Major Electricity Users' Group

Promoting a robust electricity market

21 July 2026

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Dear Tamara

Proposed reliability obligation to manage dry-year risk

1. The Major Electricity Users' Group (MEUG) welcomes the opportunity to provide a submission to the Ministry of Business, Innovation and Employment (the Ministry) on its discussion document "*A proposed reliability obligation to manage dry-year risk: Energy Package – Action 2.5*"[1] published on 9 June 2026.

2. To support this submission, MEUG has commissioned NZIER to prepare a short report that reviews the proposed obligation, with a focus on how the obligation could affect the outlook for the drivers of wholesale prices over the next five years. A copy of NZIER's report is provided in **Attachment 1**.

3. This submission does not contain any confidential information and can be published on the Ministry's website unaltered. Members may lodge separate responses.

Summary of key points – query whether this is the most appropriate intervention to address key market issue

4. MEUG welcomes the Government taking proactive action to manage dry-year risk. As the Ministry sets out, the New Zealand electricity system is becoming even more exposed to dry-year risk, and it is now evident that intervention is necessary to drive investment in the level of long-duration firm generation that the country needs. The events of winter 2024 demonstrate the economic impact and uncertainty that can arise when consumers are not confident in the market settings to provide secure and affordable electricity.

5. We support the broad range of actions[2] that the Ministry has set out to strengthen the dry-year regulatory framework for the electricity market. Providing the Electricity Authority (the Authority) with an explicit function and responsibility for managing and reporting on dry-risk year is an essential step following the learnings from winter 2024. The amendments to the 2024 Government Policy Statement (GPS) on electricity are also well targeted. MEUG looks forward to future engagement on the additional rules and tools to be developed by the Authority to improve market conditions.

[1] https://www.mbie.govt.nz/dmsdocument/32058-a-proposed-reliability-obligation-to-manage-dry-year-risk-discussion-document
[2] Table 2 of the discussion document.

6. Having reviewed the reasoning for and analysis undertaken on a two-layer reliability obligation, MEUG questions whether this is the most appropriate intervention. In particular:

- We question if this intervention effectively targets the core policy problem – the need to invest in firming generation and whether this obligation will sufficiently change the behaviour of generators in the market.
- MEUG does not support the long-term obligation sitting with wholesale purchasers, rather we consider the obligation should sit with generators. We do not believe that large industrial or commercial users should be treated the same as retailers, and placing an obligation on direct users would negatively impact businesses who are not best placed to manage firming. We are also concerned that proposed threshold of 500 GWh of aggregate load over the winter period may capture a greater number of large users over time, as businesses electrify and expand, and this may deter demand growth. There are also risks around the threshold itself if it is able to be adjusted over time, creating uncertainty for participants.
- We have concerns with reliance primarily on the Security of Supply Assessment (SoSA) for triggering the long-term obligation. We believe hat considerable updates are still required to this document, to bring it to a state where it is robust enough to justify the application of substantial penalties for any non-compliance. We are also concerned that the SoSA may vary significantly from year to year, sending mixed signals to obligated parties.
- We do query what viable options are available to wholesale purchasers to respond to the long-term obligation in the three-year window for compliance. MEUG expects that it will drive more solar generation to be built, but question whether it will drive the type of firming investment needed to deal with an increasingly level of intermittent generation.
- It is important that treatment of demand-side response under the long-term obligation does not undermine or negatively impact current negotiations with large users about the establishment of demand side response.
- MEUG has less concerns with the proposed short-term obligation, as it has a clear focus on securing fuel for the immediate year under consideration. However, there is uncertainty about how this may impact hydro usage, alongside the administrative costs of this measure.
- MEUG believes the Ministry needs to provide further analysis and ideally a cost-benefit analysis (CBA), to demonstrate that this proposed two-layer obligation will have a positive impact on the market and not drive-up prices for consumers (above the status quo).

7. MEUG calls for greater consultation and analysis on this proposed reliability obligation to ensure that the Ministry introduce an intervention that both tackles the underlying market problem, while being workable, robust and beneficial to end consumers. We expand on these points below.

Support intervention but solution does not address the identified problem

8. The Government and the Ministry have clearly set out the key problem that needs to be addressed – how to manage dry year risk and ensure sufficient firming generation in an increasingly renewable yet intermittent market.

9. The events of August 2024 starkly highlighted the issues present in the electricity sector, which were a culmination of many years, with increasing renewable generation added to the system, balanced against the decommissioning of thermal plant alongside the dramatic reduction in natural gas. Consumers have faced increased prices year on year; with wholesale prices peaking at $800 / MWh, seeing some businesses temporarily or permanently shut down. Wholesale prices have more than doubling since 2018, and a considerable risk premium built

into the ASX futures prices – a reference point which is used for setting many large industrial and commercial businesses contracts with gentailers. Transpower's Security of Supply Assessment (SoSA) has also called consistently for more investment in firming generation, storage, and demand response, yet the sector (until recently) has been slow to respond.

10. We agree with the Ministry that "*dry year risk is…not just a reliability problem – it is also an affordability and economic growth problem*".[3] It is clear that the market will not deliver the firming that we need in coming years, therefore MEUG agrees with the Minister of Energy and Ministry that intervention from government is justified. We acknowledge that recent market improvements and commercial agreements such as the Huntly Strategic Reserve over the last year have helped, but there is still a gap.

11. MEUG questions whether this proposal is sufficiently targeted enough to address the underlying problem. It is unclear whether:

    - This two-layer obligation will be sufficient to incentivise change in the existing gentailers behaviour.
    - This will drive new investment in firming generation or simply accelerate the build of more renewable intermittent energy. The discussion document sets out how "the market" hasn't developed a solution in recent years but then expect the market to now provide solutions.
    - It will deliver actual firming and electrons when called upon for a dry year.
    - It will provide consumers with confidence that there is a sufficient pipeline of generation.
    - It will encourage sector agreement on the size of the shortfall. The discussion document outlines a firming requirement of up to 3TWh, but in recent events and media, gentailers have discussed anywhere between 0.5 – 1 TWh. It is difficult for consumers to have confidence in what they actual size of the gap currently is.

12. The supporting report from NZIER in **Attachment 1** discusses the size of this potential gap, looking at both the long and short-term obligations.

Broader measures

13. We support the Ministry developing this obligation (but not the proposed details) as part of a broader suite of measures to strengthen the dry-year regulatory framework (Table 2 of document). The events of recent years including winter 2024, the findings of the Frontier Economics report and the Government Energy Package make it clear that this is a complex issue, and action is needed across many fronts to address both security and affordability.

14. We welcome the legislative changes proposed to give the Authority an explicit function relating to dry-year risk. Until recently, there has been some uncertainty and overlap about how this was being addressed within the sector, and the regulator ultimately responsible for overseeing management of dry-year risk. This will be a step change in activity required by the Authority, and we encourage the Ministry to closely monitor the progress of the Authority, to ensure that it is meeting the intent of these changes.

