Meeting Date: 21 October 2021

2021 Security of Supply Annual Assessment

Security and Reliability Council

The Security of Supply Annual Assessment 2021, covering energy and capacity adequacy over a ten-year horizon

1. Background

The Security and Reliability Council is asked to consider the Security of Supply Annual Assessment 2021

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 Security of Supply Annual Assessment (SOSAA) is the primary source of information on adequacy of generation investment to provide energy and capacity over a time horizon of years. It provides a long-term view of the balance between supply and demand in the New Zealand electricity system.

1.3. With the SOSAA usually due in April, the system operator was granted an exemption for delivery of this year's SOSAA due to system operator work commitments relating to the 2021 dry year event but has committed to delivering it by 31 October. Consultation on the draft SOSAA closed on 5 October and a final report is expected to be published by 29 October, including responses to any submissions made.

1.4. The SRC is asked to consider the SOSAA 2021, so it can provide meaningful feedback to the system operator. The SOSAA is attached as Appendix A (SRC summary paper) and Appendix B (full paper)). The secretariat notes that SRC members do not need to read the entire SOSAA and offers the following guidance:

a) The SRC summary paper provides a useful overview of the key findings and areas of concern

b) Section one (the Executive Summary in the full report) is essential reading

c) Section five is very relevant to the SRC, as it shows a broader range of results (with sensitivities) than the Executive Summary and includes a comparison with last year's assessment

d) Sections two and three may be useful for readers unfamiliar with SOSAA reports, covering background and a summary of the methodology

e) Section four is detailed-oriented and should only be used by SRC members seeking to understand the mechanics of the methodology and underlying assumptions.

1.5. The system operator will attend the SRC meeting to answer any questions about the SOSAA and the secretariat will provide the SRC with a link to the final report once it is published.

The SOSAA framework

1.6. The security standards set by the Authority are:

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

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

h) 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).

1.7. The margins 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.

1.8. 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.

1.9. 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.

1.10. The system operator is obliged to annually publish an assessment of security of supply against the NZ-WEM, SI-WEM and WCM margins.

1.11. 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.

1.12. Demand forecasts were updated this year by Transpower to be consistent with its "Whakamana I Te Mauri Hiko" framework,[2] which considers the impact of more renewable generation and electrification.

Annual updates will be provided

1.13. The SRC will be updated on the Security of Supply Annual Assessment 2022.

2. The findings of the SOSAA 2021

[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/whakamana-i-te-mauri-hiko-empowering-our-energy-future

Results for the four core scenarios

2.1. The assessment uses four core scenarios. The four scenarios are labelled:

a) low demand

b) medium demand

c) high demand

d) gas constrained.

2.2. Each scenario has a different ‘underlying’ demand growth rate (for winter only) and a different rate of uptake of electrification and distributed energy resource technologies.

2.3. Existing thermal generation remains in place in the low, medium and high demand scenarios. The ‘gas constrained’ scenario uses ‘medium demand’ growth rates but assumes no new gas generation is commissioned until at least the end of 2030.

2.4. The ‘low demand’ scenario is characterised as “a world where New Zealand’s response to climate change is delayed with limited electrification of transport and industry”.

2.5. The ‘high demand’ scenario is where “there is a much stronger and more urgent response to climate change”.

2.6. All scenarios assume the Tiwai smelter closes at the end of 2024 and the 350MW Taranaki Combined Cycle power station is decommissioned at the end of 2023.

2.7. Sensitivities may also be applied to each scenario to reflect uncertain changes in supply and demand. The range of sensitivities apply to either the demand or supply side, for example TCC remains and delayed build times for new generation (supply side) and Transmission pricing increases peak demand and Tiwai remains until 2030 (demand side).

2.8. Because of the large number of potential combinations of scenarios, the report only considers a subset in detail.

2.9. As in 2020, generation is divided into the following categories:

a) existing and committed

b) consented

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

2.10. As noted in the summary, “for all scenarios, existing and committed generation should be able to maintain New Zealand winter energy margins above the security standard to 2030”. This is positive, with the proviso that “to build resiliency to changes in supply or demand new projects would need to be identified and developed” to maintain margins under the ‘gas constrained’ scenario.

