovered from balancing parties, such as electricity suppliers or their agents.

Box 5: Strategic reserves in Belgium

Belgium introduced a strategic reserve in the winter of 2014/15 to address security of supply risks caused by plant closures and impending nuclear phase-outs. Belgium has very little hydro generation, so the reserve was primarily aimed at capacity adequacy. The transmission system operator (TSO), Elia, managed the mechanism, recommending the reserve size each year for ministerial approval before running tenders to procure capacity. Eligible participants included generation units that would otherwise have been decommissioned and demand response, with remuneration based on availability and activation payments, subject to regulatory oversight. When activated, the reserve operated outside the energy and ancillary service markets, and market prices were set at an Administrative Imbalance Price of about €10,500/MWh. Activation could occur day-ahead or intraday if shortfalls were anticipated, with minimum notice periods as short as five hours. Between 2014/15 and 2017/18, Belgium procured between 725 MW and 1,535 MW of capacity (roughly 4 to 8% of installed capacity). Costs were recovered through transmission tariffs. No further procurement occurred due to changes in European regulations and a view that strategic reserves was insufficient to address larger resource adequacy challenges posed by electrification and nuclear phase-out. Belgium now operates a market-wide capacity market introduced in 2025.

Box 6: Strategic reserves in Australia

Australia's Reliability and Emergency Reserve Trader (RERT) has been part of the National Electricity Market (NEM) since its inception in 1998. Initially intended as a transitional measure, it persists today as a last-resort mechanism to maintain reliability when supply is projected to fall short of the reliability standard. The Australian Energy Market Operator (AEMO) procures reserves across three timeframes: long notice (12 months to 10 weeks ahead), medium notice (10 weeks to 7 days), and short notice (less than 7 days). Procurement is via tenders, with a panel of pre-approved providers for short- and medium-term needs, with demand response participation featuring strongly. While long notice procurement was briefly removed in 2017 to avoid distorting market investment, it was reinstated in 2018 due to system changes such as coal plant closures and rising intermittent generation. Activation occurs under Lack of Reserve (LOR) conditions, and costs, ranging from about \$15,000/MWh to \$50,000/MWh depending on event and region, are recovered from NEM purchasers in affected areas. The RERT has faced criticism for enabling tactical short-notice procurement, which can lead to suboptimal outcomes. To address this, the Interim Reliability Reserve (IRR) was introduced in 2020 to provide longer-term availability contracts, complementing the RERT and retailer reliability obligations. Both scheduled and unscheduled assets can participate, but restrictions apply to prevent market distortion.

