Meeting Date: 28 March 2019

2019 Annual Assessment of Security of Supply

Security and Reliability Council

The Security of Supply Annual Assessment 2019, covering energy and capacity adequacy over a ten-year horizon

Note: This paper has been prepared for the purpose of the Security and Reliability Council. Content should not be interpreted as representing the views or policy of the Electricity Authority.

1. Background

The Security and Reliability Council is asked to consider the Security of Supply Annual Assessment 2019

1.1. The Security and Reliability Council's (SRC) functions include offering advice to the Electricity Authority on the security of the power system. One aspect of security is adequacy of generation investment to provide energy and capacity.

1.2. The system operator's annual Security of Supply Assessment (SOSA) is the primary source of information on adequacy of generation investment to provide energy and capacity over a time horizon of years.

1.3. The SRC is asked to consider the SOSA 2019 (attached as Appendix A), which covers energy and capacity adequacy to 2028. The SOSA was published on 28 February 2019, following consultation.

1.4. The system operator has provided a short note (attached as Appendix B), and will attend the SRC meeting to present the SOSA.

This paper also addresses an action on the SRC secretariat

1.5. SRC action 5 is for the secretariat to "report back to the SRC on the sensitivities of the annual assessment assumptions and how the assessment could:

a) better take into account the dynamic nature of the market

b) include a scenario in which a shortage of stored fuel other than gas and an extended critical gas contingency coincide."

1.6. Section 2.5 of this cover paper explains how the SOSA 2019 addresses the above issues.

The SOSA framework

1.7. The security standards set by the Authority are:

a) a winter energy margin for New Zealand (NZ-WEM) of 14-16% greater than forecast energy consumption

b) a winter energy margin for the South Island (SI-WEM) of 25.5-30% greater than forecast energy consumption

c) a winter capacity margin for the North Island (WCM) of 630-780 MW greater than forecast peak demand (in MW). Note that this margin includes an allowance for instantaneous reserve (IR).

1.8. The margins set reflect that if under-supply occurs, there is an increase in costs to the country through loss of production and loss of load events. When over-supply occurs, there is a cost to consumers through cost recovery for the surplus generation. While the risks are asymmetric, the margins represent an efficient level of generation supply that minimises overall cost to the country.

1.9. The results against the margins help inform stakeholders whether an efficient level of energy or capacity generation supply exists now and in future scenarios. Results outside the efficient margins (especially results exceeding the margins) are not necessarily problematic. They are a single measure and need to be examined in a broader context before conclusions can be reliably drawn.

1.10. There are no legislative consequences for generators not meeting the efficient margins; the margins are intended to be informative. By contrast, measures like the customer compensation scheme and scarcity pricing are explicitly designed to provide incentives that augment spot price signals to better promote reliability.

1.11. The system operator is obliged to annually publish an assessment of security of supply against the NZ-WEM, SI-WEM and WCM margins. As noted in the update to the 24 October 2018 SRC meeting, the Authority analysed the margins and concluded that changes may be warranted but they were not significant enough to justify further effort to implement the changes.

1.12. The Authority provides certain assumptions that the system operator must use when preparing the annual assessment. These assumptions are published in the Security Standards Assumptions Document (SSAD).[1] The purpose of the SSAD is to help ensure that results against the margins are calculated in a way that is consistent with the derivation of the margins. The system operator can use alternative assumptions if it provides reasons for doing so and still notes the results of using the Authority's assumptions.

Annual updates will be provided

1.13. The SRC will be updated on the Security of Supply Annual Assessment 2020 in a year's time.

1.14. The system operator has indicated that its development focus for the coming year is on:

a) "working with gas industry stakeholders and the Gas Industry Company to refine its gas supply assumptions"

b) "using [its white paper] Te Mauri Hiko[2] to develop a framework for security of supply management into the future" – including developing "appropriate frameworks that will enable electrification in transport and industry while meeting supply reliability expectations".[3]

2. The findings of the SOSA 2019

Results for the three core scenarios

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1 https://www.ea.govt.nz/operations/wholesale/security-of-supply/security-of-supply-policy-framework/security-standards-assumptions/

2 https://www.transpower.co.nz/resources/te-mauri-hiko-energy-futures

3 The system operator is not required to carry out this work under the Electricity Industry Act 2010, but wishes to do so. The Authority does not expect the system operator to seek any additional funding for this purpose.

2.1. Rather than having a single base case, the assessment uses three core scenarios. The three scenarios are labelled:

a) low demand

b) medium demand

c) thermal constraints.

2.2. Existing thermal generation remains in place in the ‘low demand’ and ‘medium demand’ scenarios. The ‘thermal constraints’ scenario, driven by uncertainty about the future of thermal generation in NZ, involves a 500 MW reduction in thermal generation.

2.3. The ‘low demand’ scenario is characterised as “an energy future where New Zealand’s electrification and decarbonisation aspirations are not met within the next 10 years”.

2.4. The Tiwai smelter remains in operation in all three core scenarios (though a sensitivity scenario in Appendix 2 models early Tiwai closure).

2.5. As in 2018, generation is divided into the following categories:

a) existing and committed

b) consented

c) not consented, but consent could be sought soon.

2.6. Section 4.3 of the SOSA forecasts that new generation will be needed in order to meet the *national* energy security standard by 2024 (in the ‘medium demand’ or ‘thermal constraints’ scenarios) or 2026 (in the ‘low demand’ scenario).

2.7. Section 4.4 forecasts that new generation will be needed to meet the *capacity* security standard by 2026 (in the ‘medium demand’ or ‘thermal constraints’ scenarios) or after the end of the modelling horizon (in the ‘low demand’ scenario).

2.8. Appendix 1 provides forecasts of South Island energy margins, but these can be ignored as the national energy standard always binds before the South Island energy standard.

2.9. Under all three scenarios, there is enough consented generation to meet all three security standards to 2028 and beyond.

2.10. The SRC has previously commented that some renewable generation consents will expire in the coming years. This issue is not modelled in the SOSA 2019, but is acknowledged in the text – “if [such] projects are not committed before their consents lapse, then new consents or other sources of generation will be required. This may delay commissioning dates in some instances.”

Sensitivity analysis

2.11. There are some sensitivities in which new generation is needed earlier.

2.12. In each of the following sensitivities, new generation is needed to meet the national energy standard by 2022:

a) high demand

b) thermal decommissioning

c) reduced generation availability ("a 5% reduction in non-thermal generation output").

2.13. Combinations of these sensitivities are even more adverse – e.g. when 'high demand' is combined with 'reduced generation availability', NZ-WEM drops below the national energy standard immediately and remains there until new generation is built in 2021.

Changes following consultation

2.14. The system operator consulted on a draft version of the SOSA 2019. Following consultation, it made some revisions to the demand forecast and clarified some issues in the text.

2.15. The final version of the SOSA 2019 forecasts:

a) essentially the same level of energy security as the draft, but

b) a substantially higher level of capacity security than the draft – presumably due to downward revision of the peak demand forecast.

2.16. The 'need date' for new generation is not materially affected by the above changes, because it is driven by energy security rather than capacity security.

Differences between the SOSA 2019 and last year's SOSA

2.17. This year's assessment projects an overall higher level of security of supply than last year's:

a) the three SOSA 2019 scenarios forecast that new generation will be needed between 2024 and 2026 in order to meet the security standards

b) the three SOSA 2018 scenarios forecast that new generation would be needed between 2021 and 2025.

2.18. The SOSA methodology was essentially the same in 2018 as it was in 2019, but some input assumptions have changed.

2.19. The SOSA 2018, like the SOSA 2019, used three core scenarios, but they were different scenarios – 'Thermal Remains', 'Thermal Retirement', 'Low Carbon and Electrification'. The key uncertainties remain the same – how quickly will demand grow and when will existing thermal generation retire?

2.20. Thermal generation retirement aside, existing and new generation assumptions do not appear to have changed greatly.

2.21. The energy and peak demand forecasts have been revised downwards on the back of continuing low demand growth – especially in the 'low demand' scenario, and to a lesser extent in the 'medium demand' scenario.

2.22. The SOSA 2018, like the SOSA 2019, assumed that the Tiwai smelter would remain in operation, but explored early Tiwai closure in a sensitivity scenario.

2.23. The system operator notes two other important substantive changes in the SOSA 2019:

a) the demand forecast models additional load from NZAS with the new pot-line

b) “contributions from distributed solar generation, batteries and other small scale embedded generation [have been explicitly modelled] on the supply side of the analysis”. Additional solar, combined with batteries to some extent, is forecast over the coming decade.

2.24. Te Mauri Hiko was published late last year and the system operator now uses it as a base for two of its three scenarios. As far as Authority staff are aware, this is the first time that the Transpower White Paper has been used to inform the system operator’s security of supply work. The SOSA does not document any consideration of the merits of aligning with Te Mauri Hiko assumptions.

2.25. Since 2018, improvements have also been made in the presentation of the assessment and the way in which key concepts are explained. In particular, the SOSA now explains that instantaneous reserve requirements are included in WCM by saying “…for example, if the WCM is 1000 MW, this includes approximately 300-600 MW that would be needed for [instantaneous reserve]”.

2.26. This helps to avoid giving the mistaken impression that when WCM is in the efficient range (630-780 MW), there is approximately 700 MW of excess capacity in the system. In fact, some of this capacity will be required for instantaneous reserve. Nonetheless, there is still potential for confusion.

2.27. There is a chance of capacity shortfall at any time, even if results are above the efficient range. The efficient range is predicated on occasional capacity shortfalls being efficient. In general, the lower the result, the increased probability of capacity shortfalls.

The SOSA addresses the three issues raised in SRC action 5

2.28. The SRC sought information from the secretariat on “the sensitivities of the annual assessment assumptions”. Sensitivity analyses are provided in Appendix 2 of the SOSA 2019, and now also through a web tool. This enables users to choose combinations of scenarios and sensitivities to analyse.

2.29. The SRC also sought information on “how the assessment could better take into account the dynamic nature of the market”. The secretariat understands that this relates to the ability of the market to bring forward new generation investment if there is a forecast shortfall. This is reflected in the text of the SOSA 2019, which acknowledges that:

> *“Subject to a stable investment environment, it should be possible to meet the standards over the next 10 years, providing that participants are able to advance projects to consent and build on these resources. This will likely require generation projects beyond those that we are presently aware*

of as not all projects in our assessment are likely to be able to proceed."[4]

2.30. The SRC also sought information on "how the assessment could include a scenario in which a shortage of stored fuel other than gas and an extended critical gas contingency coincide". The SOSA 2019 addresses gas supply issues from an *investment* perspective, through:

a) a "thermal constraints" scenario, which removes 500 MW of gas generation over time, and

b) a "thermal decommissioning" sensitivity, in which "one of the two combined cycle gas turbines shuts down in 2022".

2.31. The system operator has also recently addressed gas supply issues from an *operational* perspective, in the context of:

a) the New Zealand Generation Balance (NZGB), which will be discussed further under agenda item nine

b) the hydro risk curves, which is discussed in the subsection below.

One of the issues raised in SRC action 5 has also been addressed in the context of the hydro risk curves

2.32. The system operator has prepared a document titled *HRC Thermal Scenarios* (attached as Appendix C). Although this document relates to the hydro risk curves rather than the SOSA, we briefly discuss it here as it:

a) helps to address the third issue raised under SRC action 5 (relating to treatment of gas supply issues under the security of supply framework)

b) is not covered under any other agenda item for this SRC meeting.

2.33. *HRC Thermal Scenarios* considers two scenarios for 2019:

a) a "gas supply shortage scenario", in which "one CCGT is de-rated to 50% capacity [for an extended period] to represent a decrease in available gas supply for electricity generation or reduction in plant availability"

b) a "gas pipeline disruption scenario", in which "Huntly gas-fired generation [is reduced] to zero for 3 months".

2.34. Simulations show that the "gas supply shortage scenario" causes storage to fall into the Emergency Zone in 2.5% of inflow sequences, and the "gas pipeline disruption scenario" in 7.5% of inflow sequences.

2.35. It remains to be seen how (if at all) this work will be incorporated into the security of supply framework on an ongoing basis.

2.36. The secretariat considers that the impact of an extended critical gas contingency is better analysed with the operational approach of *HRC Thermal Scenarios* rather than the investment approach of the SOSA. This is because:

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4 Page 11 of the SOSA 2019.

a) The efficient margin in the 'investment approach' accounts for the long-term likelihood of a gas supply disruption and estimates the efficient amount of generation surplus. Comparing that margin with a scenario in which there is a 100% certainty of a gas supply disruption is meaningless.

b) The operational approach does not suffer the above problem. It simply illustrates the impact the gas supply disruption would likely have on the hydro risk curves.

3. Questions for the SRC to consider

3.1. The SRC may wish to consider the following questions.

Q1. Is the SRC satisfied with the changes made in the 2019 SOSA? Is the SRC satisfied that action item #5 can be closed?

Q2. What further information, if any, does the SRC wish to have provided to it by the secretariat?

Q3. What advice, if any, does the SRC wish to provide to the Authority?

4. Appendices

4.1. Appendix A: *Security of Supply Annual Assessment 2019* (system operator)

4.2. Appendix B: *Annual Security of Supply Assessment: update for SRC* (system operator)

4.3. Appendix C: *HRC Thermal Scenarios* (system operator)

Security of Supply Annual Assessment 2019

Transpower New Zealand Limited

February 2019

Keeping the energy flowing




TRANSPOWER

Version[1]	Date	Change
1.0	08/02/2019	Draft for industry review
2.0	28/02/2019	Final version
2.1	1/03/2019	Updated figures 5, 69, 70, 87, 88, 89, 90, 105 to show correct results.

	Position	Date
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[1] For previous assessments undertaken by the system operator refer to *https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment*

For similar assessments by the Electricity Commission prior to 2011, refer to http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/security-of-supply/asa/

Contents

1 EXECUTIVE SUMMARY

This document is Transpower's annual medium-term security of supply assessment. It provides a ten-year view (2019 to 2028) of security of supply metrics for three key supply and demand scenarios, covering energy and capacity. This assessment enables industry stakeholders to compare the risk of supply shortages both between scenarios and over time to inform risk management and investment decisions.

In this year's annual assessment, we have evolved the scenarios used last year to test the ability of the power system to meet security of supply standards. These three scenarios are based on current, committed and consented generation projects that we are aware of.

The scenarios show a mixture of demand and supply variations. Two of the three explore different demand scenarios - a low and medium demand growth rate. The low growth illustrates the impact of continued modest energy growth in New Zealand. The medium growth scenario is similar to the Te Mauri Hiko[2] base case where the electrification of transport and industrial process heat prompts higher rates in growth in the 2020s. All scenarios also assume Tiwai Point Smelter remains viable until 2030.

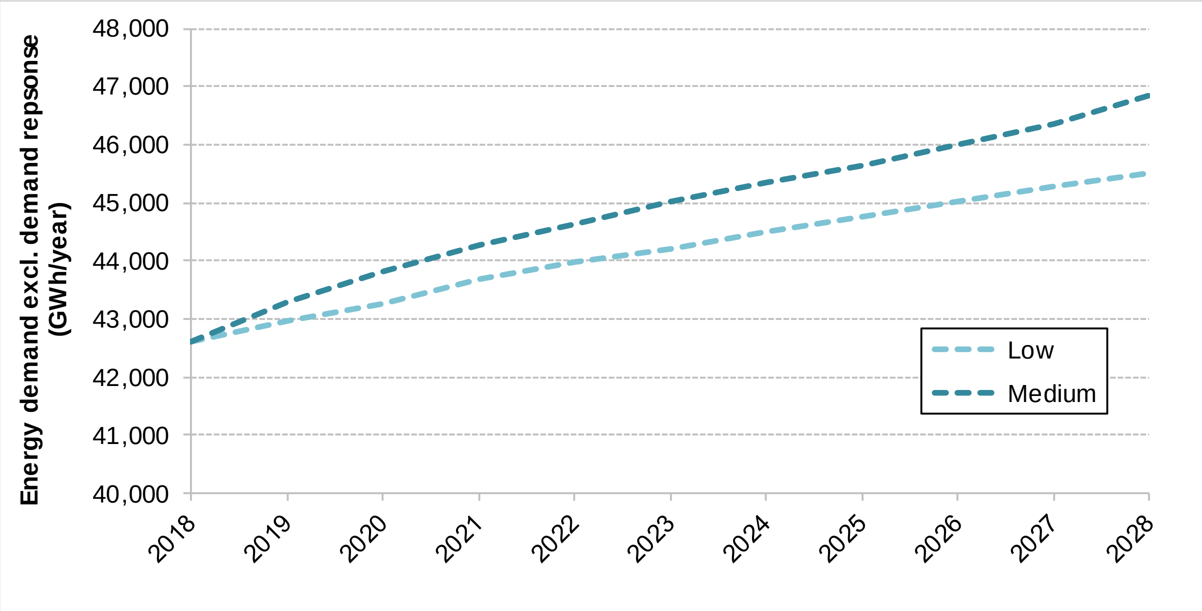

Figure 1: Energy demand forecasts in the two demand scenarios

We also include an third scenario, "Thermal constraints", to reflect uncertainty around the future generation mix. This uses the "medium" demand case but assumes a limit on the addition of gas generation, by removing 500MW from future supply.

Demand for electricity assumed in the assessment is based on Transpower's demand forecasts. For supply—that is existing and potential new generation—assumptions are supplied in confidence by generators and presented in aggregate in Figure 2. There are also several key assumptions described in the Security Standards Assumption Document.[3]

This assessment explicitly models for the first-time contributions from small-scale embedded generation. As a result, demand and supply have increased compared to previous assessments. Based on Te Mauri Hiko, we assume growth in distributed solar generation reaches 3,000 GWh of annual generation by 2028 in all three scenarios. Existing embedded and distributed generation has a neutral effect on the security of supply assessment. The additional solar that is forecast in the coming years has a small positive contribution to the security of supply assessment.

In all three scenarios, investment in new generation will be required in the next 5-7 years to maintain security of supply margins at an efficient level. The additional pot-line at the New Zealand Aluminium smelter as well as wider electricity demand growth is forecast to reduce winter margins. In last year's

[2] https://www.transpower.co.nz/resources/te-mauri-hiko-energy-futures

[3] https://www.ea.govt.nz/dmsdocument/14134-security-standards-assumptions-document-ssad

assessment we forecast the need for new generation between 2021 (with thermal closures) and 2025. Without any thermal closure we now expect additional supply will not be required until between 2024-5.

In all scenarios maintaining the security of supply standard will require an ongoing pipeline of new generation—especially from mid-2020s. Under the three main scenarios there are sufficient known new generation options that, if built, would ensure efficient levels of reliability in the coming decade.

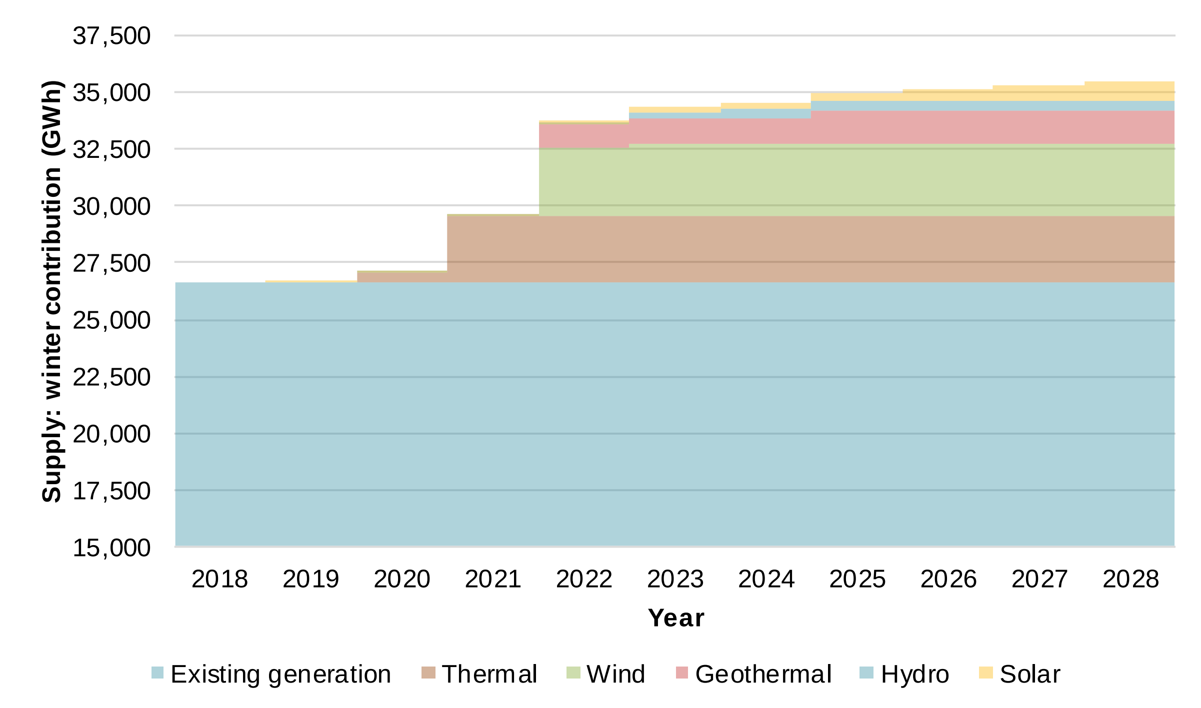

Figure 2: Modelled supply additions, by year of earliest availability

These results are illustrated in the New Zealand Winter Energy Margin in the diagram below. For each scenario, the lower, light bands are existing generation. The upper, dark bands are known new generation options that could be built.

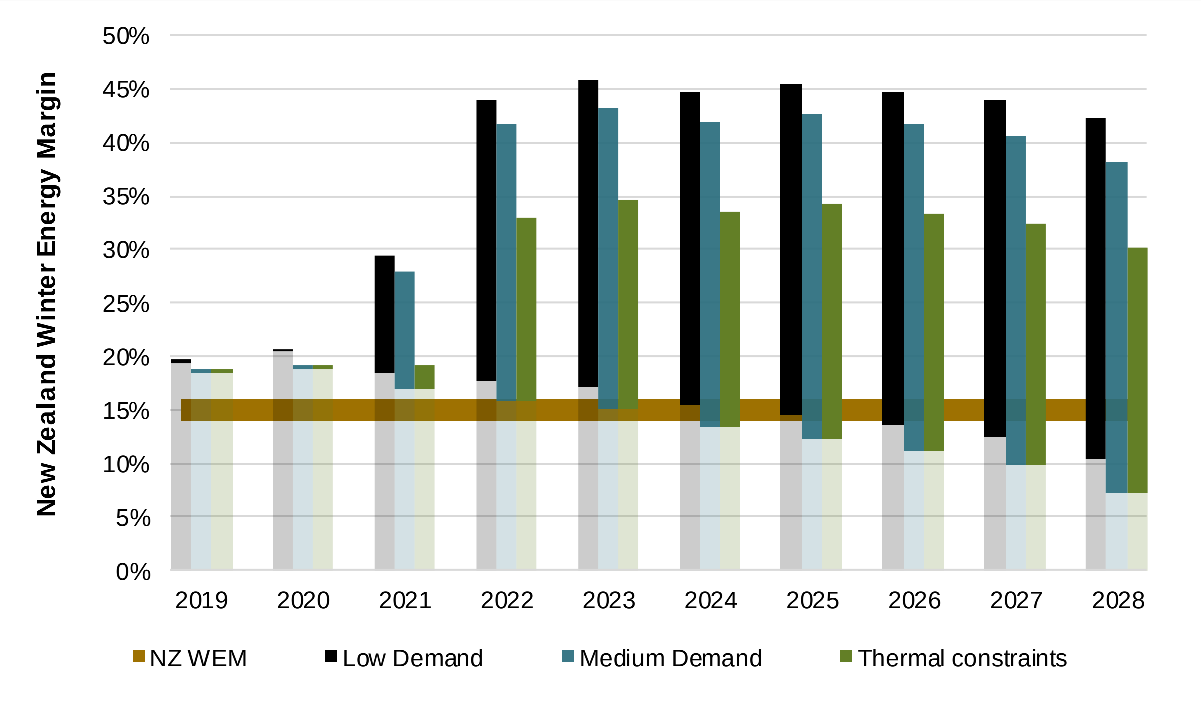

Figure 3: New Zealand Winter Energy Margin for all scenarios

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We also consider several sensitivities in our analysis. This enables the three scenarios to be adjusted. A new online tool has been developed to present the results in a more accessible way, given the wider number of cases from added sensitivity studies.

Overall our assessment signals that maintaining an efficient level of reliability will require new generation in the next 5-10 years. To meet security standards for the New Zealand Winter Energy Margin, even under the low growth scenario, New Zealand will need to commission at least 100 GWh of new winter generation[4] by 2026, and approximately 900 GWh by 2028. Under the medium demand scenario New Zealand will need to commission around 150 GWh of new winter generation by 2024. In all three scenarios new generation will need to be consistently added in the mid to late 2020s, up to 1,700 GWh of winter generation in 2028 in the medium scenario.

When analysing these results, it should be noted the annual assessment results are based on a simplified model of the New Zealand electricity system. As such, the assessment makes several assumptions that should be considered when drawing conclusions. In particular:

- The timelines illustrated in the results for new generation do not account for the consenting and construction times for additional transmission infrastructure, nor do they account for intra-island locational issues (such as regional voltage issues). This may delay commissioning dates in situations where major transmission investment is required.
- All scenarios highlight the reliance on consented (but on hold) generation to meet security of supply standards. If these projects are not committed before their consents lapse, then new consents or other sources of generation will be required. This may delay commissioning dates in some instances.

Transpower seeks to continually evolve and improve security of supply assessments, and the broader security of supply framework to ensure it adds value during a period of significant change. This year the focus will be on:

- working with gas industry stakeholders and the Gas Industry Company to refine our gas supply assumptions for the annual assessment.
- using Te Mauri Hiko to develop a framework for security of supply management into the future. This is to inform the development of appropriate frameworks that will enable electrification in transport and industry while meeting supply reliability expectations.[5]

[4] Generation required during months April through September

[5] Note this work is being undertaken separately from Transpower’s role as system operator un the System Operator Service Provider Agreement.

2 BACKGROUND

2.1 ASSESSMENT CONTEXT

This document is Transpower's annual medium-term security of supply assessment. Its purpose is to inform risk management and investment decisions by generators, other market participants, and investors.

It forms part of New Zealand's electricity security of supply framework. Transpower performs other security of supply-related functions described in its *Security of Supply Forecasting and Information Policy* and the *Emergency Management Policy*.[6] These include:

- Short-term monitoring and information provision, such as the weekly reporting of hydro levels relative to the hydro risk curves.
- Implementation of emergency measures where necessary.
- Detailed assessment of grid capability to meet demand over the next three years, available in Transpower's System Security Forecast.
- Detailed capacity assessment for the current year, available in Transpower's New Zealand Generation Balance assessment.

To supplement this work we plan to build upon the Te Mauri Hiko white paper to determine what changes may be required to meet the reliability expectations of consumers in the coming decades.