15. In addition, there are several new actions and improvements that have been assigned to the Authority to develop and introduce into the Code, where appropriate. We welcome oversight of all these actions and how they fit within the framework and look forward to engagement with Authority staff on these matters. Again, we encourage the Ministry to ensure that these actions are monitored and delivered in a reasonable timeframe.

[3] Page 8 of the discussion document.

Concerns with long-term obligation

16. MEUG has several significant concerns with the proposed long-term obligation, relating to who the obligation sits with, the reliance on the SoSA, and what tangible generation options are available to meet this long-term obligation.

17. **MEUG does not support the long-term obligation sitting with wholesale purchasers; rather we strongly recommend that this obligation sit with generators**. The Ministry currently proposes that the winter energy obligation will sit with "large wholesale purchasers" whose aggregate load over the winter period exceeds the *de minimis* threshold of 500 GWh. The obligated parties may be required to secure more cover than they might otherwise, to ensure the dry-year risk is reduced. The proposed obligation currently captures the four main gentailers, as well as the New Zealand Aluminium Smelter. However, we note that more large industrials could be captured in future, as businesses electrify process heat and large users such as data centres reach the full scale of forecast operations.

18. We do not believe this is a suitable approach as individual large industrial users are not best placed to manage firming on behalf of New Zealand Inc:

- The building of generation, and particularly firming, is the key activity for generators in New Zealand, who have the required skillset, capital and resources to undertake these projects. Large industrial and commercial businesses, in contrast, are focused on manufacturing goods and services, treat electricity as one of many key business inputs, and very rarely manage electricity generation assets (except for some smaller scale co-generation). This proposed obligation would see large users having to contract for firming generation, leading to more concentration of possible market power within our already concentrated electricity market. Large users could only offer demand response, but this does come at a significant cost to economic activity.
- Industrial users should not be treated the same as retailers, as they are two distinct types of market participants. Retailers are better placed to manage risk, as part of running a retail book and covering their diverse customer base. Large users focus on contracting electricity solely to meet their own operational needs, based on their specific load profile.
- Industrial users would face a cost of firming above that required for their own needs. This would add additional cost into their business, for a requirement that may or may not be called on. Many large users would not be able to simply pass this cost on, given they operate in international commodity markets.
- The proposed threshold of 500 GWh of aggregate load over the winter period may capture a greater number of large users over time, leading to the risk that it could deter demand growth. Alternatively, it could discourage some gentailers from taking on new customers where it would significantly increase their obligation. There are also threshold risks if the threshold can be adjusted over time, creating uncertainty for those who may become obligated parties.
- There is currently uncertainty around how demand side response would be counted towards the obligation. It should not interfere or interrupt existing demand side response arrangements or negatively impact the negotiation of further demand side response agreements.
- This creates uncertainty around how large users' co-generation might be treated under the obligation. This requires further consideration.
- It could deter large users from being wholesale purchasers, rather preferring to continue or adopt other contracting obligations (i.e. purchasing via a retailer) that do not require this extra obligation.

19. We strongly recommend that the Ministry amend this proposal so that the obligation sits with generators. Alternatively, we request that the Ministry consider exempting large users, as is done in the Australian scheme (see below).

20. **We have concerns with reliance primarily on the Security of Supply Assessment (SoSA) for triggering the long-term obligation**. While the SoSA is a well-established document within the sector, many of the inputs into the assessment and the underlying Security Standards Assumptions Document (SSAD) have not been updated in recent years. Transpower has begun improvements in this area, following feedback from many participants across the sector. However, we consider that considerable updates are still required to this document, to bring it to a state where it is robust enough to justify the application of penalties for any non-compliance.

21. We are also concerned that the SoSA may vary significantly from year to year, sending mixed signals to obligated parties. This is counter to the signals needed for generators to invest in large, long-life assets. We note that Transpower tends to take a more conservative approach to preparation of the SoSA, so we could expect more years of shortfall. It is essential that obligated parties have confidence in the process for monitoring compliance, so that any penalties are clearly established and not disputed.

22. **We do query what viable options are available to wholesale purchases to respond to the long-term obligation in the three-year window for compliance**. We expect that it will drive more solar generation to be built,[4] but question whether it will drive the type of firming that is needed to manage security. Given consenting requirements, it would still be very difficult to develop any new thermal generation, and the necessary fuel supply, or any significant new hydro. This risks then creating a rush toward contracting the existing thermal generation, which is controlled by only three parties (Contact Energy, Genesis Energy and Nova) and put upward pressure on prices.

Commentary on short-term obligation

23. MEUG has less concerns with the proposed short-term obligation, as currently drafted. This obligation has a clear focus on securing fuel for the immediate year under consideration and therefore should enable clearer assessment of whether obligated parties – the generators – have met their obligations. However, we do have queries around:

- How hydro may be treated under this new obligation, whether this is focused on the national level or greater consideration given down to an individual catchment level.
- How this may impact water values and subsequent prices for consumers. If a dry year is approaching, there would be a tendency to hold water back. This would increase the overall wholesale price, in comparison to short term spikes in prices experienced in some years.
- The level of administrative cost and resources this will require. This option does seem to require a considerable amount of assessment to be undertaken in a short term. It would be helpful to understand what resources may be required at the Authority, above those within its existing monitoring and compliance teams.
- Whether this would push generators into using LNG, as there may be very few other viable fuels available within the timeframe.

24. MEUG believes these issues need to be explored and analysed further before proceeding with this obligation.

[4] We consider the timeframe is probably too short for wind unless a project is already consented and in the connection queue.

Consideration of other options to address dry-year risk

25. The discussion document is light on analysis to demonstrate the impact of this two-layer obligation on wholesale prices or resulting prices for consumers. Nor is there a cost-benefit analysis to understand the overall benefits of this intervention. This makes it difficult for submitters to comment on the value of this intervention, particularly in comparison to the status quo or other interventions.

26. The two-layer obligation is the equivalent of an "insurance product" and in that sense, it is likely that this premium will be passed to end consumers, driving up prices. In addition, if large users remain an obligated party under the long-term obligation, it could see them paying twice for the same cover (through obligation costs and increase in wholesale price). It would also be helpful to understand the cost of taking action to meet the obligation versus the proposed penalty. This is necessary to ensure that the intervention drives action, rather than seeing these costs solely passed through to consumers.

27. It was helpful that the Ministry provided summary information on the wider options that have not been pursued.[5] However, it would have been more useful to have greater detail on each and potentially rank all these interventions against some standard criteria, to see how the two-layer obligation stacks up against alternatives. We consider that when assessing the viability of different measures, that the Ministry needs to focus on the following factors:

    - Additionality: It must lead to more generation being built, particularly firming generation.
    - Robustness: It must be robust to any future changes in market design or sector developments.
    - Certainty: It must be clear that dry year risk cover will be available when called upon and the scale of the cost consumers will face.
    - Workability: It should not cut across any existing demand side response arrangements that are already in place.