5 Conclusions

91. Our unique, islanded hydro-dominated New Zealand electricity system is evolving rapidly. We face both dry year energy adequacy and peak demand capacity challenges in reliably meeting demand when it is highest in winter for both peak and seasonal energy. Our thermal generation assets are aging, risks to availability of gas supplies to substitute for hydro have increased, intermittent solar and wind generation is increasing as a portion of supply, and our hydro storage capacity is relatively limited. This combination of effects is challenging resource adequacy now, and as we look towards an even more highly renewable future in which low SRMC generation will tend to reduce average spot prices and increase spot price volatility. Consequent revenue uncertainty for firm thermal generation assets could ultimately erode the system's energy adequacy and its ability to weather dry years.
92. In this context it is timely to consider whether and how the System Operator's security of supply information and forecasting assessments may need to evolve to be fit for the present and the future. The System Operator is currently working with the Authority on proposed changes to the SOSFIP that would be no regrets improvements to our monthly ERCs and SSTs updates, and annual 10-year ahead SOSA reporting. We expect SOSFIP changes be in place before winter 2026. Broader changes, including to the SOSA, are dependent on the Authority's review of the security standards and SSAD, other policy changes to support both better risk assessments, and/or greater certainty that any resource adequacy gaps will be filled.
93. Under the current framework this security of supply reporting is designed to be information-provision only. There are no consequences from breaching security standards and industry participants are relied on to coordinate investments and fuels to achieve both capacity and resource adequacy for New Zealand electricity consumers.
94. The Government has endorsed the Frontier Economics recommendation that a review of the security standards and SSAD is needed. The Authority is progressing this work. We think there is an opportunity to also consider how the SOSA might be more effectively utilised within the security of supply framework.
95. The Government's review has also recommended that Transpower produce an annual EOS to highlight opportunities for market participants, investors and government to invest in the new assets and systems needed to maintain a reliable and secure supply of electricity. Internationally, these are typically prepared by the System Operator and provide a whole of system view. It could be a useful addition to our suite of analysis, and Transpower, as both the System Operator and Grid Owner, is uniquely positioned at the heart of the sector to provide clarity on what investment might be needed to address any gap.
96. Contingent storage is currently the fuel of last resort in the Aotearoa New Zealand power system. It is set aside in consents for environmental reasons and, under those consents, is only accessible for electricity generation in developing or actual emergency conditions. In section 7 of our draft SOSFIP amendment proposal consultation paper, we discussed the current trigger for contingent storage. This includes a default buffer to account for operational restrictions. Having reassessed the potential operational restrictions across the relevant controlled storage catchments, we proposed a bigger default buffer for the Alert curve that is profiled across the year. Giving effect to a new default buffer permanently requires the Authority to approve an amendment to the SOSFIP. We are currently considering the feedback we received from stakeholders and working to complete our final SOSFIP amendment proposal, which will be published once we have provided it to the Authority.

97. Some market participants have requested the ability to utilise the water that is currently set aside as contingent storage in a wider set of security of supply situations. If access to contingent hydro storage were to be eased (perhaps through changes to resource consents or direct legislation) then this would impact the extent to which, and how frequently, contingent storage is used.
98. To understand the impacts of easing access to contingent storage, we have presented the insights of JC2's analysis of a potential future in which consents might allow Unrestricted Access to contingent storage at the generators' full discretion. A decision on whether to make access easier than the current Restricted Access scenario does not sit with Transpower in its role as System Operator. Rather, the purpose of the analysis is to provide clarity about the cost-security trade-off that is inherent in contingent storage arrangements and by implication our current strategic reserves. The conclusions we have reached for the short and longer term are summarised below.
99. In the **short-term** (2026 and 2028), if easier access to contingent hydro storage were granted:
- Hydro generation will increase (on average) with storage levels in our major hydro catchments reducing and contingent hydro storage being used more frequently.
 - System costs, spill, and emissions will likely reduce with higher cost resources (such as demand response and thermal generation) being used less.
 - There will be increased exposure to uncontrollable events such as a dry year and unplanned outage of a major thermal generator/thermal fuel outages, and the system will become less resilient.
 - Impacts on spot electricity prices are uncertain and depend on participant offer behaviour, as well as the balance between high-priced periods to conserve storage and low-priced periods when spill risk increases when compared against a restricted access regime. Under stressed system conditions, prices are expected to be significantly higher with unrestricted access as hydro storage would likely be lower and because last-resort resources hold greater value during extreme events.
100. There is an estimated benefit to the electricity system from unrestricted access to contingent storage of ~\$38M per annum. But realising this requires a trade-off with consequent reduced resilience and increased load curtailment costs during uncontrollable, high-impact, low-probability events. The estimated load curtailment cost from our modelled Stressed case assuming three Huntly units are retained is significant (~\$440M), and this excludes broader economic and environmental impacts. Decision makers will need to assess whether the potential benefits outweigh the possible costs from such a change.
101. The inclusion of the third Rankine generator, with sufficient fuel (additional strategic reserves), is vital. It reduces cost impacts as it provides additional energy and capacity to the system to help maintain higher storage levels as well as respond to extreme events. Thermal generation as strategic reserve (in addition to hydro) provides a more diversified form of strategic reserves for the country (both in terms of fuel type and location). This assumes there is sufficient coal available at Huntly when it is most needed for electricity system resilience. The proposed Huntly deal with the major gentailers is a step in the right direction.
102. In the **longer-term** (2035):
- New lower-SRMC generation investment is expected to come to market (geothermal, wind and solar, with wind and solar also being variable in output). As a result, it is expected hydro storage will transition to its long-term role, acting as the system shock-absorber increasing output when intermittent generation is lower and reducing output when higher. On average, it is expected

that hydro storage will tend to be held higher due to increased renewable generation on the system and hydro spill will increase. This is consistent with the MDAG findings.³⁸