For more detail on the security of supply framework see *https://www.transpower.co.nz/system-operator/security-supply*.

2.2 SECURITY OF SUPPLY ASSESSMENT

This assessment provides a medium-term view of the balance between supply and demand in the New Zealand electricity system. The security of supply assessment forecasts two winter margins, the Winter Energy Margin (WEM) and the Winter Capacity Margin (WCM).

- The energy margins, for New Zealand and the South Island, are the sum of the respective available winter energy supply, in gigawatt-hours (GWh), divided by the expected winter energy demand, in GWh. The margins are expressed as a percentage of total demand.
- The capacity margin is the sum of North Island generation capacity less the expected peak demand plus surplus South Island capacity able to be sent via the HVDC link to the North Island.[7] The margin is expressed as a megawatt (MW) value.

Winter is defined as the period from April to October for the WCM, and April to September for the WEMs.

The energy margins assess whether it is likely there will be an adequate level of generation and, in the case of the South Island, HVDC south transmission capacity, to meet expected electricity demand during the winter. The capacity margin assesses whether it is likely there will be adequate generation and HVDC north transmission capacity to meet peak North Island demand.

The security of supply standards are defined by the Electricity Authority as part of its responsibility to ensure that the regulatory environment promotes an efficient level of reliability. The standards represent an efficient level of reliability—that is the expected cost of shortage is equal to the expected cost of new generation.

[6] *https://www.transpower.co.nz/system-operator/security-supply/security-supply-forecasting-and-information-policy*

[7] Noting we do not make allowances for spinning reserve—that is, the peak demand is not increased by the amount of reserves required. This means the subsequent margin represents excess supply *prior* to the provisioning of reserves. Thus, in reality the actual margin observed would be available, but not dispatched generation, and reserves required.

It is important to note that falling below the standards does not equate to electricity shortage. It simply implies that investment in new generation would result in an efficient increase to reliability. It can also be interpreted as representing the *likelihood* of electricity shortage – the higher the actual margin observed the less likely electricity shortage will be.

The current security of supply standards[8] specified in the Code are:

- a WEM of 14-16% for New Zealand
- a WEM of 25.5-30% for the South Island
- a WCM of 630-780 MW for the North Island.

While demand scenarios are from Transpower analysis, supply includes future generation projects as supplied in confidence by generators.

A more detailed description of the security of supply assessment methodology may be found in Appendix 3: Methodology.

[8] The Authority reviews the security of supply standards on a regular basis to ensure they account for the risks to supply, the mix of generation and demand side technologies employed by participants, uncertainty in primary fuel availability (especially hydro inflow uncertainty), and costs.

3 ANALYSIS

We use three scenarios[9] to represent quite different, but plausible, futures. These scenarios evolve our scenarios from last year's assessment and we assess the degree to which margins are met against each of these scenarios.

In May 2018, Transpower published Te Mauri Hiko.[10] This white paper, along with other recent publications, identifies that New Zealand's energy future will require significant electrification if we are to meet climate change goals. This white paper highlighted that there could be substantial growth in electricity demand in the 2020s and 2030's from the electrification of transport and process heat. Te Mauri Hiko also identifies that in the longer term (15-30 years), the future mix of generation types and storage capabilities will have a material impact on security of supply. For this year's annual assessment, we have used Te Mauri Hiko as a basis[11] for two of the three scenarios (Medium Demand and Thermal Constrained), however it is worth noting that in the short- to medium-term Te Mauri Hiko aligns closely with our traditional forecasts.

In this year's assessment two of the three scenarios are differentiated by the demand assumptions they use—a low demand growth case and a medium demand growth case, each capturing different levels of future growth. The low demand growth scenario represents an energy future where New Zealand's electrification and decarbonisation aspirations[12] are not met within the next 10 years, and growth is more representative of what has been observed in recent years. The medium demand scenario is aligned to the assumptions used in Transpower's Te Mauri Hiko report—medium demand equates broadly to the Te Mauri Hiko base case. This scenario still uses strong assumptions about increasing energy efficiency, but the increasing demand from electrification of transport and process heat leads to medium levels of demand growth by the mid-2020s.

The final scenario of the three examines the impact of generation mix. This scenario uses the medium demand growth assumptions but constrains the growth of thermal generation. This could be due to lower investment in new gas-fired generation or the closure of a significant existing thermal plant.

Existing supply and new generation options (excluding small scale embedded generation and storage) used in these scenarios are those reported to us by generators in confidence and the results are presented in a way that seeks to preserve that confidence.

3.1 SCENARIOS

The three scenarios are:

- **Low demand:** this scenario represents a world where New Zealand's carbon emissions are not addressed through the electrification of transport and industry. As a result, electricity demand growth is similar to what has been observed in recent years. This scenario assumes a demand forecast that is similar to forecasts used in previous annual assessments where significant electrification of transportation and industry was not accounted for and assumes underlying wholesale market demand for electricity growth averages 0.6-0.7% across the decade.
- **Medium demand:** this scenario uses a demand forecast that broadly aligns with the base case scenario in Te Mauri Hiko. The Te Mauri Hiko base case scenario involves a coordinated, but moderate response to climate change—increasing electricity growth is observed as regulation and market incentives lead to the electrification of transport and process heat. This effect starts

[9] In this document, we use the term scenario to denote a standalone, plausible future. We use sensitivities to denote exploration of the impact of various factors on each of these scenarios.

[10] https://www.transpower.co.nz/resources/te-mauri-hiko-energy-futures

[11] We have not adopted the exact forecast used in TMH, but we have used a medium demand forecast that does assume electrification of industry and transport at a level aligned to Te Mauri Hiko (in addition to other components of the Te Mauri Hiko future scenarios).

[12] That is, electrification of the transport fleet and industrial process heat as many industry experts are predicting.

slowly but grows over time and this scenario assumes underlying wholesale market demand for electricity grows at an average of 1.0% per year.

- **Thermal constraints:** this scenario represents a future where gas-fired thermal generation growth is limited. It uses the same demand outlook as the medium demand scenario above but assumes 500 MW of new gas-fired thermal generation is unavailable. This could occur if less new thermal generation is built, or, equivalently, existing thermal generation is reduced by 500 MW.

In keeping with the findings of Te Mauri Hiko, we assume New Zealand Aluminium Smelter (NZAS) remains viable under all scenarios for the forecast period.[13]

For further information on the assumptions used in this assessment see section 5 for high level information and appendices 3 - 6 for detailed information.

3.2 Changes to this year's assessment and Future development

The Security of Supply Annual Assessment is a key tool in the suite of security of supply analysis. However, it is something we aim to develop and evolve over time such that it keeps up with the needs of our stakeholders and remains a valid and useful tool.

3.2.1 Changes in this year's edition of the Annual Assessment

This year we have implemented several important changes to both how the results are derived, and how the information is provided.

- 2018 saw two months of additional load from NZAS with the new pot-line. This is included in our demand forecasts as a one-time step-change that underpins all scenarios, with 2019 as the first full year of this additional load.
- We have explicitly modelled contributions from distributed solar generation, batteries and other small scale embedded generation on the supply side of the analysis. Previously these technologies had been included by implicitly modelling demand net of small scale embedded generation. As such, both demand and supply have increased to account for these new sources of generation. By forecasting additional solar over the coming decade, the capacity and energy margins increase slightly as solar provides some diversity and supply for winter generation when combined with batteries to enable time-shifting of this energy to meet the evening peaks.
- We have developed a web-application to present the results in a more accessible way.[14]

3.2.2 Future development

Further work will be undertaken during 2019 to ensure that future security of supply assessments, and the broader security of supply framework, provide support and advice to industry stakeholders during this anticipated period of change. This year key areas of focus in this work will be:

- To work with gas industry stakeholders and the Gas Industry Company to refine our gas supply assumptions for the annual assessment.
- Use Te Mauri Hiko to develop a framework for security of supply management into the future. This is to inform the development of appropriate frameworks that will enable electrification in transport and industry while meet supply reliability expectations.[15]

This work will be progressed in the 2019 calendar year, and feedback from the industry or other interested parties is welcome. Feedback can be sent to *system.operator@transpower.co.nz*.

[13] Given our high proportion of renewable electricity, it is possible aluminum made in New Zealand may be an attractive product in international markets.

[14] *https://www.transpower.co.nz/system-operator/security-supply/annual-assessment-results*

[15] Note this is beyond the scope of the System Operator Service Provider Agreement.

4 Results

4.1 Discussion of results

This assessment indicates that if demand grows at a low (0.6-0.7%) or medium rate (1.0%) then there are sufficient known new generation options to ensure efficient levels of reliability in the coming decade. However, if thermal generation options are restrained in the coming years, further new generation options beyond those presently contemplated will be required to maintain the security of supply standards. Regardless of the scenario, investment in new generation will be required to maintain the security of supply standards. It is likely this generation will be required from ~2024 onwards to maintain security of supply margins at an efficient level.

If no new generation is built, it is expected that all margins will fall below security of supply standards at some point during the assessment, indicating the New Zealand electricity system could face increased risk of shortfalls in trying to meet demand in winter. New generation investment is required as early as 2024. It should be noted that the timelines illustrated in the results for new generation do not account for transmission consent and build times, nor do they account for intra-island locational issues (such as regional voltage issues). Accounting for transmission consent and build issues for some new generation projects may lead to commissioning dates for these projects being deferred or delivered later than assumed in this assessment, and hence margins inclusive of new generation may be overstating generation potential.[16]

In context, to meet security standards for the New Zealand Winter Energy Margin in 2025 under the medium growth scenario, we need to commission between 400-500 GWh of new winter generation, with an additional 1,200-1,300 required by 2028.

New Zealand has significant generation potential from many sources including geothermal, wind and hydro. Subject to a stable investment environment, it should be possible to meet the standards over the next 10 years, providing that participants are able to advance projects to consent and build on these resources. This will likely require generation projects beyond those that we are presently aware of as not all projects in our assessment are likely to be able to proceed.

This assessment makes simplified assumptions around timing of generation investment. Investment decisions are closely linked to market conditions and as market conditions are often volatile and difficult to forecast there is a large amount of uncertainty associated with when generation investment will occur. Therefore, the results of this assessment present *potential* generation investment with generic timings, rather than attempting to guess when specific generation plant may be built. As such, generation investment may be restricted in specific situation—including project delays, transmission and connection development requirements or other factors that delay specific projects—and the margins may be lower than those presented in this assessment.

4.2 Interpretation of results

The charts in this section show the margins for the three key scenarios assessed. Each chart presents three key pieces of information:

- The security standard represented by a horizontal blue or orange line on the charts. This is a reference to compare the margins against. Security standards are calculated by the Electricity Authority as the upper and lower margins that represent an efficient level of reliability.
- The margins calculated with the electricity supply from existing and committed generation. This is represented by the grey bars on the charts. As time passes, and demand grows, the margin based on this generation decreases.

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[16] Although outside the scope of assessing the WCM, should thermal generation be withdrawn from the Waikato region ahead of new generation or transmission in the northern Waikato or further north, the ability to meet demand in this region could become constrained. For more information please see: https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation

- The margins with new generation added. That is, the margins if all known new generation options are built (assuming some practical limitations on lead times). This is represented by the series of red coloured bars on the charts.

We have drawn conclusions from the results by firstly analysing what the future looks like with no new generation. Following this, we made an assessment on the ability of known new generation options to meet the security standard in the future. If there is a significant volume of new generation options available that, when added to existing generation, results in a margin that exceeds the security standard, then it is likely the electricity system will be able to maintain the margin at or near the security standard.

Conversely, if the sum of known generation options, on top of existing generation, results in a margin that is below the standard then industry participants will need to investigate and develop new generation options beyond already known, or the margin may fall below the standard, and the New Zealand electricity system may experience inefficiently high levels of shortage risk. This situation does not occur in any of the current scenarios.

For perspective, in the New Zealand WEM analysis, to increase the margin by 5% would require approximately 1,000 GWh of generation over the period April to September inclusive.[17]

The South Island WEM analysis results are not shown in this section as they are not materially different from the conclusions of the New Zealand WEM analysis. For full results, including South Island WEMs, and a complete set of results from the sensitivity analysis please see Appendix 1: South Island Winter Energy Margin Results and Appendix 2: Sensitivities respectively.

4.3 ENERGY MARGIN RESULTS

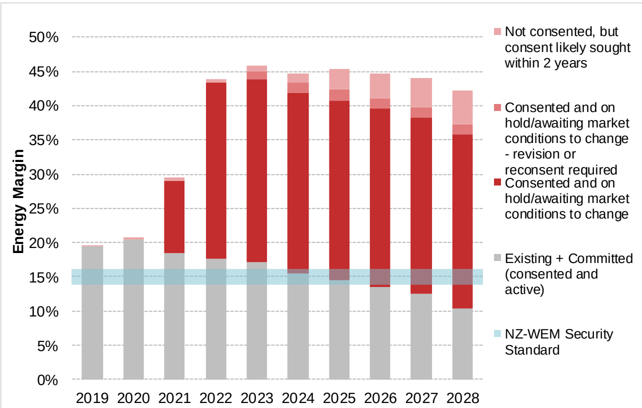

Figure 4: NZ WEM – Low demand

- In the Low demand scenario, it is expected that, without additional generation, we will fall below the NZ WEM standard in 2026.
- If demand growth is low, some consented generation will still need to be commissioned and built within 7 years to continue to meet the NZ WEM standard.
- By 2028 approximately 850-900 GWh of new winter generation is required to maintain the standard.

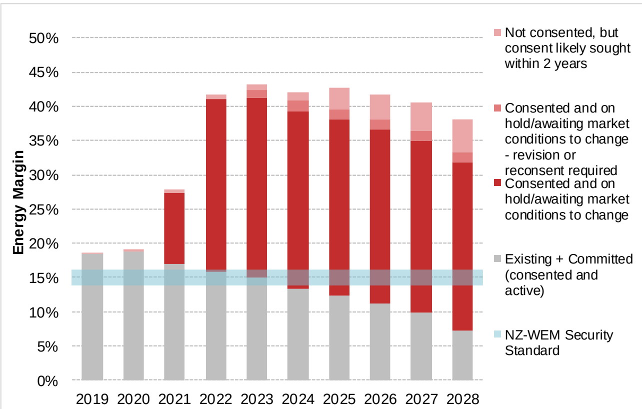

Figure 5: NZ WEM – Medium demand

- In the Medium demand scenario, it is expected that, without additional generation, we will fall below the NZ WEM standard in 2024.
- Some consented generation will need to be commissioned and built within 5 years to continue to meet the NZ WEM standard.
- By 2028 approximately 1,700 GWh of new winter generation is required to maintain the standard.

[17] 1,000 GWh of winter generation is equivalent to a 230-240 MW of geothermal generator (95-98% capacity factor) or a 560-570 MW wind farm (40% capacity factor).

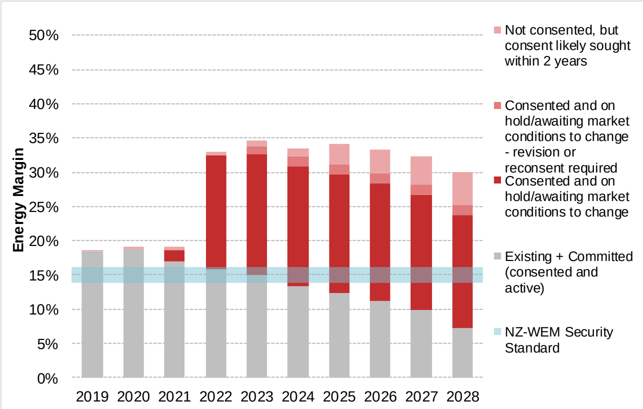

Figure 6: NZ WEM – Thermal Constraints

- In the Thermal constraints scenario, it is expected that, without additional generation, we will fall below the NZ WEM standard in 2024.
- New generation supply required is the same as that in the Medium demand scenario, but this additional 1,700 GWh is now 35% of the pipeline of generation (up from 24% with including an additional 500 MW of thermal generation). If the 500MW constraint comes from closure of existing thermal plant 3,300 GWh of new winter generation would be required to meet standard by 2028, which equates to 36% of all known generation projects.

4.3.1 Winter Energy Margins sensitivities

A number of sensitivities to changes in supply and demand were assessed against the scenarios, including:

- **High Demand:** Based on the Te Mauri Hiko Vibrant Haven scenario, we consider the impact of a faster rate of electrification as well as stronger economic and population growth.
- **Solar generation:** The assumed growth in solar generation is based on Te Mauri Hiko. We offer additional sensitivities with a lower, higher or very high growth rate.
- **NZAS and Rankine closure:** NZAS ramps down production from 2025 (it is assumed the Rankine units at Huntly would shut at the same time)
- **Thermal decommissioning:** One of the two Combined Cycle Gas Turbines shuts down in 2022.
- **Delayed build times:** Generation takes longer than expected to be built.
- **Reduced generation availability:** a 5% reduction in non-thermal generation output to account for lower than expected generation output. This sensitivity covers a lot of potential situations including, but not limited to, lower than expected wind capacity factors, geothermal steam field pressure or solar radiation.

For the results of the sensitivities please see Appendix 2: Sensitivities.

4.4 CAPACITY MARGIN RESULTS

It should be noted that in the calculation of the Winter Capacity Margins no generation has been set aside for instantaneous reserves when calculating the margins. That is, the calculation of the peak margin does not allow for reserve requirements as part of the calculations, and instead includes instantaneous reserve requirements in the margin. For example, if the winter capacity margin is 1000 MW, this value includes approximately 300-600 MW that would be needed for instantaneous reserves.

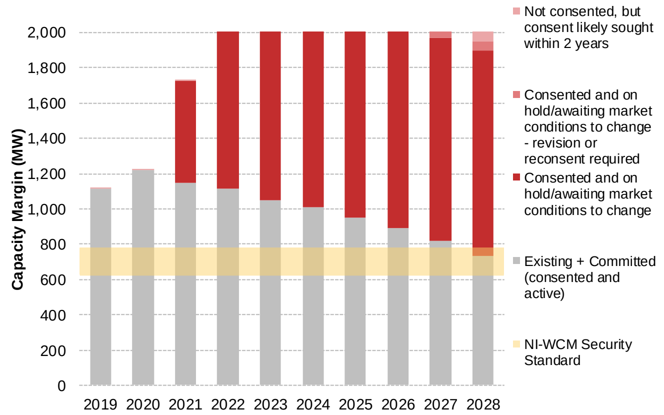

Figure 7: NI WCM – Low demand

- In the Low demand scenario, it is not expected that the NI WCM will fall below the standard during the timeframe of this assessment.

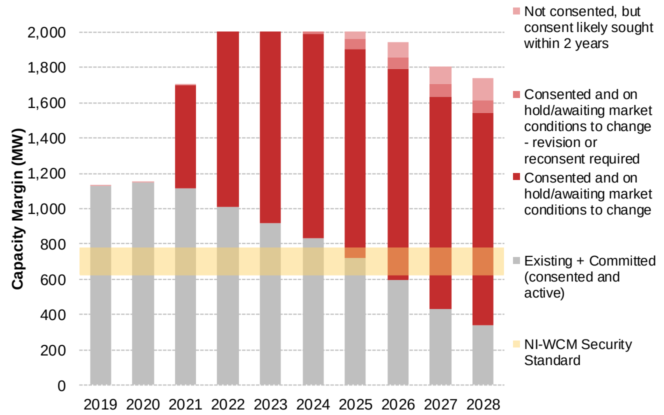

Figure 8: NI WCM – Medium demand

- In the Medium demand scenario, it is expected that, without additional generation, we will be below the NI WCM standard from 2026.
- In 2028 approximately 300 MW of peaking capacity will be required to meet the WCM standard.

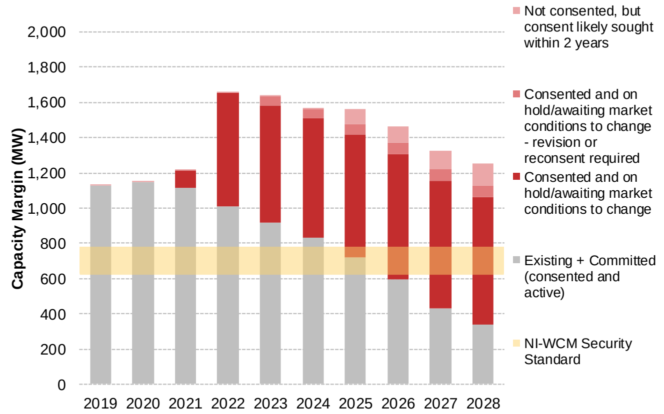

Figure 9: NI WCM - Thermal Constraints

- In the Thermal Constraints scenario, it is expected that, without additional generation, we will be below the NI WCM standard from 2026.
- In 2028 approximately 300 MW of peaking capacity will be required to meet the WCM standard.
- Given the constraints in this scenario on adding new thermal generation, this will require approximately half of all known consented generation projects to be built by 2028.

4.4.1 North Island Winter Capacity Margin sensitivities

A number of sensitivities to changes in supply and demand were assessed against the scenarios, including:

- **High Demand:** Based on the Te Mauri Hiko Vibrant Haven scenario, we consider the impact of a faster rate of electrification as well as stronger economic and population growth.
- **Solar generation:** The growth in solar generation is assumed based on Te Mauri Hiko. We offer additional sensitivities with a lower, higher or very high growth rate.
- **NZAS and Rankine closure:** NZAS ramps down production from 2025 (it is assumed the Rankine units at Huntly would shut at the same time)
- **Thermal decommissioning:** One of the two Combined Cycle Gas Turbines shuts down in 2022.
- **Delayed build times:** Generation takes longer than expected to be built.
- **Reduced generation availability:** a 5% reduction in non-thermal generation output to account for lower than expected generation output. This sensitivity covers a lot of potential situations including, but not limited to, lower than expected wind capacity factors, geothermal steam field pressure or solar radiation.

For the results of the sensitivities please see Appendix 2: Sensitivities.

5 Input Assumptions

A set of standardised assumptions are used to determine the margins.[18] The main input assumptions used in this assessment were the levels of:

- electricity generation (existing and proposed new projects)
- electricity demand (including demand response)
- inter-island transmission capability.

5.1 Demand Forecast

Future electricity demand is a critical factor to consider when assessing security of supply. The demand forecast used in the Annual Assessment is prepared by Transpower for both capacity (for the WCM) and energy (for the WEMs). Both peak and energy forecasts use an ensemble approach where 4 forecasts are combined to form a single base forecast, with additional discrete step changes added to the base where more detailed information is available. For example, a major consumer may increase or decrease consumption at some point in the future—this may be a known committed step change or involve using a sensitivity if the change is uncertain.

Note the expected capacity demand is based on the highest 100 hours of demand in 2018 (base year of the forecast), inclusive of both transmission losses and embedded generation, and increased by the forecast growth-rate in the ensemble forecast.

The ensemble uses the following input forecasts:

- Traditional econometric forecast
- Long term linear regression
- Short term linear regression
- MBIE Energy Demand and Generation Scenarios

The base forecast uses reconciliation data as its primary input and is calculated for each Grid Exit Point (GXP). Thus, the forecast inherently accounts for embedded generation and distribution losses but does not account for transmission losses. The base ensemble forecast is then adjusted to account for any know step changes or future deviations from what has been historically observed—for example in the forecasts based on Te Mauri Hiko forecasts (Medium demand), the impact of electrification of industry and transport have been estimated and added to the forecast. The final step is to apply transmission:

- for energy, losses are calculated by determining GXP offtake quantities, and applying a static loss factor, however,
- for peak, the Annual Assessment peak value (which is based off the average of the top 100 hours of demand during the winter period) is determined using generation output information for the base year (2018), with the growth rate observed in the forecast applied to determine subsequent years. Therefore, the peak forecast implicitly includes transmission losses.

The flow chart below shows how both the underlying peak and energy forecasts are determined.

[18] The assumptions and methodology are based on the Electricity Authority's Security Standards Assumptions Document (SSAD) http://www.ea.govt.nz/dmsdocument/14134 .

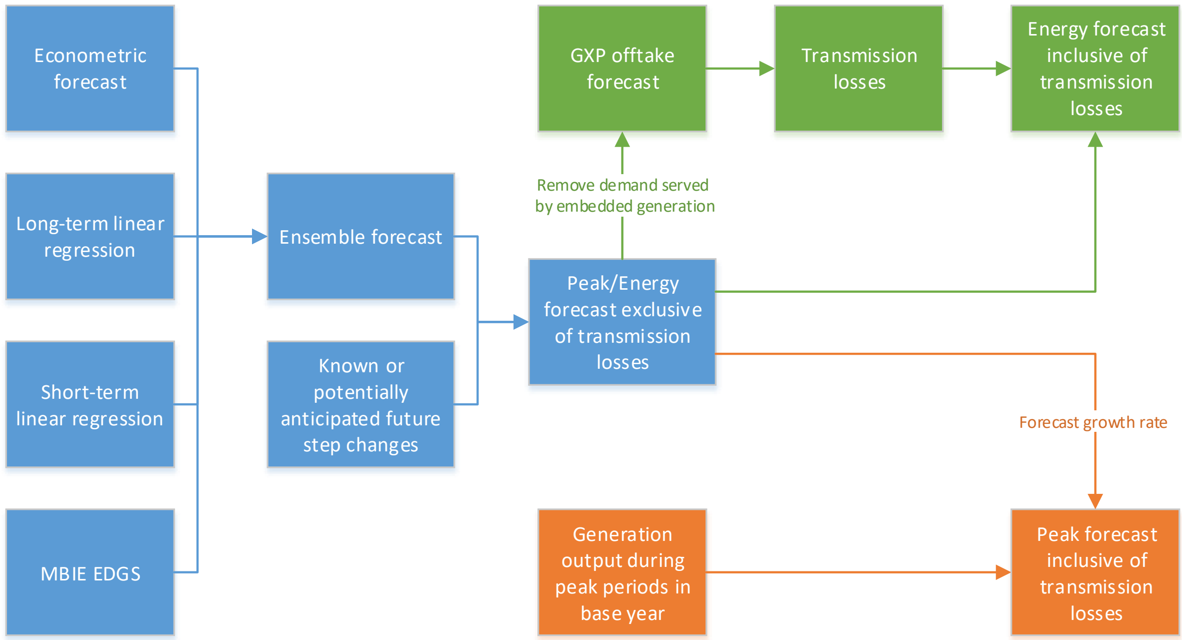

Figure 10: Schematic of how demand forecast is prepared

The demand forecasts include historical data up to 2018.

See Appendix 6: Detailed Demand Forecast Assumptions for more detailed assumptions about the electricity demand forecast used in this assessment.

5.2 Generation Assumptions

Generation companies are surveyed confidentially about their existing and proposed new generation.

The expected winter energy supply in GWh used to determine the winter energy margins is the sum of:

- controlled hydro generation based on an average hydrological year.[19]
- thermal generation capacity de-rated to allow for any outages, multiplied by the number of winter hours.
- other major sources of generation (uncontrolled hydro, geothermal, wind, co-generation, solar) based on reported capacity and utilisation, multiplied by the number of winter hours.

