

Review of security of supply standards

Consultation paper

6/10/2026

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is reviewing New Zealand's security of supply standards to ensure they continue to reflect an efficient level of investment in electricity supply reliability.

Security standards are a key part of New Zealand's security of supply framework

New Zealand's electricity system has unique characteristics. The country is heavily reliant on hydro generation, has limited stored energy relative to annual demand and cannot rely on electricity imports during periods of system stress. As a result, the electricity market places significant value on transparent information about future security of supply risks.

The security of supply standards provide reference points to help assess how secure electricity supply is expected to be over the medium term. The standards support investment and risk-management decisions by participants and underpin the System Operator's annual Security of Supply Assessment (SOSA). The resulting security margins provide a common reference point for assessing whether New Zealand is expected to maintain an economically efficient level of security of supply over the next one to 10 years.

The standards recognise that New Zealand must manage two distinct, but related, security of supply challenges. The first is energy adequacy: ensuring sufficient fuel and energy resources are available to meet demand even in prolonged periods of low hydro inflows in winter. The second is capacity adequacy: ensuring sufficient generation capacity is available to meet peak demand while maintaining operational security.

The current standards are set out in Part 7 of the Code:¹

- a New Zealand Winter Energy Margin (NZ-WEM) of 14 – 16%
- a South Island Winter Energy Margin (SI-WEM) of 25.5 – 30%
- a Winter Capacity Margin (WCM) of 630 – 780 MW.

These standards are intended to represent an efficient level of security of supply. They seek to identify the point at which the cost of investing in additional generation is balanced against the economic cost of supply shortages. They are not operational limits or reliability targets: they are benchmarks used to assess whether the expected level of generation and demand is consistent with an economically efficient level of reliability.

Existing standards no longer fully reflect current system conditions

The current standards were established by the Authority in 2012 and were last reviewed in 2018. While the 2018 review identified opportunities to improve the methodology, it concluded that the resulting standards were broadly similar to the existing standards and did not warrant amendment.

Since the standards were last reviewed, the electricity system has changed significantly. Wind and solar generation now comprise a much larger share of new generation investment, grid-scale batteries are emerging as a source of flexible capacity, thermal generation is increasingly operating as firming and reserve capacity rather than baseload generation and assumptions about fuel availability and costs have changed materially. Demand forecasts have also become more uncertain as electrification and large new loads emerge. These developments warrant revisiting both the level of the standards and the methodology used to derive them.

This review is primarily focused on ensuring that the standards remain fit for purpose as a security of supply monitoring tool. The review is also timely given the Government's proposed Winter Energy Reliability Obligation (WERO). If this is implemented, the security standards and SOSA

¹ Clause 7.3(2)(a) and (b) of the Code.

may have a greater role in informing future obligations on market participants to manage dry-year risk. While this review does not seek to redesign the standards for that purpose, it is important that the standards continue to be robust, transparent and fit for purpose.

We are seeking feedback on changes to the security standards framework and supporting assumptions

The proposed changes are not intended to materially alter the role of the security standards. Rather, they update the assumptions and methodologies underpinning them, so they better reflect the characteristics of today's electricity system.

The proposals seek to ensure that the standards continue to provide credible and transparent signals about future energy and capacity adequacy risks and support efficient investment and risk-management decisions.

The revised standards are intended to take effect from the 2028 SOSA onwards:

Area	Proposal
WCM	Update methodology, model BESS as new peak capacity, update shortage costs
NZ-WEM	Update fuel assumptions, include contingent storage, revise dry-year modelling assumptions
SI-WEM	Remove from the Code and SSAD
SSAD	Interim changes for 2027 SOSA: New demand forecasting and generation pipeline requirements

Winter Capacity Margin

The Winter Capacity Margin (WCM) is used to assess whether there is likely to be an economically efficient level of generation capacity available to meet winter peak demand. We propose a number of changes to the methodology used to determine the standard:

- updating the modelling approach to better reflect observed variability in demand and generation
- modelling additional peak-capacity investment as battery energy storage systems (BESS) rather than thermal generation
- introducing an updated shortage cost curve that reflects scarcity pricing and recent market developments
- continuing the approach of separating reserve requirements from the WCM so the margin better reflects true surplus generating capacity.

These changes are intended to better reflect the increasing role of batteries and intermittent generation, changing market conditions and how reliability risks emerge during periods of peak demand.

Winter Energy Margin

The Winter Energy Margin (NZ-WEM) is used to assess whether there is likely to be an economically efficient level of energy available to manage extended periods of low hydro inflows and other dry-year risks. We propose several updates to the modelling assumptions used to calculate the NZ-WEM, including:

- modelling additional generation as LNG-fuelled thermal generation
- reflecting changing thermal fuel availability and costs
- incorporating contingent hydro storage into the modelling framework

- updating assumptions and methodologies to better reflect current dry-year risks and system conditions.

These changes are intended to ensure the standard appropriately reflects the cost and availability of firm energy resources in a highly renewable electricity system.

Proposal to remove the South Island Winter Energy Margin

We propose removing the South Island Winter Energy Margin (SI-WEM) from the Code. The SI-WEM was originally intended to identify situations where a South Island energy shortage could occur despite the national energy outlook remaining adequate. The Authority considers that it is highly unlikely that a South Island energy adequacy issue would arise without the NZ-WEM first signalling a national energy adequacy issue.

Improvements in transmission capability and the changing characteristics of the electricity system mean the NZ-WEM is expected to remain the primary indicator of national energy adequacy.

Removing the SI-WEM would simplify the security standards framework without materially reducing visibility of South Island energy security risks. Those risks would continue to be monitored through the NZ-WEM, SOSA modelling, hydro storage monitoring and the System Operator's wider security assessments.

Changes to the Security Standards Assumptions Document

The SSAD explains how the System Operator must calculate the security margins reported in the SOSA. It sets out key assumptions and methods to ensure that the margins are consistent with how the standards are derived and to ensure that sufficient information is provided for the Authority and other stakeholders to have confidence in these margins.

Its role is to guide how the standards are applied in practice when assessing future security of supply. This means it has an important role in helping stakeholders understand why margins change from year to year.

We propose interim changes to the SSAD for the 2027 SOSA, focused on demand forecasting and generation pipeline assumptions. These areas strongly influence the calculated margins but are not clearly specified in the current SSAD.

These changes would not alter how the standards are derived. They would improve transparency about the assumptions used by the System Operator when assessing future security of supply. A broader SSAD review would follow once the revised standards have been finalised.

Next Steps

Following this consultation, the Authority will consider submissions to refine the proposed inputs, assumptions and methodology for calculating the WEM and WCM.

The Authority expects to make decisions on the proposed interim SSAD changes by the end of 2026, so they can inform the 2027 SOSA.

The Authority will then use the refined methodology to develop proposed updated security standards. Stakeholders will have a further opportunity to comment on those proposed standards before any Code amendment is finalised.

Subject to consultation and final decisions, the updated standards would apply from the 2028 SOSA. The Authority will also undertake a broader review of the SSAD, so it reflects the updated standards and supports future SOSA calculations.

Contents

Executive summary	2
1 Purpose of this consultation paper.....	7
2 How to make a submission.....	7
3 Security of supply standards in New Zealand's electricity market.....	8
New Zealand's power system needs to manage both energy and capacity adequacy	8
Role of the security standards.....	8
Why the current security standards were selected	9
How the security standards are implemented	10
Security standards are set out in the Code	10
Security Standards Assumptions Document	10
Existing standards	11
The Authority substantively updated the standards in 2012	11
The Authority reviewed the security standards in 2018	11
Changing context and review of the standards	12
Changing generation mix	12
Changing role of thermal generation	13
Proposed winter energy reliability obligation	13
4 Winter Capacity Margin.....	15
Winter Capacity Margin methodology	15
Overview.....	15
Modelling approach.....	15
Proposed changes for WCM modelling	16
Sensitivities.....	20
Preliminary results.....	21
Preliminary modelling suggests an optimal base WCM of 488MW (excluding the reserve requirement)	21
Sensitivities.....	21
5 Winter Energy Margin	22
Winter Energy Margin methodology.....	22
Overview.....	22
Modelling approach.....	23
Proposed changes to WEM modelling	24
Proposed sensitivities	27
South Island Winter Energy Margin.....	29
6 Security Standards Assumptions Document	31
Overview of the SSAD.....	31

The SSAD aims to ensure consistency in how the standards and margins are calculated by the System Operator	31
Changes to the SSAD	32
Interim changes proposed for the 2027 SOSA	32
7 Next Steps.....	34
Appendix A Winter Capacity Margin assumptions and inputs	35
Appendix B Winter Energy Margin assumptions and inputs	36
Appendix C Submission form	37

1 Purpose of this consultation paper

- 1.1 The Electricity Authority Te Mana Hiko (Authority) seeks feedback on proposed changes to how the security of supply standards are calculated, and on proposed changes to the Security Standards Assumptions Document (SSAD).
- 1.2 The proposal would inform changes to the security standards which are set out in Part 7 of the Electricity Industry Participation Code 2010 (the Code), and subsequent amendments to the SSAD.
- 1.3 This consultation paper seeks feedback on proposed changes to the methodology and assumptions used to calculate the security standards that will take effect for the 2028 Security of Supply Assessment (SOSA). After this consultation, the Authority will revise the methodology and develop the proposed new standards. Stakeholders will have another opportunity to comment on these new standards before a decision on amending the Code is made. We are aiming to undertake a Code change consultation on these changes in early 2027.
- 1.4 While the new standards are intended to be implemented for the 2028 SOSA, we have identified two interim improvements to the SSAD that can be made ahead of the 2027 SOSA.

2 How to make a submission

- 2.1 The Authority's preference is to receive submissions in a Word document in the format shown in Appendix C.
- 2.2 Submissions should be emailed to operationsconsult@ea.govt.nz with 'Consultation – Review of Security of Supply Standards' in the subject line by 5pm, 17 November 2026.
- 2.3 The Authority will confirm receipt of all submissions.
- 2.4 If you cannot send your submission electronically, please email operationsconsult@ea.govt.nz or call 04 460 8860 to discuss alternative arrangements.
- 2.5 We will publish all submissions. If you consider that we should not publish any part of your submission, please:
 - indicate which part should not be published and explain why,
 - provide a version of your submission that we can publish (if we agree not to publish your full submission).
- 2.6 All submissions, including any parts the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Act.

3 Security of supply standards in New Zealand's electricity market

- 3.1 The security standards are key elements in New Zealand's security of supply monitoring framework. They serve as points of reference for the System Operator to assess how likely it is that economically efficient levels of generation will be available to supply demand over the next 1 – 10 years. They are set out in Part 7 of the Code.
- 3.2 The standards were designed to reflect New Zealand's unique electricity system. This system is now rapidly evolving, with significant developments of new intermittent generation capacity, new technologies (such as grid-scale batteries), and a reduction in the availability of domestic gas.
- 3.3 This section sets out:
 - (a) a brief overview of the role of the security standards;
 - (b) the rationale for the adoption of the security standards that we have; and
 - (c) why changes to the security standards are being considered now.