2.11. A useful table summarising options to improve both energy and capacity margins is set out in figure 32 on page 52.

Sensitivity analysis

2.12. The 'Tiwai departure' in 2024 sensitivity is reflected as a 'significant upward step change' in margins in 2025, giving comfort that existing and committed generation should be able to maintain winter energy margins above the security standard to 2030. Given the uncertainty around this, the report (in part 5) combines the 'Tiwai remains and 'Demand Step Changes' sensitivities, under which the margins fall below the security standard in 2027. However, the system operator considers this combination of scenarios is unlikely on the basis that "incentives to develop new sources of demand pre-2024 are likely to be less if Tiwai signals that it may remain in operation.

2.13. With the government's aspirations to increase the proportion of renewable generation, the 2021 SOSAA considers the impact of this on the security margins. New generation necessary to displace thermal generation is described as "significant". For example, to maintain NZ-WEM in the "no base thermals" sensitivity, would need an additional 3,000 GWh of additional projects, with 507GWh from projects not yet actively being pursued.

2.14. Transpower have a web-application to view results and sensitivities. It is available at https://www.transpower.co.nz/system-operator/security-supply/annual-assessment-results.

Differences between the SOSAA 2021 and previous SOSAAs

2.15. This year's assessment projects a slightly higher level of security of supply than previous year's, particularly for the first half of the decade:

a) The four 2021 scenarios forecast that new generation will be needed by 2026-28 in order to meet the security standards

b) the four SOSAA 2020 scenarios forecast that new generation will be needed between 2025 and 2029 in order to meet the security standards

c) the three SOSAA 2019 scenarios forecast that new generation would be needed between 2024 and 2026 in order to meet the security standards

2.16. COVID-19 effects have resulted in an adjustment to the underlying energy demand forecast, by forecasting demand as if 2019 demand was repeated in 2020 (see p21).

2.17. A reduction of 90 MW in underlying peak demand due to an updated forecast of industrial peak demand.

2.18. Lower forecast electric vehicle load (for the medium demand scenario)

2.19. A converse impact is the slower uptake of electric vehicle *smart* charging resulting in faster peak growth in 2021.

2.20. The key uncertainties in forecasting remain the same – how quickly will demand grow and when will existing thermal generation retire?

3. Questions for the SRC to consider

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

Q1. Is the SRC comfortable with the SOSAA 2021 results?

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: System operator's summary paper for the SRC

4.2. Appendix B: *Security of Supply Annual Assessment 2021* (system operator)

Appendix A: System operator's summary paper for the SRC

Appendix B: Security of Supply Annual Assessment 2021

TRANSPOWER

Security and Reliability Council Paper

Meeting date:	21 October 2021
Author:	Steve Torrens Senior Analyst, Market & Business

2021 Security of Supply Annual Assessment

1 Purpose

The purpose of this paper is to summarise the approach and key findings for the 2021 Security of Supply Annual Assessment ('the assessment') to inform the Security and Reliability Council members and provide the opportunity for discussion.

2 Summary and key findings

- The assessment provides a ten-year view (2021 to 2030) of security of supply for four key supply and demand scenarios.
- For all our scenarios, existing and committed generation should be able to maintain New Zealand winter energy margins above the security standard through to 2030.
- As with last year's assessment, North Island winter capacity margins are a potential concern. To maintain North Island winter capacity margins above the security standard, new supply projects will need to be built by 2026 to 2028.
- This year's assessment also considers the impact on margins of increasing the proportion of renewable generation as of 2030. Significant new renewable supply additions will be required to displace existing thermal generation, increase the proportion of renewable energy beyond 90%, and maintain efficient levels of supply reliability.
- The assessment was published for consultation on 16 September 2021. This consultation closed on 5 October 2021 and a final report will be published by 29 October 2021.

3 What we measure and why

The assessment provides a ten-year view (2021 to 2030) of security of supply for four key supply and demand scenarios. The purpose is to enable industry stakeholders to compare the risk of supply shortages both between scenarios and over time to inform risk management and investment decisions. Transpower is Code-obligated to produce the assessment, and many of the assumptions used are prescribed by the Electricity Authority. This year's assessment was published for consultation on 16 September 2021.

The assessment is essentially a long-term view of the balance between supply and demand in the New Zealand electricity system. We present this information using three margins, all of which represent the difference between supply and demand. Generally, an excess of supply (i.e. generation) is maintained in order to ensure that demand can always be met – this excess is referred to as the margin (Figure 1).