The expected generation capacity in MW used to determine the winter capacity margin is the sum of:

- expected thermal and controlled hydro generation capacity, de-rated to allow for any outages.
- expected winter peak contributions for all other generation (i.e. uncontrolled hydro, geothermal, wind, co-generation, solar, batteries) based on historical winter peak contributions (in MW).[20]

All existing generation is expected to remain operationally available throughout the assessment period unless otherwise stated, with the exception of generation with a publicly notified retirement date.

We assume thermal fuel availability, or operational limitations, will not constrain electricity generation, with the exception of the Whirinaki diesel generator. Whirinaki's energy contribution is limited to 30 GWh per winter period for the calculation of the WEMs due to fuel delivery logistics.

Proposed new generation options have been aggregated to preserve confidentiality. New generation development options under consideration by investors may or may not proceed for a variety of reasons. New generation projects have been allocated to four categories:

- Consented and proceeding (i.e. Committed)

[19] This is the average of inflows into controlled hydro lakes in years 1931 to 2017.

[20] In the case of solar and batteries, contributions are based on expected contributions—zero peak contribution from solar, and moderate to high contribution from batteries.

- Consented and on hold/awaiting market conditions to change
- Consented and on hold/awaiting market conditions to change—consent revision, or reconsenting will be required
- Not consented.

The dates at which new generation becomes available is based on the type of generation, and its consent status. Table 1 shows the earliest potential commissioning dates for different types of generation and the consent status.[21]

Table 1: Earliest new generation commissioning dates based on consent status and generation type

	Committed	Consented and on hold	Consented, on hold, requires consent revision	Not consented
Thermal	Estimated build date	2021	2022	2024
Geothermal	Estimated build date	2022	2023	2025
Wind	Estimated build date	2022	2023	2025
Hydro	Estimated build date	2023	2024	2026

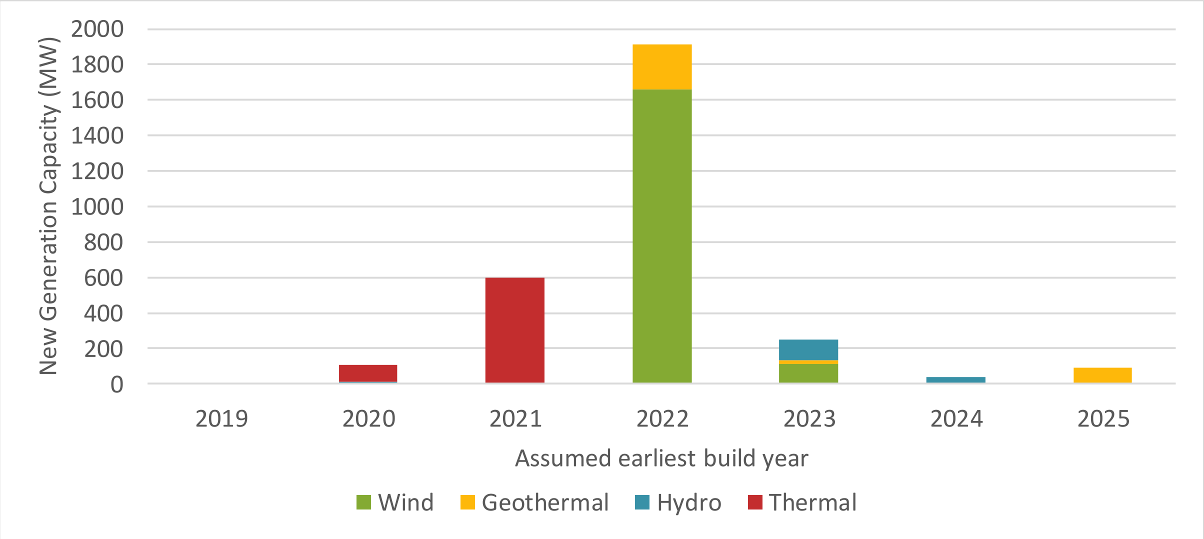

Figure 11: New generation time line in Low and Medium Demand scenarios

It is assumed that generation could be built in the timeframes described, but it is expected that generation will be built when market conditions justify investment, as such the above information should be treated as *potential* generation available, and not representative of what *will* be built. It is also likely that some time frames will vary—for example, delays may occur for a variety of reasons (for example plant availability, logistics, transmission requirements); similarly, some projects may be expedited if market conditions justify it.

[21] These commissioning dates are one year earlier in the Low Carbon and Electrification scenario.

See section Appendix 4: Detailed Supply Assumptions for further details about existing and new generation supply assumptions.

5.3 Inter-Island Transmission Assumptions

North Island energy supply can meet some of the South Island's energy demand in the assessment of the South Island WEMs. It is assumed the North Island will be able to supply the South Island with up to 2,102 GWh (480 MW average transfer) of energy during the winter period, depending on the surplus energy available in the North Island[22].

Similarly, South Island capacity can meet some North Island demand in the assessment of the North Island WCMs. The contribution of the South Island is a function of the surplus capacity available in the South Island and has been derived using simulation analysis.

See Appendix 5: Transmission for detailed assumptions about inter-island transmission.

[22] Energy surplus in the North Island is calculated by subtracting North Island demand from available North Island supply.

Appendix 1: SOUTH ISLAND WINTER ENERGY MARGIN RESULTS

1.1 SOUTH ISLAND WINTER ENERGY MARGINS

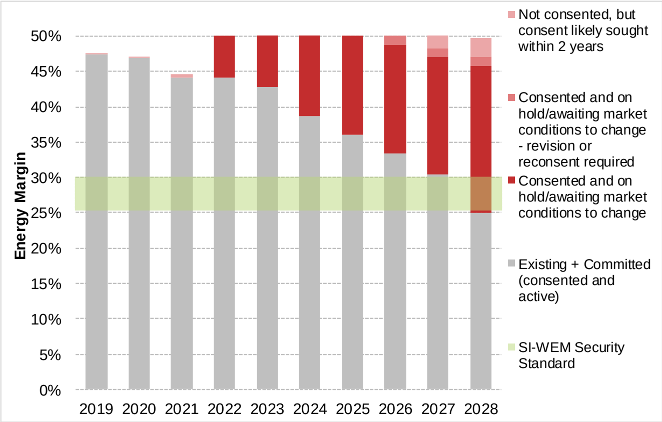

Figure 12: SI WEM – Low demand

- In the Low demand scenario, it is expected that, without additional generation, we will fall below the SI WEM standard in 2028.
- If demand growth is low, some consented generation will still need to be commissioned and built within 9 years to continue to meet the SI WEM standard.
- By 2028 approximately 50 GWh of new winter generation is required to maintain the standard.

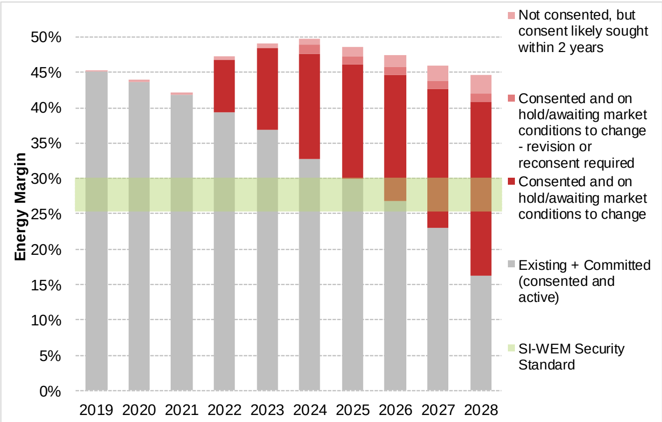

Figure 13: SI WEM – Medium demand

- In the Medium demand scenario, it is expected that, without additional generation, we will fall below the standard in 2027.
- Some consented generation will need to be commissioned and built within 8 years to continue to meet the SI WEM standard.
- By 2028 approximately 850 GWh of new winter generation is required to maintain the standard.

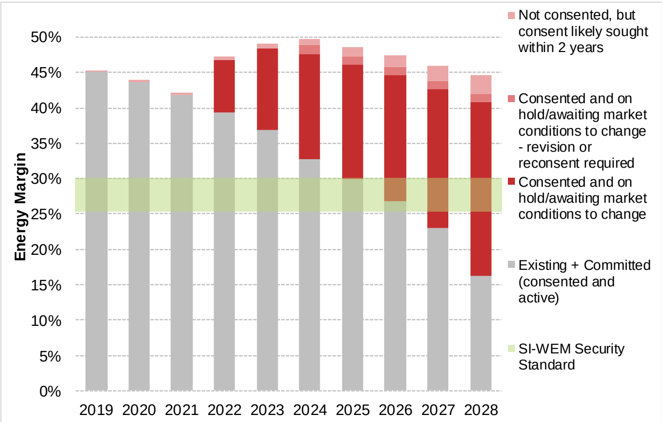

Figure 14: SI WEM – Thermal constraints

- In the Thermal constraints scenario, it is expected that, without additional generation, we will fall below the SI WEM standard in 2027.
- New generation supply required is the same as that in the Medium demand scenario.
- Note thermal constraints has little impact on the SI WEM as the North Island generation contribution is limited by the HVDC.

Appendix 2: Sensitivities

A number of sensitivities to changes in supply and demand were assessed against the scenarios.

Table 2 describes the change to assumptions for each of the following sensitivities:

- **High Demand:** Based on the Te Mauri Hiko Vibrant Haven scenario, we consider the impact of a faster rate of electrification as well as stronger economic and population growth.
- **Solar generation:** The growth in solar generation is assumed based on Te Mauri Hiko. We offer additional sensitivities with a lower, higher or very high growth rate.
- **NZAS and Rankine closure:** NZAS ramps down production from 2025 (it is assumed the Rankine units at Huntly would shut at the same time)
- **Thermal decommissioning:** One of the two Combined Cycle Gas Turbines shuts down in 2022.
- **Delayed build times:** Generation takes longer than expected to be built.
- **Reduced generation availability:** a 5% reduction in non-thermal generation output to account for lower than expected generation output. This sensitivity covers a lot of potential situations including, but not limited to, lower than expected wind capacity factors, geothermal steam field pressure or solar radiation.

This year we have are prepared a web-application to view sensitivities. This is available on the Transpower website: https://www.transpower.co.nz/system-operator/security-supply/annual-assessment-results.

Table 2: Sensitivities

Sensitivity	Affects Energy	Affects Capacity	Rationale	Assumptions
High demand	Yes	Yes	This sensitivity explores the situation where demand growth is higher than anticipated.	Follows the Vibrant Haven Te Mauri Hiko demand forecast, equivalent to an average growth rate of 2-3% annual growth rate (growth increases rapidly near the end of the 2020s.
Solar generation	Yes	Yes	This sensitivity explores the impact that different degrees of solar uptake could have on future demand and generation. Solar energy generation is related to the demand forecast used, and the impact of solar on capacity is approximated to battery storage at peak.	Solar generation is divided into 4 sensitivities with the following annual increases – very high solar, high solar, medium solar, and low solar.
NZAS and Rankine closure	Yes	Yes	This sensitivity explores the situation where the NZAS aluminium smelter starts reducing its output from 2025 and closes at the end of 2026. It is assumed the Rankine units at Huntly would shut at the same time.	NZAS reduces load in stages beginning in 2025 until it reaches 0 GWh of demand in 2027. Assumed to consume 616 MW in 2024, 411 MW in 2025 and 205 MW in 2026. Generation at the Huntly Rankines stops in 2025.
Thermal decommissioning	Yes	Yes	This sensitivity explores the situation where one of the two Combined Cycle Gas Turbines shuts down in 2022.	Generation from one of the Combined Cycle Gas Turbines stops at the beginning of 2022 (equivalent to 360 MW of generation).
Delayed build times	Yes	Yes	This sensitivity explores the situation where the commissioning date for new generation is delayed by 1 year.	Commissioning dates for all new generation is delayed by 1 year.
Reduced generation availability	Yes	Yes	This sensitivity explores the impact of a reduction in electricity supply. This sensitivity is designed to indirectly account for internal and external influences that may reduce the output of electricity generation. External influences include effects such as reduction in geothermal field pressure, systemic changes to inflow patterns, etc. Internal influences include effects such as statistical errors in historical generation data and forecast errors for new generation.	In the calculation of energy margins, all non-thermal generation energy contribution is reduced by 5%. In the calculation of capacity margins, all non-thermal generation capacity factors are reduced by 5%.