New Zealand's power system needs to manage both energy and capacity adequacy

- 3.4 The electricity system's strong reliance on hydro (contributing roughly 50% of total energy in recent years), combined with limited hydro storage (roughly six weeks' worth), means that we need other forms of generation to increase output to fill the gap between the demand for electricity and the available fuel over an extended period of time (such as a dry winter).² This is the energy adequacy problem.
- 3.5 The wholesale market, including both the 'spot' and derivative markets, signal energy adequacy through increased price. This was observed during the dry period in 2024, where limited availability of thermal fuels and low hydro inflows increased spot prices to over \$800/MWh, 4.5 times higher than the average winter price from 2018–2023 of around \$180/MWh.
- 3.6 Capacity adequacy is also an issue that New Zealand's power system must manage. This is having enough generation capacity to meet peak demand and maintain system security with enough margin (known as 'residual') to allow for unexpected plant loss or more severe weather conditions than expected. This issue has evolved as intermittent generation capacity has increased and thermal generation has retired. This means that the electricity system has experienced an increased level of 'low residual' events over the past 10 years. One of these events on 9 August 2021 resulted in the unplanned load shedding of ~34,000 consumers.
- 3.7 These events emphasise the importance of managing both energy and capacity adequacy.

Role of the security standards

- 3.8 Providing transparent information to inform risk-management and investment decisions by participants is essential for the efficient operation of the wholesale market, and for ensuring that market outcomes support the Authority's statutory objective.
- 3.9 Under the Electricity Industry Act 2010 (Act) the System Operator must provide information, and short- to medium-term forecasting on all aspects of security of supply.³ A key element of

² [Hydro storage limits and why rain matters for electricity | Electricity Authority](#)

³ Section 8 of the [Electricity Industry Act 2010 | New Zealand Legislation](#)

the System Operator's forecasting activity is the capacity and energy security standards and the corresponding capacity and energy margin metrics: North Island winter capacity margin (WCM), New Zealand winter energy margin (NZ-WEM), and South Island winter energy margin (SI-WEM). These standards are set by the Authority, and the System Operator presents the metrics in the annual [Security of Supply Assessment](#) (SOSA).

- 3.10 The security standards use winter measures because this is when New Zealand's electricity demand and draw on the South Island hydro lakes is highest.⁴ Therefore, the optimal energy margin over winter represents the optimal outcome over the year. North Island peak demand is used for the capacity margin as it has a higher peak demand relative to available generation compared to the South Island and faces the transmission constraint of the inter-island HVDC link.
- 3.11 The standards are based on the concept of "efficient levels" of generation, which refers to a theoretical optimum level of investment. At this point, the combined costs of shortage and new generation are minimised. This theoretical optimum is the level where the marginal cost of adding new generation is equal to the marginal benefit of reducing unserved energy.
- 3.12 The standards are expressed as a range, given the range of uncertainties involved in estimating this optimum and the fact that there is not a single precise level of security of supply. Determining this range requires some judgement from the Authority. Submitter feedback on this consultation paper will help us to refine these judgements.
- 3.13 The security standards were designed to be robust over time. However, it was acknowledged when they were created that they will shift as various aspects of the power system change (including generation mix, transmission configuration, shortage costs, etc). It was originally envisaged that the security of supply standards would be reviewed roughly every five years.

Why the current security standards were selected

- 3.14 The standards were developed by the Electricity Commission (Commission) in the late-2000s.⁵ The standards were key aspects of the Commission's Security of Supply Policy. This policy set out that, under the Reserve Energy scheme, the Commission would consider contracting for additional reserve capacity or reserve energy if either the WCM or WEM measure was expected to fall below the relevant standard.
- 3.15 In October 2010, the Reserve Energy scheme was terminated, and the standards were no longer linked to procurement of reserve energy or capacity.
- 3.16 The Authority has retained the overall design of the Commission's standards, while making modelling and methodological changes to reflect system changes.

Winter Energy Margin

- 3.17 The Commission favoured an energy margin as it was a more practical and economically efficient operational standard than other reliability measures commonly used overseas.⁶ The Commission's analysis showed that the optimal level of security of supply should be based on balancing the cost of additional reserve energy against the cost of demand restraint and unserved energy.

⁴ For the purposes of the WCM winter is defined as the period from 1 April to 31 October, and for the WEM it is the period between 1 April and 30 September.

⁵ The Commission's reports from when the standards were introduced provide a useful reference: 'Electricity Security of Supply Policy Review' and 'Description of the development of a Capacity Adequacy standard'. We have republished these on the Authority's [website](#).

⁶ See page 7 of the 'Development of a Capacity Adequacy Standard' for examples.

- 3.18 Stakeholders generally supported the energy margin approach because it was transparent, easier to communicate, and better aligned with New Zealand's unique dry-year risk than overseas measures focused primarily on peak-capacity reliability.

Winter Capacity Margin

- 3.19 The Commission selected a capacity margin expressed in megawatts as it can be calculated directly from assumptions about generation capacity, transmission capability and demand, making it a more transparent and operationally useful measure.
- 3.20 The Commission considered the internationally common reliability measures of Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP) and Expected Unserved Energy (EUSE). LOLE and LOLP focus primarily on the expected frequency of supply shortages, while EUSE measures the expected quantity of unserved energy. The Commission found that these output metrics are not easily derived from the underlying supply and demand assumptions and are more difficult to communicate to market participants and stakeholders.
- 3.21 The Commission found that a North Island winter MW margin provided a more stable and robust indicator of reliability across a range of future demand and generation scenarios. Modelling demonstrated that the expected margin remained relatively constant, at around 780 MW, despite changes in demand growth and the addition of intermittent generation such as wind. By comparison, LOLP, LOLE and EUSE varied according to modelling assumptions and could only be determined through detailed probabilistic analysis.

How the security standards are implemented

Security standards are set out in the Code

- 3.22 The security standards are set out in Part 7 of the Code, at clause 7.3(2)(a) and (b):
- (a) the energy security of supply standard is:
 - (i) a NZ-WEM of 14 – 16%
 - (ii) a SI-WEM of 25.5 – 30%
 - (b) the capacity security of supply standard, the Winter Capacity Margin, is 630 – 780 MW.
- 3.23 In addition, Part 7 specifies that the System Operator must prepare, publish, implement, and comply with a security of supply forecasting and information policy (SOSFIP).
- 3.24 The SOSFIP must also include a requirement for the System Operator to publish a security of supply assessment that contains detailed supply and demand forecasts for at least 5 years, which assists interested parties to assess whether the energy security of supply standard and the capacity security of supply standards are likely to be met.⁷ The methods used to calculate the margins in the SOSA must be set out in the SOSFIP.

Security Standards Assumptions Document

- 3.25 The Code also provides that the Authority may publish a security standards assumptions document (SSAD) that the System Operator must use in preparing the SOSA.⁸ The current SSAD is available on [our website](#). The document sets out:
- (a) the formulae to be used to calculate WCM and WEM;
 - (b) some key assumptions relating to generation, demand, and transmission;

⁷ Clause 7.3(1)(a)(i)

⁸ Clauses 7.3(2A) – 7.3(2D)

- (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; and
 - (d) the conditions under which the document will be updated.
- 3.26 The Authority chose to publish an SSAD to ensure that the security of supply margins calculated by the System Operator are consistent with how the standards are derived; and to ensure that sufficient information is provided for the Authority and other stakeholders to have confidence in these margins.
- 3.27 Many of the assumptions required to calculate WCM and WEM are not set out in this SSAD (eg, how to incorporate future generation investment). The System Operator is expected to use its judgement in these areas, and to publish the assumptions it makes in calculating the margins, to the extent that confidentiality permits. The System Operator may also provide additional analysis exploring the sensitivity of the margins to changes in assumptions.
- 3.28 The System Operator can use assumptions that differ from the SSAD if it has good reasons for doing so. If it does, the SOSA must explain:
- (a) what assumptions were used
 - (b) why those assumptions were used instead of the Authority's published assumptions
 - (c) how the results differ from what the SOSA would have shown using the SSAD assumptions.
- 3.29 For example, in the 2026 SOSA the System Operator departed from the SSAD assumptions by incorporating the contracted demand-response arrangement at New Zealand Aluminium Smelters into its NZ-WEM and SI-WEM calculations. This reflected that the arrangement materially affects expected demand during periods with a high risk of energy shortage.

Existing standards

The Authority substantively updated the standards in 2012

- 3.30 As noted previously, the original standards were set by the Commission for the Reserve Energy Scheme which was terminated in 2010. The Authority reviewed the standards in 2012 to ensure that these were still appropriate, and to reflect the expected availability of Pole 3 of the HVDC link (commissioned in 2014), and changes to the installed generation mix.
- 3.31 These new standards provided a range for each of the margins, as opposed to a single number, to reflect the uncertainty in the calculated outcomes. The System Operator was also requested to undertake a review of the SOSFIP to align the methodology for calculating the margins with the methodology used to develop the standards.

The Authority reviewed the security standards in 2018

- 3.32 In 2018, the Authority reviewed the security standards and concluded that while significant methodological improvements were warranted, the resulting standards were broadly equivalent to the existing standards. The Authority significantly improved the modelling methodologies used to determine the standards and expanded the data sources used as inputs.
- 3.33 The 2018 review made several key methodological and input changes:
- (a) It found that the SI-WEM was considered unnecessary as modelling indicated that it was extremely unlikely the SI-WEM would be breached without breaching the NZ-WEM first. However, retaining it was assessed as having limited operational consequence

- (b) added contingent storage to the WEM analysis – the 2012 review excluded contingent storage from Lakes Hāwea, Pūkaki and Tekapo. The Authority considered that exclusion understated the real capability of the electricity system and artificially increased the resulting energy margin
- (c) altered the way reserves were treated in the WCM. Rather than including reserve requirements inside the margin, the proposed methodology separated true surplus generating capacity, reserve requirements, and interruptible load contributions. The Authority considered this was a clearer measure of actual surplus capacity and allowed future assessments to reflect changes in reserve procurement and interruptible load participation.

3.34 We have taken these methodological improvements and further refined them to reflect changes to the electricity system since 2018. We have set out the methods and proposed enhancements in the relevant sections for the WCM and WEM.