28. We encourage the Ministry to undertake and/or release further information on these other options to aid sector debate.

Perspectives on the Australian obligation

29. The discussion document details the Australian retailer reliability obligation (RRO), which it describes as the "closest readily identifiable comparator to the long-term obligation"[6]. MEUG spoke to our equivalent association in Australia, the Energy Users Association of Australia (EUAA), to get their perspective on the relative success and workability of that obligation. We summarise the following points from that discussion:

    - Australia's obligation was driven by the rapid increase in intermittent renewable electricity and a lack of coordination of how supply would be firmed, particularly over short periods. In contrast, the New Zealand situation is driven by a fuel issue and a high reliance on hydro. In some sense, it may be more helpful comparing New Zealand to the state of Tasmania, who are hydro dominant and have been focused on ensuring a minimum level of storage capacity to ensure security.
    - Through discussion and consultation with industry, an opt-in scheme was developed to address involvement of large industrial users. This ensured that large users didn't get treated the same as retailers, were exempt from any fees associated with the scheme where they had firm contracts in place for own use, and it avoided the situation of "double insurance".

[5] Pages 47 – 49 of the discussion document.
[6] Page 29 of the discussion document.

- The RRO was discussed by the electricity sector for approximately 18 months, then took between 6 – 12 months to implement. It followed the standard rule making process, including the ability to comment on exposure drafts of the obligation.
- There were considerable compliance costs for the RRO, which particularly impacted smaller retailers.
- The Australian RRO was never triggered, except in South Australia in the early days of introducing the RRO. The RRO has been now reviewed as part of the Nelson Review,[7] and it is understood that it will be replaced by a new obligation from 2030.[8] The findings of the Nelson Review and development of this new obligation provide good insights for New Zealand, on what elements work and what did not. There were concerns that it did not have an impact on supply and did not address the tenor gap.
- There are other measures that could be of more reliance to New Zealand, including:
    - The short- and long-term Reliability and Emergency Reserve Trader (RERT) which relies on demand response and includes payment for long-term demand response that must be available when called upon.
    - The Firm Energy Reliability Mechanism (FERM)[9] in Southern Australia, where the Government has gone out to tender to get firm energy supply to address low wind/low sunshine periods. This need has mainly been met through batteries, which must be held out of market for a fee.

Next steps

30. MEUG appreciated the opportunity to meet with Ministry staff during the consultation process to discuss this proposal in more depth.

31. Given the significance of this intervention and its impact on both the security and affordability of the electricity system, we encourage the Ministry not to rush the development of this intervention. It is important that the Ministry establish a robust mechanism that tackles the underlying problem, drives actual changes in generation build and provides a clear benefit for consumers over the status quo. It must be robust enough to work in both today's conditions and going forward and should avoid any ongoing disputes about how monitoring and penalties may be applied.

32. MEUG calls for further consultation on this intervention, the chance for cross submissions and possibly workshop on submissions to understand the full range of costs, benefits and insights on how this intervention would work in practice.

[7] https://www.dcceew.gov.au/energy/markets/nem-wms-review
[8] Signalled to be the Electricity Services Entry Mechanism (ESEM) , a key outtake from the Nelson Review and offers a sophisticated solution to the "tenor gap" problem that has plagued project financing.
[9] https://energymining.sa.gov.au/industry/firm-energy-reliability-mechanism-ferm

33. If you have any questions regarding our submission, please contact MEUG on 027 472 7798 or via email at karen@meug.co.nz.

Yours sincerely

Privacy of natural persons

Karen Boyes
Major Electricity Users' Group



MBIE Dry-year risk obligation

Input for submission on MBIE proposal

NZIER report to MEUG

21 July 2026

About NZIER

The New Zealand Institute of Economic Research (NZIER) is an independent, not-for-profit economic consultancy that has been informing and encouraging debate on issues affecting Aotearoa New Zealand for more than 65 years.

Our core values of independence and the promotion of better outcomes for all New Zealanders are the driving force behind why we exist and how we work today. We aim to help our clients and members make better business and policy decisions and provide valuable insights and leadership on important public issues affecting our future.

We are unique in that we reinvest our returns into public good research for the betterment of Aotearoa New Zealand.

Our expert team is based in Auckland and Wellington and operates across all sectors of the New Zealand economy. They combine their sector knowledge with robust economic logic, models and data, and an understanding of the linkages between government and business to help our clients tackle complex issues.

Authorship

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Key points

Dry-year risk obligation objective

MBIE's proposed dry year reliability obligation is designed to convert abundant renewable energy into reliable and affordable electricity and has the following key elements:

- Treats the dry-year reliability risk as an issue of that can be managed by contracts to secure generation during dry-year periods – the winter months of years with low hydro inflows and ensure that sufficient generation is constructed to exceed the forecast winter energy demand by a required margin.
- Allocates the dry-year risk responsibility for projected shortages on a:
  - Long term obligation - A five year and three-year outlook to generators and 'large purchasers' to ensure there is sufficient capacity to cover the winter energy margin projected under SoSA.
  - Short-term obligation – triggered over a period of up to three weeks followed by a seven-week response period in response to a sustained fall in hydro storage below the watch curve.

Long-term obligation requires a material increase in capacity

Based on the 2026 SoSA lower security standard, the long-term obligation would require at least 362 MW of new capacity in 2029 and a further 533 MW of capacity over 2030 and 2031 (assuming 90 percent utilisation over the winter period.). This a material increase over the capacity that generators plan to construct while the utilisation assumption suggests the capacity needs to be thermal or geothermal. Provided demand increases as forecast in the SoSA forecasts, the additional capacity will be fully utilised in subsequent years.

Short-term obligation

The short-term obligation is intended to cover rapid falls in hydro storage, but the level of cover required is not clearly quantified in the MBIE consultation paper. The recent shortfalls discussed in the MBIE paper range from 500 GWh to 1,000 to 1,500 GWh with up to four instances over the past six years. The cover for this hydro shortfall risk needs to be in place each year but will not be required each year. Based on recent thermal generation cost and wholesale electricity prices during periods of low hydro storage, this obligation along with earlier deployment of thermal generation that it facilitates may help to limit wholesale price spikes.

Long-term obligation

A long-term obligation based on the SoSA New Zealand Winter Energy Margin is difficult to interpret and assess. It seems to require the construction of substantial reserve generation capacity in an energy-only market – without a mechanism to recover the capital cost of the generation capacity. The probable use of the generation capacity over its life is not clearly indicated by the SoSA demand forecasts.