- Provided sufficient new generation comes online, the cost and risks of easing access to contingent storage should reduce over time.
- On the other hand, easing access to contingent storage could reduce the incentives on back-up thermal fuel and viability of the third Rankine generator, increasing security risks.
- Market price impacts of restricted access versus unrestricted access are likely to reduce as additional lower-priced SRMC renewable generation come online which helps hold hydro storage higher at lower prices.

103. Easing access to contingent storage without the third Rankine unit would reduce the level of system security. The retention of the third Rankine together with its associated fuel to 2035 supports system security during a period of anticipated significant renewable build. Investing in and building these new renewable generation assets will take time. During this period, the risks of easing access to contingent storage should reduce as sufficient new renewable build enters the market.
104. The retention and fuelling of a third Rankine is one of a number of elements that would be needed to support easier access to contingent storage. Other elements that we have noted throughout this section are summarised below.
105. A combination of hydro and thermal fuel provides diversity benefits over the status quo, which sees TCC retire at the end of this year. The third Rankine deal is a step in this direction, but our assessment is it would need to endure for the full 10-years as currently contemplated. Additional fuel and capacity is required to replace any lowering of lake levels during the period to 2035 and so the current acceleration of generation build must continue. It will also be necessary to ensure there is sufficient thermal fuel available to be able to respond in uncontrollable, high-impact, low-probability events.
106. The JC2 Consulting analysis also highlights that there could be a pathway to utilising New Zealand's valuable hydro resources in a different way. This would be a fundamental shift in the approach to managing security of supply and is not a decision that can be made by the System Operator. We have highlighted the risk trade-offs and what conditions we consider would need to be met to at least maintain security of supply at current standards if there were a decision by the Government or the Authority to make changes to the amount of contingent storage that was set aside for developing emergency and emergency use.
107. This paper also touches on the point that there are a range of market design options that can be used in a targeted way to help address resource adequacy issues.

38 See [Price discovery in a renewables-based electricity system: Final Recommendations PAPER 2023](#)

Appendix A: Current contingent storage access arrangements

108. Resource consents for Lakes Pūkaki (Meridian Energy), Hāwea (Contact Energy), and Tekapo (Genesis Energy) include arrangements through which extra storage is available to generators contingent on access being necessary for national security of supply. This “contingent storage” is currently the fuel of last resort in the Aotearoa New Zealand power system. Consent decisions made by local authorities set it aside for environmental reasons and, under those consents, is only accessible for electricity generation in emergency conditions.
109. The framework through which any decision to trigger access to contingent storage would be made is set by the Electricity Authority and relies on security of supply information provided by the System Operator including through the Security of Supply Forecasting and Information Policy (**SOSFIP**). We recently completed consultation on a draft proposal to amend the SOSFIP that would refine the trigger for access to contingent storage.³⁹ We think our draft SOSFIP amendment proposal would ensure the trigger for access to contingent storage operates as intended within the current security of supply framework and improve certainty about the circumstances in which contingent storage would be accessible.
110. Currently, re consenting processes are in progress for all the Lakes Pūkaki, Hāwea, and Tekapo generation schemes. The consent holders have proposed changes that would introduce more flexibility to access the water that is contingent storage. Some electricity market participants think this greater flexibility to access contingent storage has the potential to result in both lower electricity prices for consumers, and lower emissions.
111. However, any change to contingent storage levels would alter the electricity system’s risk profile and impact the ability to maintain supply during challenging conditions. Given New Zealand’s unique and highly renewable electricity system, decisions about access to contingent storage require careful consideration of potential risks and benefits. Ultimately, authority for changes to these arrangements rests with the relevant consenting agencies, not Transpower in its System Operator role.