Changing context and review of the standards

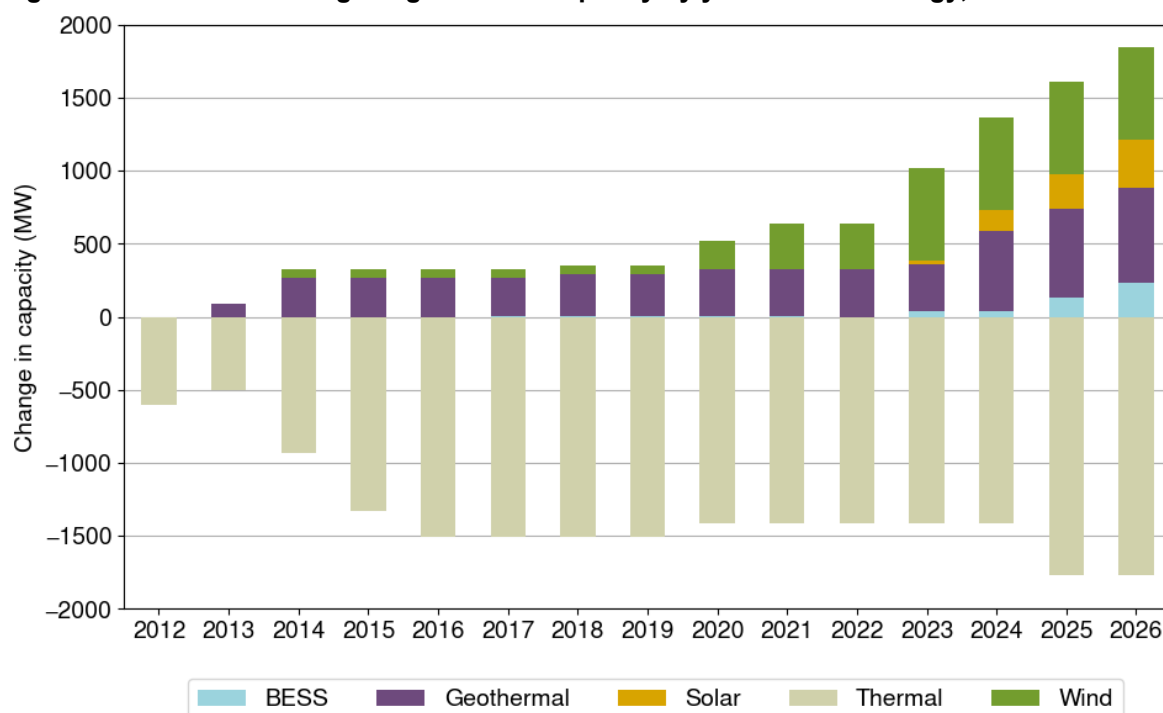
- 3.35 New Zealand's electricity system is becoming very highly renewable, more weather-dependent, and more operationally complex. Investment in wind and solar generation has increased, grid-scale batteries are emerging as a practical source of flexible capacity, and existing thermal generation is increasingly used as firming or reserve capacity rather than as baseload generation.
- 3.36 Demand has begun to show signs of growth, with demand forecasting becoming more challenging as electrification progresses across all sectors of the economy, and significant new loads are connected.
- 3.37 We are reviewing the standards so that they appropriately reflect current system conditions, including the changing role of thermal generation, increasing intermittent generation, demand response arrangements, access to contingent storage, and updated assumptions about the cost and availability of firm energy.
- 3.38 This review focuses on both the level of the standards and the methods used to calculate them. It considers whether the WCM should better reflect the changing nature of peak capacity risk, whether the NZ-WEM should better reflect current dry-year risks and fuel assumptions, and whether the SI-WEM continues to provide useful information.

Changing generation mix

- 3.39 The most significant change is the increasing amount of intermittent generation capacity, which is expected to continue: 83% of projects in New Zealand's generation pipeline are intermittent generation.⁹ Wind and solar generation contribute to energy adequacy by reducing the need to draw on hydro storage when they are generating, but their contribution to peak capacity depends on weather conditions and the timing of the demand peak. This makes the relationship between installed capacity and reliable supply less straightforward than when the current standards were set. It also increases the importance of modelling actual generation profiles and correlations between demand, hydro inflows, wind and solar output.
- 3.40 Figure 1 below demonstrates the change in generation capacity and composition due to plant commissioning and decommissioning since 2012.

⁹ Electricity Authority: [Generation investment pipeline](#), August 2026

Figure 1: Cumulative change in generation capacity by year and technology, 2012-2026



- 3.41 Grid-scale batteries are also expected to rapidly grow in installed capacity. Batteries can provide flexibility during peak demand periods, but their contribution depends on their state of charge and charging behaviour. The current standards were not developed with large-scale battery participation in mind.
- 3.42 Additionally, the existing standards do not incorporate contingent storage from lakes Hāwea, Pūkaki, and Tekapo. Contingent storage would likely be accessed during an extended dry sequence, and its omission understates the availability of energy to meet demand. This means that the WEM could be higher than is optimal for an economically efficient level of energy surplus, all other factors held equal.

Changing role of thermal generation

- 3.43 Much of the installed thermal generation capacity now operates as firming or reserve capacity rather than baseload generation. At the same time, domestic gas availability has become more uncertain and thermal fuel costs have increased. These factors are particularly relevant to the WEM, because dry-year security depends heavily on the availability and cost of firm generation when hydro inflows are low.
- 3.44 We have greater certainty about the future operation of the Rankine units at Huntly Power station, with the signing of the Strategic Reserve Agreement in late-2025. This provides that the Rankine units will likely remain in operation for dry-year reserve capacity through to 2035. Previous modelling had made assumptions about the retirement of these units.
- 3.45 The Government has also committed to the procurement of a Liquefied Natural Gas (LNG) terminal at Port Taranaki to provide additional fuel to support the electricity sector during dry-year events. While the WEM does not consider the availability of fuel in its calculations (this is done in the SOSA), the Authority has considered the likely cost of using this LNG as a fuel in its calculation of the WEM. This is discussed further in section 5.

Proposed winter energy reliability obligation

- 3.46 There is significant focus on New Zealand's ability to manage energy adequacy. The Government's proposed [Winter Energy Reliability Obligation](#) (WERO) would utilise the

security standards and SOSA. They would form part of the trigger for an obligation on the largest four gentailers and the NZ Aluminium Smelter to secure additional 'firm' cover to address any gap between the standards and the System Operator's calculated winter energy margin, as well as the magnitude of these obligations.

- 3.47 This means the security standards and SOSA would no longer operate only as an information and monitoring mechanism. They would also form part of the basis for a regulatory obligation on market participants with potentially significant costs, market impacts and penalties for non-compliance.
- 3.48 The implementation of the WERO would represent a significant shift in the purpose of the security standards. Should the Government proceed with the WERO, we will undertake further work to analyse the security standards and SSAD to ensure that these are fit for purpose for this new regime.

Q3.1. Do you consider that there are other changes in the electricity system context that the Authority should consider as part of the review of the security standards? If so, please explain these.

4 Winter Capacity Margin

- 4.1 This section sets out an overview of the method, assumptions and preliminary results for the capacity security of supply standard (WCM).
- 4.2 We have included results from the proposed modelling approach for the WCM as this modelling is significantly less resource intensive to complete compared to the WEM modelling. The modelled results should be treated as indicative and will be refined for further consultation.
- 4.3 Further information on specific data and methods can be found at Appendix A.

Winter Capacity Margin methodology

Overview

- 4.4 The modelling for the WCM determines the economically efficient level of surplus supply capacity for the electricity system operating at peak demand in its normal state, ie. where the expected costs of shortage during a peak event are equal to the cost of developing additional generation capacity.
- 4.5 When the actual WCM is zero, expected demand equals expected supply capacity (that is, where expected demand is met with no margin) and the system operates with the required reserve cover. This means sufficient instantaneous reserves must be available. The required reserves are determined by the largest risk setter operating at the time. This is generally an unplanned outage of either a single HVDC pole or the largest generating unit.
- 4.6 When the actual WCM is greater than zero, it represents the level of excess expected supply capacity above the expected demand after reserve requirements have been met.
- 4.7 In practice, the System Operator operates the electricity system to a 200 MW residual standard. This residual threshold is used to signal an increased risk of capacity shortfall in real-time. It means that there is less headroom in the system to be able to manage unexpected variations between forecast and real-time conditions.¹⁰ If the system drops beneath this residual level or it assesses that there is potential for downside risk, the System Operator works with the industry to respond and avoid potential load shedding events.
- 4.8 This residual is different from the WCM standard. The WCM measures the amount of headroom that is economically efficient to have (ie. where the cost of additional generation is equal to the cost of shortfall), where the System Operator's low residual threshold reflects the practical realities of operating the power system and is used to manage system variability.

Modelling approach

- 4.9 The overall process taken to determine the revised WCM standard is consistent with the approach taken for previous reviews:
 - (a) Develop and run a model to calculate the optimum amount of capacity
 - (b) Consider various sensitivities
 - (c) Having regard to the modelling, determine the appropriate standard.

¹⁰ The System Operator's consultation on the Low Residual Situation process provides useful background: [Low Residual Situation Review Consultation.pdf](#)

- 4.10 The process uses a “steady state” analysis (as opposed to a model of the expansion of the generation system over a period of years), with shortage and generation costs expressed in millions of dollars (NZ\$M) per annum. The model follows the following steps:
- (a) simulating power system operation for each of the top 200 trading periods with the highest demand in a calendar year
 - (b) determining in each trading period the extent (in MW) of North Island capacity shortage (if any) when some existing thermal generation is removed
 - (c) applying a shortage cost curve and the costs of any necessary additional generation to determine the societal cost
 - (d) summing the additional generation costs and shortage costs to provide a total across the 200 trading periods
 - (e) repeat the modelling with different levels of additional capacity.

Proposed changes for WCM modelling

The deterministic method used accounts for variability in supply and demand

- 4.11 The current (2012) WCM was calculated using a Monte Carlo simulation and the randomised application of generation data for the different technology types.
- 4.12 This review adapts the approach taken for the 2018 review, which used a deterministic approach instead of the Monte Carlo simulation. This approach uses actual demand and generation data to account for variability of demand and supply. This approach is expected to be superior to the previous model as it is no longer dependent on the choice of random data that was applied. The 2018 review used the distribution of demand and adjusted supply distributions for the top 500 demand trading periods.
- 4.13 For this review, we have used the 200 highest demand trading periods from 2025. We have reverted to using 200 trading periods for the calculation, as we consider that the use of more trading periods may smooth the peak demand signal.
- 4.14 We have tested the 500 vs 200 trading periods as a sensitivity to illustrate the peak smoothing. Increasing the number of top trading periods reduces expected (mean) demand. As the WCM is the difference between expected capacity and expected demand, the use of 500 trading periods results in an increase of 225 MW to the optimal base case margin.