Contents

1 Approach 1
1.1 Our approach 1

2 MBIE dry-year risk framework 1
2.1 Problem definition is focused on a change in behaviour 1
2.2 Estimated long-term and short-term obligation levels 3
2.3 Proposed long and short-term obligations are materially different. 7

3 Impact on wholesale electricity prices 7
3.1 Choice of fuel and new generation 7
3.2 Recent wholesale prices and thermal generation 8
3.3 Long-term obligation 10

Appendices

Appendix A Load and generation mismatch 11

Appendix B SoSA – 'Medium Demand Growth+Low Gas Supply' 15

Figures

Figure 1 Total annual demand (GWh) for each half hour 11

Tables

Table 1 SoSA based estimate of required generation capacity to meet the proposed long-term obligation 5
Table 2 2026 SoSA – new supply by fuel and commissioning date 6
Table 3 Load and thermal generation and wholesale prices 8
Table 4 Load and thermal generation and wholesale prices 9
Table 5 Annual electricity generation volume 12
Table 6 Variation in annual electricity generation from 2020-25 average 13
Table 7 Electricity generation volume – 1 March to 30 September 14
Table 8 Variation in winter electricity generation from 2020-25 average 14
Table 9 SoSA based estimate of required generation capacity to meet the proposed long-term obligation 16

1 Approach

1.1 Our approach

Our approach is to consider how the MBIE dry-year risk obligation could affect the outlook for the drivers of wholesale prices over the next five years based on the choice of generation required to satisfy the obligation. The purpose of this report is to estimate the change in generation profile under the proposed MBIE dry-year obligation and consider how this might affect wholesale electricity prices.

2 MBIE dry-year risk framework

The Ministry of Business Innovation and Employment (MBIE) is proposing an allocation of responsibility for managing dry-year risk in its consultation paper *'A proposed reliability obligation to manage dry-year risk'*[1] (referred to as 'MBIE consultation paper'). The high-level problem definition is to provide incentives for more effective dry-year risk management while delivering affordable wholesale electricity prices.

2.1 Problem definition is focused on a change in behaviour …

The Minister's Foreword states the high-level problem definition as:

> *To turn abundant renewable energy into reliable and affordable electricity, we need enough firm generation and fuel to back it up, especially in dry years when hydro lakes are low. The year 2024 showed what happens when we fall short … Dry-year risk should not define New Zealand's electricity system …*
>
> *new two-layer reliability obligation to strengthen incentives to manage dry-year risk, while maintaining a flexible, market-based approach …*
>
> *The obligations will have substantial penalties attached to ensure parties comply and change their behaviour, rather than just accept a penalty.* [2].

The Minister's Foreword refers to LNG imports, strengthening incentives to manage dry-year and change participants behaviour. The problem statement at the beginning of the MBIE consultation paper repeats the need for additional incentives but shifts the focus to long term decline in existing thermal capacity[3].

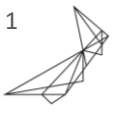
2.1.1 But the size and pace of the change is not clearly quantified

The MBIE consultation paper suggests the current shortfall is approximately 1.5TWh inferred from the following comment:

1 MBIE. '*A proposed reliability obligation to manage dry-year risk - Energy Package - Action 2.5, 9 June 2026*', downloaded from https://www.mbie.govt.nz/dmsdocument/32058-a-proposed-reliability-obligation-to-manage-dry-year-risk-discussion-document .

2 MBIE. '*A proposed reliability obligation to manage dry-year risk - Energy Package - Action 2.5, 9 June 2026*', page 3.

3 '*Confirming that due to the exposure of New Zealand's electricity system to dry-year risk as a result of reliance on weather dependent renewables, a decline in domestic gas supply, and legacy thermal generation retiring, additional incentives are required to manage dry-year risk.*'



On one view, cover in the order of 3TWh may be appropriate to insure against a significant three-month dry period. The recent agreement between the four gentailers to maintain three coal-fired Rankine units at Huntly may help to address part of that need. However, it appears capable of providing only around half that amount at most – approximately 1.5TWh – and only for so long as those units remain operational.[4]

However, this estimate or how it might evolve over time is not referred to in either the short-term or long-term obligation metrics suggested in the MBIE consultation paper.

Long-term obligation based on SoSA

The long-term (5 to 3 year) obligation is based on the 'Expected Future Energy Scenario'[5] for the New Zealand Winter Energy Margin (NZWEM) in the Security of Supply Assessment (SoSA) falling below the 'minimum standard'[6]. For the 2026 SoSA, the lower and upper security standards are 14% and 16% respectively. We have based our calculation of the obligation on the SoSA on the 'Medium Demand Growth+Ref Gas Supply'[7]. scenario. This scenario requires slightly less additional generation than SoSA 'Expected Future case (Final)'[8]. For the 2026 SoSA, the difference between the required supply for the two standards is 476 GWh but increases to 4,259 GWh by 2029 (the first three year obligation) and 4,571 GWh by 2031 (the first five year obligation).

Short-term obligation is focused on recent hydro storage variations

The size of the shortfall under the short-term obligation is not clear from the description in the MBIE consultation paper. The obligation would be triggered using a two-step process:

- A 'notification curve' is derived '*if projected hydro storage crosses the Watch Curve within the next 90 days accounting for a hydro storage decline of 18GWh/day between 1 January and 31 July.'* (The 'Watch Curve'[9] effectively indicates a 1 percent risk of running out of hydro storage in the next 12 months. A decline in hydro storage of 18 GWh per day for 90 days is equal to a decline in storage of 1.62 TWh.)
- If hydro storage is at or below the notification curve for 21 days a formal obligation is triggered. After this period the obligated generators would have four weeks to demonstrate that they have sufficient firm fuel cover to meet the winter load for which each is responsible on the assumption that conditions deteriorate as forecast under the trigger. (The winter load an obligated generator is responsible for is the demand from its own retail base plus any contractual arrangements with other parties.)

4 MBIE. '*A proposed reliability obligation to manage dry-year risk - Energy Package - Action 2.5, 9 June 2026*', page 62, para A49.

5 MBIE. '*A proposed reliability obligation to manage dry-year risk - Energy Package - Action 2.5, 9 June 2026*', page 20, Box 1.

6 MBIE. '*A proposed reliability obligation to manage dry-year risk - Energy Package - Action 2.5, 9 June 2026*', page 21, Figure 2.

7 Transpower – System Operator. '*Security of Supply Assessment 2026, Version:1.0, Date: 29 June 2026*' page 13. The Expected Future case (Final) is based on Medium Demand Growth plus a low gas supply forecast with additional gas (18 PJ over 6 months) from LNG imports in dry year. We were not able to find this scenario in the file'2026 SOSA - Final Supplementary Data - Final Version.xlsx'.

8 We also calculated the long-term obligation for the 'Medium Demand Growth+Low Gas Supply' as we expect this will be an upper bound for the additional generation and generation capacity forecast for the Expected Future case (Final).

9 Definition of energy security outlook, see Transpower. *'Security of Supply 101'* page 8, para 15. Determination of watch curve, see Transpower. *'Security of Supply 101'* page 15, para 47.