What is contingent storage?

112. Resource consents for Lakes Pūkaki (Meridian Energy), Hāwea (Contact Energy) and Tekapo (Genesis Energy) include arrangements through which extra storage is available to generators contingent on access being necessary for national security of supply.
113. The decisions by the local authorities to make access to this water contingent on the risk to electricity security of supply – as we understand it – reflect concerns about the known and likely impacts of very low storage levels on the environment, and the communities local to the storage lakes including through downstream economic implications for industries such as tourism and agriculture. This

39 [Invitation To Comment: SOSFIP Consultation 2025 - Draft amendment proposal | Transpower](#)

means access to contingent storage for electricity generation is currently allowed only under exceptional/limited circumstances.⁴⁰

114. Contingent hydro storage is therefore effectively the stored fuel of last resort for Aotearoa's power system, playing a role sometimes referred to as strategic energy reserve. It is held back through regulation,⁴¹ to be available to respond when events and/or weather move against us. In that sense it is a form of insurance. Relative to other electricity systems worldwide its role is important. We do not have interconnection to other jurisdictions, so we cannot diversify the management of the risks inherent in renewable fuels availability/reliability across broad geographic regions. And our location in the world means lead times for onshoring importable, storable fuels (currently coal and diesel) are long (typically months). We do not import gas and our ability to store gas is limited. This situation may change in the coming years.
115. There is currently no other form of energy storage (or strategic reserve) in our power system that is held out of the market through regulation for use only when the risk of electricity shortage is sufficient to make accessing it necessary. After contingent storage has been accessed, the last tools available to protect the ability of the power system to supply consumers are official conservation campaigns and rolling outages. Both these tools would have substantial impacts for households, businesses and industries – and New Zealand, both economically and reputationally.
116. Figure A shows the amount of contingent storage available in each lake across the year at each of the electricity system risk statuses (Alert and Emergency).⁴² The mechanisms for setting these electricity risk statuses are set in the SOSFIP.⁴³ These include the requirements for calculating the Watch, Alert and Emergency electricity risk curves.