Additional capacity modelled as Battery Energy Storage Systems (BESS)

- 4.15 The existing WCM was determined assuming that thermal generation would be the additional generation most likely to be built to meet peak demand. A key change for this review is to assume that BESS will instead be used as the additional generation used solely to meet peak demand.
- 4.16 This assumption is consistent with what we are beginning to observe in the market – that BESS are playing an increasingly important role in meeting short duration, high-demand periods. With the ongoing proliferation of intermittent generation capacity in the system, we expect that day-time power prices will be subject to significant downward pressure, enabling BESS to undertake energy arbitrage for peak management.
- 4.17 With BESS deployment at an early stage, we have relatively limited market data to analyse to inform enduring assumptions about expected behaviour. We have chosen to adapt the System Operator’s assumptions used in the SOSA to model the behaviour of BESS for the WCM calculation.

4.18 Overview of key BESS assumptions:

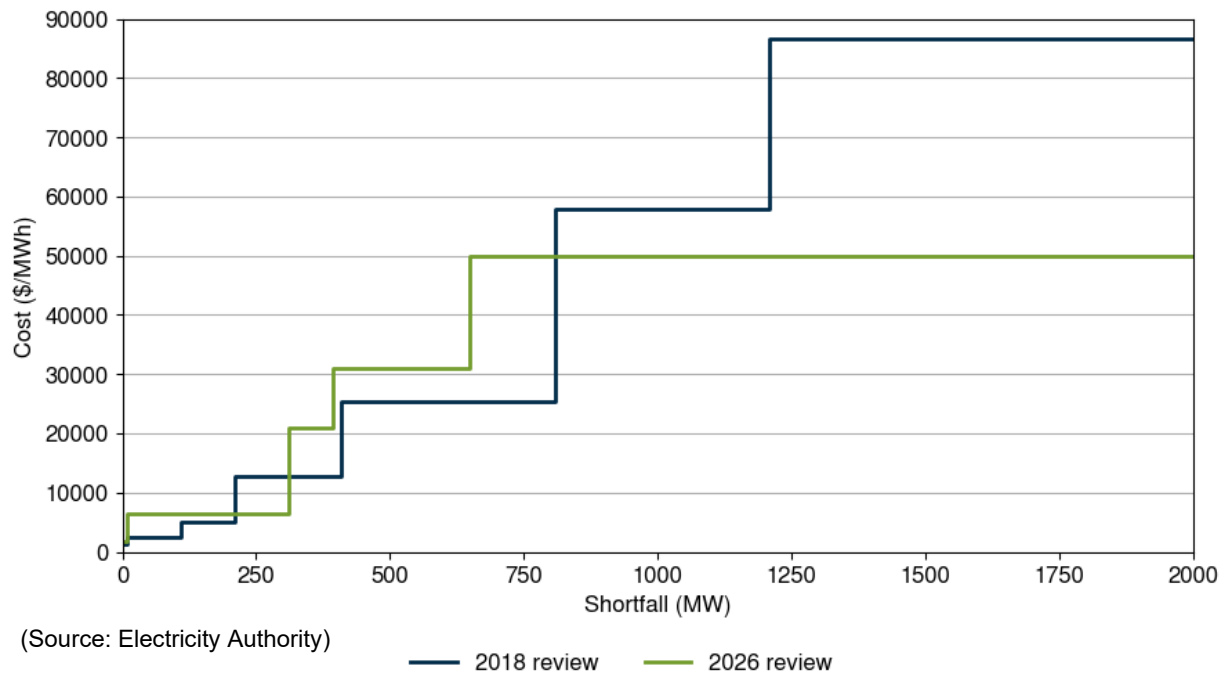
- (a) The annualised capital cost of adding BESS capacity is calculated to be \$135k/MW/yr based on data from BECA and Concept Consulting's 2025 Generation Stack Report¹¹
- (b) The cost to run new BESS capacity is assumed to be \$120/MWh, based on actual battery charging costs over 2025
- (c) A capacity factor of 60% has been applied to existing BESS capacity, as used by the System Operator for the 2025 and 2026 Security of Supply Assessments.

New shortage curve in modelling to reflect real-time pricing and other market changes

- 4.19 The WCM uses a shortage curve to represent the costs of a capacity shortage during a given trading period. The shortage curve has a strong influence on the optimal level of the WCM.
- 4.20 The existing 2012 standard utilises a shortage curve which is a CPI-adjusted version of the curve used for the original 2008 analysis. The existing tranches are as follows:
 - (a) a minimal 10 MW of price-responsive demand at \$1,210/MWh;
 - (b) 100 MW of IR shortfall at \$2,420/MWh (intended to represent the expected cost of unserved energy occurring because of a contingent event that cannot be covered by available IR – a low probability but high impact event);
 - (c) 100 MW of IR shortfall at \$4,840/MWh;
 - (d) 200 MW of IR shortfall, and/or energy curtailment at \$12,100/MWh; and
 - (e) 400 MW of energy curtailment at \$24,200/MWh, with a further 400 MW at \$55,000/MWh and unlimited amounts at \$82,500/MWh (though these deep tranches are not typically used by the model).
- 4.21 We have set the shortage curve based on energy and reserve [scarcity pricing](#) as a proxy for the Value of Lost Load, which reflects the cost to consumers of the shortage.

¹¹ Concept Consulting: [2025 Generation Stack Report](#), p28.

Figure 2: Comparison of 2018 and 2026 shortage curves for 2000MW shortfall



4.22 The updated shortage curve has been set as follows:

- Tranche one: A modest 10MW of price-responsive demand flexibility priced at \$1,725/MWh. The assumption of 10MW has been carried forward from the 2018 review
- Tranche two: 200MW of reserve scarcity and/or the use of requested [controllable load](#) that electricity distribution businesses (EDBs) have used when requested by the System Operator.¹² The reason we have combined these into the same tranche is to reflect that the counterfactual to using EDB controllable load is entering further reserve scarcity
- Tranche three: Up to 5% of load at \$21,000/MWh, including the use of EDB controllable load that is instructed off under a Grid Emergency, the use of the Emergency Reserve Scheme, and other forms of load shedding (up to 5%)
- Tranche four and beyond aligns with the scarcity pricing settings in the Code.¹³

4.23 In future, we will look to incorporate the updated findings from the Value of Lost Load (VoLL) review that is currently underway.

New treatment of reserves

4.24 The 2018 Review proposed a new way to model the reserves requirement for the WCM by separating the reserve requirement from the WCM. This would allow the System Operator to model the appropriate level of reserve required in the SOSA, reflecting their operational knowledge. We consider that this approach is still appropriate and have used it for the 2026 review.

¹² This controllable load refers to the load [submitted by EDBs via difference bids](#) when called for by the system operator. When the System Operator [instructs](#) EDBs to disconnect available controllable load, this puts the system into scarcity – setting the price at the first tranche of energy scarcity \$21,000. When EDBs respond to a System Operator [request](#) to reduce controllable load this does not trigger scarcity pricing. This is the reason for the different treatment of controllable load in tranche 2 and 3.

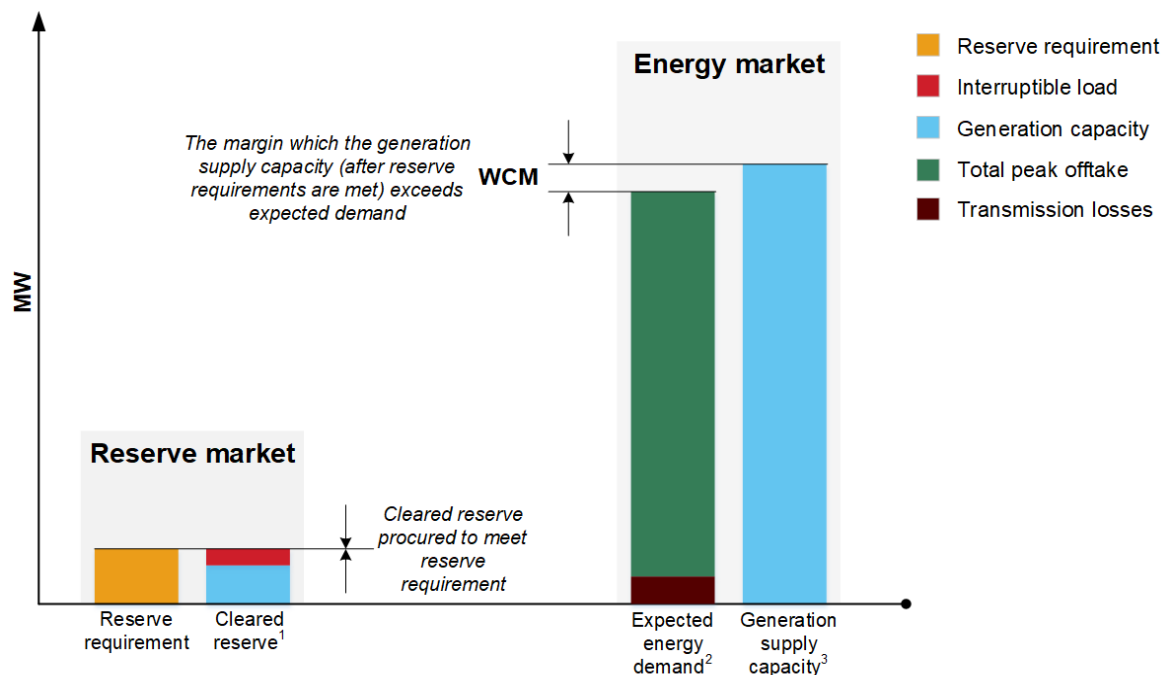
¹³ Assigned values for energy scarcity are set out in Clause 13.58AA(2) of the Code.

4.25 There are two key advantages to separating reserve from the WCM:

- (a) the WCM is a measure of the economically efficient surplus of supply (ie. true 'surplus') to hold in the system distinct from any required generation capacity surplus to meet reserve requirements
- (b) the System Operator can use the most up-to-date assumptions for both the reserve requirement and interruptible load. That is, the interruptible load capacity and reserve requirement are not baked into the margin itself; they are inputs into the evaluation.

4.26 Figure 3, below, demonstrates how under the new approach the WCM relates to the components of the reserve and energy markets:

Figure 3: Graphical illustration of Winter Capacity Margin



(Source: Electricity Authority)

Notes:

- 1. Cleared reserve consists of interruptible load, and generating capacity in the form of tail water depressed and partially loaded spinning reserve.
- 2. Expected energy demand is the expected offtake from the grid and networks in the North Island during the top 200 trading periods during winter. Transmission losses including HVDC losses are added.
- 3. Generation supply capacity is the available generation supply after reserve requirements of the system are met.

4.27 For the updated modelling approach:

- (a) The WCM represents an economic level of surplus generating capacity in an operating system where all reserves are met
- (b) 140 MW of interruptible load contributes to meeting the reserve requirement of the system which is 400 MW. Interruptible load can free up tail water depressed or spinning reserve (generation capacity) to meet demand but cannot contribute to meeting demand itself.