2.1 ENERGY MARGIN SENSITIVITIES

2.1.1 High Demand Sensitivity

New Zealand Winter Energy Margin

South Island Winter Energy Margin

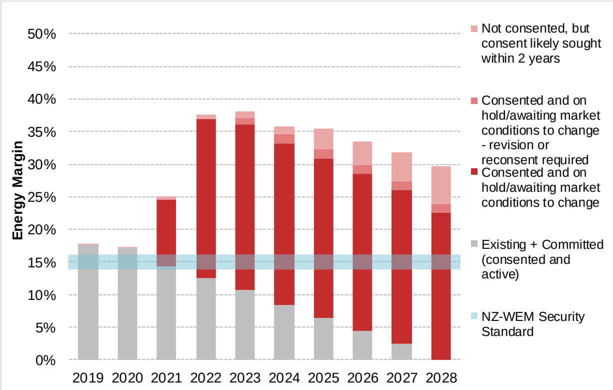

Figure 15: NZ WEM – High Demand and Very High Solar

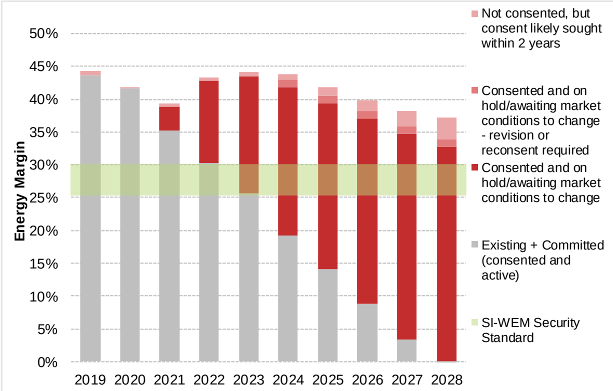

Figure 16: SI WEM – High Demand and Very High Solar

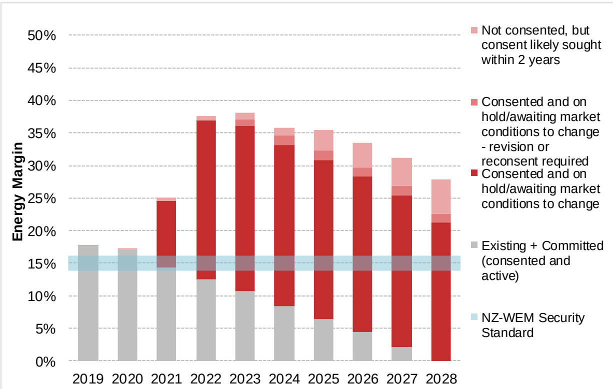

Figure 17: NZ WEM – High Demand and High Solar

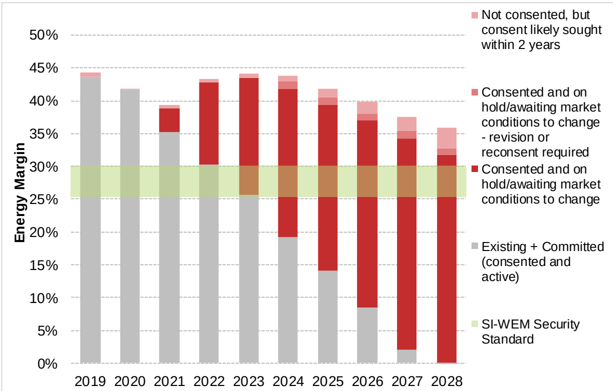

Figure 18: SI WEM – High Demand and High Solar

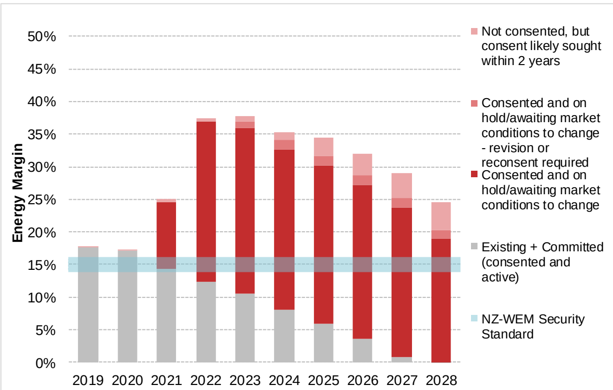

Figure 19: NZ WEM – High Demand and Medium Solar

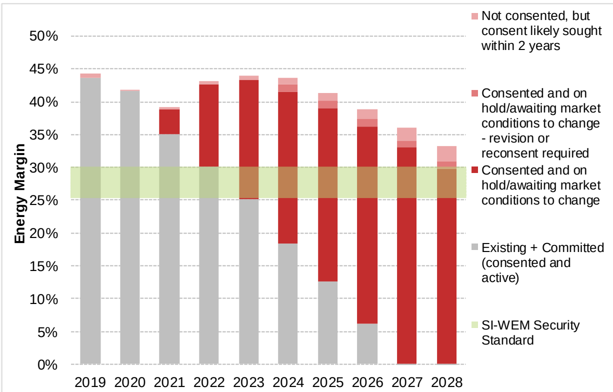

Figure 20: SI WEM – High Demand and Medium Solar

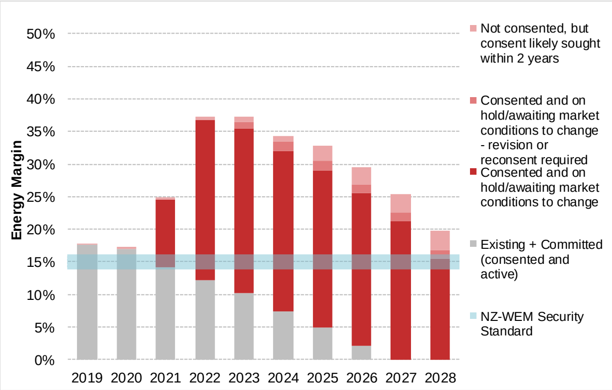

Figure 21: NZ WEM – High Demand and Low Solar

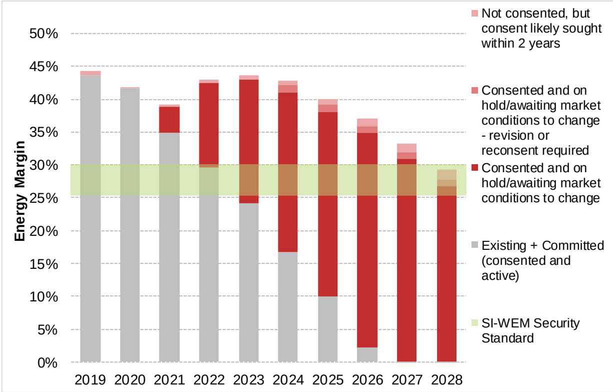

Figure 22: SI WEM – High Demand and Low Solar

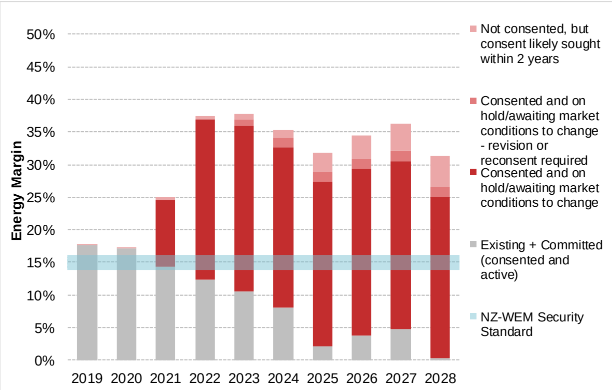

Figure 23: NZ WEM – High Demand and NZAS and Rankine Closure

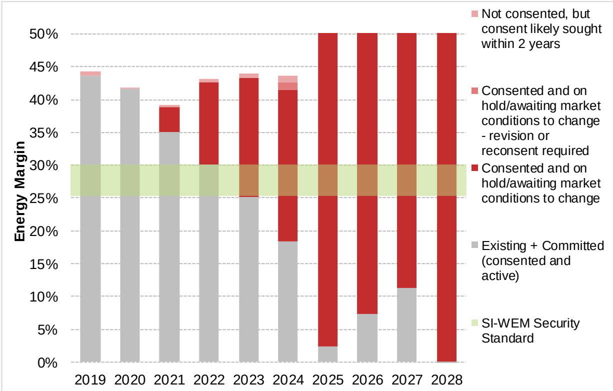

Figure 24: SI WEM – High Demand and NZAS and Rankine Closure

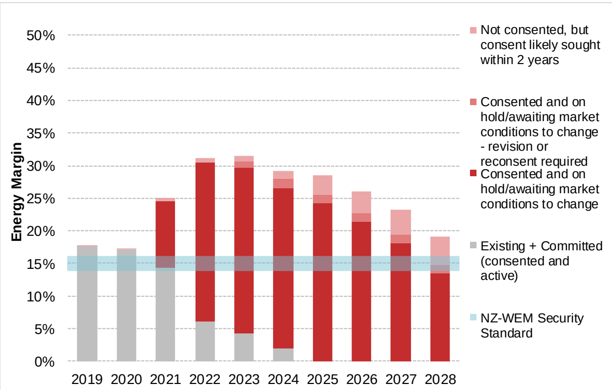

Figure 25: NZ WEM – High Demand and Thermal Decommissioning

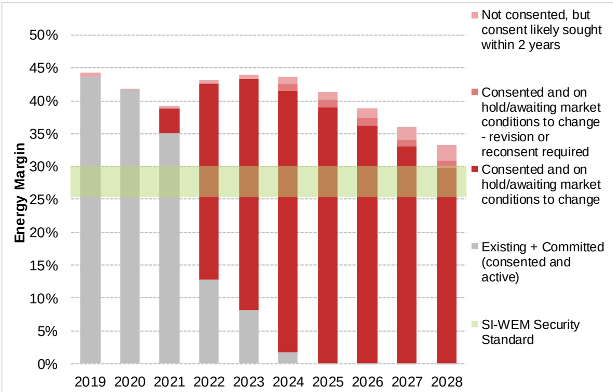

Figure 26: SI WEM – High Demand and Thermal Decommissioning

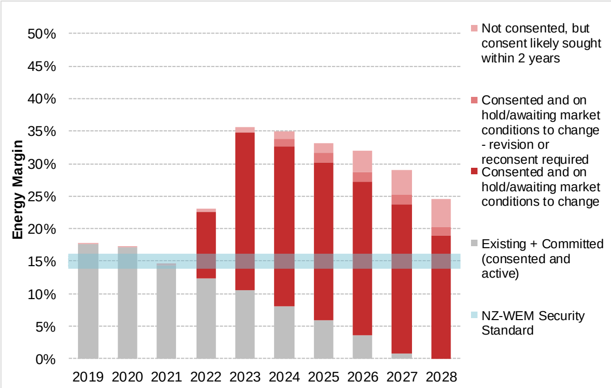

Figure 27: NZ WEM – High Demand and Delayed Build Times

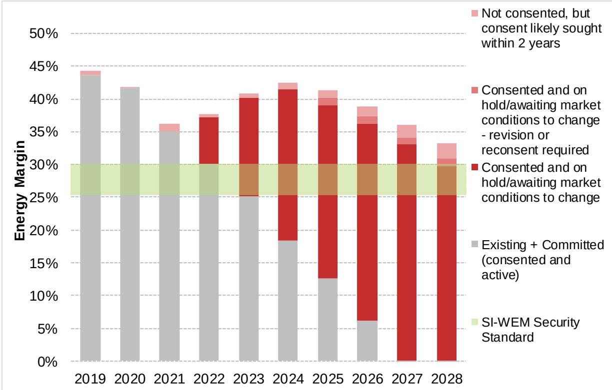

Figure 28: SI WEM – High Demand and Delayed Build Times

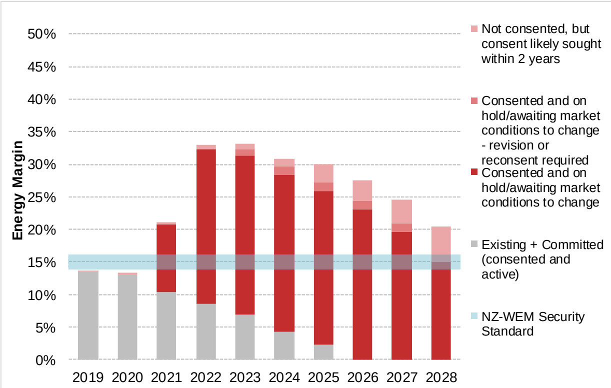

Figure 29: NZ WEM – High Demand and Reduced Generation Availability

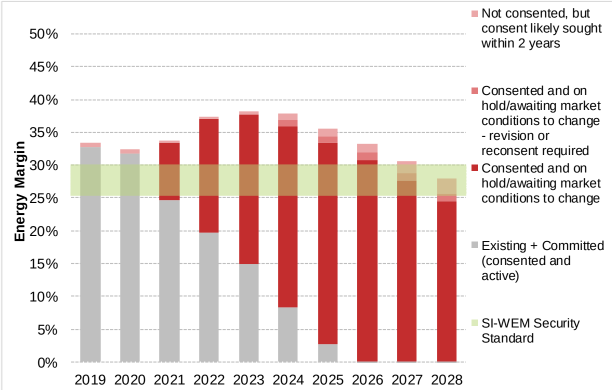

Figure 30: SI WEM – High Demand and Reduced Generation Availability

2.1.2 Solar Generation Sensitivity

Low Demand Scenario

New Zealand Winter Energy Margin

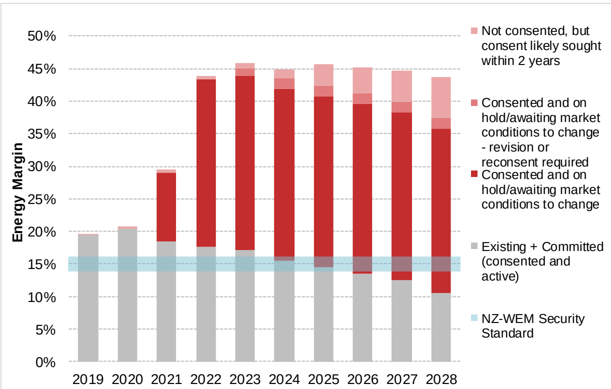

Figure 31: NZ WEM – Low Demand and Very High Solar

South Island Winter Energy Margin

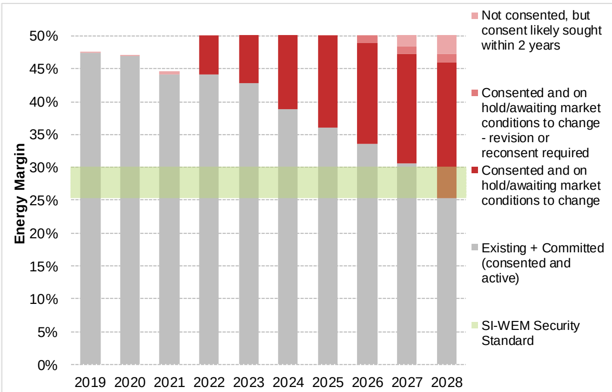

Figure 32: SI WEM – Low Demand and Very High Solar

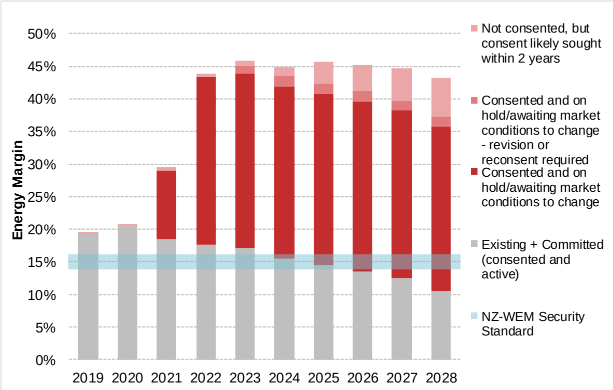

Figure 33: NZ WEM – Low Demand and High Solar

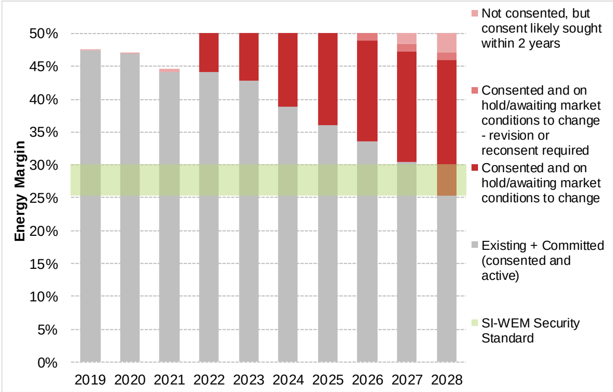

Figure 34: SI WEM – Low Demand and High Solar

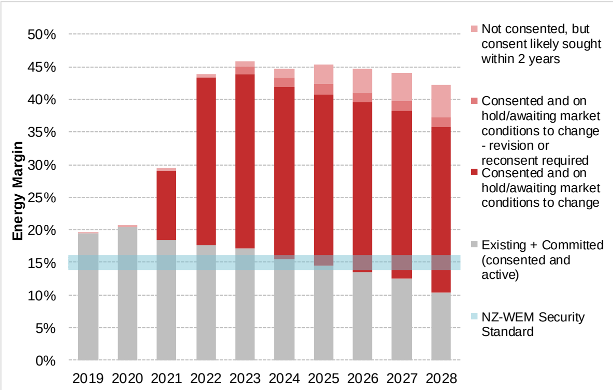

Figure 35: NZ WEM – Low Demand and Medium Solar

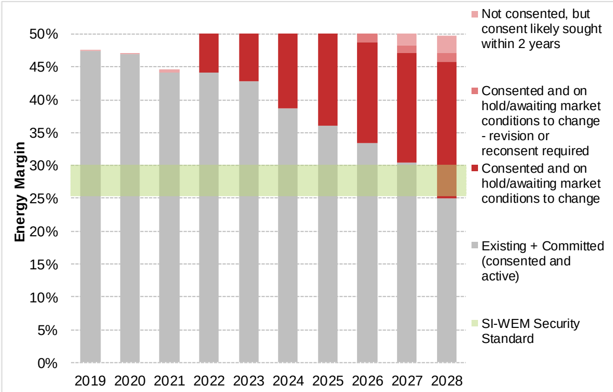

Figure 36: SI WEM – Low Demand and Medium Solar

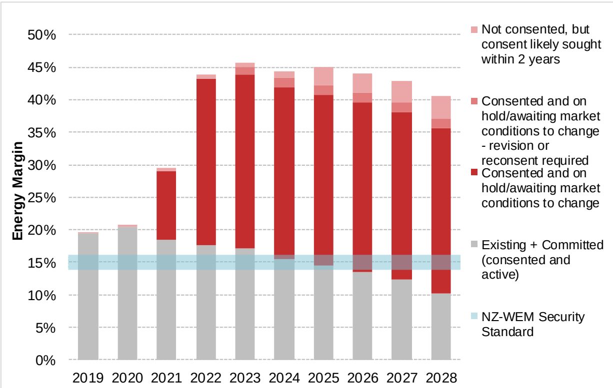

Figure 37: NZ WEM – Low Demand and Low Solar

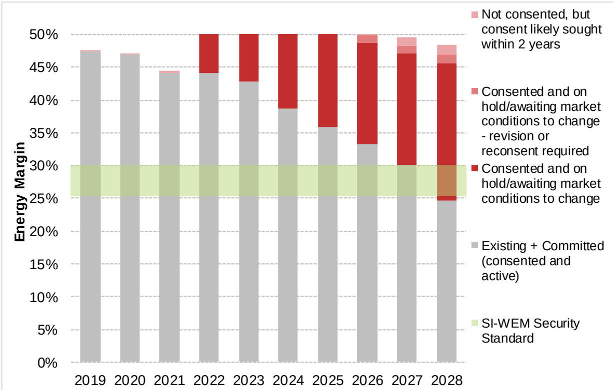

Figure 38: SI WEM – Low Demand and Low Solar

Medium Demand Scenario

New Zealand Winter Energy Margin

South Island Winter Energy Margin

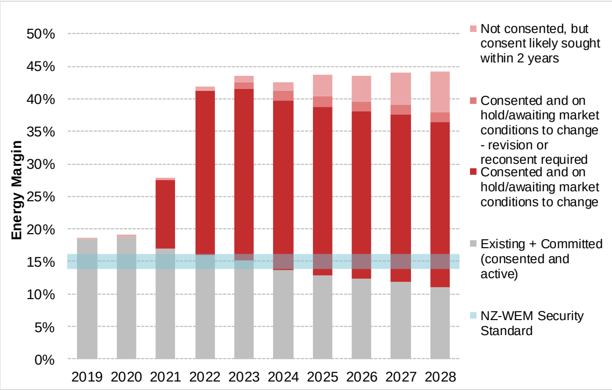

Figure 39: NZ WEM – Medium Demand and Very High Solar

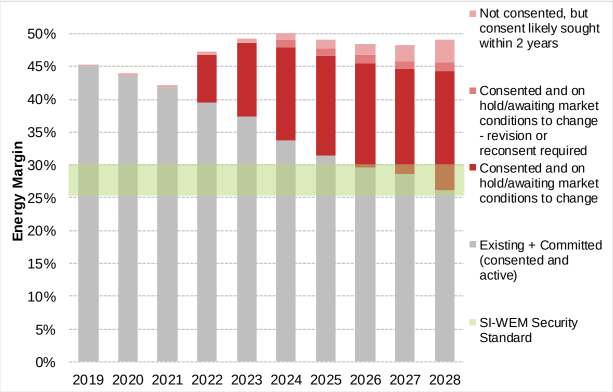

Figure 40: SI WEM – Medium Demand and Very High Solar

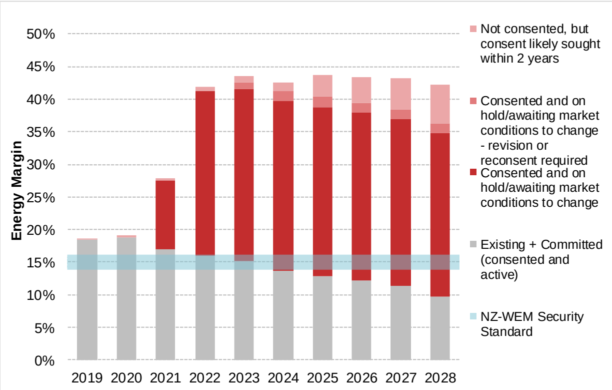

Figure 41: NZ WEM – Medium Demand and High Solar

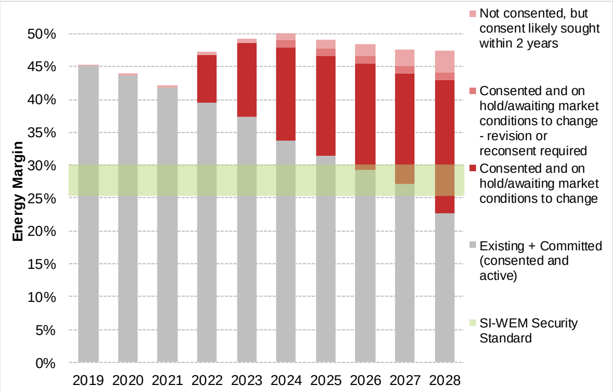

Figure 42: SI WEM – Medium Demand and High Solar

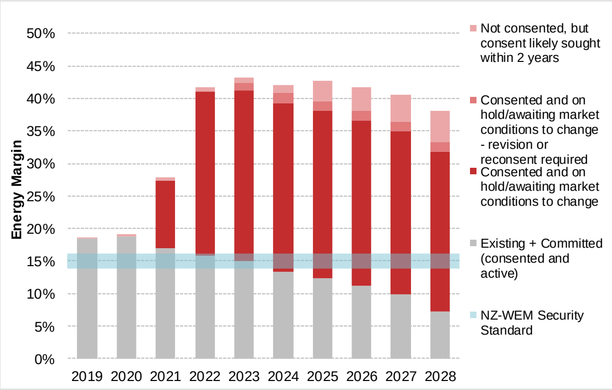

Figure 43: NZ WEM – Medium Demand and Medium Solar

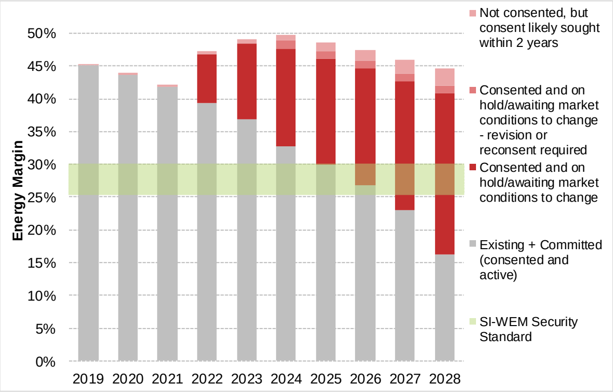

Figure 44: SI WEM – Medium Demand and Medium Solar

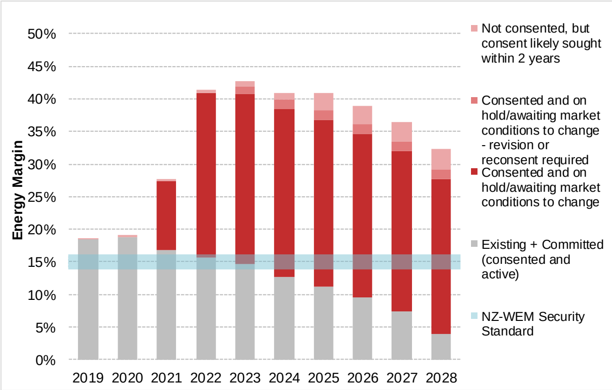

Figure 45: NZ WEM – Medium Demand and Low Solar

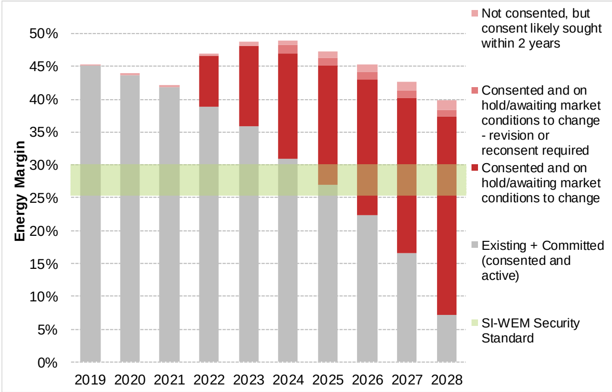

Figure 46: SI WEM – Medium Demand and Low Solar

Thermal Constraints Scenario

New Zealand Winter Energy Margin

South Island Winter Energy Margin

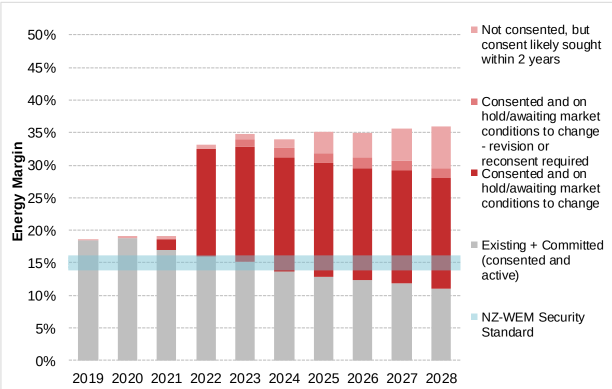

Figure 47: NZ WEM – Thermal Constraints and Very High Solar

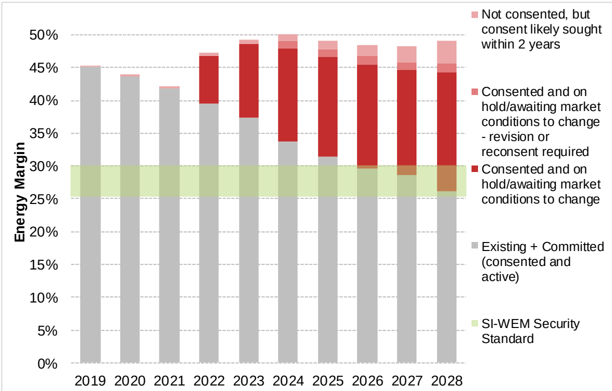

Figure 48: SI WEM – Thermal Constraints and Very High Solar

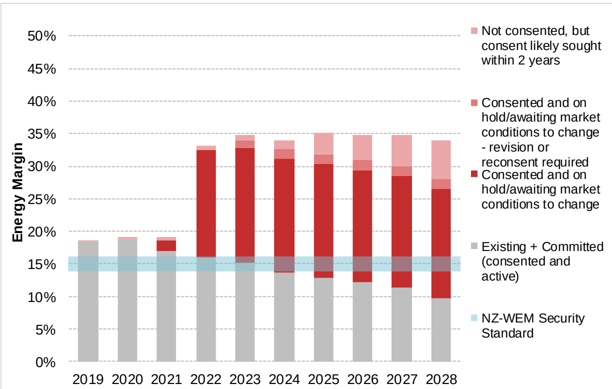

Figure 49: NZ WEM – Thermal Constraints and High Solar

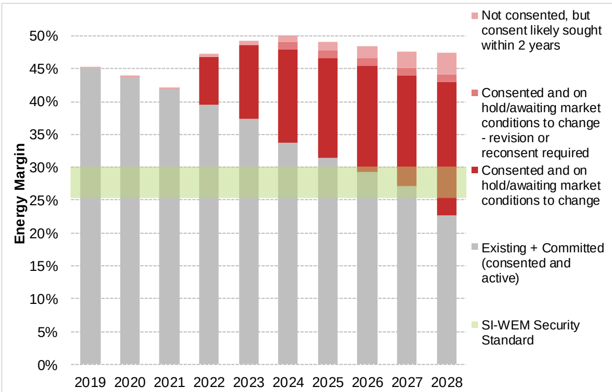

Figure 50: SI WEM – Thermal Constraints and High Solar

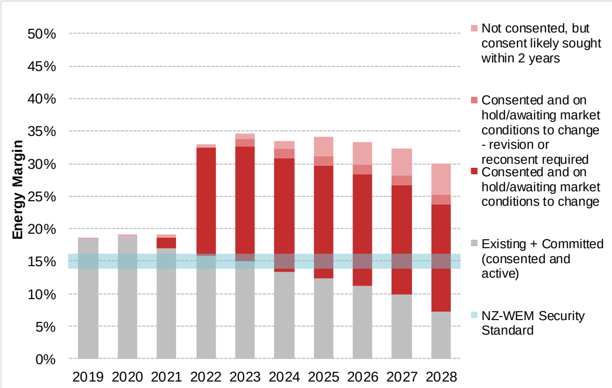

Figure 51: NZ WEM – Thermal Constraints and Medium Solar

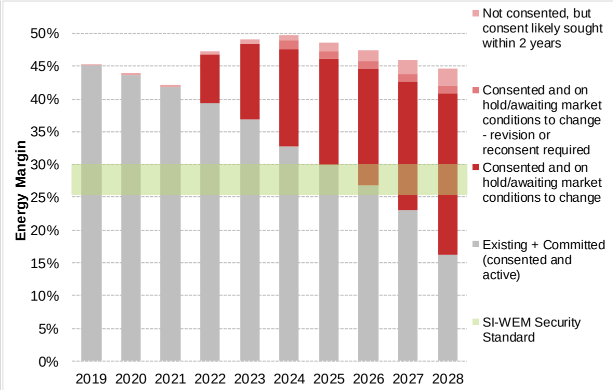

Figure 52: SI WEM – Thermal Constraints and Medium Solar

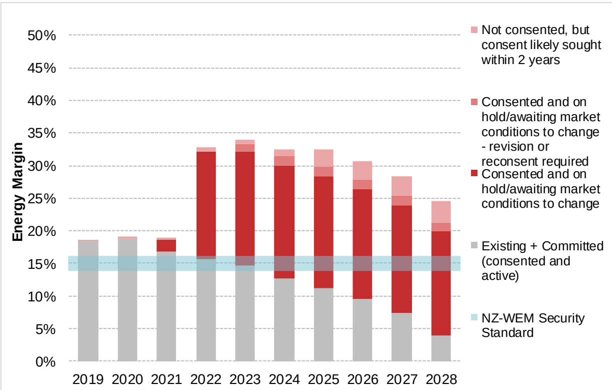

Figure 53: NZ WEM – Thermal Constraints and Low Solar

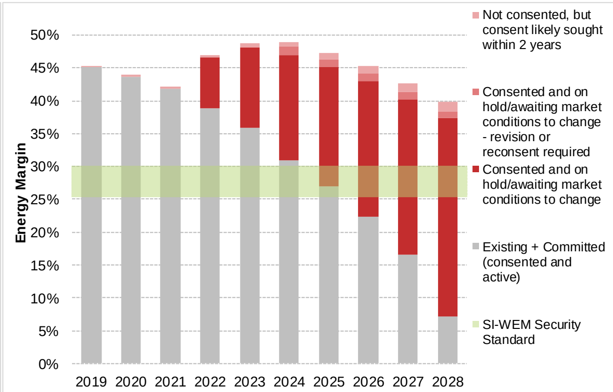

Figure 54: SI WEM – Thermal Constraints and Low Solar

2.1.3 NZAS and Rankine Closure Sensitivity

New Zealand Winter Energy Margin

South Island Winter Energy Margin

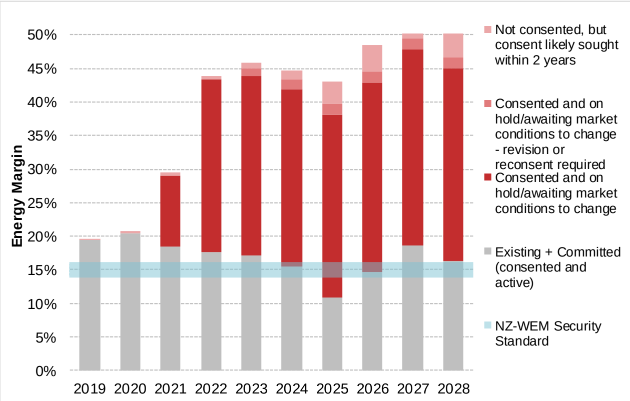

Figure 55: NZ WEM – Low Demand and NZAS and Rankine Closure

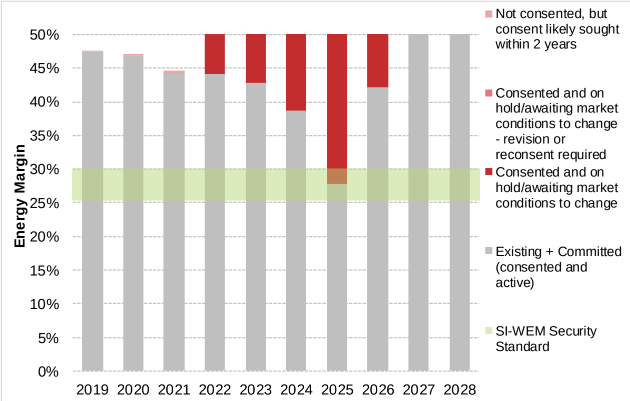

Figure 56: SI WEM – Low Demand and NZAS and Rankine Closure

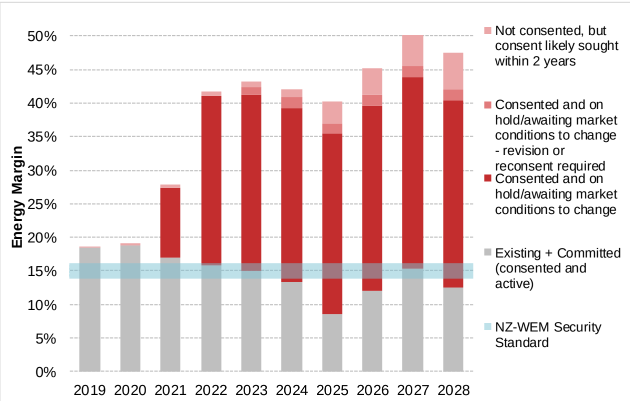

Figure 57: NZ WEM – Medium Demand and NZAS and Rankine Closure

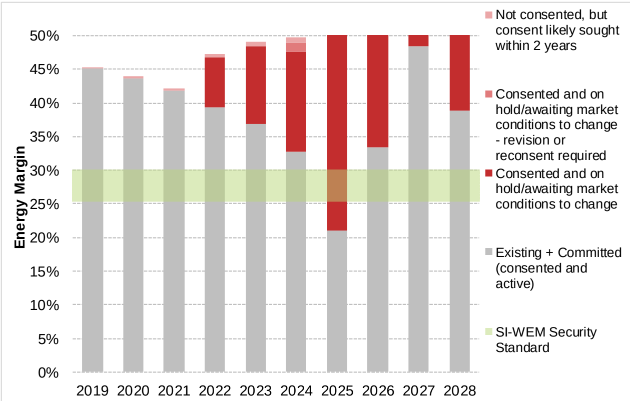

Figure 58: SI WEM – Medium Demand and NZAS and Rankine Closure

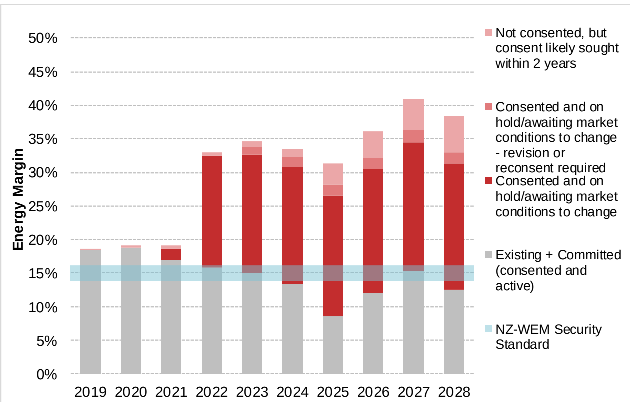

Figure 59: NZ WEM – Thermal Constraints and NZAS and Rankine Closure

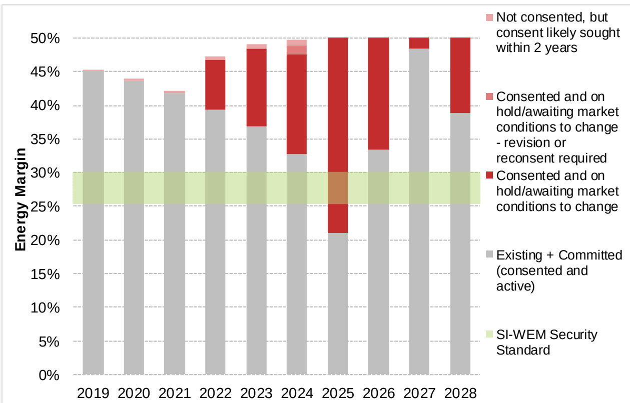

Figure 60: SI WEM – Thermal Constraints and NZAS and Rankine Closure

2.1.4 Thermal Decommissioning Sensitivity

New Zealand Winter Energy Margin

South Island Winter Energy Margin

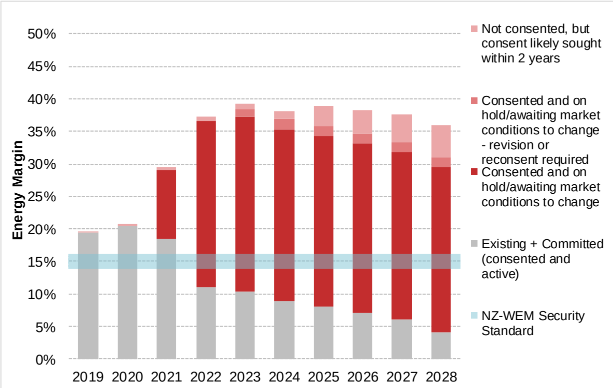

Figure 61: NZ WEM – Low Demand and Thermal Decommissioning

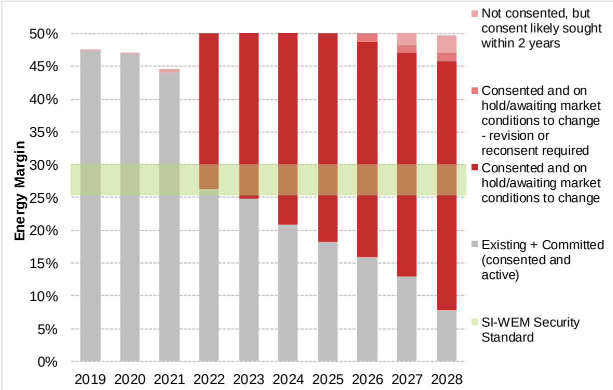

Figure 62: SI WEM – Low Demand and Thermal Decommissioning

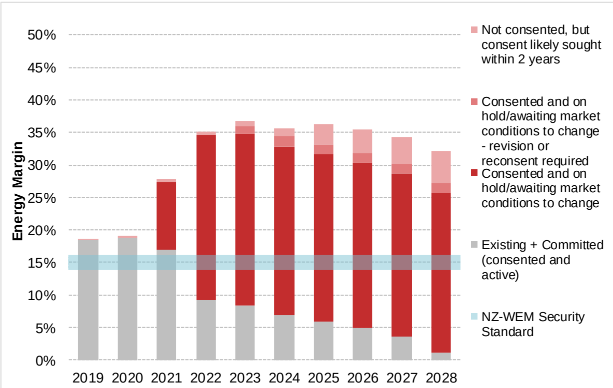

Figure 63: NZ WEM – Medium Demand and Thermal Decommissioning

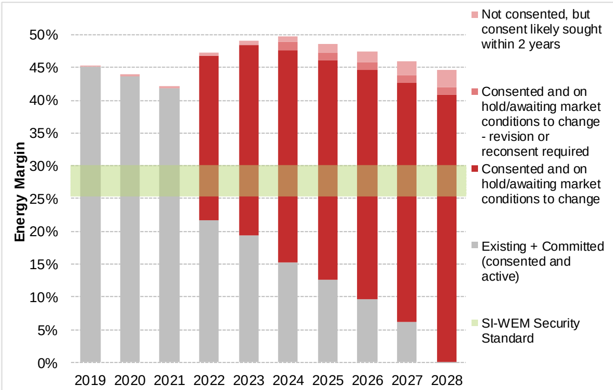

Figure 64: SI WEM – Medium Demand and Thermal Decommissioning

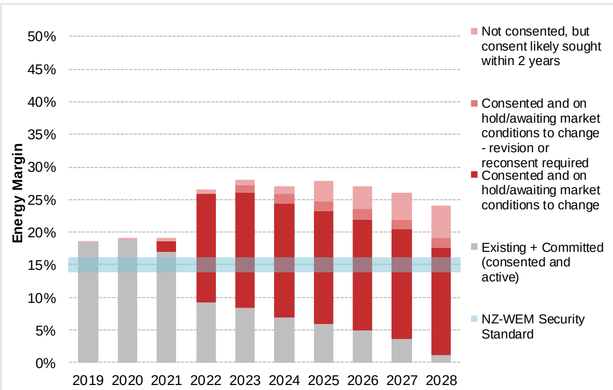

Figure 65: NZ WEM – Thermal Constraints and Thermal Decommissioning

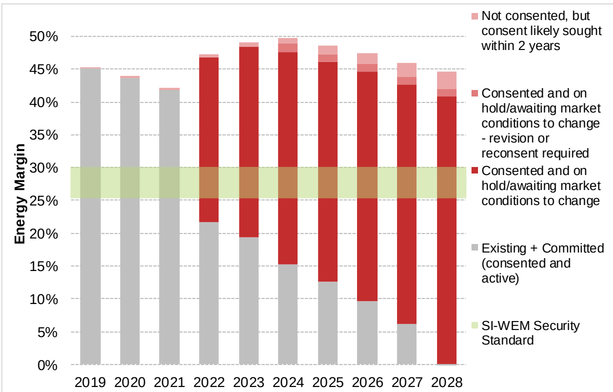

Figure 66: SI WEM – Thermal Constraints and Thermal Decommissioning

2.1.5 Delayed Build Times Sensitivity

New Zealand Winter Energy Margin

South Island Winter Energy Margin

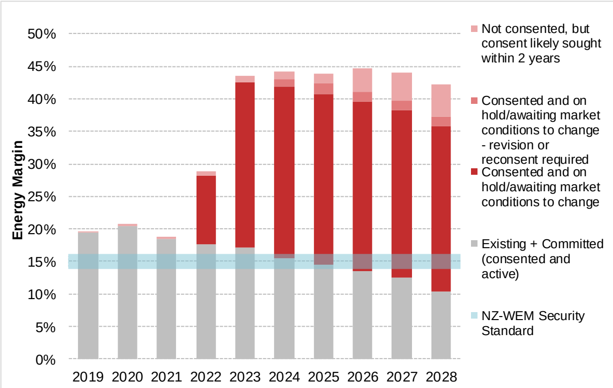

Figure 67: NZ WEM – Low Demand and Delayed Build Times

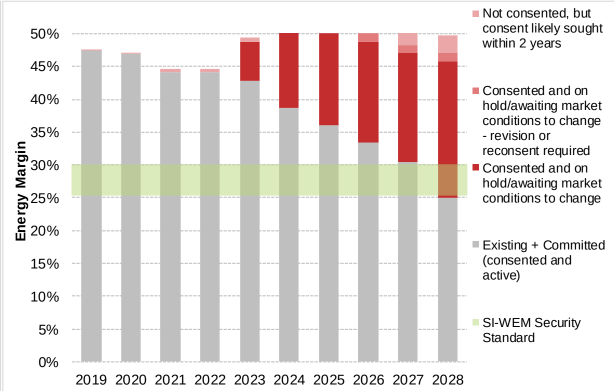

Figure 68: SI WEM – Low Demand and Delayed Build Times

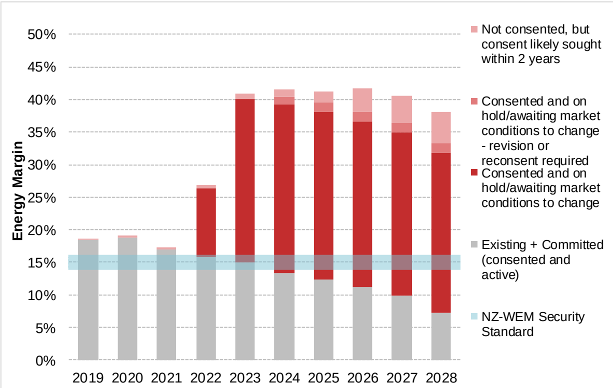

Figure 69: NZ WEM – Medium Demand and Delayed Build Times

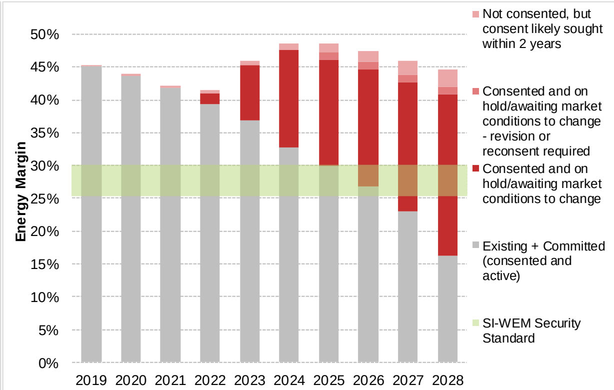

Figure 70: SI WEM – Medium Demand and Delayed Build Times

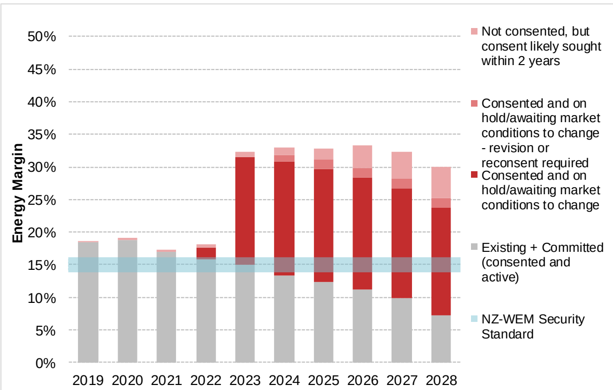

Figure 71: NZ WEM – Thermal Constraints and Delayed Build Times

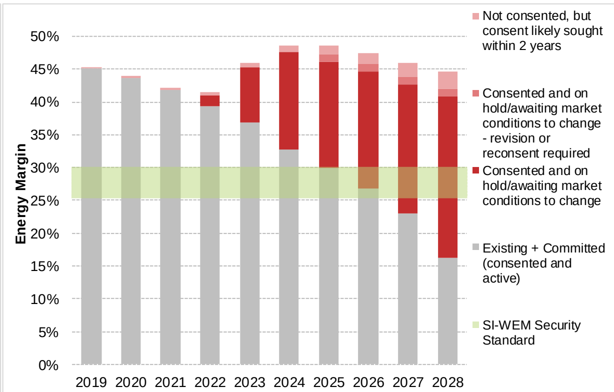

Figure 72: SI WEM – Thermal Constraints and Delayed Build Times

2.1.6 Reduced Generation Availability

New Zealand Winter Energy Margin

South Island Winter Energy Margin

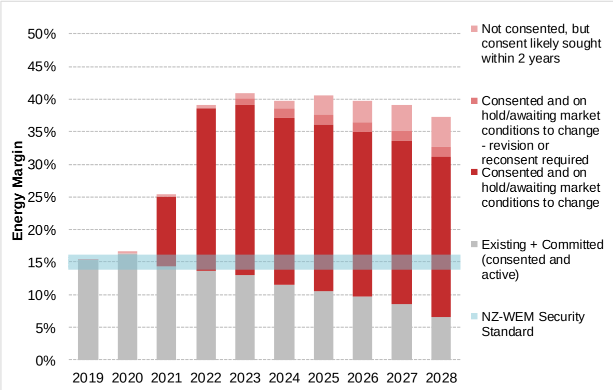

Figure 73: NZ WEM – Low Demand and Reduced generation

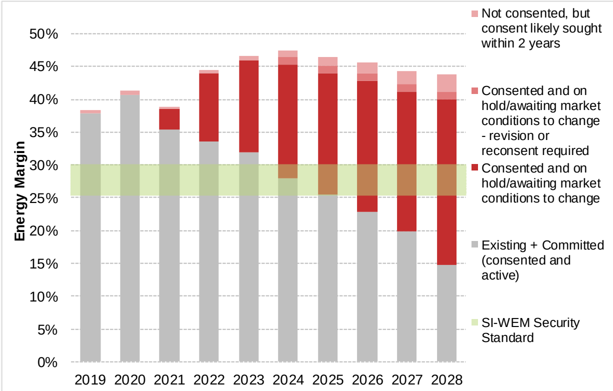

Figure 74: SI WEM – Low Demand and Reduced generation

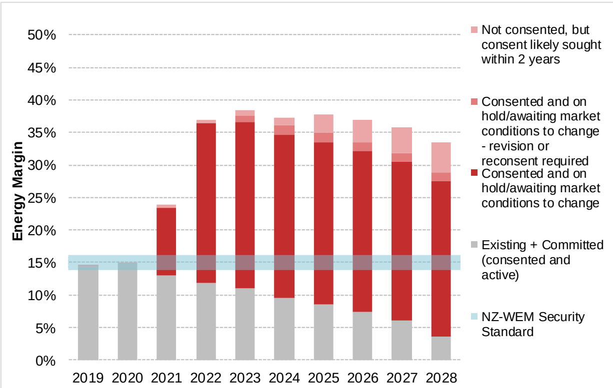

Figure 75: NZ WEM – Medium Demand and Reduced generation

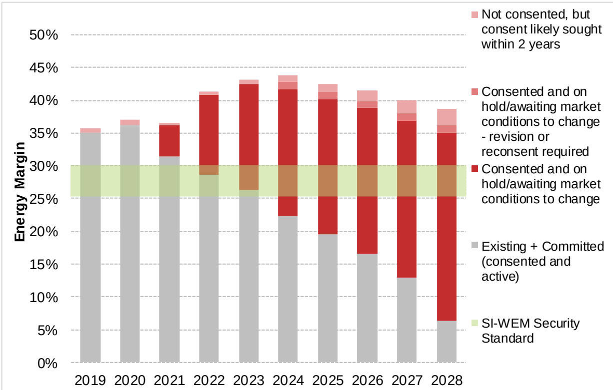

Figure 76: SI WEM – Medium Demand and Reduced generation

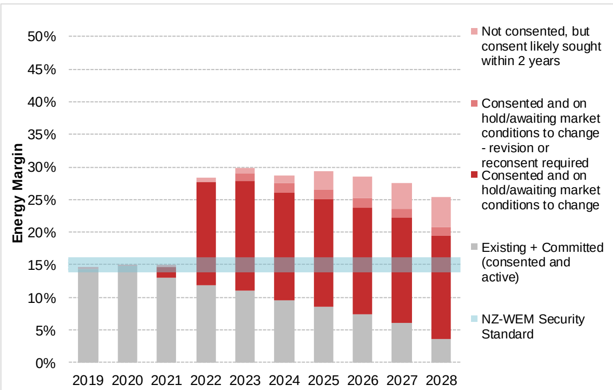

Figure 77: NZ WEM – Thermal Constraints and Reduced generation

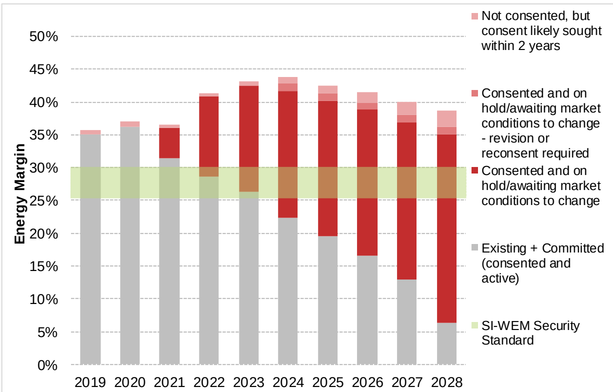

Figure 78: SI WEM – Thermal Constraints and Reduced generation

2.2 CAPACITY MARGIN SENSITIVITIES

2.2.1 High Demand Sensitivity

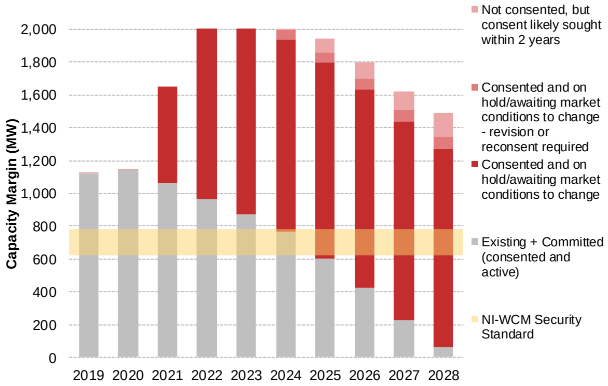

Figure 79: NI WCM – High Demand and Very High Solar

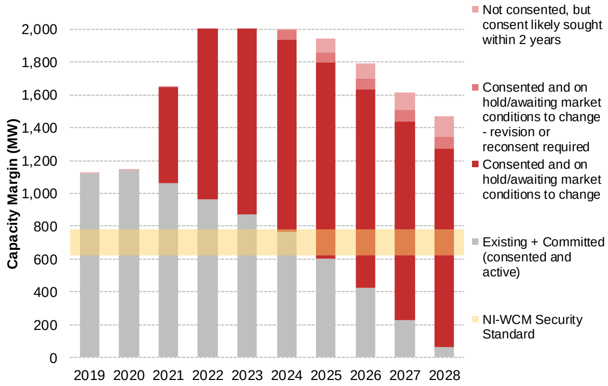

Figure 80: NI WCM – High Demand and High Solar

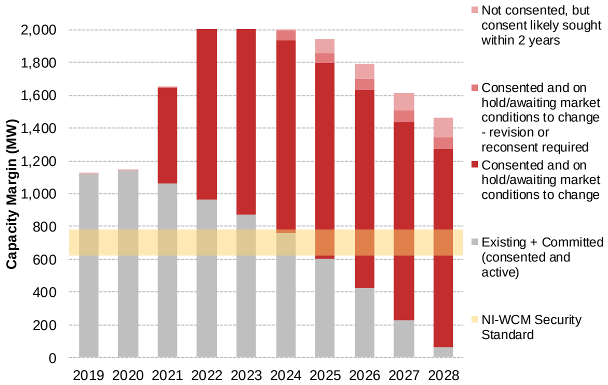

Figure 81: NI WCM – High Demand and Medium Solar

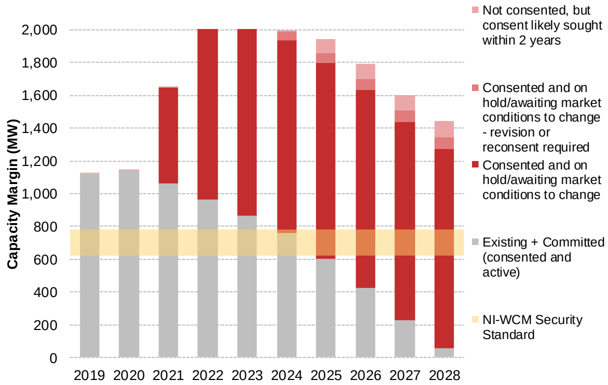

Figure 82: NI WCM – High Demand and Low Solar

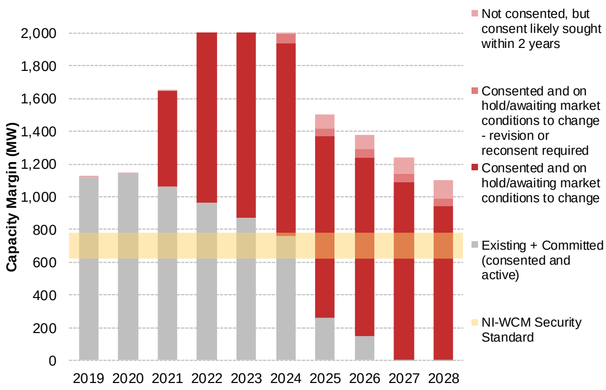

Figure 83: NI WCM – High Demand and NZAS and Rankine Closure

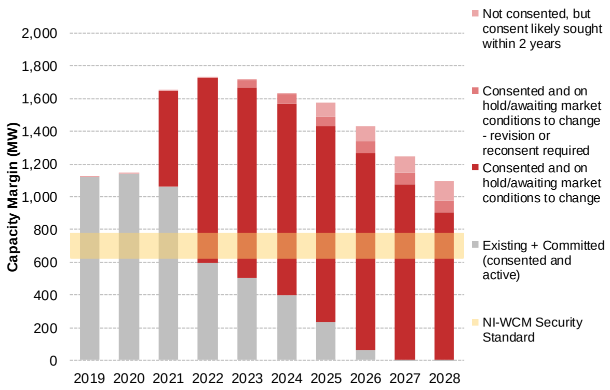

Figure 84: NI WCM – High Demand and Thermal Decommissioning

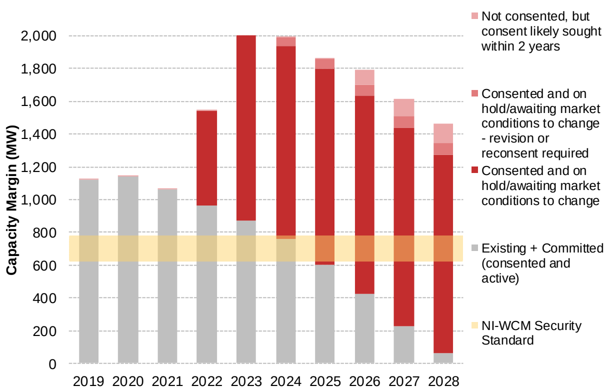