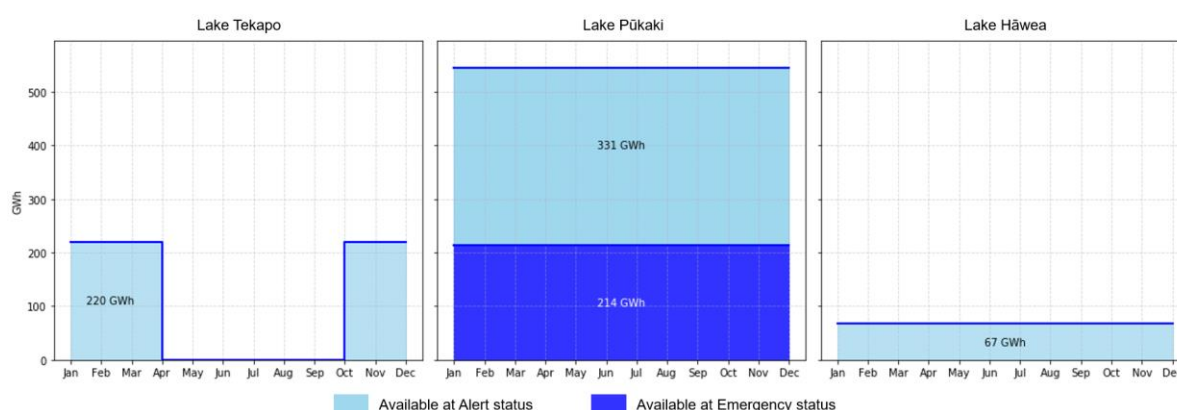


Figure A: Contingent storage availability

40. Currently, Meridian has indicated it will apply for resource consent to enable it to access contingent storage in the absence of an Alert or Official Conservation Campaign being in place, for a three-year term. It has been reported ([Contact Energy seeks to dip deeper into Lake Hāwea | RNZ News](#)) that Contact will apply to fast-track applications for resource consent to increase its access to water on a day-to-day basis, by lowering the minimum normal operating lake level to include storage that is currently contingent storage, and providing for additional water lower in the lake to be available as contingent storage. Should these consenting processes result in a change to contingent storage arrangements there may be a need to consider amendments to the SOSFIP and/or other elements of the security of supply information and forecasting framework.
41. Including the Waitaki Catchment Water Allocation Plan (**WAP**), Manapouri-Te Anau Development Act 1963, resource consents and operating rules.
42. Contingent storage is specified in metres in resource consents. The conversion to GWh is based on the electrical energy potential from downstream generators. As an example, the 220 GWh at Lake Tekapo represents the total potential generation from all downstream generators. ~80 GWh of the 220 GWh of Tekapo contingent storage is generated at Tekapo A and B. The remainder (~140 GWh) will be generated by the Meridian power stations on the Waitaki scheme.
43. More information about how Alert and Emergency statuses are set and used to trigger access to contingent storage under current consents and arrangements is available in our [System Operator - SOSFIP review consultation - October 2025.pdf](#).

117. The amount of contingent storage available under Alert status changes during the year:
- October to March (across summer): ~612 GWh of contingent storage is accessible across Pūkaki, Tekapo and Hāwea (equivalent to ~106 days of running a Huntly Rankine generator at 240 MW).
 - April to September (across winter): The normal minimum operational level of Lake Tekapo is 220 GWh lower. This means during the winter there is 220 GWh more storage that can be accessed under normal operation. As a result, ~398 GWh of contingent storage is available under Alert status from Lakes Pūkaki and Hāwea (~68 Rankine days).
 - There is an additional ~214 GWh of contingent storage accessible in Pūkaki at Emergency status (37 days of running a Rankine generator) all year.

How is contingent storage access triggered?

118. Access to contingent storage is triggered by the risk facing the system based on a clearly articulated risk-based framework. Industry receives regular (at least monthly) updates on the current risk status of the system through the System Operator's Energy Security Outlook. As such, all participants should have the ability to factor when access to contingent storage will be triggered into their trading and wholesale market risk management decisions.⁴⁴ In this sense, accessing contingent storage is not bringing new energy to the market – it is more about how and when that access occurs based on the risks facing the system.
119. Currently if actual hydro storage crosses the Alert curve (either nationally or in the South Island), the Alert status is triggered, and Alert contingent storage is accessible for generation.⁴⁵ If this situation happens, we would expect high wholesale market spot prices (prices rise as storage tracks towards the boundary of contingent storage). This incentivises available price-responsive market resources (fuels and assets) to generate or reduce consumption.⁴⁶ Figure B: shows the correlation over the last five years between increasing spot prices and increasing thermal generation volumes as hydro storage reduces and approaches the Alert curve.⁴⁷
120. Additional Emergency contingent storage in Lake Pūkaki becomes available when an OCC is triggered. An OCC is a Code-mandated regulatory mechanism that asks consumers of all types and sizes (including households, businesses, and industrials) to voluntarily reduce their electricity consumption. An OCC is called if hydro storage is expected to remain below the Emergency curve for more than 7 days or unless otherwise agreed between the System Operator and Authority. The Emergency curve reflects a modelled 10% risk of running out of hydro storage (accounting for the Emergency CSRB floor).
121. These current supply emergency protocols (including as reflected in the SOSFIP) utilise contingent storage as the fuel of last resort: after all other fuels and resources have contributed in response to market price signals, before a public campaign asks consumers to voluntarily conserve power, and before it is necessary for rolling outages to cut supply to households and businesses. These regulatory protocols have been designed to buy time for it to rain before all useable hydro storage is used up.

44 The System Operator can also bring forward access to contingent storage if operational risks mean there is an increased risk to security of supply ahead of using contingent storage. The System Operator has outlined its discretion process in its public-facing [Energy Security Outlook 101](#) and covered this off at its SO industry forum.