4.28 In contrast, in the 2012 modelling:

- (a) The WCM represents the optimal capacity of generating plant above the expected demand reduced by interruptible load. However, this representation combines the economic capacity surplus with the reserve requirement to operate the system.

- (b) The 2012 modelling effectively assumed that all reserves were provided by generation and that reserves could be reduced (with an associated cost) before load was not served.
- (c) Expected demand was reduced by 176 MW to account for interruptible load and some demand response. This meant that the cost of not serving this load did not appear in the resulting system cost curve used to find the optimal WCM. This would have the effect of lowering the security standard.

Sensitivities

- 4.29 Several sensitivity analyses have been run. These sensitivities test whether the proposed standards are set at the appropriate level, rather than testing whether the proposed standard is sufficient to accommodate the sensitivity scenarios.

WCM SENSITIVITIES	
Demand	• Increase number of top North Island demand periods used from 200 to 500 • Increase expected demand (+2% and +5%) • Increase and decrease shortage (VoLL) costs ($\pm 10\%$)
Supply	• Increase battery and thermal outage rates by 10% • Change new additional generation from BESS to reciprocating diesel engines • Increase capital costs for additional generation (10% and 50% increases)
Transmission	• Increase HVDC outage rates (rates of 5% and 10%, as opposed to a 1% chance of having at least one pole unavailable in the base case) • Reduce HVDC transfer capacity (from 1100 MW to 1000 MW and 800 MW), with consequential constraints in the contribution of South Island generation.

Q4.1. Do you support modelling additional capacity for the WCM as BESS rather than thermal generation? If not, what technology or mix of technologies should be assumed and why?

Q4.2. Do you agree with the proposed assumptions for how BESS would contribute to meeting peak demand? If not, what assumptions should be changed?

Q4.3. Do you support the proposed shortage cost curve for the WCM modelling? If not, what changes should be made and why?

Q4.4. Do you support separating reserve requirements from the WCM, so that the WCM represents surplus generating capacity after reserve requirements are met? If not, why not?

Q4.5. Do you agree with the list of sensitivities being tested for the WCM? If not, why not?

Q4.6. Do you have any suggestions for additions to the WCM sensitivities? If so, please explain your reasoning behind their inclusion.

Q4.7. Are there any other changes to the WCM modelling approach, assumptions, or inputs that the Authority should consider? If so, please explain why.

Preliminary results

- 4.30 The results presented in this section are preliminary and have been determined following the proposed methodology set out in the previous section. We will refine our assumptions and method based on feedback from submitters.

Preliminary modelling suggests an optimal base WCM of 488MW (excluding the reserve requirement)

- 4.31 The base case analysis indicates an optimal WCM of 488 MW, compared to the current value of 690MW. Small variations in the level of WCM (from ~400-600 MW) have relatively insignificant impact on the system cost (\$196 million for base case).
- 4.32 The proposed 488 MW may seem to be a significant decrease on the current WCM but, due to the different treatment of the reserve requirement, this represents an effective increase of ~374 MW.
- 4.33 In addition to the different treatment of reserve requirements, the use of statistically derived generation capacities, rather than the simulated approach used in 2012, further increases the WCM.

Sensitivities

- 4.34 The optimal results of the sensitivity analyses are presented below. The analysis showed that the optimal WCM is reasonably insensitive to most of these uncertainties. Societal costs were materially higher than the base case for some scenarios but did not result in margins outside the optimal range identified in the base case (ie. they fell within the range of 400–600 MW).
- 4.35 The only scenarios that caused the WCM to fall significantly outside that range were:
- (a) Increasing expected demand by 5%
 - (b) Increasing the number of trading periods used to 500

Sensitivity	Optimal WCM
Number of top trading periods increased to 500	713 MW
Demand increase (2%)	398 MW
Demand increase (5%)	264 MW
VoLL decrease (10%)	468 MW
VoLL increase (10%)	508 MW
Battery outage rate increase (10%)	488 MW
Thermal outage rate increase (10%)	488 MW
Reciprocating diesel engines (as opposed to BESS)	408 MW
Capital cost increase (10%)	468 MW
Capital cost increase (50%)	408 MW
HVDC outage rate increase (5%)	503 MW
HVDC outage rate increase (10%)	512 MW

Reduce bipole limit (1000 MW)	482 MW
Reduce bipole limit (800 MW)	445 MW

Q4.8. Do you have any comments on the WCM modelling results?

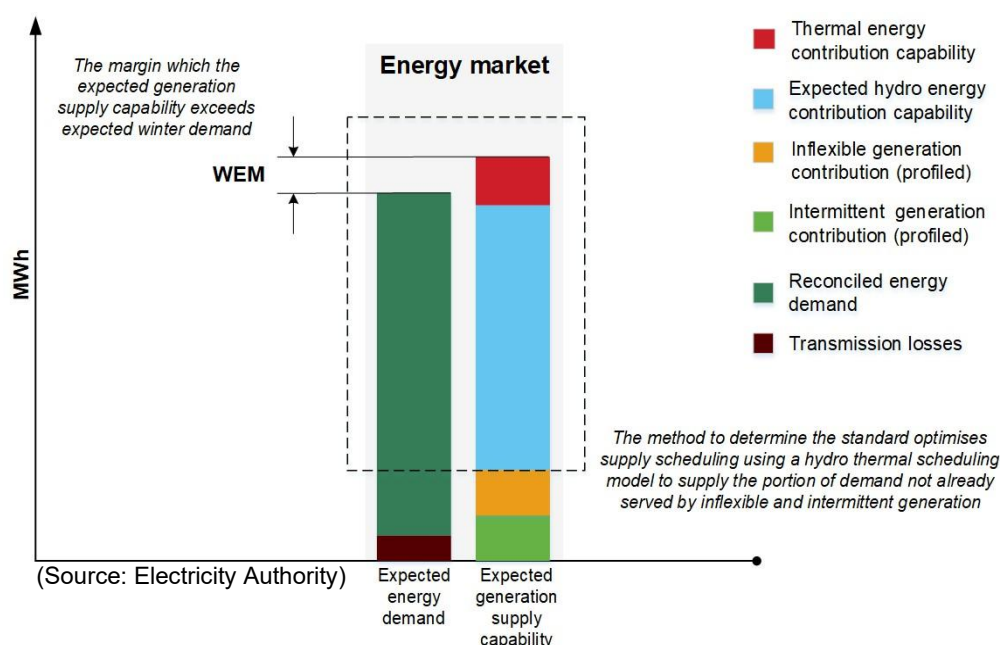
5 Winter Energy Margin

- 5.1 This section explains the proposed approach to calculating the WEM and seeks feedback on the key inputs, assumptions and methodology. We are particularly interested in whether submitters agree that the proposed approach reflects current dry-year risks and system conditions.
- 5.2 We have not included modelling results for the WEM in this paper. Producing those results is time-intensive because it requires detailed market simulation across multiple hydro inflow sequences and sensitivity cases. At this stage, we consider submitter feedback will be most useful if it focuses on whether the proposed inputs, assumptions and methodology are appropriate.
- 5.3 After considering submissions, we will refine the WEM modelling approach and use it to develop proposed updated standards. Stakeholders will have a further opportunity to comment on the resulting standards before any Code amendment is finalised.

Winter Energy Margin methodology

Overview

Figure 4: Graphical illustration of Winter Energy Margin



- 5.4 The WEM modelling estimates the economically efficient level of the winter energy margin. It does this by comparing the expected cost of additional firm generation capability with the expected cost of energy shortages across a range of hydro inflow sequences. The model does not forecast whether fuel will physically be available in a future dry year. Instead, it

assumes the modelled thermal generation can access fuel and uses fuel costs to estimate the efficient level of energy margin. Figure 4, above, graphically represents the WEM:

- 5.5 A market simulation model is used to estimate the expected system costs. The model only considers energy shortage costs that arise from periods of high spot prices, public conservation campaigns and rolling outages—it does not consider the costs of shortage during capacity shortfalls.
- 5.6 The process for determining the WEM is:
 - (a) run a model to progressively add firm generation capability until the model identifies the efficient balance between additional supply and expected shortage costs
 - (b) run sensitivities
 - (c) make a judgement as to the appropriate standards, based on the modelling results.

Modelling approach

- 5.7 We use a market simulation model to estimate the WEM, undertaken with the JADE modelling package. JADE implements a multistage stochastic optimisation representing the New Zealand electricity generation sector, with a rich treatment of the hydrological aspects of the sector. The key outputs of the model include a water value surface for each stage or week of the modelled time horizon, typically a year, and corresponding marginal water values for each reservoir represented in the model.¹⁴
- 5.8 The modelling process uses a base case that represents the current system. Demand is increased to invoke shortage, then additional generation progressively added to it until the optimum point is identified. The model estimates the societal cost of unserved energy (in NZ\$M p.a.) for a given scenario and level of additional generating capacity needed to meet that energy deficit.
- 5.9 The factors simulated or represented within the modelling framework include:
 - (a) Demand factors:
 - (i) variability in demand
 - (ii) system losses
 - (iii) demand response to high spot prices, voluntary conservation during public conservation campaigns, mandatory conservation during rolling cuts, and the associated costs with these responses to shortage
 - (b) Supply factors:
 - (i) variation in inflows into hydro reservoirs
 - (ii) variation in the starting level of the hydro reservoirs
 - (iii) management of flexible generation, including controlled hydro and thermal and associated costs
 - (iv) availability factors for thermal plant
 - (v) generation from inflexible generation including run-of-river hydro and geothermal (profiled)
 - (vi) generation from intermittent generating plant including wind, solar and other embedded generating assets (profiled)
 - (c) Transmission factors:
 - (i) constraints on the power flow between the islands.

¹⁴ More information about JADE can be found on [our website](#).

5.10 Factors excluded from the modelling include:

- (a) fuel constraints
- (b) AC transmission constraints
- (c) strategic generator behaviour, contracting, and inefficiency.

Proposed changes to WEM modelling

5.11 This section sets out the key changes we propose to assumptions and inputs for calculating the WEM that we seek submitter feedback on. The aim of these changes is to modernise the modelling approach and respond to key system changes since the existing standards were determined.

Additional generation modelled as LNG-fuelled thermal generation

5.12 We have retained the assumption used in previous reviews of the standards that the additional generation technology is an Open Cycle Gas Turbine (OCGT). However, we propose to change the fuel-cost assumption for marginal dry-year reserve generation to LNG.

5.13 The WEM modelling does not forecast whether fuel will physically be available in a dry-year. Instead, it assumes the modelled thermal generation can access the fuel it needs and uses fuel costs to estimate the efficient level of energy margin.

5.14 This reflects the changing outlook for thermal fuel availability. The WEM modelling assumes sufficient fuel is available for the thermal generation added by the model. However, the cost of that fuel is a key input. Domestic gas availability is becoming more uncertain, and there may be less ability to redirect gas to electricity generation during a future extended dry period. This means it is no longer appropriate to assume that new dry-year reserve generation could rely on low-cost domestic gas.