Figure 85: NI WCM – High Demand and Delayed Build Times

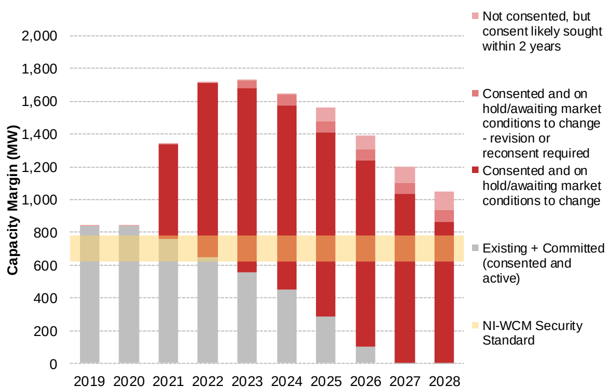

Figure 86: NI WCM – High Demand and Reduced Generation Availability

2.2.2 Solar Generation Sensitivity

Low Demand Scenario

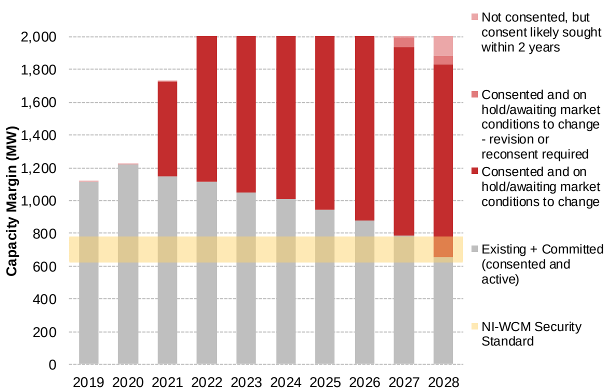

Figure 87: NI WCM – Low Demand and Very High Solar

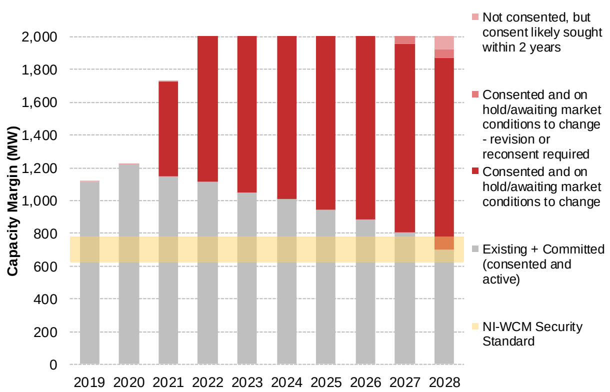

Figure 88: NI WCM – Low Demand and High Solar

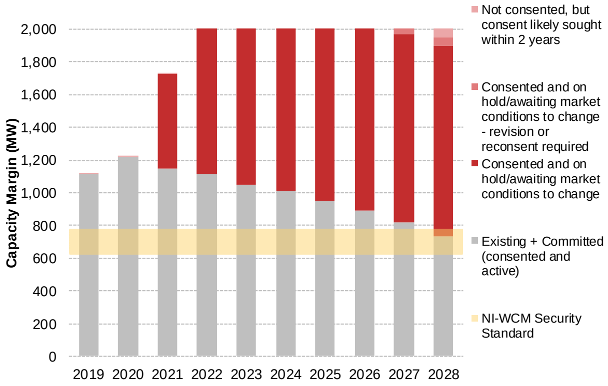

Figure 89: NI WCM – Low Demand and Medium Solar

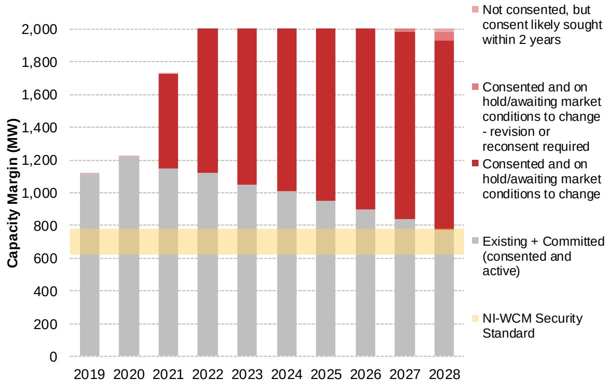

Figure 90: NI WCM – Low Demand and Low Solar

Medium Demand Scenario

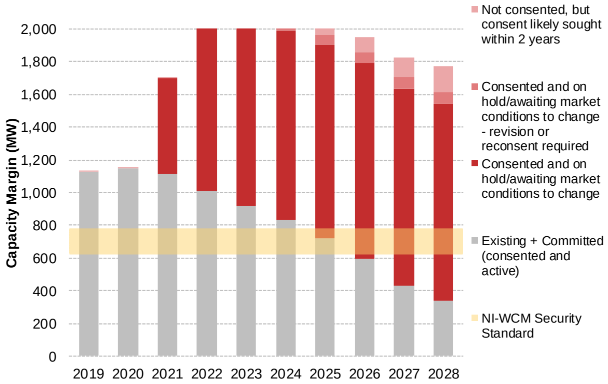

Figure 91: NI WCM – Medium Demand and Very High Solar

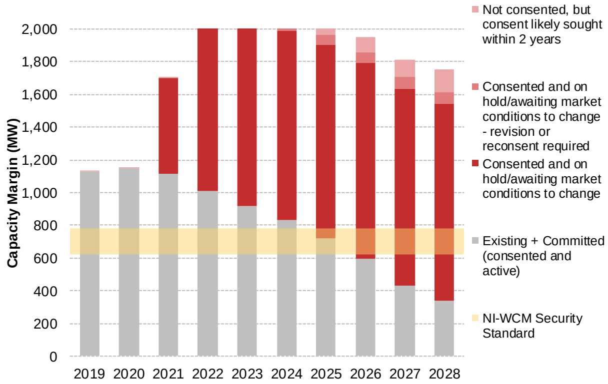

Figure 92: NI WCM – Medium Demand and High Solar

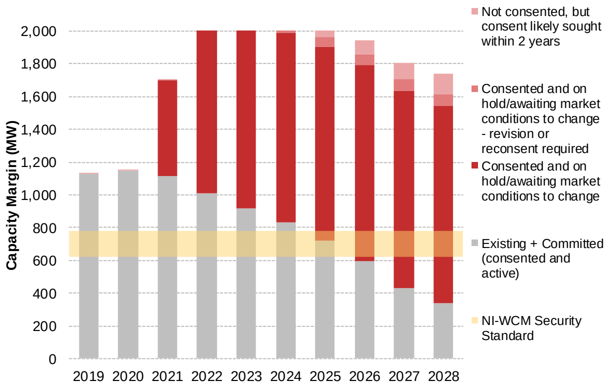

Figure 93: NI WCM – Medium Demand and Medium Solar

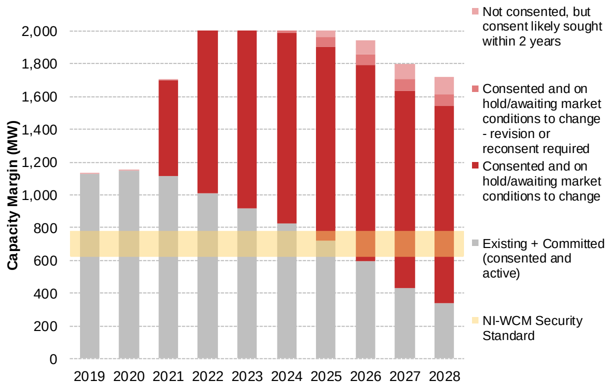

Figure 94: NI WCM – Medium Demand and Low Solar

Thermal Constraints Scenario

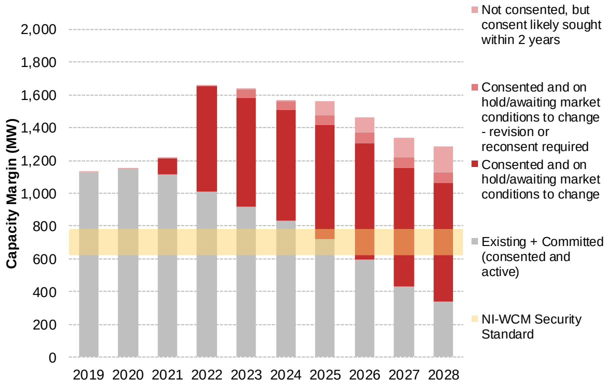

Figure 95: NI WCM – Thermal Constraints and Very High Solar

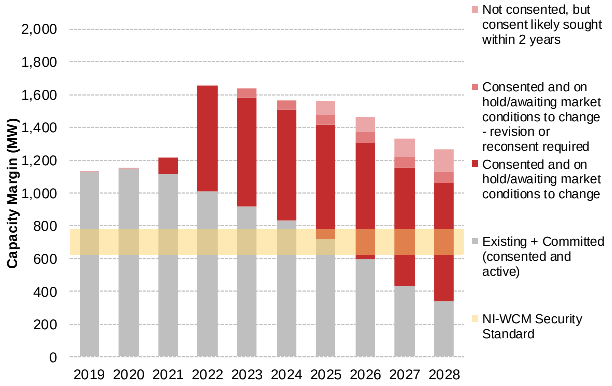

Figure 96: NI WCM – Thermal Constraints and High Solar

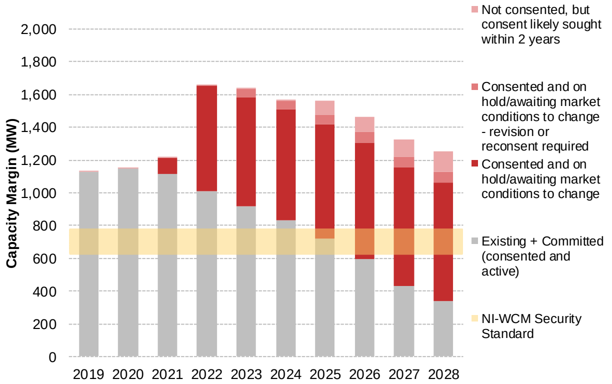

Figure 97: NI WCM – Thermal Constraints and Medium Solar

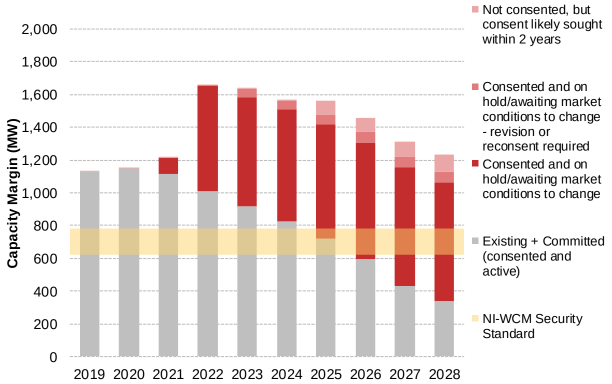

Figure 98: NI WCM – Thermal Constraints and Low Solar

2.2.3 NZAS and Rankine Closure Sensitivity

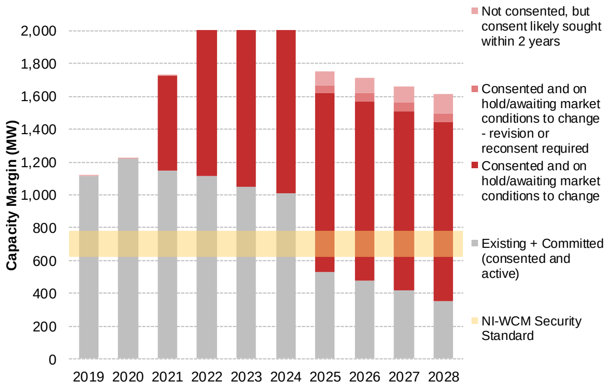

Figure 99: NI WCM – Low Demand and NZAS and Rankine Closure

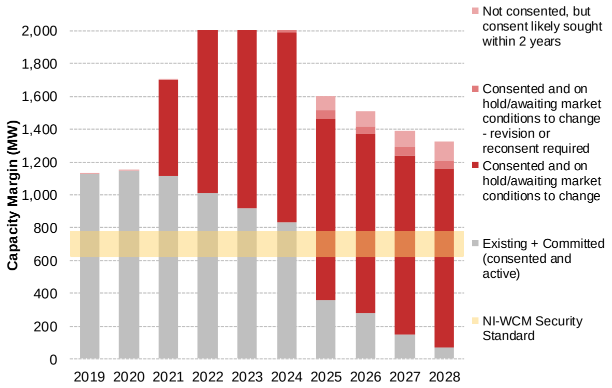

Figure 100: NI WCM – Medium Demand and NZAS and Rankine Closure

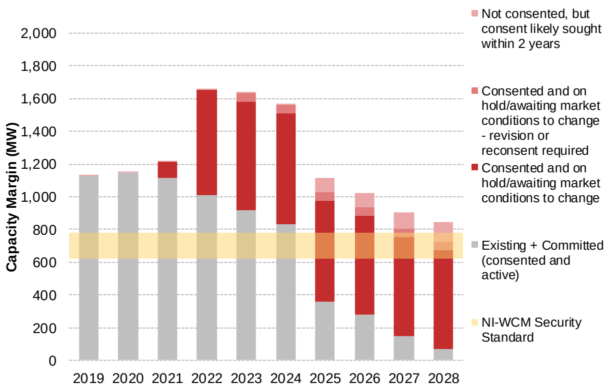

Figure 101: NI WCM – Thermal Constraints and NZAS and Rankine Closure

2.2.4 Thermal Decommissioning Sensitivity

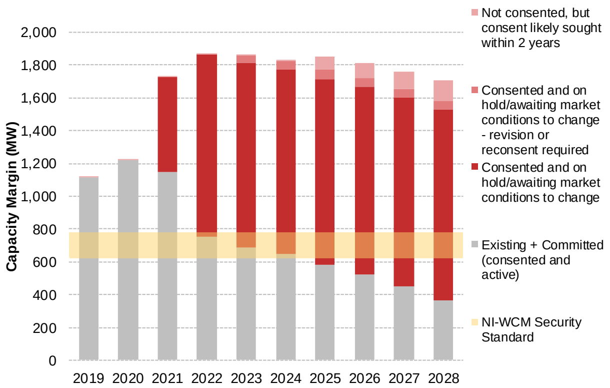

Figure 102: NI WCM – Low Demand and Thermal Decommissioning

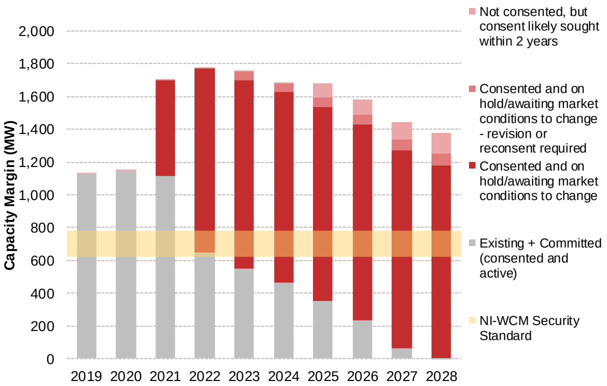

Figure 103: NI WCM – Medium Demand and Thermal Decommissioning

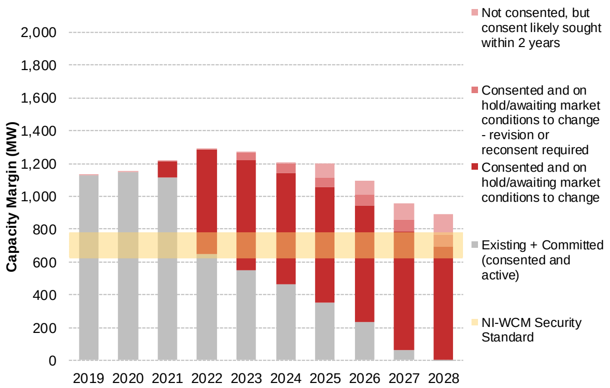

Figure 104: NI WCM – Thermal Constraints and Thermal Decommissioning

2.2.5 Delayed Build Times Sensitivity

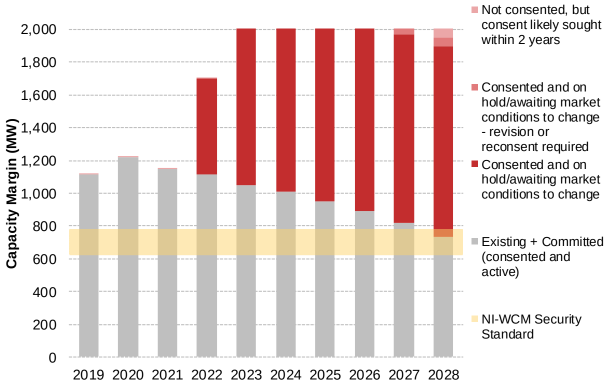

Figure 105: NI WCM – Low Demand and Delayed Build Times

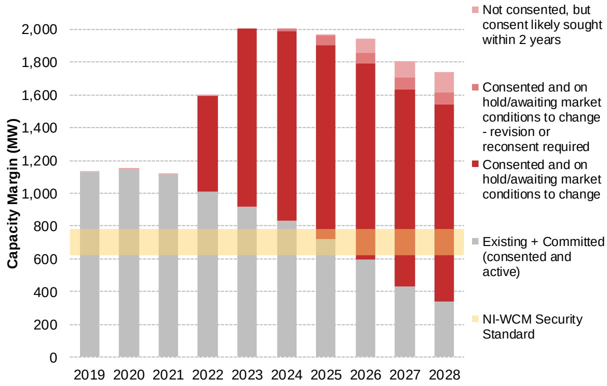

Figure 106: NI WCM – Medium Demand and Delayed Build Times

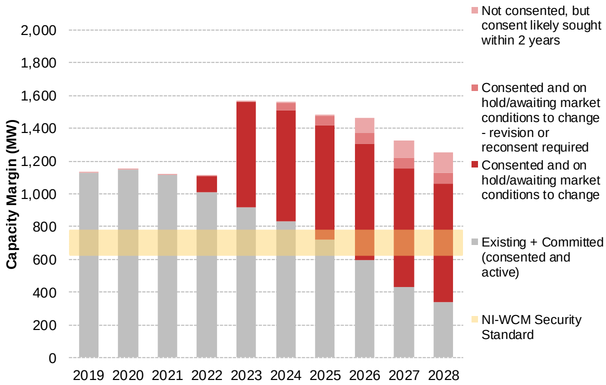

Figure 107: NI WCM – Thermal Constraints and Delayed Build Times

2.2.6 Reduced Generation Availability Sensitivity

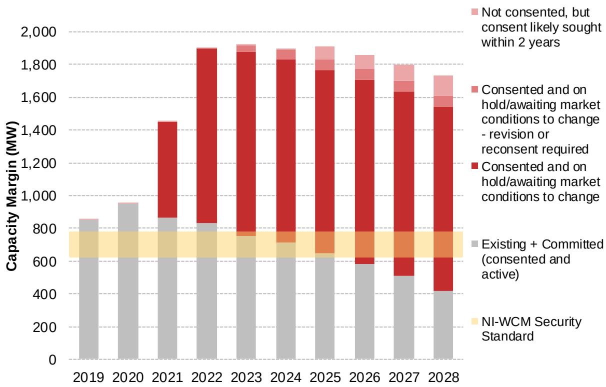

Figure 108: NI WCM – Low Demand and Reduced Generation Availability

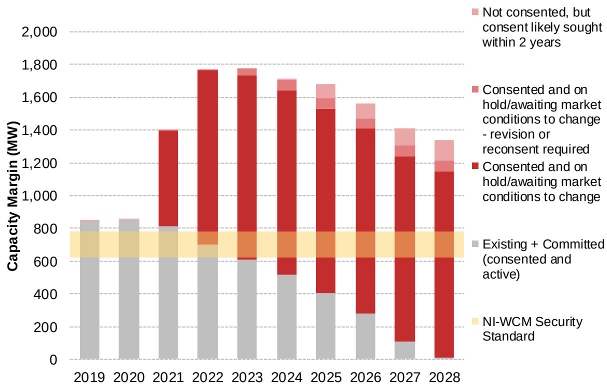

Figure 109: NI WCM – Medium Demand and Reduced Generation Availability

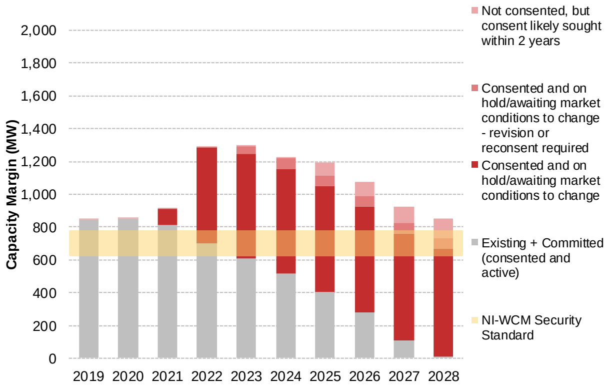

Figure 110: NI WCM – Thermal Constraints and Reduced Generation Availability

Appendix 3: METHODOLOGY

3.1 SECURITY OF SUPPLY STANDARDS AND INTERPRETATION

The security of supply assessment enables interested parties to compare projected winter energy and capacity margins over the next 10 years. The margins that define the security of supply standards used in this assessment are determined by the Electricity Authority (the Authority) and are documented within the Code.[23] The Authority derived the margins in 2012 using a probabilistic analysis.[24] The analysis sought to determine:

- the efficient level of North Island peaking capacity, defined as the level that minimises the sum of the expected societal cost of capacity shortage plus the cost of providing peaking generation capacity
- the efficient level of national winter energy supply, defined as the level that minimises the sum of the expected societal cost of energy shortage plus the cost of providing thermal firming capacity
- equivalently, the efficient level of South Island winter energy supply.

The current security of supply standards are:

- a WEM of 14-16% for New Zealand;
- a WEM of 25.5-30% for the South Island;
- a WCM of 630-780 MW for the North Island.

The Authority suggests that assessed margins should be interpreted as:

- A North Island WCM below 630 MW indicates an inefficiently low level of capacity; the cost of adding more capacity (or instantaneous reserves) would be justified by the reduction in shortage costs at times of insufficient capacity (or instantaneous reserves).
- A North Island WCM between 630 and 780 MW indicates an approximate efficient level of capacity.
- A North Island WCM above 780 MW indicates a capacity level that is inefficiently high in terms of the trade-off between supply costs and the cost of shortage at times of insufficient capacity (but may still be efficient for other reasons).

Assessed WEMs should be interpreted in a similar fashion (with the exception that any additional instantaneous reserves supply no energy, and therefore would not impact the margin).

The Authority's security of supply standards are expressed as winter requirements, reflecting when New Zealand's power system demand is highest and the impact of low thermal plant availability and low hydro inflows are greatest.

[23] See Part 7, clause 7.3 of the Electricity Industry Participation Code 2010 for more information

[24] http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/security-of-supply-standards/consultations/#c13932

3.2 Energy Margin Assessment

There are two Winter Energy Margins. The New Zealand Winter Energy Margin is calculated as:

$$NZ\ WEM = \left(\frac{New\ Zealand\ expected\ energy\ supply}{New\ Zealand\ expected\ energy\ demand} - 1\right) \times 100\%$$

The South Island Winter Energy Margin is calculated as:

$$SI\ WEM = \left(\frac{South\ Island\ expected\ energy\ supply + expected\ HVDC\ transfers\ south}{South\ Island\ expected\ energy\ demand} - 1\right) \times 100\%$$

Table 3: Summarising the New Zealand WEM components

Component	Comprises of	Description
New Zealand expected energy supply (GWh)	Thermal GWh	Maximum expected thermal generation available to meet winter (1 April to 30 September) energy demand allowing for forced and scheduled outages, available fuel supply and operational and transmission constraints.
	Mean Hydro GWh	Expected winter (1 April to 30 September) hydro generation based on mean inflows and expected 1 April start storage of 2,750 GWh.
	Other GWh	Expected winter (1 April to 30 September) energy available from cogeneration[25], geothermal and wind generation based on long-run average supply.
New Zealand expected energy demand (GWh)	NZ Energy Demand GWh	Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).

Table 4: Summarising the South Island WEM components

Component	Comprises	Description
South Island expected energy supply (GWh)	Mean Hydro GWh	Expected winter (1 April to 30 September) hydro generation based on mean inflows and assumed 1 April start storage of 2,400 GWh.
	Other GWh	Expected winter (1 April to 30 September) wind generation based on long-run average supply.
Expected HVDC transfers south (GWh)	HVDC GWh	Expected winter (1 April to 30 September) HVDC transfers received in the South Island.
South Island expected energy demand (GWh)	SI Energy Demand GWh	Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).

[25] Cogeneration has not been treated as thermal generation as it is assumed the primary fuel supply is based on industrial processes and not controlled in the same way as major thermal generators.

3.3 Capacity Margin Assessment

The North Island Winter Capacity Margin is calculated as:

$$NI\ WCM = North\ Island\ expected\ capacity - North\ Island\ expected\ demand + expected\ HVDC\ transfer\ north\ (function\ of\ SI\ capacity - SI\ demand)$$

Table 5: Summarising the North Island WCM components

Component	Comprises	Description
North Island expected capacity (MW)	NI Thermal MW	Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages, available fuel supply and operational and transmission constraints.