2.2 Estimated long-term and short-term obligation levels

2.2.1 Long-term obligation

We estimated the potential evolution of the long-term obligation generation capacity from the 2026 SoSA medium demand forecasts in three steps:

- Apply the forecast NZWEM margin to the medium demand scenario to calculate the expected generation for each year of the SoSA medium demand forecast as well as the generation implied by the lower and upper security standards (forecast demand multiplied by 1 plus the security standard).
- Calculate the additional generation required to meet the security standard as the difference between the forecast demand multiplied by 1 plus the security standard and the expected generation. This additional generation is a combination of two elements:
  - SoSA demand forecasts from 2032 onwards exceed SoSA estimates of generation from the capacity.
  - The lower security standard which is 14 percent above demand.
- Convert the additional generation into an increase in generation capacity that would be required to supply it using a 90 percent 'utilisation' factor over the winter (6 months) This assumption produces a low estimate of the required increase in generation capacity.

The results are listed in Table 1 and the key observations are:

- The choice of upper or lower security standard alters the start of the long-term obligation by one year but the annual increase in the obligation is similar for each standard. To illustrate the capacity required to cover the shortfall, if the shortfall was covered by new generation operating at a 90 percent availability[10] factor over the six-month period, a long-term obligation based on the:
  - lower security standard would require 362 MW of new capacity in 2029 and a further 533 MW of capacity over 2030 and 2031
  - higher security standard would require 128 MW of new capacity in 2028 and a further 912 MW of capacity over 2029 to 2031.
- This substantial increase in capacity required to meet the SoSA based long-term obligation arises alongside the commissioning of a substantial amount of new generation capacity as listed in:
  - Over 2026 and 2027, additional wind generation capacity 267 MW and solar generation of capacity of 1,639 MW with a combined annual output[11] of about 3,800 GWh

10

11 Combined annual output is estimated using a 40 percent utilisation rate for wind and a 20 percent utilisation rate for solar. Wind out. Actual solar farm output over the six months to 30 September is estimated at about 35 percent of annual output their generation over the December and March quarters can conserve hydro reserves over these months.



- Over 2028 and 2029 additional wind generation capacity 1,373 MW and solar generation of capacity of 3,530 MW with a combined annual output of about 11,000 GWh
- Over 2030 and 2031 additional wind generation capacity 1,300 MW and solar generation of capacity of 1,908 MW with a combined annual output of about 7,900 GWh.

Table 1 SoSA based estimate of required generation capacity to meet the proposed long-term obligation

Demand and required supply in GWh, NWEM as a percentage, capacity reported in MW

Year	Demand[1]		SoSA NZWEM	Winter Supply[2]	Required supply[3]		Shortfall		Additional capacity[4]		Annual Capacity change	
	Gross	Net			Lower[4]	Upper[4]	Lower	Upper	Lower	Upper	Lower	Upper
2026	24,310	23,824	18.77%	28,296	27,159	27,636	-1,137	-660				
2027	25,320	24,814	16.02%	28,789	28,288	28,784	-501	-5				
2028	26,091	25,569	14.01%	29,152	29,148	29,660	-4	508		128.4		128.4
2029	27,399	26,851	8.67%	29,179	30,610	31,147	1,431	1,968	362.0	497.8	362.0	369.4
2030	28,434	27,865	5.34%	29,353	31,766	32,323	2,413	2,970	610.4	751.4	248.5	253.6
2031	29,407	28,819	1.72%	29,316	32,854	33,430	3,538	4,114	895.0	1,040.8	284.5	289.3
2032	30,092	29,490	-0.43%	29,363	33,619	34,209	4,256	4,846	1,076.6	1,225.9	181.7	185.1
2033	30,861	30,244	-2.77%	29,405	34,478	35,083	5,072	5,677	1,283.3	1,436.3	206.6	210.4
2034	31,594	30,963	-4.60%	29,539	35,297	35,917	5,758	6,378	1,456.8	1,613.4	173.5	177.2
2035	32,318	31,672	-6.48%	29,620	36,106	36,739	6,486	7,119	1,640.8	1,801.0	184.0	187.6

Notes:

1 This estimate of SoSA net demand is based on 'Medium Demand Growth' reduced by an annual 2 percent demand response. This is consistent with the approach described in the worksheet 'Example NZ energy margin calc' of the workbook ''2026 SoSA - Final Supplementary Data - Final Version.xlsx'.

2 'Winter supply' is estimated as 'Net Demand' multiplied by (1 + SoSA NZWEM Medium Demand Growth+Ref Gas Supply).

3 Required supply is estimated as net demand multiplied by 1.14 for the lower security standard and 1.16 for the upper security standard.

4 Additional capacity generation capacity is estimated assuming the winter demand is supplied with the plant operating at an availability factor of 90 percent factor over the six month winter period.

Source: NZIER analysis of Transpower 2026 SoSA and the supporting dataset '2026 SoSA - Final Supplementary Data - Final Version.xlsx'.

Table 2 2026 SoSA – new supply by fuel and commissioning date

Capacity by fuel type in MW

Year	Geothermal	Hydro	Wind (onshore)	Solar
2026	106	14	232	416
2027	100	3	35	1,223
2028		3	755	2,117
2029	65		618	1,413
2030	57		700	1,078
2031	85	9	600	830
2032	25		60	250
2033			200	200
2034	90	44		
2035		10		

Source: '2026 SoSA - Final Supplementary Data - Final Version.xlsx'

Overall, the long-term obligation requires large scale purchasers (mainly generators) to construct a material amount of dispatchable generation in addition to what Transpower estimates is the generators committed construction of non-dispatchable wind and solar generation. The need for the additional generation is driven by a combination of:

- The projected increase in winter electricity demand ahead of the projected increase in the capacity generators are expected to build.
- The surplus generation over forecast demand required to meet the lower security standard. The utilisation of this additional generation or how its capital cost might be recovered is not clear from the SoSA modelling.

2.2.2 Short-term obligation

The MBIE consultation paper[12] does identify three periods when the short-term obligation would have been triggered:

- January to April 2021 when hydro storage fell by approximately 800 GWh to about 2,300 GWh.
- January to April 2024 when hydro storage fell by approximately 500 GWh to 3,000 GWh
- December 2024 to March 2025 when hydro storage fell approximately 1,000 GWh to about 2,800

These comments suggest the size of the obligation could vary between the 500 and 1,000 GWh. The analysis also identifies a fourth period April 2024 to August 2024 when hydro storage fell from 3,000 GWh to 1,500 GWh. However, the MBIE consultation paper

[12] MBIE. '*A proposed reliability obligation to manage dry-year risk - Energy Package - Action 2.5, 9 June 2026*', page 36, Figure 4 and page 35 paragraph 125.

notes this was due to lack of fuel and argues that the earlier triggering of the obligation over January to April 2024 would have increased incentives for generators to ensure they had sufficient fuel to run the available capacity and reduced the risk of the second decline in storage over the period April to August 2024.