5.15 The Government has stated that its proposed LNG facility is intended to support the electricity system during dry years. We therefore consider LNG is a reasonable proxy for the cost of marginal firm energy in a dry-year event. LNG is likely to be more expensive than coal and broadly comparable with diesel-fired generation. Using LNG therefore gives a relatively conservative, high-cost assumption for new dry-year reserve generation.

5.16 This assumption matters where the model identifies a need for additional firm energy. In those cases, the efficient WEM depends on the balance between the cost of additional generation and the cost of unserved demand. If firm energy could be provided at lower cost than LNG, a higher WEM may be efficient because additional supply would be cheaper relative to shortage costs. We propose to test this through sensitivities using different thermal fuel-cost assumptions.

5.17 For the base case, we assume:

- (a) existing peaking plant continues to operate on domestic gas
- (b) the Rankine units operate on coal
- (c) Huntly unit 5 and any new generation built specifically for dry-year reserve operate on LNG.

5.18 As Huntly unit 5 is a Combined-Cycle Gas Turbine (CCGT) plant, rather than an OCGT, it is more likely to run for sustained periods in a dry-year event and therefore better represents the type of demand that could support LNG importation. This avoids assuming that LNG can be imported without matching demand for the fuel.

- 5.19 Because the funding and cost-recovery arrangements for LNG import infrastructure are not yet known, we have not included terminal or supply-chain infrastructure costs in the base-case fuel cost. The LNG assumption should therefore be understood as a high fuel-cost assumption, not a full estimate of the delivered system cost of LNG-backed dry-year reserve. We will consider whether and how to reflect these costs once further details are available.

Addition of contingent storage

- 5.20 A notable exclusion from the existing security standards is that contingent storage is not included in the calculation of the WEM.
- 5.21 Resource consents held by generators for some South Island lakes enable additional water to be used to avoid shortages of electricity supply to consumers (ie. the generators can lower lake levels further than the normal operating range in response to low controlled hydro storage levels either nationally or in the South Island). Access to contingent storage is linked to the [Electricity Risk Curves](#) published by the System Operator.¹⁵
- 5.22 Access to contingent storage is a key mechanism in New Zealand's dry-year response framework, and its exclusion from the security standards influences the overall efficient margin produced by the modelling.
- 5.23 Current contingent storage arrangements:
- (a) Lake Hāwea:
 - (i) 67GWh if reported storage falls below the New Zealand or South Island Alert Contingent Storage Release Boundary (CSRB).
 - (b) Lake Tekapo:
 - (i) 220 GWh of hydro storage available for electricity generation between October and March inclusive if reported storage falls below the New Zealand or South Island Alert CSRB.
 - (ii) Between April and November inclusive, the 220 GWh of hydro storage is available as controlled storage, independent of the Risk Meter status.
 - (c) Lake Pūkaki:
 - (i) A total of 545 GWh of additional hydro storage available for electricity generation;
 - 331 GWh if reported storage falls below the New Zealand or South Island Alert Contingent Storage Release Boundary. A recent fast-track consent decision means that Meridian now has access to this water under normal conditions, for the next three years.
 - 214 GWh if the System Operator or an authority with equivalent powers and functions declares an Official Conservation Campaign.
- 5.24 Contingent storage should be included because it is part of the energy resource that could be accessed in a dry year. However, it should not be treated as equivalent to ordinary hydro storage because accessing it can have operational, environmental, commercial, or regulatory consequences. We therefore propose to include contingent storage but apply a penalty cost so the model uses it only when lower-cost options have been exhausted.
- 5.25 We have also added this penalty to the volume of contingent storage that has been made available to Meridian Energy at Lake Pūkaki for the next three years. Our rationale for this is

¹⁵ A more fulsome explanation of contingent storage arrangements can be found [here](#).

that it reflects Meridian's public comments about how it intends to treat the use of this storage.

- 5.26 The penalty cost means the model will only use contingent storage when its value exceeds the cost of alternative options available in the model.
- 5.27 Adding contingent storage to the WEM would recognise storage that is only available in elevated security of supply conditions, improving the measure's reflection of dry-year resilience rather than ordinary market supply. The 2018 review found that the addition of contingent storage reduced the WEM by about 2%, down to 12%.
- 5.28 It is difficult to identify what an appropriate level of penalty is for the contingent storage. We propose to test the impact of the penalty via sensitivities. Our proposed sensitivities for the contingent storage penalties are:
- (a) \$0/MWh – Assuming that access to contingent storage is free
 - (b) \$200/MWh
 - (c) \$800/MWh – Broadly the spot market prices during winter 2024 when we were close to accessing contingent storage.

Shortage costs

- 5.29 We propose to update the shortage curve used for calculating the shortage costs.
- 5.30 The shortage cost curve allocates a price to escalating demand response required due to an energy shortage in the WEM modelling. The curve assumes a level of voluntary demand response first, primarily from industrial demand response to high wholesale prices and later through an official conservation campaign¹⁶.
- 5.31 The first two tranches of the shortage cost curve include assumptions about industrial demand response derived from observations of previous dry winters. This includes periods when the Tiwai Point aluminium smelter (NZAS) has reduced demand to help conserve hydro storage
- 5.32 The later involuntary demand response tranches represent increasingly severe uses of participant rolling outage plans (PROPS) as part of the System Operator Rolling Outage Plan (SOROP).
- 5.33 The 2018 review of the security standards applied a CPI adjustment to the prices allocated to 5 blocks of demand response modelled in the 2012 review:

Demand response level	2018 modelled cost (\$/MWh)
2.5% (voluntary)	\$529.24
2.5% (voluntary)	\$740.94
5% (voluntary)	\$3,175.46
15% (involuntary)	\$5,292.43
75% (involuntary)	\$10,584.85

- 5.34 In May 2024¹⁷, with the signing of the 20-year supply deal between NZAS, Mercury, Meridian, and Contact, the NZAS dry-year demand response has been formalised and the

¹⁶ Electricity Authority: [Security of supply policy](#) | Electricity Authority

¹⁷ Energy News: [New Tiwai contract a game-changer - Rio](#) | Energy News, 5 December 2024

cost included in the contract terms. This allows the cost of NZAS demand response to be internalised between the contract parties rather than explicitly considered a cost to the power system over the winter period.

- 5.35 The maximum demand response available under the contract is approximately equivalent to 2.5% of demand over the mid-winter period.
- 5.36 We propose not to model the Tiwai demand response arrangement in the base case, instead we propose to test it as a sensitivity. The method we propose for this is to adapt the shortage cost curve by removing the first 2.5% tranche and applying the demand reduction to the demand side of the model (given the internalised cost and more certain nature of this response). This reduction would be applied to the mid-winter period only.
- 5.37 In addition to modifying the number of tranches, we propose increasing the cost of the remaining tranches to reflect CPI growth since 2018:

Demand response level	2026 proposed cost (\$/MWh)
2.5% (voluntary)	\$996
5% (voluntary)	\$4,268
15% (involuntary)	\$7,113
77.5% (involuntary)	\$14,226

- 5.38 While the implementation of rolling outages via the SOROP constitute directed demand management, the wholesale market scarcity pricing settings are not applied. Scarcity pricing is intended to apply during short duration, unplanned capacity shortages to incentivise investment in low capacity-factor peaking equipment. While rolling outages would lower prices generally, the extremely low hydro storage levels would likely still see elevated wholesale prices over a sustained period. For this reason, the final shortage cost curve tranche remains below the energy scarcity price.

Proposed sensitivities

- 5.39 We have developed several sensitivities to see whether the proposed standards are set at the appropriate level, rather than testing whether the proposed standard is sufficient to accommodate the sensitivity scenarios:

PROPOSED WEM SENSITIVITIES	
Demand	• Increase the number of load blocks which are based on residual demand (demand minus wind and solar generation) from three to five, providing a more detailed representation of the peak demand periods. • The maximum NZAS demand response is activated over the winter months (ignoring the ramp-down and ramp-up periods).¹⁸
Supply	• Base run of river fixed generation on the year corresponding to the lowest output over the last 20 years (2006 – 2025). • Construct synthetic wind and solar generation using weather data from the last 20 years, identify and use the wind and solar generation from the weather year with the lowest total generation. • Model a future state where the wind and solar generation we expect to have in 2035 is installed.

¹⁸ Meridian Energy: [Demand Response Agreement](#) 30 May 2024

Transmission	• The reserve plant uses diesel instead of LNG (which has a higher fuel cost). • Initial hydro storage based on the lowest storage (in terms of GWh) over the last 20 years on 1 January (which was 1 January 2006). • Use the inflow data from 1933 – 2025 (instead of 1986 – 2025) in the simulation. • The storage levels in the simulation roll forward to the next hydro year (instead of resetting). • The contingent storage penalty is changed to: ○ \$0 / MWh / week ○ \$200 / MWh / week ○ \$800 / MWh / week • All schedulable hydro is on 14% outage over winter and summer (based on 2021 POCP data). Default is 15% in summer and 12% over winter (the mean from 2021-2025). All dispatchable thermal is on 31% outage over summer and 23% outage over winter (based on 2023 POCP data). Default is 26% in summer and 17% over winter (the mean from 2021-2025).
	• We do not propose sensitivities relating to transmission for the WEM. The Authority's understanding is that the HVDC upgrades that will occur in the 2030s will not materially change Southward HVDC flow capacity, due to AC network transmission constraints.

Q5.1. Do you support modelling additional firm generation for the WEM as LNG-fuelled thermal generation? If not, what technology or fuel-cost assumption should be used and why?

Q5.2. Do you agree with the proposed base-case fuel assumptions for existing peaking plant, the Rankine units, Unit 5, and any new dry-year reserve generation? If not, what assumptions should be changed?

Q5.3. Do you support including contingent storage in the WEM modelling framework? If not, why not?

Q5.4. Do you agree with applying a penalty cost to contingent storage so the model uses it only when lower-cost options have been exhausted? If not, how should contingent storage be treated?

Q5.5. Do you support the proposed changes to the WEM shortage cost curve, including the treatment of contracted NZAS demand response? If not, what changes should be made and why?

Q5.6. Do you agree with the list of sensitivities being tested for the WEM? If not, why not?

Q5.7. Are there any other changes to the WEM modelling approach, assumptions, or inputs that the Authority should consider? If so, please explain why.