45 The Alert curve is the higher of a forecast 4% risk of future shortage and the Alert CSRB floor

46 This is consistent with the Authority's market design.

47 From January 2020

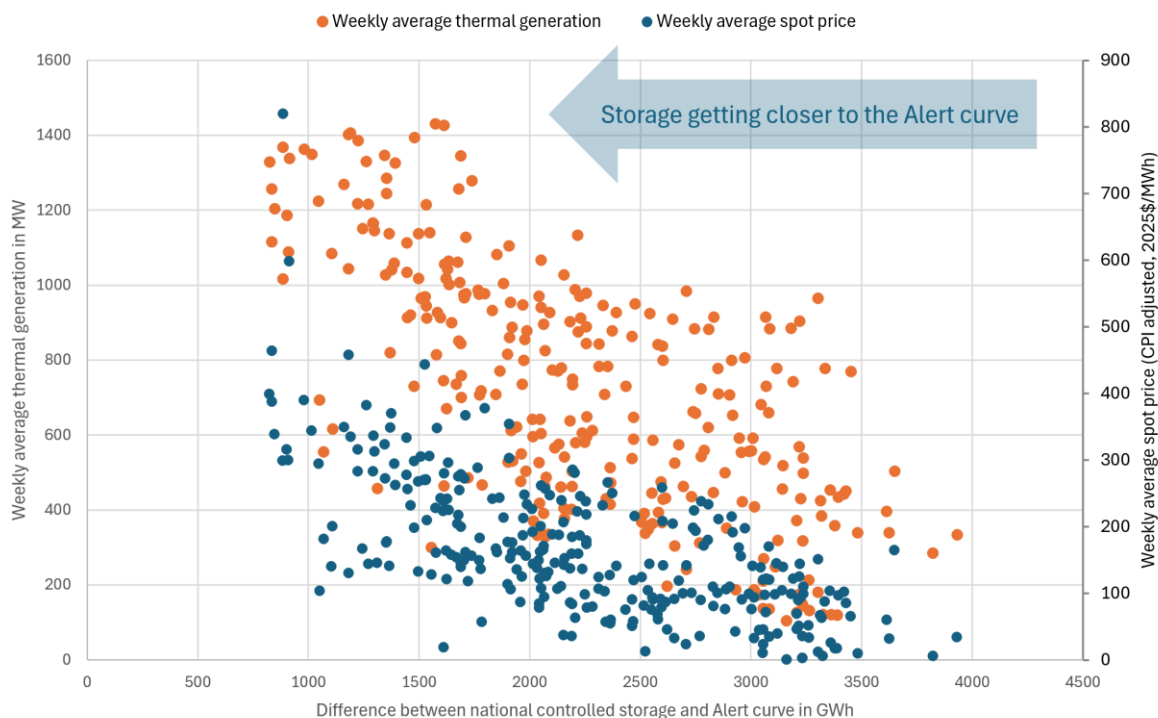


Figure B: Increased thermal generation and spot prices as storage approaches the Alert curve

Contingent storage access incentives within our market design

122. We recognise that some market participants would like more flexibility to access the water that is currently set aside as contingent storage given generating more electricity from water has potential to reduce the need to rely on thermal generation. This potential suggests that easing the current restrictions on access to contingent storage could result in both lower electricity prices for consumers, and lower emissions.
123. However, any change to the amount of storage kept as contingent storage would also change the risk profile of the electricity system. It would change the resources available to maintain security of supply to consumers during adverse circumstances such as dry sequences or when assets fail. As such, changes to contingent storage access arrangements need full consideration of the potential consequences within the context of New Zealand's internationally unique islanded and already highly renewable electricity system in which the impacts of energy-constrained events can be swift and severe. We are therefore taking the opportunity to set out our analysis of the potential benefits and risks including to inform any decision making by other parties such as the Government and the Authority.
124. Contingent storage is currently utilised as our fuel of last resort. It is set aside for environmental reasons and made available through regulatory mechanisms for generation only in developing electricity emergency situations, ahead of an OCC and rolling outages. As such its purpose is not to mitigate the consent holders' portfolio wholesale electricity market risks or offer short term wholesale price relief. Rather its purpose is to mitigate the risks to New Zealand of uncontrollable circumstances that could otherwise result in widespread negative impacts for electricity consumers and the wider economy.