The four-week response time for the short-term obligation leaves very little time for generators to organise additional fuel for the generation capacity they have available. In addition, the water storage and notification curves on page 36 of the MBIE consultation paper show that low hydro storage levels are volatile and have been reversed quickly in the recent past following a variety of interventions and contractual arrangements to obtain additional fuel for other forms of generation. As illustrated by the Huntly Firming Option, random variations in hydro storage within a predictable range encourage generators to use thermal generation earlier and hold larger fuel stocks. The key assessment questions for the proposed short-term obligation should be:

- What is the expected size and frequency of the shortfalls after the HFO is in place and with a more stable gas supply?
- How much is the proposed obligation expected to lower average winter wholesale prices compared to recent years?

However, it is difficult to answer these questions without a more detailed quantification of the short-term obligation than is provided in the MBIE consultation paper.

2.3 Proposed long and short-term obligations are materially different.

The proposed long-term objective requires the construction of more firming (dispatchable or at least more predictable) generation than signalled by generators. Meeting this requirement with thermal generation may increase the proportion of winter trading periods where the wholesale price is set by thermal fuel costs. Meeting this requirement using geothermal energy will increase spilled generation in the March and December quarters of the year. (Over 2020 to 2025 demand for the March and December quarters combined was on average 8 percent lower than demand for the June and September quarters combined.)

The short-term obligation is focused initially on smoothing hydro storage by supplementing hydro generation using existing thermal capacity at higher storage levels than has been the case in the past. This will be enabled by a requirement for thermal generators to have sufficient fuel.

3 Impact on wholesale electricity prices

3.1 Choice of fuel and new generation

The main drivers on wholesale electricity prices of the short-term and long-term obligation are the choice of generation fuel. The MBIE consultation paper does not include quantitative analysis of the expected impact on wholesale prices or describe a counterfactual for prices in the absence of the obligations. We think this is an important question that needs detailed simulation of generation mixes and price outcomes as part of the next round of the design of the scheme. To illustrate this point we consider:



- The recent history and short-term outlook for thermal generation costs – which is relevant to meeting the short-term obligation through increased use of existing thermal generation to conserve hydro storage and avoid wholesale price spikes.
- Forecast capital and operating cost of new thermal and geothermal generation as potential sources of capacity to meet the long-term obligation.

3.2 Recent wholesale prices and thermal generation

Table 3 Load and thermal generation and wholesale prices

Wholesale price is a weighted average in $/MWh, total load thermal generation in GWh

Quarter ended	Wholesale price	Total load	Total thermal	Other thermal	Huntly total	Huntly gas	Huntly coal
31-Mar-20	75.77	**9,901**	1,472	263	**1,209**	809	400
30-Jun-20	123.55	**9,944**	1,685	422	**1,263**	988	275
30-Sept-20	137.90	**11,189**	2,197	892	**1,305**	751	553
31-Dec-20	113.46	**10,127**	1,256	253	**1,003**	644	359
31-Mar-21	217.13	**9,685**	1,721	248	**1,473**	605	868
30-Jun-21	283.84	**10,505**	2,362	641	**1,721**	547	1,175
30-Sept-21	136.61	**11,147**	1,490	384	**1,106**	771	334
31-Dec-21	72.86	**9,952**	601	27	**574**	569	6
31-Mar-22	175.10	**9,626**	1,350	361	**989**	706	283
30-Jun-22	199.85	**10,326**	1,697	630	**1,067**	710	357
30-Sept-22	73.77	**11,243**	884	234	**650**	627	23
31-Dec-22	47.61	**9,995**	248	18	**230**	224	6
31-Mar-23	143.47	**9,520**	926	238	**688**	633	55
30-Jun-23	86.85	**10,381**	722	105	**617**	605	12
30-Sept-23	129.05	**11,313**	1,622	778	**844**	646	198
31-Dec-23	149.46	**10,082**	743	249	**494**	262	232
31-Mar-24	195.61	**10,001**	1,220	534	**686**	492	194
30-Jun-24	272.57	**10,697**	1,788	530	**1,258**	522	736
30-Sept-24	325.37	**11,040**	1,875	594	**1,281**	587	694
31-Dec-24	41.65	**9,879**	344	58	**286**	276	10
31-Mar-25	232.22	**9,548**	1,434	481	**953**	559	394
30-Jun-25	219.69	**10,388**	1,490	396	**1,094**	658	436
30-Sept-25	137.82	**11,452**	1,016	232	**784**	630	154
31-Dec-25	38.16	**10,250**	113	28	**85**	76	9

Source: NZIER analysis of EA data and Genesis Quarterly Operating Reports

The MBIE consultation paper identified the periods of substantial falls in hydro storage where the short-term obligation would apply: January to April 2021 (800 GWh fall), January

to April 2024 (500 GWh fall) and December 2024 to March 2025 (1,000 GWh fall). The level of thermal generation over these periods suggests that subject to fuel availability, earlier dispatch of thermal generation could have conserved hydro storage and most of this capacity will be available in over the next five years with the HFO partly offsetting the retirement of the Taranaki combined cycle plant. Also, despite recent increases in the cost of gas and coal, short run marginal cost of Huntly thermal generation (particularly for gas and disregarding periods of very low output) has been lower than the average wholesale electricity prices for the periods when the short-term obligation might arise.

Table 4 Load and thermal generation and wholesale prices

Wholesale price is a weighted average in $/MWh, total load thermal generation in GWh

Quarter ended	Wholesale price	Gas cost ($/GJ)	Gas cost ($/MWh)	Gas cost + NZU ($/MWh)	Coal cost ($/GJ)	Coal cost ($/MWh)	Coal cost + NZU ($/MWh)
31-Mar-20	75.77	9.17	73.68	85.31	6.59	74.14	102.05
30-Jun-20	123.55	8.50	68.83	80.52	6.30	71.02	98.90
30-Sept-20	137.90	9.00	68.31	82.09	6.10	69.71	105.26
31-Dec-20	113.46	9.00	69.88	84.93	6.00	67.69	105.17
31-Mar-21	217.13	9.60	72.99	88.77	6.10	68.38	108.22
30-Jun-21	283.84	10.80	86.87	103.53	6.40	71.19	110.66
30-Sept-21	136.61	12.70	98.83	120.80	7.30	84.37	140.26
31-Dec-21	72.86	9.21	72.84	100.93	7.39	83.46	152.18
31-Mar-22	175.10	9.40	73.23	105.75	7.50	90.11	176.02
30-Jun-22	199.85	9.50	72.25	103.64	8.00	87.39	164.61
30-Sept-22	73.77	9.20	79.19	116.54	8.00	105.96	204.41
31-Dec-22	47.61	10.30	92.12	132.19	8.00	90.35	177.05
31-Mar-23	143.47	9.60	77.40	107.07	7.90	99.69	179.25
30-Jun-23	86.85	10.00	85.89	111.43	7.90	89.22	146.76
30-Sept-23	129.05	9.30	99.33	133.91	7.90	83.79	142.60
31-Dec-23	149.46	10.00	110.80	152.63	8.00	89.55	161.96
31-Mar-24	195.61	10.10	86.27	117.50	8.00	90.58	161.50
30-Jun-24	272.57	12.30	96.53	118.91	8.00	88.09	141.88
30-Sept-24	325.37	16.20	129.78	154.23	9.30	100.46	156.92
31-Dec-24	41.65	16.10	140.04	169.65	11.20	155.56	236.54
31-Mar-25	232.22	13.80	108.63	135.00	11.50	129.00	193.39
30-Jun-25	219.69	14.90	113.23	135.44	11.60	127.96	183.18
30-Sept-25	137.82	15.70	122.11	146.07	11.60	134.08	195.08
31-Dec-25	38.16	13.30	175.88	209.71	11.60	123.67	170.39
31-Mar-26		16.80	182.97	216.52	11.70	134.07	194.55