South Island Winter Energy Margin

We propose to remove the South Island Winter Energy Margin

- 5.40 We consider the SI-WEM no longer provides useful additional information beyond the NZ-WEM, because a South Island energy shortage is highly unlikely to occur without the NZ-WEM first indicating a national energy security issue.
- 5.41 The SI-WEM is designed to cover the situation where the NZ-WEM may be above the standard, but a potential energy security issue remains in the South Island. This might occur if the ability to utilise North Island generation to send energy south during a South Island supply shortage is significantly limited by transmission constraints between the islands.
- 5.42 The SI-WEM was originally included because South Island hydro storage is central to New Zealand's dry-year risk, and because transmission limits could, in theory, prevent sufficient North Island generation from supporting South Island demand during a South Island energy shortage.
- 5.43 The usefulness of the SI-WEM depends heavily on assumptions about how much electricity can be transferred south across the HVDC link during a dry-year event:
- (a) In both the original 2007 standards, and in the 2012 review, north-to-south transfer was limited (by the HVDC link capability and an AC-transmission constraint, respectively). The transfer capacity was modelled at a maximum of 580 MW and with a lower sustainable average, reflecting that it is not possible to operate a full capacity continuously.
 - (b) Following the upgrade of the HVDC link in 2013, the commissioning of the new Pole 3, and other AC-system upgrades, southward transfer capacity is now significantly higher.
 - (c) In the 2018 review, the HVDC was modelled with a sustainable capacity of 900MW in both directions (as opposed to 850 MW South, 1200 MW North). This is higher than the actual southward maximum capacity of 850 MW under ideal conditions.¹⁹

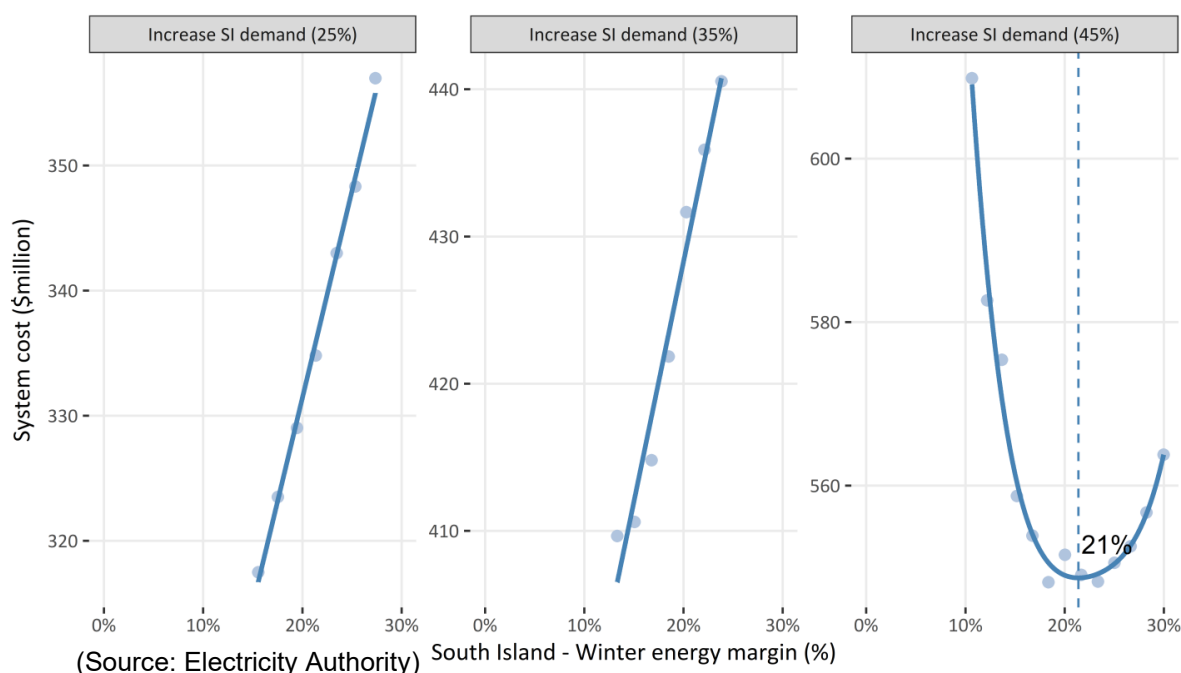
A breach of the SI-WEM, without a corresponding NZ-WEM breach is extremely unlikely

- 5.44 Our modelling indicates it is highly unlikely that the NZ-WEM would remain above standard while the South Island experienced an energy shortage. This is highlighted by the results in Figure 4. The modelled results are for the 2018 generating fleet, including the thermal plant in the North Island. Demand needed to be increased by nearly 50% before the model started to invoke the cost of shortage. We then added diesel reciprocating plant in increments of 50 MW to address any shortage and derive an optimal standard.
- 5.45 Removing the SI-WEM would not mean South Island energy security risks are no longer monitored. Those risks would continue to be reflected in the NZ-WEM modelling, the SOSA, hydro storage monitoring, and the System Operator's wider security of supply assessments. The proposal is that a separate South Island standard is no longer necessary because it does not appear to provide an additional warning signal.
- 5.46 Figure 5 shows results for three scenarios, each with increasing levels of South Island demand above 2017 levels:

¹⁹ 850MW is the current steady state operating limit – see page 8 of the [Interconnection Asset Capacity and Grid Configuration](#) report. To test the impact of using 900 MW instead of 850 MW, the 2018 review identified occasions when the modelling simulations resulted in southward HVDC transfers greater than 850 MW. 11% of simulations included such transfers. Of those 11% of simulations, the maximum aggregate duration of those transfers was 2% of the hours simulated

- (a) At a 25 per cent demand increase adding thermal increases capital cost to the system but doesn't avoid any shortage cost as demand was already served.
- (b) At a 35 per cent demand increase the system cost is higher as more demand is being supplied, but adding thermal still just adds capital cost as there is no shortage cost to avoid.
- (c) At a 45 per cent demand increase we eventually start to see shortage that can be avoided by the addition of South Island thermal generation.

Figure 5: Optimal SI-WEM with increased South Island demand (2018 modelling)



- 5.47 It is possible to derive a South Island energy margin when there is a 45 per cent demand increase, but it makes little sense to do so given:
- (a) the demand increase will have already reduced the actual NZ-WEM margin in comparison to the standard
 - (b) it is completely unrealistic for the scenario to transpire within the maximum useful life of this review of the standards.
- 5.48 While large step increases in South Island load are proposed, such as the Datagrid AI data centre, we note that at least a portion of that load will be serviced through new-build generation PPAs.²⁰ The Authority's generation pipeline also has a significant new investment in South Island renewable generation forecast for the coming years.²¹ This provides some comfort that, at least in the near term, it is unlikely that we will see a situation where the SI-WEM can be breached without the NZ-WEM being breached first.

We propose to remove the SI-WEM for the 2028 SOSA

- 5.49 As the SI-WEM is specified in the Code, we propose to remove it at the same time as the WCM and WEM are updated. This will mean that the System Operator would still produce the SI-WEM for the 2027 SOSA.

²⁰ Datagrid: [Datagrid New Zealand and Mercury establish 140MW Power Purchase Option Agreement to drive AI infrastructure growth](#) — Datagrid March 2026

²¹ Electricity Authority: [Generation investment pipeline](#) | Electricity Authority

- 5.50 This conclusion is consistent with the Authority's 2018 review, which found it was extremely unlikely the SI-WEM would be breached without the NZ-WEM being breached first. At that time, the Authority retained the SI-WEM because it had limited operational consequences. Given the proposed update to the standards and SSAD, we now consider it is appropriate to remove a metric that does not provide useful additional information.
- 5.51 Removing the SI-WEM would not mean South Island energy security risks are no longer monitored. Those risks would continue to be reflected in the NZ-WEM modelling, the SOSA, hydro storage monitoring, and the System Operator's wider security of supply assessments. The proposal is that a separate South Island standard is no longer necessary because it does not appear to provide an additional warning signal.
- 5.52 We considered whether the SI-WEM should be retained as a supplementary monitoring metric rather than a Code standard. We do not prefer this option because the modelling suggests the SI-WEM is unlikely to provide a distinct signal from the NZ-WEM. Retaining it could add complexity without materially improving the information available to market participants.

Q5.8. Do you support removing the SI-WEM? If not, what role do you consider the SI-WEM should continue to play, and why?

Q5.9. Are there circumstances where you consider the SI-WEM could provide a useful signal that would not be captured by the NZ-WEM or other security of supply monitoring? If so, please explain.

6 Security Standards Assumptions Document

- 6.1 We are proposing to:
- (a) make interim changes to the SSAD for the 2027 SOSA, focused on demand forecasting and generation pipeline assumptions
 - (b) undertake a more comprehensive review of the SSAD after the new security standards are set, with changes intended to take effect for the 2028 SOSA.

Overview of the SSAD

The SSAD aims to ensure consistency in how the standards and margins are calculated by the System Operator

- 6.2 The SSAD sets out the methodology and key assumptions the System Operator uses when preparing the SOSA. It helps ensure the WEM and WCM are calculated consistently with the way the security standards were derived. It also provides transparency about how the margins are calculated, so interested parties can understand and assess the results.
- 6.3 The SSAD specifies the formulae for calculating the NZ-WEM, SI-WEM, and the WCM. It sets out assumptions relating to generation availability, demand forecasting, demand response, wind contribution, and transmission capability.
- 6.4 The SSAD does not prescribe every modelling input. This allows the System Operator to use informed assumptions where appropriate. If the System Operator uses assumptions that differ from those specified in the SSAD, it must explain the assumptions used and why it used them.
- 6.5 This flexibility has allowed the System Operator to reflect changing market conditions in the SOSA. For example, in the 2026 SOSA, the System Operator updated the NZ-WEM and SI-

WEM assumptions to account for contracted demand response at New Zealand Aluminium Smelters (NZAS).

Changes to the SSAD

- 6.6 The Authority considers a first-principles review of the SSAD will be needed after any new security standards are finalised.
- 6.7 The existing SSAD is relatively prescriptive and does not provide a clear framework on how the System Operator may exercise its judgement. While there is a need to ensure consistency with how the security standards were determined, there is also a need to ensure that the System Operator can clearly and consistently articulate changes to assumptions. This is particularly important where individual assumptions can materially affect the results, such as forecast demand growth.
- 6.8 A full SSAD review should occur after the new security standards are finalised, so the SSAD can reflect those standards. Because the SOSA must be published by 30 June each year, and SSAD changes require consultation, a full review is unlikely to be completed in time for the 2027 SOSA.
- 6.9 We will also work with the System Operator on any transitional SOSFIP changes needed to support the 2027 SOSA.

Interim changes proposed for the 2027 SOSA

- 6.10 These interim changes would affect the forward-looking assumptions used in the SOSA. They would not change the methodology used to derive the standards themselves, so the resulting margins would remain comparable with previous assessments.
- 6.11 When the SSAD was first published, the electricity system was experiencing a period of relatively flat demand and limited generation capacity development. Demand growth and new generation development strongly influence the WCM and WEM metrics. The Authority considers there is merit in formalising how the System Operator treats these assumptions in the SOSA.