125. Access to contingent hydro storage currently begins at Alert status.⁴⁸ As hydro storage drops and the risk of running out increases, the value of the remaining available water increases (or the opportunity cost of using stored water increases). The New Zealand electricity market design relies on hydro generators increasing offer prices to reflect the increasing value of stored water to the point that other generation is dispatched first. Typically, this results in the market coordinating available generation and demand response so that hydro generation can be held back to conserve storage. Real-time wholesale market prices (spot prices) rise. This increase in prices is necessary to provide the incentive for higher cost generation (typically thermal generation) and demand response to offer and be cleared in the market. The extent to which prices must rise is dependent on the availability of the alternative forms of generation and associated fuels, the cost of the alternative fuels (including ETS costs), and the price at which demand will turn off (whether directly in response to spot prices or through contracted demand response).
126. Prices and incentives should coordinate resources over time such that consumers are insulated from spot price volatility (including at times of high prices) and receive a reliable, lower cost supply of electricity over time. This should allow contingent hydro storage to be held back so that it is there to be utilised in extreme outlier climatic and/or adverse system conditions. This is reflected in the trade-off made in setting the current consent conditions: in extreme, uncontrollable situations the national interest in maintaining a secure electricity supply to consumers is sufficient to outweigh the negative impacts on local communities, businesses and the environment from drawing the lake levels very low.
127. The wholesale electricity spot price is therefore the primary mechanism used to signal that supply resources are getting more scarce, relative to demand. On the demand side, there is an incentive for electricity users to contract to reduce this risk. If this contracting takes place with sufficient consistency over time,⁴⁹ it should incentivise the investment in generation and demand-side capability necessary to mitigate the energy risks inherently associated with uncontrollable inter-seasonal and year-to-year variation of renewable fuel supplies (hydro inflows, wind and solar).
128. For example, in winter 2024 and again early in 2025, extended periods of low inflows and ongoing gas production challenges resulted in Meridian calling on its demand response agreement with NZAS to reduce demand. In addition, electricity generators purchased gas from Methanex to increase thermal back-up generation. In 2024 the drawdown of hydro storage was accelerated by a coincident period of very low wind generation (despite then-record high wind generation capacity), and spot prices rose to high levels reflecting the limited ability of the system to bring in new energy resources, gas supply constraints, and limited time to source additional coal to fuel Rankine generators. At the start of 2025, while inflows were at historic low levels (especially in the South Island), early contracting activity by generators ensured that thermal fuels (both gas and coal) were readily available to supplement renewable fuels. This market response supported the power system to get through winter 2025 without needing such a substantial contribution from electricity demand response or the high spot prices that were needed in 2024.⁵⁰

48 Based on the 4% ERC. An additional portion of Pūkaki contingent storage is available under an OCC at Emergency status based on the 10% ERC or if otherwise agreed with the Authority.

49 Buyers and sellers need to agree on contract terms such as price and duration. Reaching agreement can be challenging, especially when the resources required to meet the contractual obligations have longer payback periods and the risks are considered as rare. The recent NEM review highlighted this mismatch as a source of uncertainty impacting new investment and strategic reserves. The NEM proposed an Electricity Services Entry Mechanism to help bridge this gap. See [National Electricity Market wholesale market settings review](#)

50 Over winter 2024, weekly average spot prices got up to ~\$800/MWh and the NZAS demand response resulted in it reducing demand by up to ~210 MW. In contrast, with more thermal fuels available, 2025 weekly average spot prices reached ~\$370/MWh and the NZAS demand response was around 50 MW.