Source: NZIER analysis of EA data and Genesis Quarterly Operating Reports

3.3 Long-term obligation

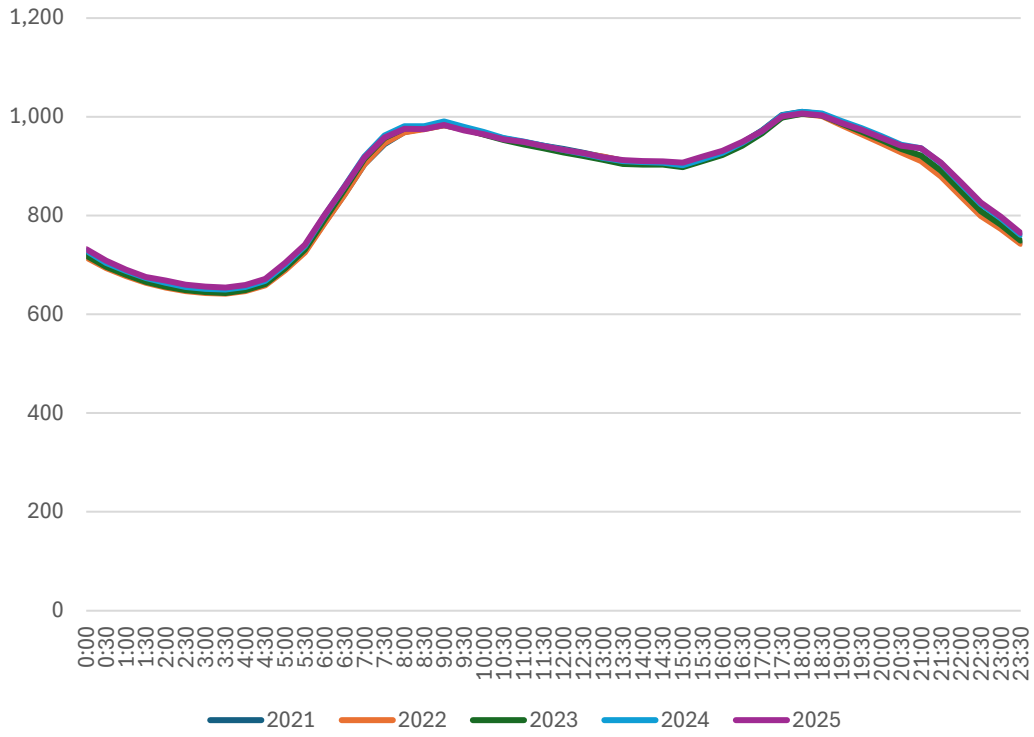
The long-term obligation based on the SoSA New Zealand Winter Energy Margin seems to require the construction of substantial reserve generation capacity in an energy-only market – without a mechanism to recover the capital cost of the generation capacity. The probable use of the generation capacity over its life is not clearly indicated by the SoSA demand forecasts but use particularly in the initial years of the asset is likely to be low as its requirement is based on a 14 percent addition to demand that is forecast to grow at almost at 3.9 percent per year.

Appendix A Load and generation mismatch

A.1 Load profile by quarter and half hour period

The main driver of recent (since 2020) dry-year[13] risk is the reduced availability and increased cost of dispatchable thermal generation. Electricity demand has been flat over this period and the distribution of demand between quarters and over trading periods within quarters has not materially altered over the past 5 years as a shown in Figure 1.

Figure 1 Total annual demand (GWh) for each half hour



Source: NZIER analysis of EA Reconciled Injection and Offtake

The recent flat level of electricity demand contrasts with the assumption in the 2026 SoSA of compound annual growth rate in demand of 3.9 percent over 2026 to 2031.

A.2 Variation in generation is the main source of mismatch

The purpose of this section is to describe the current size and future drivers of the generation mismatch task.

We have used the MBIE 'Electricity statistics'[14] to provide a broad indication of generation over the calendar years from 2020 to 2025 in Table 5. The main observations from Table 5 about aggregate generation outputs are:

[13] The main recent dry-year events were in 2021 and 2024.

[14] Downloaded from https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/electricity-march-2026-q1.xlsx

- Increases in geothermal and wind have displaced gas and coal fuelled thermal generation and have been larger than the variations in hydro generation. Geothermal generation and average wind generation are relatively stable from one trading period to the next and are not dispatchable. However geothermal output is predictable and stable, while wind generation is not.
- Baseload coal and gas generation have been displaced by the increase in geothermal and wind generation.

Table 5 Annual electricity generation volume

Volume in GWh

Type	2020	2021	2022	2023	2024	2025	Average
Hydro	24,078	23,979	26,071	26,295	23,490	23,991	24,651
Geothermal	7,834	7,968	8,013	7,732	8,741	9,547	8,306
Biogas	271	263	271	295	310	305	286
Wood	460	483	439	403	442	254	413
Wind	2,294	2,606	2,835	3,219	3,940	3,811	3,118
Solar[1]	161	210	285	374	578	959	428
Oil	13	26	7	5	25	6	14
Coal	2,159	3,020	1,251	1,031	2,243	1,523	1,871
Gas	5,935	4,653	4,315	4,106	4,082	3,538	4,438
Waste Heat[2]	40	43	40	33	27	21	34
Total	**43,244**	**43,251**	**43,528**	**43,492**	**43,877**	**43,956**	**43,558**

Notes:

1 MBIE has used EA data to estimated distributed Solar PV Generation. The method is not disclosed. We estimate grid scale solar output in 2024 was 94.9 GWH and in 2025 was 272.0 GWh.