	NI Hydro MW	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and de-rated to account for energy and other constraints which affect output during peak times.
	NI Other MW	Expected winter peak generation from geothermal, wind, cogeneration and uncontrolled hydro scheme generation.
North Island expected demand (MW)	NI Peak Demand MW	Expected average of the highest 100 hours of demand in winter inclusive of losses. This is referred to as H100 NI demand.
	NI Demand Response and Interruptible Load MW	Expected demand response and interruptible load over the highest 100 hours of demand during winter peak. This is subtracted from NI Peak Demand to calculate NI expected demand.
Expected HVDC transfer north	South Island MW	The net amount of MW the South Island can supply to the North Island during peak periods. This is a similar calculation to above (supply capacity minus H100 NI demand); however, also takes into account HVDC transfer capability.

Appendix 4: DETAILED SUPPLY ASSUMPTIONS

The calculation of winter margins requires some assumptions about the capacity and availability of existing and new generation as well as the contribution of the HVDC. Many of the assumptions discussed are based on the Security Standards Assumption Document (SSAD) published by the Authority.

4.1 EXISTING GENERATION

The following tables summarise the existing generation that is used in the assessment. Embedded generation has been included to align with the reconciliation data used in demand calculations.[26]

Each generator has an energy and capacity rating which includes allowances for scheduled and forced outages.

Table 6: Existing North Island Supply

Plant	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Aniwhenua	Hydro - Inflexible run-of-river	25	18	62	72.0%	57.0%
Arapuni	Controlled Hydro	192	See Waikato scheme			
Aratiatia	Controlled Hydro	78	See Waikato scheme			
Atiamuri	Controlled Hydro	74	See Waikato scheme			
Glenbrook	Thermal - Cogen	74	45	210	61.0%	64.7%
Huntly Rankines	Thermal - Coal	480	466	1962	97.0%	93.3%
Huntly U5	Thermal - Gas	385	373	1595	97.0%	94.6%
Huntly U6	Thermal - Gas	45	44	186	97.0%	94.6%
Kaimai	Hydro - Flexible run-of-river	38	31	82	81.2%	49.3%
Kaitawa	Controlled Hydro	36	See Waikaremoana scheme			
Kapuni	Thermal - Cogen	25	15	84	61.0%	77.0%
Karapiro	Controlled Hydro	96	See Waikato scheme			
Kawerau	Geothermal	104	95	442	91.7%	96.9%
Kawerau Onepu	Geothermal	60	55	208	91.7%	79.0%

[26] Transpower's SCADA system was used to gather data on embedded generators. If no SCADA data was available for a generator it was included in the supply calculation as "Other Embedded Generation" equal to that included in the demand calculation.

Plant	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Kinleith	Thermal - Cogen	28	17	87	61.0%	71.0%
Kiwi Dairy, Hawera (Whareroa)	Thermal - Cogen	70	43	202	61.0%	66.0%
Mangahao	Hydro - Inflexible run-of-river	42	30	72	72.0%	39.0%
Maraetai	Controlled Hydro	352	See Waikato scheme			
Matahina	Controlled Hydro	80	66	133	98.0%	38.0%
McKee	Thermal - Gas	100	97	414	97.0%	94.6%
Mill Creek	Wind	60	15	119	25.0%	45.3%
Mokai	Geothermal	112	103	464	91.7%	94.6%
Nga Awa Purua	Geothermal	135	124	570	91.7%	96.4%
Ngatamariki	Geothermal	83.2	76	350	91.7%	96.1%
Ngawha	Geothermal	26	24	103	91.7%	90.2%
Ohaaki	Geothermal	40	37	140	91.7%	80.0%
Ohakuri	Controlled Hydro	106	See Waikato scheme			
Patea	Controlled Hydro	32.2	27	53	98.0%	37.2%
Piripaua	Controlled Hydro	44	See Waikaremoana scheme			
Poihipi	Geothermal	55	50	222	91.7%	92.0%
Rangipo	Hydro - Inflexible run-of-river	120	86	281	72.0%	53.4%
Rotokawa	Geothermal	34.5	32	145	91.7%	95.9%
Stratford Peaker	Thermal - Gas	200	194	829	97.0%	94.6%
Tararua I	Wind	31.68	8	57	25.0%	41.1%
Tararua II	Wind	36.3	9	66	25.0%	41.6%
Tararua III	Wind	93	23	161	25.0%	39.5%
TCC	Thermal - Gas	377	366	1562	97.0%	94.6%
Te Ahi O Maui	Geothermal	24	22	95	91.7%	
Te Āpiti	Wind	90	23	106	25.0%	27.0%
Te Huka	Geothermal	28	26	117	91.7%	95.0%
Te Mihi	Geothermal	166	153	669	91.7%	92.0%
Te Rapa	Thermal - Cogen	44	27	164	61.0%	85.1%
Te Rere Hau	Wind	48.5	12	56	25.0%	26.2%
Te Uku	Wind	67	17	94	25.0%	32.0%

Plant	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Tokaanu	Controlled Hydro	240	216	414	98.0%	39.4%
Tuai	Controlled Hydro	59	See Waikaremoana scheme			
Waipapa	Controlled Hydro	54	See Waikato scheme			
Wairakei incl. binary	Geothermal	132	121	549	91.7%	95.0%
West Wind	Wind	142	36	255	25.0%	41.0%
Whakamaru	Controlled Hydro	112	See Waikato scheme			
Wheao	Hydro - Flexible run-of-river	24	19	54	81.2%	51.4%
Whirinaki	Thermal - Diesel	155	150	30	97.0%	4.4%

* Energy and capacity contributions of this plant are detailed in the aggregated hydro schemes shown in Table 8.

Table 7: Existing South Island Supply

Scheme	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Aviemore	Controlled Hydro	220	See Waitaki scheme			
Benmore	Controlled Hydro	540	See Waitaki scheme			
Branch	Hydro - Inflexible run-of-river	11	8	25	72.0%	50.9%
Clyde	Controlled Hydro	432	See Clutha scheme			
Cobb	Controlled Hydro	32	31	93	98.0%	66.0%
Coleridge	Controlled Hydro	39	38	130	98.0%	75.8%
Deep Stream	Hydro - Flexible run-of-river	6	5	12	81.2%	43.8%
Highbank/Montalto	Hydro - Flexible run-of-river	26.8	22	48	81.2%	40.9%
Kumara/Dillmans/Duffers	Hydro - Flexible run-of-river	10.5	9	20	81.2%	42.4%
Mahinerangi Wind	Wind	36	9	51	25.0%	32.6%
Manapouri	Controlled Hydro	800	784	2685	98.0%	71.0%

Scheme	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Ohau A	Controlled Hydro	264	See Waitaki scheme			
Ohau B	Controlled Hydro	212	See Waitaki scheme			
Ohau C	Controlled Hydro	212	See Waitaki scheme			
Paerau/Patearoa	Hydro - Inflexible run-of-river	12.25	9	27	72.0%	50.3%
Roxburgh	Controlled Hydro	320	See Clutha scheme			
Tekapo A	Controlled Hydro	30	See Tekapo scheme			
Tekapo B	Controlled Hydro	154	See Tekapo scheme			
Waipori	Hydro - Flexible run-of-river	83.6	68	87	81.2%	23.8%
Waitaki	Controlled Hydro	105	See Waitaki scheme			
Whitehill	Wind	58	15	76	25.0%	30.0%

* Energy and capacity contributions of this plant are detailed in the aggregated hydro schemes shown in Table 8.

Table 8: Existing New Zealand controllable hydro supply

Scheme	Island	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Waikato	NI	1064	984	2331	98%	47.7%
Waikaremoana	NI	139	136	266	98%	44.2%
Tekapo	SI	184	180	2775	98%	45.4%
Waitaki	SI	1553	1522		98%	
Clutha	SI	752	737	1417	98%	55.0%
Start storage	NI	n/a	n/a	350	n/a	n/a
Start storage	SI	n/a	n/a	2400	n/a	n/a

4.2 New Generation

Figures 111 and 112 show the expected capacity and energy contributions from new generation in aggregate form. Each graph shows contributions by the generator type, and in which island the generation is based.

Overall, the total winter energy contribution of future generation has increased from 8,954 GWh in 2018 to 9,113 GWh in 2019. Although there was a decrease in future thermal generation, as well as geothermal generation due to the commissioning of Te Ahi O Maui, the inclusion of solar generation and an increase in wind meant that overall the total energy contribution of future generation increased.

Conversely, the expected capacity contribution from future generation has decreased from 1,878 MW in 2018 to 1,669 MW in 2019. The decrease in future generation from thermal and geothermal was again observed in capacity contribution values, but the increase seen from the inclusion of solar and more wind was lower than that seen in energy margins due to their relative inability to react to peaks in demand.

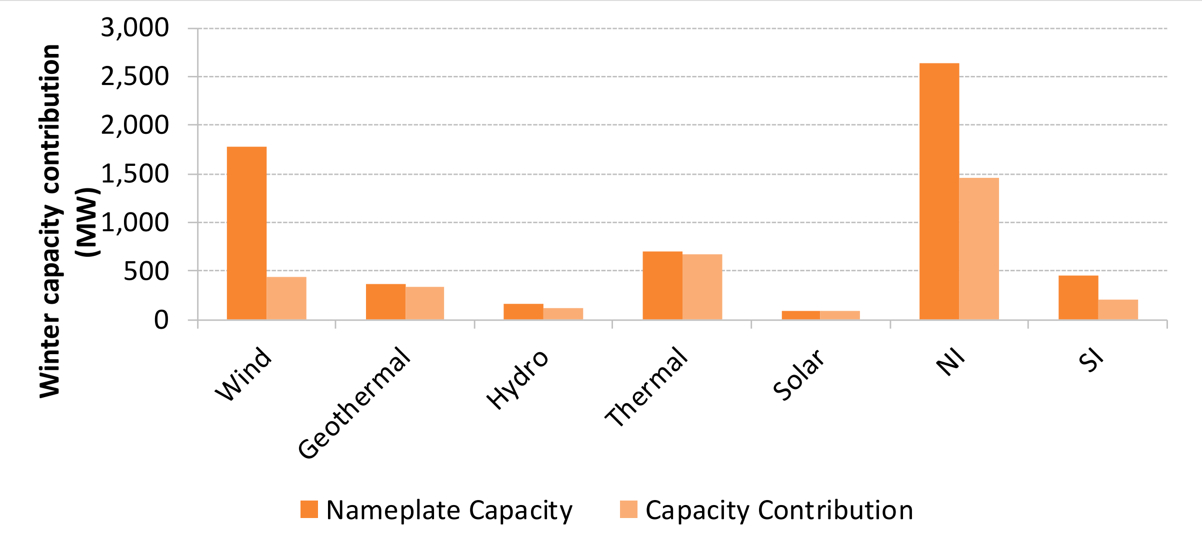

Figure 111: Winter Capacity Contribution from New Generation

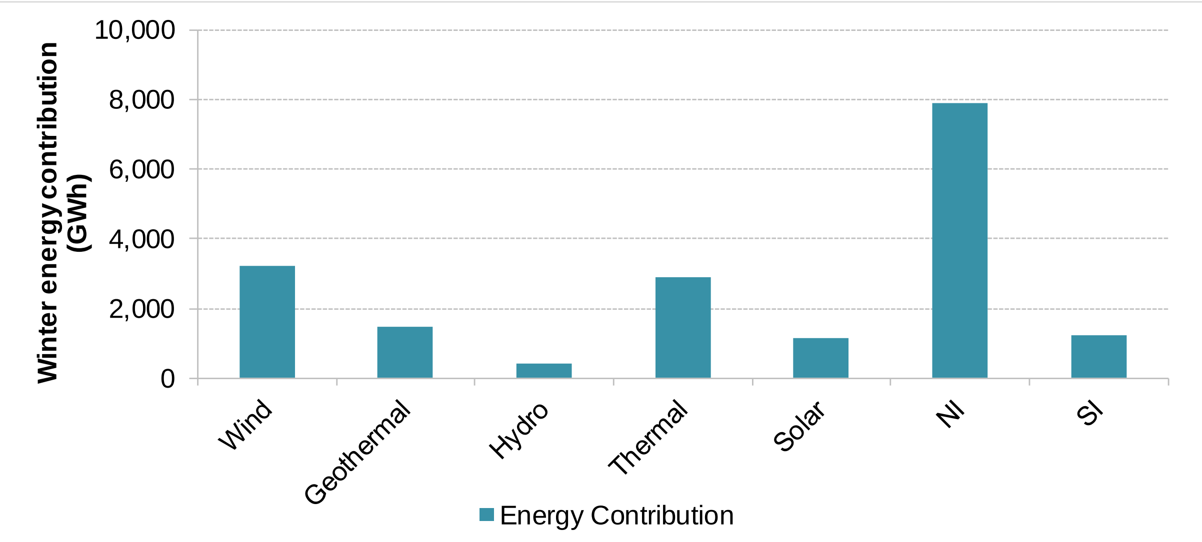

Figure 112: Winter Energy Contribution from New Generation

The following tables summarise new generation used in the assessment. The dates at which new generation becomes available is based on the type of generation, and its consent status.