129. Another example of this contracting is the provisional 10-year agreement between Contact, Genesis, Meridian, and Mercury that would ensure the third Huntly Rankine unit is not retired at the end of 2025.⁵¹ In security of supply terms a critical feature of this agreement is to ensure reliance on hydro storage can (by the market) be reduced during extended dry periods limiting the potential for contingent storage, OCCs and rolling outages to be needed. Ongoing gas production challenges have heightened the role of the Rankines, which can run on gas and/or coal and in future may also use biomass. Other thermal generators (Huntly units 5, Stratford, McKee and Junction Road peakers) can currently only run on gas, with the exception of Huntly 6 which can run on gas and diesel, and Whirinaki which runs only on diesel.⁵²
130. Some contingent storage in Lake Pūkaki is only available under Emergency status, which is declared when an OCC is called. During an OCC, electricity users are asked to voluntarily reduce electricity consumption and the Customer Compensation Scheme (CCS) requires all retailers to pay each of its qualifying customers a minimum weekly amount of \$12.⁵³ This additional cost on retailers during an OCC should (all else being equal) increase the incentive to take action that reduces the likelihood of triggering OCCs by incentivising retailers to manage spot price risk appropriately by (for example) contracting to hedge wholesale market risks.⁵⁴ This should in turn result in arrangements that incentivise generators to invest in and maintain firm dry-year generation assets and ensure associated fuel supplies are available when needed, to fulfil contracted hedge obligations.
131. Another regulatory mechanism intended to help increase the visibility and transparency about participants' management of price risk exposure during capacity and energy constrained periods is the Authority's stress testing regime.⁵⁵ These arrangements require participants to disclose their exposure to spot price risks for the current and next 11 quarters. The stress tests assess two scenarios, (a) a capacity shortage stress event (e.g. during a winter peak), and (b) an energy shortage stress event (e.g. during a dry year). Disclosing participants are required to report the stress test results to their Board and to an independent registrar appointed by the Authority. A certificate verifying that the Board has considered the stress tests must be provided.
132. The intention of the stress test regime is to incentivise participants to manage these wholesale market risks prudently, or otherwise willingly accept an appropriate level of exposure at their own risk. While individual participants can view their exposure relative to others, only the anonymised results from these tests are published on the Authority's website.⁵⁶ MDAG has proposed changes to the current stress test regime to increase its effectiveness.⁵⁷ The stress test regime is focussed on financial risk management arrangements and is not designed to also scrutinise more directly how energy and capacity risks are mitigated through assets and fuels.
133. Ensuring these market components are fit-for-purpose in addition to the pressure of competition, availability of sufficient hedge products and accurate pricing of scarcity is an important part of the security of supply framework. These are the type of matters that the Authority's work programme

51 At the time of this report this agreement was still subject to Commerce Commission approval.

52 Diesel may be a potential alternative fuel for the gas-only peakers in future.

53 A retailer's qualifying customer is a person who, at any time during an official conservation campaign is a customer of the retailer; and has a contract with the retailer for the supply of electricity in respect of an ICP at which there is a category 1 metering installation or a category 2 metering installation and there was consumption in the 12 months immediately before the start of the official conservation campaign of 3000 kWh or more. See clause 9.21 of the Code.

54 Meridian noted in its response to the SOSFIP Issues Paper: "As a retailer, Meridian would be required to pay each of our mass market customers \$12 per week in the event that an OCC is called in recognition of their energy-saving efforts. This would create an additional liability of ~\$4 million per week for Meridian."

55 See [Stress tests | Electricity Authority](#)

56 See [Electricity Authority - EMI \(market statistics and tools\)](#)

57 See [Price discovery in a renewables-based electricity system: Final Recommendations PAPER 2023](#)

continues to consider including jointly with the Commerce Commission through the Energy Competition Taskforce initiative.

Appendix B: JC2 Consulting Report

JC2 Consulting's Final Summary Report "Contingent Storage Management – Understanding the trade-offs from restricting access to contingent hydro storage" (20 September 2025) has been provided as an attachment to this paper.

[Available here](#)