2 Waste heat includes heat from chemical processes - e.g. fertiliser industry.

Source: NZIER analysis of MBIE Electricity statistics'

The comparisons of annual generation with average generation by fuel over 2020 to 2025 highlight the sensitivity of the electricity market to modest changes in hydro generation and the displacement of dispatchable thermal generation with geothermal and wind generation.

- Hydro generation was below average levels in 2024 by 1,160 GWh, 2021 by 672 GWh, 2025 by 659 GWh and 2020 by 573 GWh. The years 2024 and 2021 were 'dry years' but 2020 and 2025 were not.
- Thermal generation's contribution to covering below average hydro generation has declined from excess cover in 2020 and 2021 to no net cover in 2024 and 2025.

Table 6 Variation in annual electricity generation from 2020-25 average

Volume in GWh

Type	2020	2021	2022	2023	2024	2025	Average
Difference (GWh)							
Hydro	-573	-672	1,421	1,644	-1,160	-659	24,651
Coal	288	1,149	-620	-840	372	-349	1,871
Gas	1,497	215	-122	-332	-356	-900	4,438
Difference (%)							
Hydro	-2%	-3%	6%	7%	-5%	-3%	
Coal	15%	61%	-33%	-45%	20%	-19%	
Gas	34%	5%	-3%	-7%	-8%	-20%	

Source: NZIER analysis of MBIE Electricity statistics'

The increase in geothermal and wind generation have already shifted the role of both thermal and to a lesser extent hydro away from baseload generation toward firming. However, the firming task is different for both types of generation:

- Geothermal provides a constant output (except during maintenance shutdowns) which means the firming requirement is determined by the intraday and seasonal variations in demand.
- Wind provides an output that varies widely both intraday and between seasons. Onshore wind output is slightly higher in the quarters ended 30 September and 31 December (winter and spring) with the output over these two quarters about 55 percent of annual output. Therefore, most of the difficulty in estimating the firming task is determined by the fluctuation in the generation. The following tables illustrate this variation in output.

A.2.1 Focus on winter generation

The following tables show the variation in generation over the six months from 1 April to 30 September.

Table 7 Electricity generation volume – 1 March to 30 September

Volume in GWh

Type	2020	2021	2022	2023	2024	2025	Average
Hydro	11,923	12,077	13,276	13,944	11,414	12,293	**12,488**
Geothermal	3,998	3,956	4,134	3,847	4,611	5,016	**4,260**
Biogas	137	129	135	151	156	151	**143**
Wood	236	248	215	202	219	118	**206**
Wind	1,143	1,362	1,476	1,595	1,922	1,964	**1,577**
Solar[1]	67	87	115	155	233	372	**172**
Oil	11	19	3	3	23	3	**10**
Coal	1,130	1,853	694	489	1,768	834	**1,128**
Gas	3,461	2,740	2,572	2,362	2,463	2,154	**2,625**
Waste Heat[2]	19	22	19	15	13	10	**16**
Total	**22,125**	**22,494**	**22,638**	**22,763**	**22,821**	**22,916**	**22,626**
Winter/year[3]	**95.5%**	**92.3%**	**92.3%**	**91.1%**	**92.3%**	**91.8%**	**92.5%**

Notes:

1 MBIE has used EA data to estimated distributed Solar PV Generation. The method is not disclosed.

2 Waste heat includes heat from chemical processes - e.g. fertiliser industry.

3 Winter generation as percentage of annual generation.

Source: NZIER analysis of MBIE Electricity statistics'

Table 8 Variation in winter electricity generation from 2020-25 average

Volume in GWh

Type	2020	2021	2022	2023	2024	2025	Average
Difference (GWh)							
Hydro	-564	-411	788	1,456	-1,074	-195	**12,488**
Coal	2	725	-434	-639	640	-294	**1,128**
Gas	835	114	-53	-263	-163	-471	**2,625**
Difference (%)							
Hydro	-5%	-3%	6%	12%	-9%	-2%	
Coal	0%	64%	-38%	-57%	57%	-26%	
Gas	32%	4%	-2%	-10%	-6%	-18%	

Source: NZIER analysis of MBIE Electricity statistics'

Appendix B SoSA – ‘Medium Demand Growth+Low Gas Supply’

In this section we have repeated the calculations described in section 2.2.1 to estimate the additional generation that would be required under the long-term obligation for the ‘Medium Demand Growth+Low Gas Supply’ an upper bound for the additional generation and generation capacity forecast for the Expected Future case (Final).

Table 9 SoSA based estimate of required generation capacity to meet the proposed long-term obligation

Demand and required supply in GWh, NWEM as a percentage, capacity reported in MW

Year	Demand[1]		SoSA NZWEM	Winter Supply[2]	Required supply[3]		Shortfall		Additional capacity[4]		Annual Capacity change	
	Gross	Net			Lower[4]	Upper[4]	Lower	Upper	Lower	Upper	Lower	Upper
2026	24,310	23,824	18.77%	28,296	27,159	27,636	-1,137	-660				
2027	25,320	24,814	16.02%	28,789	28,288	28,784	-501	-5				
2028	26,091	25,569	11.59%	28,532	29,148	29,660	617	1,128	156.0	285.4	156.0	285.4
2029	27,399	26,851	5.70%	28,381	30,610	31,147	2,229	2,766	563.9	699.7	407.8	414.3
2030	28,434	27,865	1.09%	28,168	31,766	32,323	3,598	4,156	910.3	1,051.3	346.4	351.6
2031	29,407	28,819	-2.51%	28,094	32,854	33,430	4,759	5,336	1,204.0	1,349.9	293.7	298.6
2032	30,092	29,490	-5.38%	27,903	33,619	34,209	5,716	6,306	1,446.1	1,595.3	242.1	245.4
2033	30,861	30,244	-7.99%	27,826	34,478	35,083	6,652	7,256	1,682.7	1,835.8	236.6	240.5
2034	31,594	30,963	-10.04%	27,854	35,297	35,917	7,443	8,063	1,883.1	2,039.7	200.3	203.9
2035	32,318	31,672	-11.55%	28,015	36,106	36,739	8,091	8,724	2,046.9	2,207.1	163.8	167.4

Notes:

1 This estimate of SoSA net demand is based on 'Medium Demand Growth' reduced by an annual 2 percent demand response. This is consistent with the approach described in the worksheet 'Example NZ energy margin calc' of the workbook ''2026 SoSA - Final Supplementary Data - Final Version.xlsx'.

2 'Winter supply' is estimated as 'Net Demand' multiplied by (1 + SoSA NZWEM Medium Demand Growth+Low Gas Supply).

3 Required supply is estimated as net demand multiplied by 1.14 for the lower security standard and 1.16 for the upper security standard.

4 Additional capacity generation capacity is estimated assuming the winter demand is supplied with the plant operating at an availability factor of 90 percent availability factor over the six month winter period.

Source: NZIER analysis of Transpower 2026 SoSA and the supporting dataset '2026 SOSA - Final Supplementary Data - Final Version.xlsx'.