Table 9: New generation aggregated by type

Type	Nameplate MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)
Wind	1,772	443	3,211
Geothermal	365	335	1,461
Hydro	163	120	398
Thermal	700	679	2,900

Table 10: Solar generation per island per year (medium solar)

Year	NI Solar Contribution to WEMs (GWh)	NI Capacity Contribution to WCM (MW)[27]	SI Solar Contribution to WEMs (GWh)	SI Capacity Contribution to WCM (MW)
2019	30	0.0	16	0.0
2020	42	0.0	22	0.0
2021	65	0.1	31	0.1
2022	97	0.2	44	0.1
2023	143	0.6	61	0.2
2024	204	1.1	83	0.7
2025	281	2.2	111	1.1
2026	372	6.8	146	2.3
2027	487	18.2	190	6.1
2028	638	35.5	250	12.2
2029	822	65.3	321	26.7

Table 11: New generation aggregated by island

Island	Nameplate MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)
NI	2,631	1,461	7,890
SI	461	207	1,223

[27] Solar contributing to peak is based on solar arrays accompanied by batteries to shift solar generation to peaks.

4.2.1 New generation commissioning dates

The dates at which new generation becomes available is based on the type of generation, and its consent status. The table below shows the earliest commissioning dates for different types of generation and consent status. These commissioning dates are used for all sources of new generation.

Table 12: New generation commissioning dates based on consent status and generation type

	Consented and proceeding	Consented and on hold/awaiting market conditions to change	Consented and on hold, revision or reconsent required	Not consented and on hold, but consent likely sought within 2 years
Thermal	Estimated build date	2021	2022	2024
Geothermal	Estimated build date	2022	2023	2025
Wind	Estimated build date	2022	2023	2025
Hydro	Estimated build date	2023	2024	2026

We have not explicitly accounted transmission build times into these commissioning dates, as transmission builds vary from project to project.

4.3 Other Generation Assumptions

4.3.1 Other generation de-ratings are applied

The following de-ratings are applied to generation:

- In the assessment of the New Zealand WEM and South Island WEM, thermal generation has been reduced by 92 GWh in the North Island to reflect spinning reserve and frequency keeping requirements.[28]
- In the assessment of the North Island WCM, to account for limited short-term storage availability, these generators are not treated as run-of-river hydro:
  - Matahina de-rated by 13 MW
  - Patea de-rated by 5 MW
  - Tokaanu de-rated by 20 MW.
- The Waikato hydro scheme is de-rated by 60 MW to account for the impact of chronological flow constraints in the derivation of the North Island WCM.

4.3.2 Fuel or operational limits do not constrain thermal generation

With the exception of Whirinaki, it is assumed thermal fuel availability, or operational limitations, do not limit thermal generation in this medium-term assessment.

[28] This is different than that suggested in the SSAD. This difference is due to various technological and regulatory changes over recent years; lower quantities of ancillary services are required compared to when the SSAD was published. The Authority has provided us with analysis of 2012 and 2013 dry spells that estimates the reduction in thermal generation due to spinning reserves and frequency keeping at 92 GWh. The SSAD states a value of 303 GWh, if this value was used instead of 92 GWh, the New Zealand Winter Energy Margins would increase by approximately 0.8-0.9%, and the South Island Energy Margins would increase by 2.3% (assuming HVDC isn't constrained in the margin calculation).

To reflect on-site fuel storage and delivery limitations, Whirinaki's energy contribution is limited to 30 GWh per winter in the derivation of the WEMs.

4.3.3 Average hydro storage conditions are assumed

The winter start storage for assessing WEMs are those specified in the SSAD. The start storage levels are:

- 2,750 GWh for New Zealand
- 2,400 GWh for the South Island.

4.3.4 Run-of-River Hydro, Cogeneration, Geothermal and Wind Capacity Contribution

The capacity contributions of run-of-river hydro, cogeneration and geothermal generation assumed for the North Island WCM are determined from historical generation at peak periods.

Generation output for the 500 trading periods with highest demand is collected. This is then analysed to determine the average contribution of run-of-river hydro, cogeneration and geothermal during peak periods. Flexible run-of-river hydro is assumed to contribute 81.2% of maximum nameplate capacity, inflexible run-of-river hydro is assumed to contribute 72.0% of capacity, geothermal is assumed to contribute 91.7% of capacity and cogeneration is assumed to contribute 61.0% of capacity.

For wind generation, this assessment assumes a wind capacity contribution of 25% as defined in the SSAD.

Appendix 5: TRANSMISSION

Inter-island transmission assumptions are required for assessment of the South Island WEM and the North Island WCM. North Island energy supply can meet some South Island energy demand in the assessment of the South Island WEM. Similarly, South Island capacity can meet some North Island demand in the assessment of the North Island WCM.

It is assumed that the HVDC capability will be the combined capability of Pole 2 and Pole 3 for all scenarios.

5.1 HVDC FLOW SOUTH CONTRIBUTES TO SOUTH ISLAND WEM

It is assumed that the North Island will be able to supply the South Island with 2,101 GWh (480 MW average transfer[29]) of energy during the winter period. This energy transfer is dependent on the North Island having the required surplus energy available. To allow for this restriction the lesser value of 2,101 GWh or the net NI energy surplus, which is determined in the same way as the South Island WEM, is used.

5.2 HVDC FLOW NORTH CONTRIBUTES TO WCM

It is assumed during winter the South Island has the potential to supply the North Island with capacity.

The contribution of South Island capacity to North Island demand is a function of surplus capacity available in the South Island, depicted in Figure 113. The contribution is determined in the same way as the North Island WCM. The function used in this process was derived using simulation analysis, taking account of:

- HVDC capacity
- transmission losses
- North Island instantaneous reserve requirements
- the low probability of forced outages on the HVDC link.

This assessment assumes that both Pole 2 and Pole 3 are available at all times in the four key scenarios.

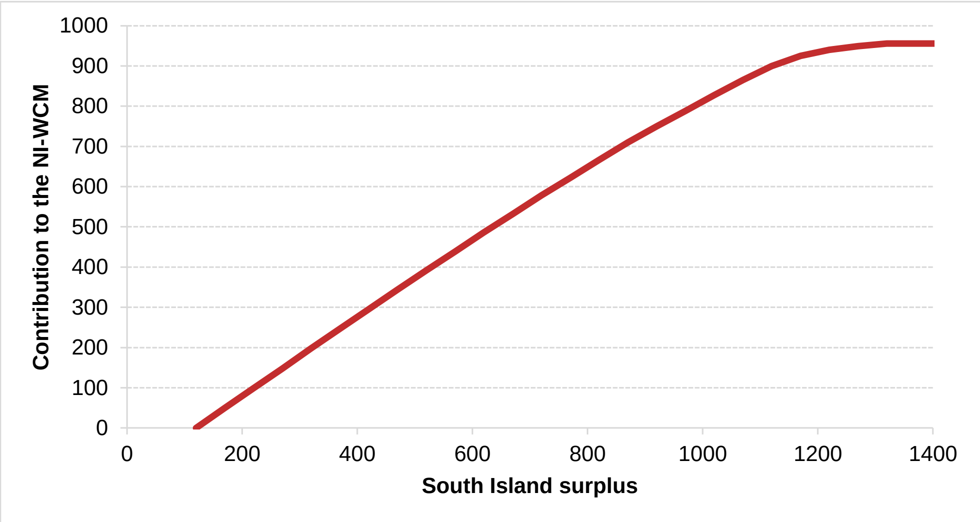

Figure 113: Relationship between South Island surplus and its contribution to the North Island WCM

[29] As discussed in the System Security Forecast, on occasion the HVDC southward limit will be restricted to 260 MW due to low wind generation in the Wellington region, however at times south transfer is also expected to reach 650 MW.

5.3 AC TRANSMISSION ASSUMPTIONS

This assessment does not explicitly model AC transmission constraints. The implicit assumption is that AC constraints will not reduce inter-island transfers below the limits specified above.

Appendix 6: DETAILED DEMAND FORECAST ASSUMPTIONS

The demand forecasts used in this assessment are based on a forecast prepared by Transpower for both capacity (for the WCM) and energy (for the WEMs) which we refer to as the demand forecast. The base year for this forecast is 2018 (this is the most recent year where there is actual data) for the peak and energy forecasts. The underlying demand forecast predicts gross demand using reconciliation data.

6.1 DEMAND FORECAST METHODOLOGY

Future electricity demand is a critical factor to consider when assessing security of supply. The demand forecast used in the Annual Assessment is an internally prepared forecast for both capacity (for the WCM) and energy (for the WEMs). Both peak and energy forecasts use an ensemble approach where 4 forecasts are combined to form a single base forecast, with additional discrete step changes added to the base where more detailed information is available. For example, a major consumer may increase or decrease consumption at some point in the future—this may be a known committed step change or involve using a sensitivity if the change is uncertain.

Note the expected capacity demand is based on the highest 100 hours of demand in 2018, inclusive of both transmission losses and embedded generation, and increased by the forecast growth-rate in the ensemble forecast.

The ensemble uses the following input forecasts:

- Traditional econometric forecast
- Long term linear regression
- Short term linear regression
- MBIE Energy Demand and Generation Scenarios

The base forecast uses reconciliation data as its primary input and is calculated for each Grid Exit Point (GXP). Thus, the forecast inherently accounts for embedded generation and distribution losses but does not account for transmission losses. The base ensemble forecast is then adjusted to account for any know step changes or future deviations from what has been historically observed—for example in the forecasts based on Te Mauri Hiko forecasts (Medium demand), the impact of electrification of industry and transport have been estimated and added to the forecast. The final step is to apply transmission losses:

- for energy, losses are calculated by determining GXP offtake quantities, and applying a static loss factor, however,
- for peak, the Annual Assessment peak value (which is based off the average of the top 100 hours of demand during the winter period) is determined using generation output information for the base year (2018), with the growth rate observed in the forecast applied to determine subsequent years. Therefore, the peak forecast implicitly includes transmission losses.

The flow chart below shows how both the underlying peak and energy forecasts are determined.

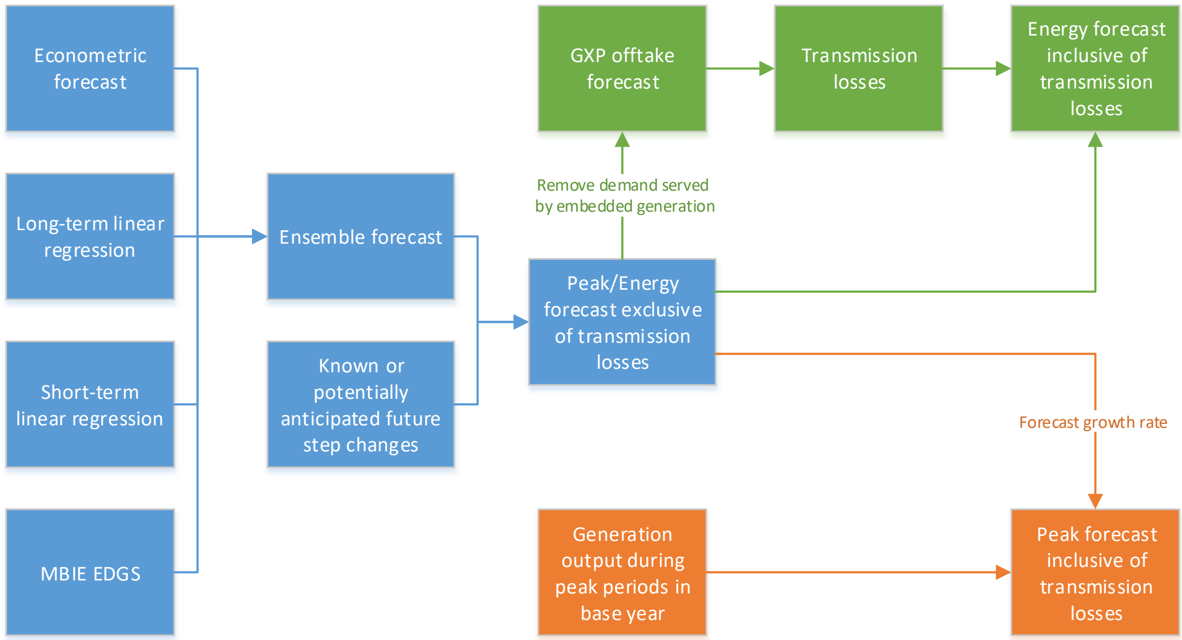

Figure114: Schematic of how demand forecast is prepared

The Expected energy demand is calculated as:

$$\begin{aligned} &Winter\ energy\ demand \\ &\quad = (wholesale\ energy\ demand) \times demand\ response\ factor\ \times winter\ scaling\ factor \end{aligned}$$

Transmission losses are only applied to net GXP demand. Demand response and conversion to winter demand are applied to wholesale energy demand (inclusive of transmission losses and embedded generation).

For all energy margin calculations, the winter (1 April – 30 September) demand values are shown in the table below.

Table 13: Winter Demand Percentage of Annual Demand

Year	% of National Annual Demand	% of South Island Annual Demand
2019	54%	54%
2020	54%	54%
2021	54%	54%
2022	54%	54%
2023	55%	54%
2024	55%	54%
2025	55%	54%
2026	55%	54%
2027	56%	54%
2028	56%	55%

6.1.1 Demand Response

Winter energy demand forecasts have been reduced by 2% to allow for voluntary demand response.

Winter peak demand (H100) forecasts in the North Island have been reduced by 176 MW to account for demand response at peak times.)

These reductions include voluntary demand response resulting from high spot prices or retailer pricing initiatives, but excludes reductions in demand as a result of savings campaigns or forced rationing.

6.1.2 Transmission Losses (for WEMs)

In the calculation of the WEMs static loss factors have been applied, as defined in the SSAD. These are:

- 3.5% losses for New Zealand for the purposes of the NZ-WEM
- 4.5% losses for the South Island for the purposes of the SI-WEM

6.1.3 Peak Demand (H100) Forecast

The underlying demand forecast models the single highest half-hourly demand in a year. For the Security of Supply Annual Assessment, the Authority recommends use of the H100 demand, which is an average of the 100 highest hours of demand falling between 7am and 10pm, 1 April and 31 October.

This assessment has derived an H100 demand that is consistent with the supply assumptions by determining demand for generation in 2018.[30] This is achieved by firstly identifying the H100 peak demand periods using aggregate data for the North and South Islands. Then, generation from each generator (including demand met by embedded generation) during those peaks is aggregated to determine demand for generation for each of those peak periods. Finally, these aggregate values were averaged to determine a single H100 figure for 2018.

The percentage growth rates for peak demand in the underlying demand forecast was then applied to the 2018 H100 figure to determine an H100 forecast out to 2028.

This approach removes the need to explicitly account for transmission losses. This methodology for calculating demand is not expected to have a material impact on the WCM results and is intended to make the derivation of H100 less resource intensive, less prone to errors and easier to align with supply assumptions.

6.1.4 Demand Data used for the 2019 Annual Assessment

The charts shown below are the demand forecasts that are used in the derivation of the margins. They include transmission losses and embedded generation, but not demand response or the conversion to winter energy. For data that includes *all* adjustments please refer to the tables below.

[30] Demand for generation is demand measured at the point of generation. This eliminates the need to adjust for embedded generation (we measure and aggregate all generation that is modelled on the supply side, including embedded generation) and transmission losses (these are implicitly included).

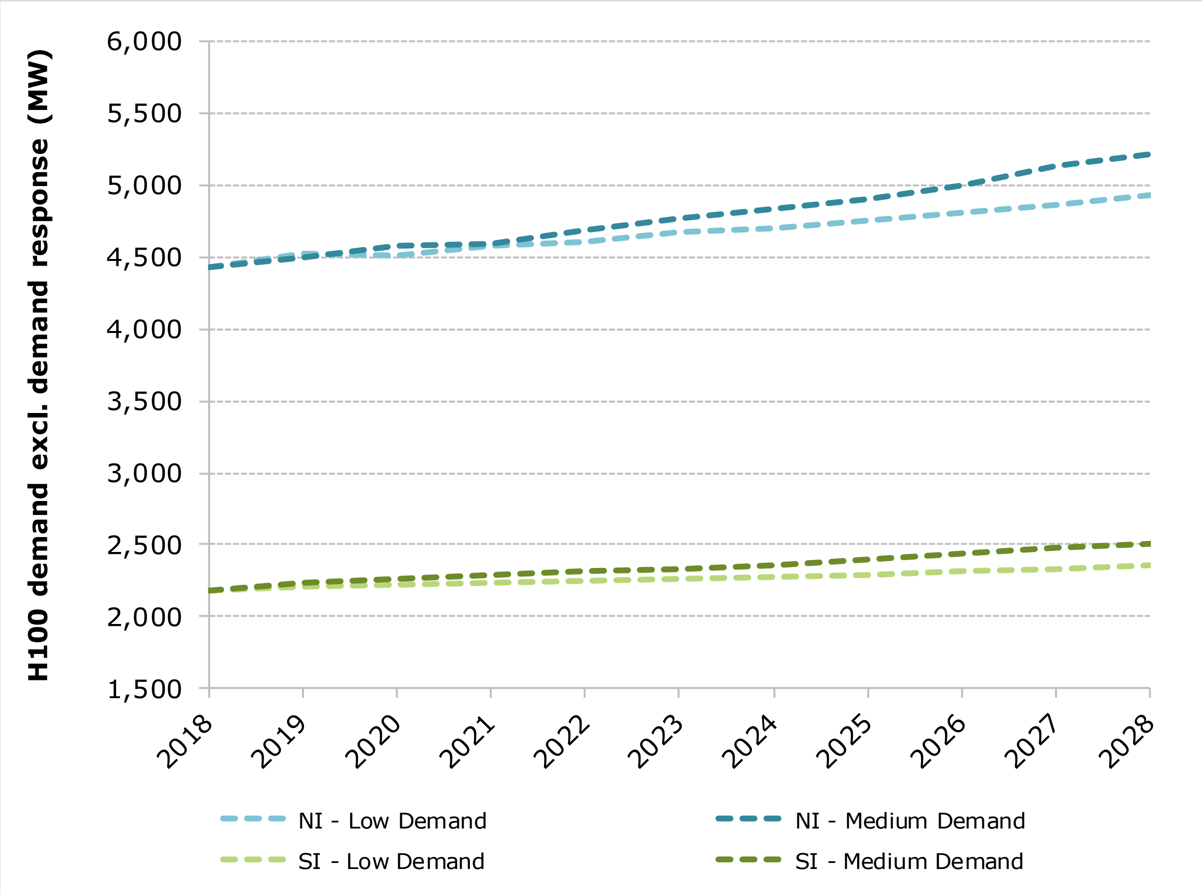

Figure115: H100 demand excluding demand response

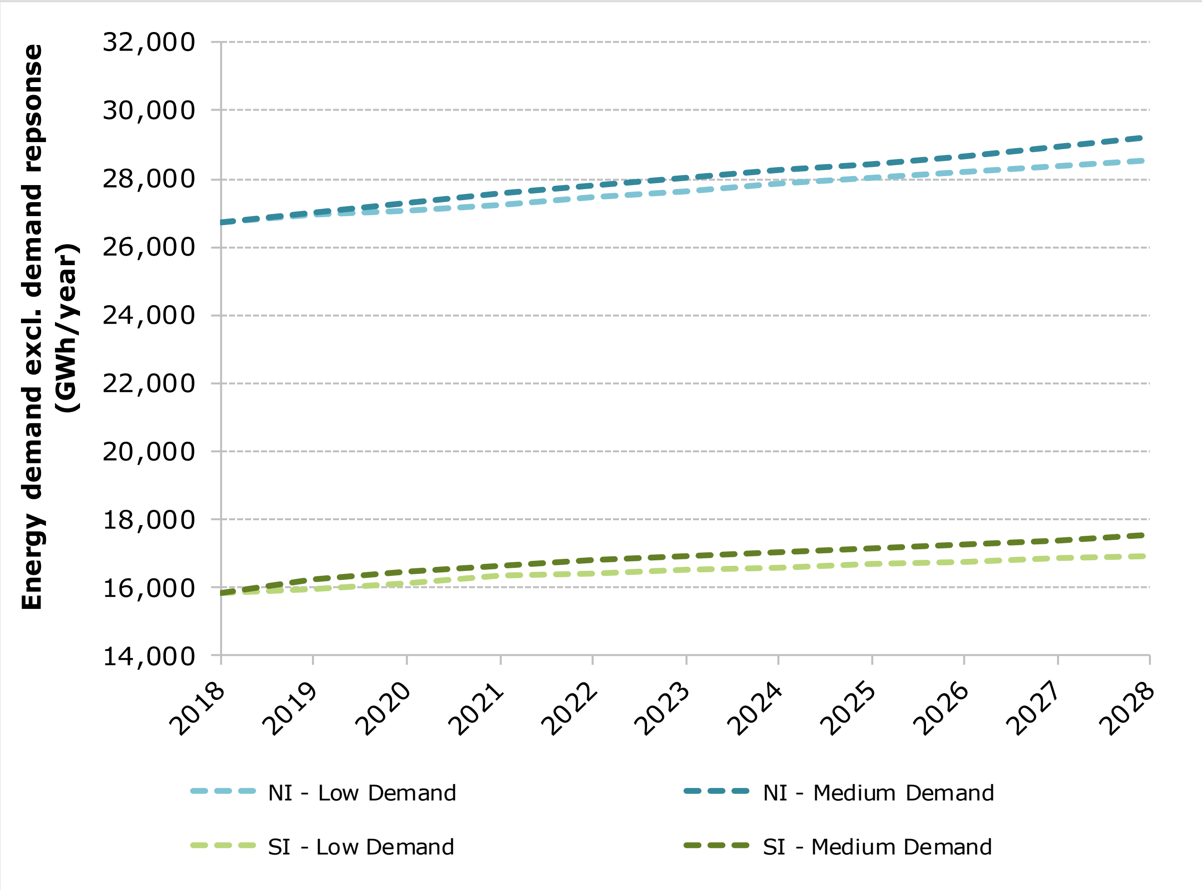

Figure116: Energy demand excluding demand response

6.1.5 Low Demand Forecast

Table 14: Annual South Island energy demand forecast

Calendar Year	South Island Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar	Expected annual demand	Winter Demand incl. demand response
2018	13,946	628	1,199	43	15,816	8,543
2019	14,084	634	1,199	57	15,974	8,600
2020	14,201	639	1,199	81	16,120	8,634
2021	14,413	649	1,199	114	16,375	8,795
2022	14,422	649	1,199	158	16,428	8,796
2023	14,442	650	1,199	217	16,509	8,871
2024	14,456	651	1,199	292	16,598	8,911
2025	14,458	651	1,199	381	16,689	8,992
2026	14,425	649	1,199	497	16,771	9,067
2027	14,356	646	1,199	652	16,854	9,170
2028	14,241	641	1,199	842	16,924	9,251

Table 15: Annual New Zealand energy demand forecast

Calendar Year	New Zealand Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar	Expected annual demand	Winter Demand incl. demand response
2018	35,588	1,248	5,607	119	42,563	22,998
2019	35,872	1,257	5,607	163	42,900	23,218
2020	36,076	1,265	5,607	245	43,193	23,543
2021	36,393	1,276	5,607	360	43,636	23,791
2022	36,503	1,280	5,607	521	43,911	23,925
2023	36,528	1,280	5,607	735	44,151	24,236
2024	36,545	1,281	5,607	1,006	44,440	24,404
2025	36,500	1,279	5,607	1,323	44,711	24,618
2026	36,351	1,274	5,607	1,733	44,966	24,863
2027	36,077	1,265	5,607	2,273	45,222	25,349
2028	35,653	1,250	5,607	2,939	45,449	25,625

Table 16: Annual peak demand forecast

Calendar Year	North Island Demand (MW)			South Island Demand (MW)	
	Peak forecast	H100 forecast	H100 forecast incl. demand response	Peak forecast	H100 forecast
2018	4510	4,430	4,254	2268	2,181
2019	4602	4,520	4,344	2293	2,205
2020	4598	4,517	4,341	2305	2,217
2021	4669	4,586	4,410	2324	2,236
2022	4696	4,613	4,437	2338	2,249
2023	4759	4,675	4,499	2353	2,264
2024	4794	4,709	4,533	2368	2,278

Calendar Year	North Island Demand (MW)			South Island Demand (MW)	
	Peak forecast	H100 forecast	H100 forecast incl. demand response	Peak forecast	H100 forecast
2025	4843	4,757	4,581	2383	2,293
2026	4892	4,805	4,629	2402	2,311
2027	4952	4,864	4,688	2423	2,331
2028	5022	4,933	4,757	2452	2,358