Generation pipeline assumptions

- 6.12 Other electricity market bodies use more formal processes for generation pipeline assumptions. For example, the Australian Energy Market Operator's Inputs, Assumptions and Scenarios Report identifies the status of existing, committed, anticipated and publicly announced projects.²² It then uses these categories to decide which projects to include in reliability and planning modelling. This gives stakeholders clearer visibility about how future generation is treated, while still allowing AEMO to apply judgement where project timing or delivery risk is uncertain.
- 6.13 The current SSAD does not contain an equivalent framework for classifying new generation projects or explaining how project-delivery uncertainty should be reflected in the SOSA. A clearer framework would reduce the risk of inconsistent treatment over time. It would also help stakeholders understand which future projects are included in the WCM and WEM calculations, while still allowing the System Operator to apply judgement where project timing or delivery risk is uncertain.
- 6.14 The System Operator uses developer surveys to develop the SOSA generation pipeline. The Authority also collects generation pipeline information from Transpower, in its role as Grid Owner, and electricity distribution businesses, including information on embedded

²² AEMO: [2025 Inputs, Assumptions and Scenarios Report](#), August 2025, p128.

generation. Where possible and sensible, we expect the System Operator to use the same information as collected via the Grid Owner, including objective project classification and expected commissioning dates. This may assist in reducing developer burden from multiple information requests.

- 6.15 Where different assumptions are used for any project, these should be clearly communicated with reasons why they differ. The Authority considers there would be value in reconciling these information sources to improve consistency and reduce the risk that relevant projects are omitted or misclassified in the SOSA.
- 6.16 Our preferred approach is for the System Operator to publish assumptions for assessing the generation pipeline. The assumptions could be published as part of the SOSA or separately. They would include:
- (a) the project classification methodology used for mapping the generation pipeline, where this differs from the classification used by the Authority, and reasons for using any different classification methodology
 - (b) an explanation of how classifications affect whether a project is included in the WCM and WEM calculations
 - (c) a statement on the information sources used (specifying the fields each information source was used for) for each project
 - (d) an explanation of the evidence considered when assessing project status, classification and likely timing
 - (e) an explanation of any material judgement applied by the System Operator, particularly where project delivery is uncertain or where assumptions differ from previous SOSAs.
- 6.17 We note that the System Operator may receive confidential information from developers, particularly about more speculative projects that the Authority may not have access to. Normal confidential-information sharing arrangements between the System Operator and the Authority would apply, and information about these confidential projects would not be added to the Authority's generation pipeline.

Demand forecasts

- 6.18 The SSAD currently requires the System Operator to identify the demand forecast used and explain how it was derived. The Authority has observed a wide range of demand forecasts across the industry. This is expected, given the uncertainty around the scale and timing of demand growth.
- 6.19 However, changes in demand growth assumptions can materially affect the projected WEM and WCM outlook. For example, in the 2025 SOSA, updated assumptions about demand were identified as one of the key input changes affecting the forecast supply/demand balance.
- 6.20 The Authority considers that additional demand-forecasting requirements are desirable so the SOSA can clearly explain potential system risk and the reasons for material changes in demand assumptions from year to year. This would help the SOSA provide a more consistent investment signal to the market over time.
- 6.21 The Authority considers there would be merit in the SSAD also requiring the System Operator to publish its assumptions around demand-forecasting. The assumptions could be published as part of the SOSA or separately. They would include:
- (a) the demand forecasts considered

- (b) the basis for the forecast selected for the SOSA
- (c) the treatment of material demand components such as large loads and demand response
- (d) the information sources used to assess expected timing and confidence
- (e) material changes from previous SOSAs and the reasons for those changes.

6.22 We consider that, consistent with the SSAD's general approach, the System Operator should also explain any material judgement applied, particularly where demand assumptions differ from previous SOSAs or materially affect the WCM or WEM outlook.

Q6.1. Do you support the proposed interim changes to the SSAD for the 2027 SOSA, including clearer frameworks for generation pipeline assumptions and demand forecasting? If not, what changes should be made and why?

Q6.2. Do you have any suggestions for additional matters that could be added to the SSAD for the 2027 SOSA? If so, please explain what these are and why these should be added.

7 Next Steps

- 7.1 Following this consultation, the Authority will consider submissions and use them to refine the proposed inputs, assumptions and methodology for calculating the WCM and WEM. The Authority will use the refined methodology to develop proposed updated security standards. Stakeholders will have a further opportunity to comment on those proposed standards before any Code amendment is finalised.
- 7.2 The Authority expects to make decisions on the proposed interim SSAD changes by the end of 2026, to support the System Operator's 2027 SOSA process.
- 7.3 Subject to consultation and final decisions, the updated standards would apply from the 2028 SOSA. The Authority will also undertake a fuller review of the SSAD, so it reflects the updated standards and supports future SOSAs.

Appendix A Winter Capacity Margin assumptions and inputs

Issue	Proposed base case assumptions
Demand Factors	Shortage costs as set out in paragraphs 4.19 to 4.21
Supply Factors	Existing Generation: 2025 generation fleet available with 1000MW North Island capacity removed²³ - Forced outage rates of 17% (thermal) and 12% (hydro) for controlled generation - Batteries assumed to be available at peaks, with capacity factor of 60% applied to account for limitations during consecutive peak periods - Probability curves for all other generation, with capacity factors applied (using actual data from 2021-2025 where available) Additional generation capacity: - Approach as set out in paragraphs 4.15 to 4.18 - Modelled as BESS with costs based on data from BECA and Concept Consulting's 2025 Generation Stack Report - The following assumptions are made when calculating additional generation costs: - Inflation factor of 2% - Weighted average cost of capital (WACC) of 6% - Tax rate of 30% - Capital life expectancy of 20 years
Reserve requirement	400 MW of SIR, of which: 260 MW is from generation capacity 140 MW is from interruptible load - FIR is excluded.
Transmission Factors	Full HVDC bi-pole available at 1,100 MW northward transfer capacity.

²³ The base case removes 1000 MW of existing capacity to ensure situations are modelled where significant shortage costs arise. The method then progressively adds back generation, with the cost characteristics of BESS. Those cost characteristics may be higher than the sunk costs of existing generation, however we are unable to make any evidence-based assumptions about the costs of such existing generation.

Appendix B Winter Energy Margin assumptions and inputs

Issue	Proposed base case assumptions
Demand Factors	• Shortage costs as set out in paragraphs 5.29 to 5.38 • Scale demand (excluding Tiwai) by 14% to induce a shortage in the model • NZAS demand response arrangement treated as set out at paragraph 5.34 to 5.38 • Three load blocks each week which are based on the residual demand (demand minus wind and solar generation).
Supply Factors	Existing Generation: • Available contingent hydro storage in Lakes Hāwea, Pūkaki and Tekapo is modelled as active storage (as set out at paragraph 5.23) • The start storage for controlled storage at 1 January is the mean of the last 20 years. • The storage level of each reservoir is reset at the beginning of each inflow year modelled. • Inflows from the last 40 years are used to train and simulate JADE. • Existing generation fleet available with newly commissioned generation modelled by mapping to stations of the same type. • Forced outage rates of 17% for thermal and 12% for hydro controlled generation over winter (April to September). Forced outage rates of 26% for thermal and 15% for hydro controlled generation over summer (October to March). • Inflexible and intermittent generation profiled based on 2025 output. Energy contribution across winter from these generation types is assumed to be relatively consistent year-on-year. • Thermal Fuel and carbon costs estimated from publicly available sources. Additional generation capacity: • Approach as set out in paragraph 5.12 to 5.19 • Costs for open-cycle gas turbines (OCGT) from the MBIE EDGS report. • Fuel costs based on available LNG cost information, with infrastructure cost not included.
Transmission Factors	Full HVDC bi-pole available at 1,100 MW northward capacity and 800 MW southward capacity.

Appendix C Submission form

Review of security of supply standards

Please email your submission to operationsconsult@ea.govt.nz by 5pm, Tuesday 17 November 2026.

Name	
Organisation	

Questions	Comments
Section 3: Security of Supply Standards in New Zealand's Electricity Market	
Q3.1. Do you consider that there are other changes in the electricity system context that the Authority should consider as part of the review of the security standards? If so, please explain these.	
Section 4: Winter Capacity Margin	
Q4.1. Do you support modelling additional capacity for the WCM as BESS rather than thermal generation? If not, what technology or mix of technologies should be assumed and why?	
Q4.2. Do you agree with the proposed assumptions for how BESS would contribute to meeting peak demand? If not, what assumptions should be changed?	
Q4.3. Do you support the proposed shortage cost curve for the WCM modelling? If not, what changes should be made and why?	
Q4.4. Do you support separating reserve requirements from the WCM, so that the WCM represents surplus generating capacity after reserve requirements are met? If not, why not?	
Q4.5. Do you agree with the list of sensitivities being tested for the WCM? If not, why not?	
Q4.6. Do you have any suggestions for additions to the WCM sensitivities? If so, please explain your reasoning behind their inclusion.	
Q4.7. Are there any other changes to the WCM modelling approach, assumptions, or inputs that the Authority should consider? If so, please explain why.	
Q4.8. Do you have any comments on the WCM modelling results?	
Section 5: Winter Energy Margin	
Q5.1. Do you support modelling additional firm generation for the WEM as LNG-fuelled thermal generation? If not, what technology or fuel-cost assumption should be used and why?	
Q5.2. Do you agree with the proposed base-case fuel assumptions for existing peaking plant,	

the Rankine units, Unit 5, and any new dry-year reserve generation? If not, what assumptions should be changed?	
Q5.3. Do you support including contingent storage in the WEM modelling framework? If not, why not?	
Q5.4. Do you agree with applying a penalty cost to contingent storage so the model uses it only when lower-cost options have been exhausted? If not, how should contingent storage be treated?	
Q5.5. Do you support the proposed changes to the WEM shortage cost curve, including the treatment of contracted NZAS demand response? If not, what changes should be made and why?	
Q5.6. Do you agree with the list of sensitivities being tested for the WEM? If not, why not?	
Q5.7. Are there any other changes to the WEM modelling approach, assumptions, or inputs that the Authority should consider? If so, please explain why.	
Q5.8. Do you support removing the SI-WEM? If not, what role do you consider the SI-WEM should continue to play, and why?	
Q5.9. Are there circumstances where you consider the SI-WEM could provide a useful signal that would not be captured by the NZ-WEM or other security of supply monitoring? If so, please explain.	
Section 6: Security Standards Assumptions Document	
Q6.1. Do you support the proposed interim changes to the SSAD for the 2027 SOSA, including clearer frameworks for generation pipeline assumptions and demand forecasting? If not, what changes should be made and why?	
Q6.2. Do you have any suggestions for additional matters that could be added to the SSAD for the 2027 SOSA? If so, please explain what these are and why these should be added.	