6.1.6 Medium Demand Forecast

Table 17: Annual South Island energy demand forecast

Calendar Year	South Island Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar Generation	Expected annual demand	Winter Demand incl. demand response
2018	13,946	628	1,199	43	15,816	8,543
2019	14,328	645	1,199	57	16,229	8,737
2020	14,546	655	1,199	81	16,481	8,828
2021	14,675	660	1,199	114	16,648	8,942
2022	14,777	665	1,199	158	16,800	8,995
2023	14,829	667	1,199	217	16,913	9,088
2024	14,862	669	1,199	292	17,022	9,139
2025	14,887	670	1,199	381	17,137	9,233
2026	14,892	670	1,199	497	17,258	9,330
2027	14,864	669	1,199	652	17,384	9,458
2028	14,823	667	1,199	842	17,532	9,584

Table 18: Annual New Zealand energy demand forecast

Calendar Year	New Zealand Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar Generation	Expected annual demand	Winter Demand incl. demand response
2018	35,588	1,248	5,607	119	42,563	22,998
2019	36,196	1,269	5,607	163	43,236	23,399
2020	36,631	1,284	5,607	245	43,767	23,854
2021	36,935	1,295	5,607	360	44,196	24,095
2022	37,152	1,302	5,607	521	44,582	24,289
2023	37,314	1,308	5,607	735	44,964	24,680
2024	37,350	1,309	5,607	1,006	45,273	24,859
2025	37,342	1,309	5,607	1,323	45,582	25,095
2026	37,281	1,307	5,607	1,733	45,929	25,393
2027	37,130	1,301	5,607	2,273	46,311	25,956
2028	36,938	1,295	5,607	2,939	46,779	26,372

Table 19: Annual peak demand forecast

Calendar Year	North Island Demand (MW)			South Island Demand (MW)	
	Peak forecast	H100 forecast	H100 forecast incl. demand response	Peak forecast	H100 forecast
2018	4683	4,430	4,254	2291	2,181
2019	4757	4,499	4,323	2349	2,236
2020	4840	4,578	4,402	2382	2,267
2021	4860	4,597	4,421	2405	2,290
2022	4956	4,688	4,512	2434	2,318
2023	5044	4,771	4,595	2451	2,333
2024	5120	4,843	4,667	2476	2,358
2025	5193	4,912	4,736	2523	2,402
2026	5294	5,007	4,831	2561	2,438
2027	5432	5,138	4,962	2609	2,484
2028	5516	5,217	5,041	2627	2,501

6.1.7 High Demand Forecast

Table 20: Annual South Island energy demand forecast

Calendar Year	South Island Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar Generation	Expected annual demand	Winter Demand incl. demand response
2018	13,946	628	1,199	43	15,816	8,543
2019	14,441	650	1,199	57	16,346	8,801
2020	14,771	665	1,199	81	16,716	8,953
2021	15,010	675	1,199	114	16,999	9,130
2022	15,229	685	1,199	158	17,272	9,248
2023	15,401	693	1,199	217	17,511	9,410
2024	15,563	700	1,199	292	17,755	9,532
2025	15,730	708	1,199	381	18,018	9,708
2026	15,902	716	1,199	497	18,314	9,901
2027	16,065	723	1,199	652	18,639	10,141
2028	16,245	731	1,199	842	19,018	10,396

Table 211: Annual New Zealand energy demand forecast

Calendar Year	New Zealand Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar Generation	Expected annual demand	Winter Demand incl. demand response
2018	35,588	1,248	5,607	119	42,563	22,998
2019	36,516	1,280	5,607	163	43,566	23,578
2020	37,274	1,307	5,607	245	44,434	24,217
2021	37,913	1,329	5,607	360	45,209	24,648
2022	38,488	1,349	5,607	521	45,966	25,043
2023	39,034	1,368	5,607	735	46,744	25,659
2024	39,512	1,385	5,607	1,006	47,511	26,090
2025	40,009	1,402	5,607	1,323	48,342	26,618
2026	40,553	1,421	5,607	1,733	49,315	27,269
2027	41,166	1,443	5,607	2,273	50,489	28,305

Calendar Year	New Zealand Demand (GWh)					
	Energy forecast	Transmission losses	Embedded generation	Solar Generation	Expected annual demand	Winter Demand incl. demand response
2028	41,859	1,467	5,607	2,939	51,872	29,255

Table 22: Annual peak demand forecast

Calendar Year	North Island Demand (MW)			South Island Demand (MW)	
	Peak forecast	H100 forecast	H100 forecast incl. demand response	Peak forecast	H100 forecast
2018	4687	4,430	4,254	2295	2,181
2019	4763	4,502	4,326	2360	2,244
2020	4847	4,581	4,405	2393	2,275
2021	4910	4,641	4,465	2427	2,307
2022	4996	4,722	4,546	2463	2,342
2023	5085	4,806	4,630	2476	2,353
2024	5177	4,893	4,717	2504	2,380
2025	5299	5,008	4,832	2557	2,430
2026	5434	5,135	4,959	2623	2,493
2027	5592	5,285	5,109	2687	2,554
2028	5752	5,436	5,260	2709	2,575

Annual Security of Supply Assessment: update for Security and Reliability Council

Background

We publish an Annual Security of Supply Assessment each year to inform industry of the future ability to meet security of supply standards over the next ten years. The purpose of this assessment is to confirm if current and known generation developments are sufficient to meet the specified winter energy and North Island peak capacity margins. The winter energy margin reflects an efficient level of generation investment to avoid dry winters; this does not infer that dry winters will never occur if the margins are met.

Differences this year

Like last year, we have again taken the approach of including three scenarios (rather than a single view) to represent a range of possible energy futures in New Zealand, depending on demand and supply growth in the years to come. These scenarios include:

- **Low demand**: where electricity demand growth is similar to that observed in recent years
- **Medium demand**: where electrification of transport and industrial process heat prompts higher rates of growth in the 2020s
- **Thermal constraints:** where gas-fired thermal generation growth is limited

This year, we have also included sensitivities such as high demand; solar generation; Tiwai early exit; thermal decommissioning; de-rated generation, and delayed build times. This gives participants the opportunity to choose for themselves which combination of scenarios and sensitivities are most relevant and compare these to understand the impacts on the future supply and demand balance.

We have also introduced a webtool that allows the user to select certain combinations of sensitivities on top of each of the core scenarios (this includes over 250 different charts of scenario and sensitivity combinations that are not published in the report).

Results

Overall, our assessment signals that maintaining an efficient level of reliability will require new generation in the next 5-10 years. To meet security standards for the New Zealand Winter Energy Margin, even under the low demand growth scenario, New Zealand will need to commission at least 100 GWh of new winter generation by 2026, and approximately 900 GWh by 2028. Under the medium demand scenario New Zealand will need to commission around 150 GWh of new winter generation by 2024. In all three scenarios new generation will need to be consistently added in the mid to late 2020s, up to 1,700 GWh of winter generation in 2028 in the medium scenario.

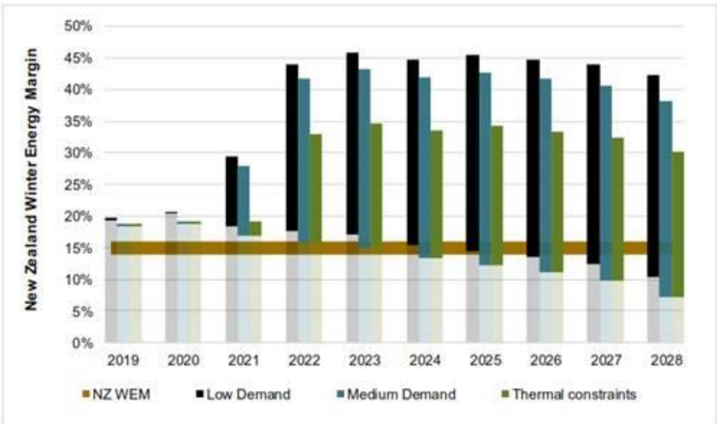

Figure 3: New Zealand Winter Energy Margin for all scenarios

This graph shows how each of the scenarios perform against the New Zealand Winter Energy Margin. The greyed-out section of the column represents the supply/demand balance met by existing generation, while the dark-coloured blue and green section of the columns represent the supply/demand balance met by potential new generation. When the light-coloured columns fall below the NZ Winter Energy Margin, this indicates that supply and demand are out of balance, and new generation must be built to fill this gap.

HRC Thermal Scenarios

March 2019

Keeping the energy flowing




Transpower New Zealand Limited The National Grid

IMPORTANT

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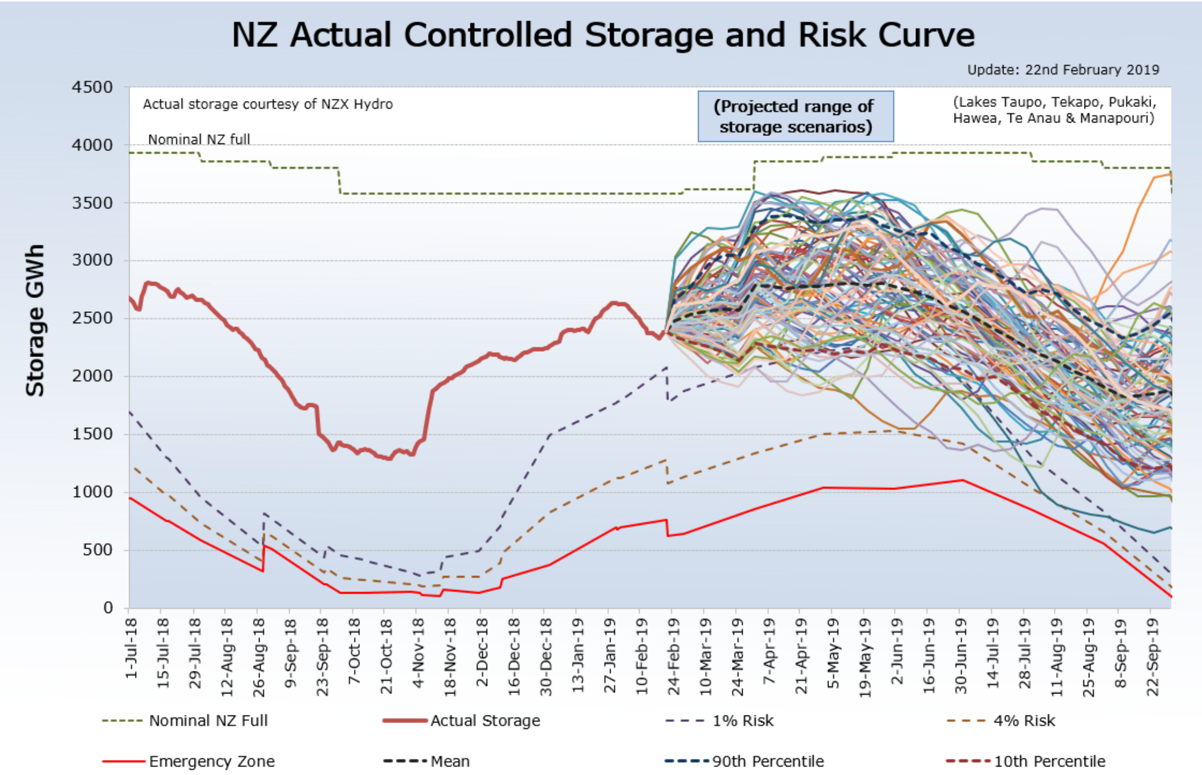
TABLE OF CONTENTS

1 Thermal What-If Scenarios

This month we have run two additional Hydro Risk Curve (HRC) and Simulated Storage Trajectory (SST) scenarios to investigate the impact of gas disruptions and fuel limitations on New Zealand energy supply. The first scenario models the impact of a gas supply limitation or generation plant failure. The second scenario models a gas pipeline disruption, like that experienced in 2011 when the Maui pipeline was out of service while repairs were made.

The most recently published HRCs and SSTs were produced in February. These charts included a de-rating to thermal generation which reflected the gas supply constraints observed in the market at that time, but did not include any additional thermal fuel scenarios. These charts have been included below as a base-case for comparison. In this chart, the 1%, 4% and 10% HRCs are denoted by 1% Risk, 4% Risk and Emergency Zone respectively, The SSTs are the cluster of 87 sequences that start from 22 February 2019.



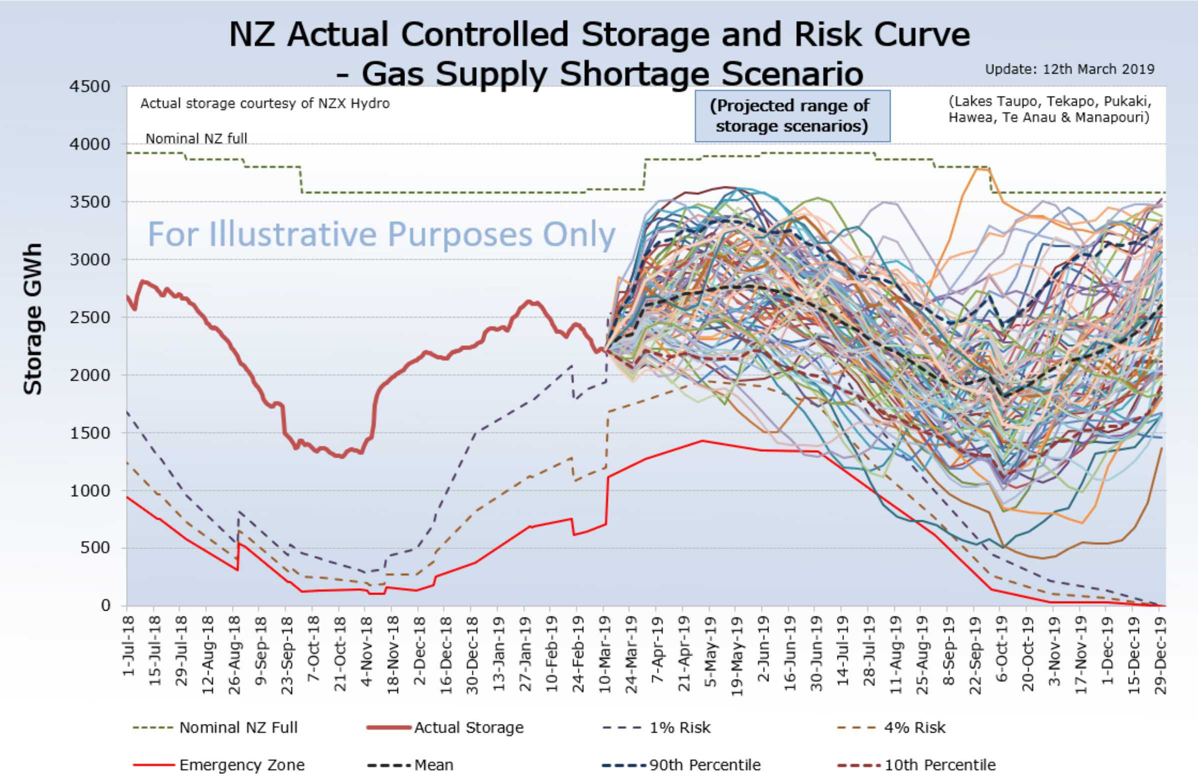
In last month's HRC and SST update, 28% of sequences crossed the 1% HRC, 2% of sequences crossed the 4% HRC, and no sequences crossed the 10% HRC. This means that, although there is a moderate chance of storage dropping below the 1% HRC, there is currently no foreseeable risk of crossing the 10% HRC and an emergency situation occurring.

A set of HRCs and SSTs have been produced for each of the thermal constraint scenarios and are specifically for the purpose of analysing potential future scenarios. It is important to note the SSTs are a complex model that includes many inputs and assumptions, including market behaviours. Certain assumptions around generator behaviours can have major impacts on the results in the SSTs, and therefore while the charts included here may represent one possible outcome of constraints in the gas market, there are many different possible outcomes depending on these assumed behaviours and specific situations modelled.

The South Island HRCs and SSTs for the base-case, as well as the two thermal scenarios, can be seen in the Appendix.

1.1 Gas Supply Shortage Scenario

In this scenario, one CCGT is de-rated to 50% capacity to represent a decrease in available gas supply for electricity generation or reduction in plant availability. This scenario could arise from a range of situations including, but not limited to, upstream gas supply outages or limitations, or unplanned plant outages.

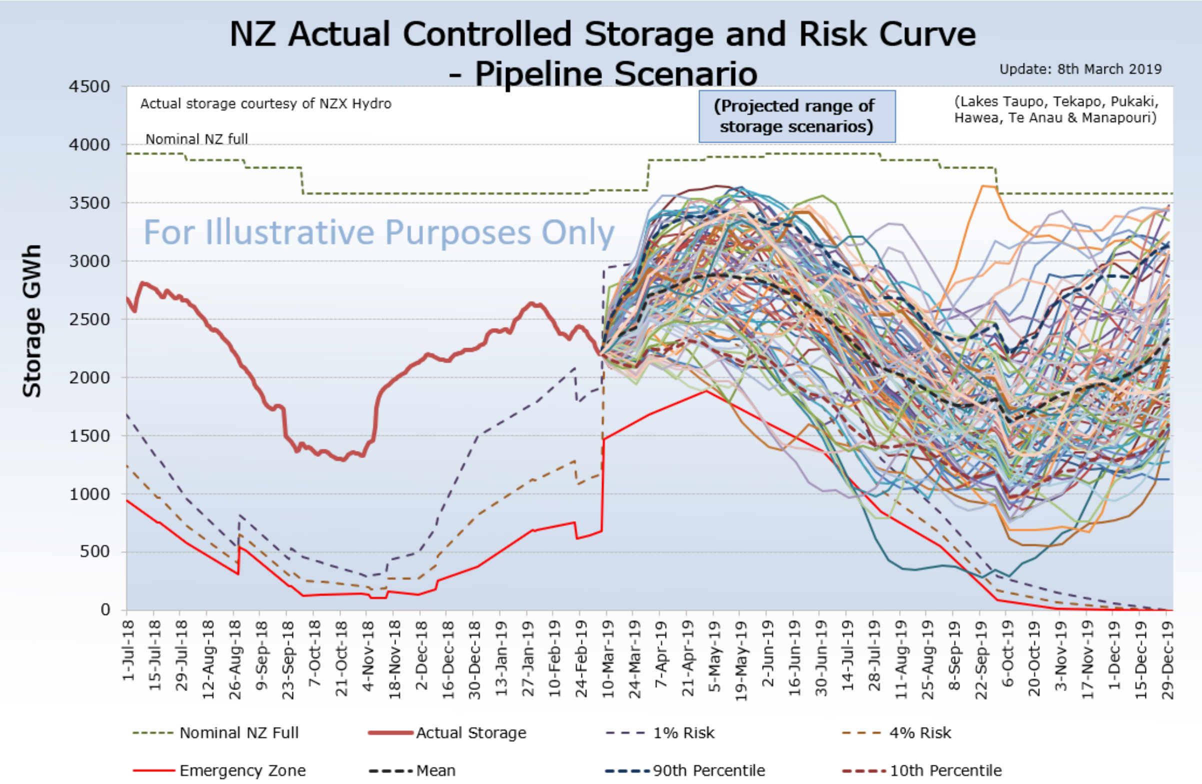


This gas constraint impacts both the HRCs and the SSTs. Restricted generation means the HRCs increase by up to 600GWh – the risk of shortage rises when potential generation is reduced. The gas constraint also impacts the SSTs in that the sequences fall to lower storage levels more rapidly as more water is used to meet demand due to reduced thermal generation.

In the chart above, 100% of sequences pass the 1% HRC (although some only very briefly), 11% of sequences cross the 4% HRC, and 2 sequences cross the 10% HRC. In this scenario there is a small chance of an emergency situation occurring due to 2 sequences crossing the 10% HRC.

1.2 Gas Pipeline Disruption Scenario

This scenario reflects a major infrastructure failure – the complete loss of gas transmission to major North Island electricity generators for an extended period (from 1 May 2019 to 31 July 2019). This scenario is reflected in the model by reducing Huntly gas-fired generation to zero for 3 months. This is an extreme, but plausible scenario (in 2011 an unplanned outage on the Maui pipeline lasted 5 days) and is designed to test the edge of the envelope in terms of plausible futures.



Similar to the gas constraint scenario, both the HRCs and SSTs are impacted by the loss of gas transmission in the North Island. In this scenario, the HRCs rise by up to 1000GWh. The increase to the HRCs is more pronounced in this scenario due to the scale of the loss of generation. The SSTs also fall at a faster rate, again due to increased hydro generation to cover for a lack of thermal generation.

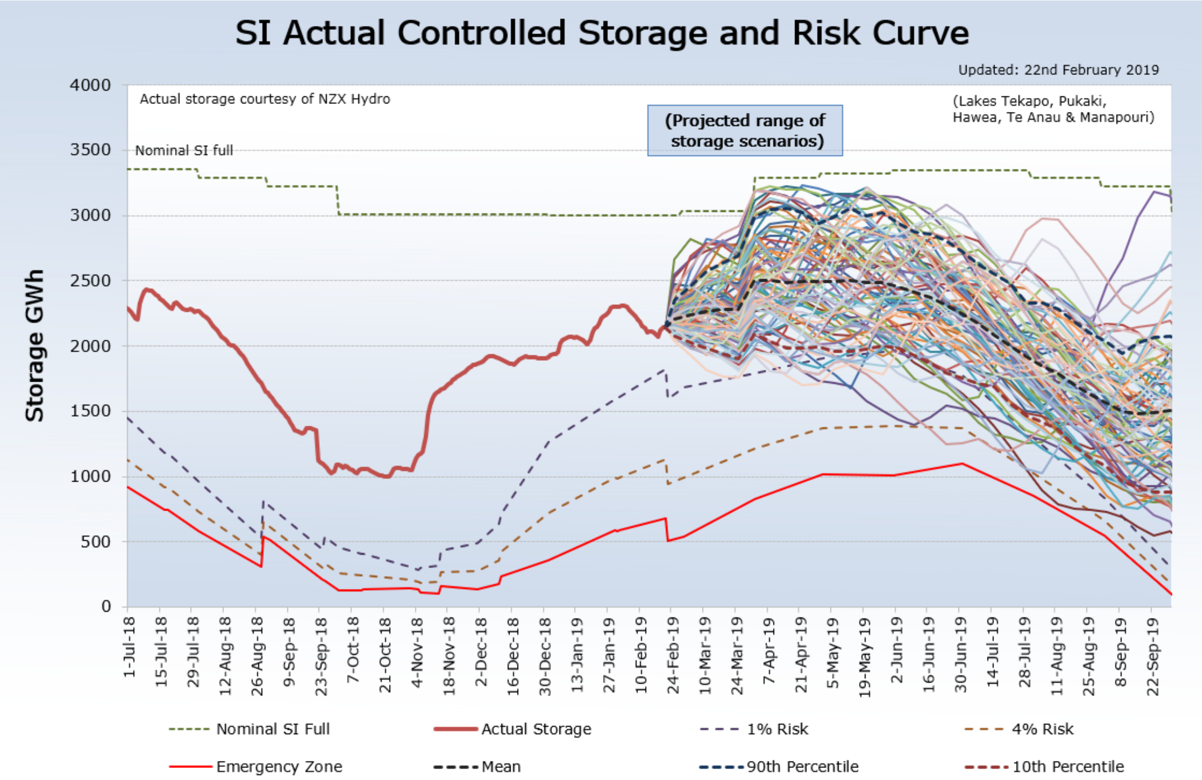
In the chart above, 100% of sequences pass the 1% HRC, 30% of sequences cross the 4% HRC, and 6 sequences cross the 10% HRC. In this scenario there is now a slightly higher chance of an emergency situation occurring due to 6 sequences crossing the 10% HRC compared to the previous scenario.

1.3 What does this all mean?

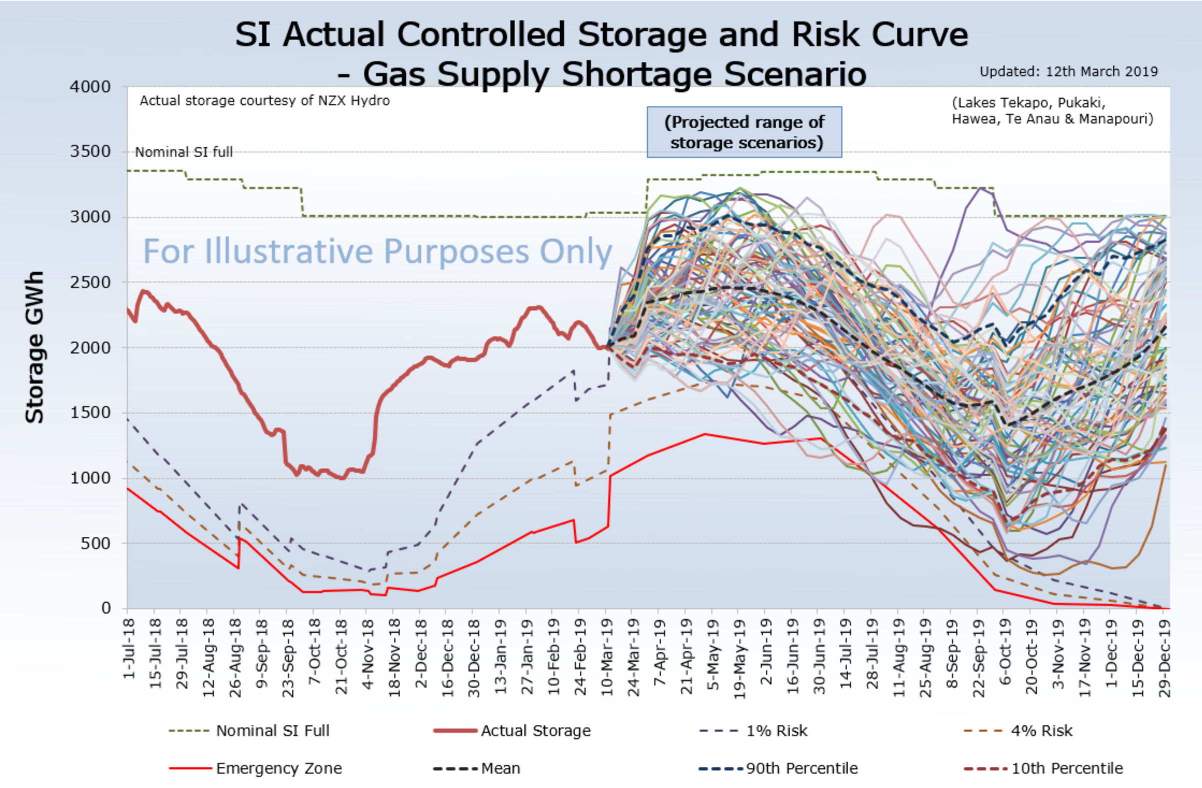
These scenarios show how a failure of a significant component of the New Zealand energy sector can have a major impact on security of supply. Small changes to the electricity system that occur over time, such as gradually increasing demand, allow for a timely response in the market to keep supply and demand in balance. But in sudden events such as the failure of major equipment, there is little time for a timely market response. Additionally, security of supply is a balance between avoiding emergency situations without over investing in costly generation.

2 Appendix: South Island Charts

2.1 Most recently published South Island HRCs and SSTs



2.2 South Island HRCs and SSTs for Gas Supply Shortage Scenario



2.3 South Island HRCs and SSTs for Gas Pipeline Disruption Scenario