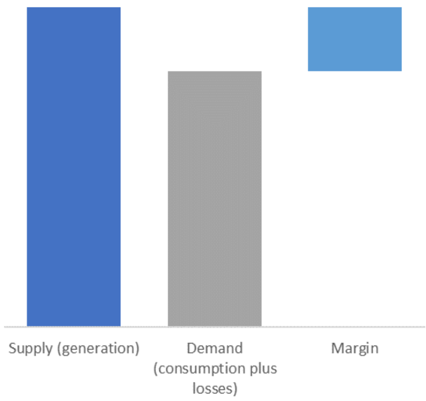

Figure 1: Margin visualisation

The three margins presented in the assessment cover the key areas of risk for the electricity system and include the New Zealand and South Island winter energy margins, and North Island winter capacity margin. The energy margins assess whether it is likely that there will be an adequate level of generation and HVDC transmission capacity to meet expected electricity demand across the winter months. The North Island winter capacity margin assesses whether it is likely there will be adequate generation and HVDC transmission capacity to meet peak North Island demand over winter.

The margins are then compared against what is known as the security of supply standards. The standards represent the Electricity Authority's view of an efficient level of electricity generation investment. For example, if the margins are below the standards, this implies that investment in new generation would be an economically rational exercise according to the Authority's winter margin assessment. It can also be interpreted as representing the likelihood of electricity shortage – the higher the margin the less likely electricity shortage will be.

4 Assessment scenarios used in our assessment

Our scenarios cover a plausible range of futures and have remained largely consistent with those used in 2020. Three of our scenarios 'Low Demand', 'Medium Demand' and 'High Demand' explore varying rates of electricity demand growth. Each scenario has a different rate of uptake of electrification and distributed energy resource technologies, consistent with Transpower's Whakamana i Te Mauri Hiko[1] modelling. We also include a fourth scenario, 'Gas Constrained'. This uses 'Medium Demand' growth rates but assumes no new gas generation. This represents an environment where the incentives for new gas generation are lacking. For this year, all scenarios assume closure of the NZAS smelter at Tiwai ('Tiwai') at the end of 2024, decommissioning of Contact Energy's Stratford combined cycle plant ('TCC') at the end of 2023 and commissioning of their 150 MW geothermal Tauhara B station in 2023.

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[1] Whakamana i Te Mauri Hiko: Empowering our energy future: https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf

For each scenario we consider the impact of a range of sensitivities. These sensitivities consider possible changes to demand or supply:

- TCC is not decommissioned and continues to operate post-2023.
- Selected thermal plant (480 MW) switch to offering dry year cover in 2027.
- Delayed build times.
- Changes in transmission pricing leading to reduced load control activities.
- Material step changes in demand, +200 MW by 2024.
- Tiwai continues operation post-2024.

5 Energy margins ok through to 2030, more concern about winter capacity margins

For all our scenarios, existing and committed generation should be able to maintain New Zealand winter energy margins above the security standard through to 2030. The closure of Tiwai in 2024 leads to an upwards step change in winter energy margins in 2025. New Zealand winter energy margins are resilient to our modelled sensitivities. For our ‘Medium Demand’ scenario, margins with existing and committed generation fall below security standards in the mid-2020s only if we combine the impact of sensitivities.

As with last year’s assessment, North Island winter capacity margins are a potential concern. To maintain North Island winter capacity margins above the security standard, new supply projects will need to be built by 2026 to 2028, depending on the scenario’s assumed winter peak demand growth rate. The impact of Tiwai closure is limited by the current southwards transfer capacity of the HVDC. For the ‘Gas Constrained’ scenario, the existing pipeline of new supply projects is much reduced, meaning that this scenario will be susceptible to potential changes in supply or demand (as considered in our sensitivities). North Island winter capacity margins are shown to be sensitive to possible changes to thermal generation or demand. For example, taking the ‘Medium Demand’ scenario as a reference, the Tiwai Remains, Demand Step Changes and Dry Year Reserve sensitivities all require new supply projects to be built one year earlier, by 2026.

The results are presented in the following charts (Figure 2). For each scenario, the lower, light bands are existing or committed generation. The upper, dark bands are known new generation options that could be built.

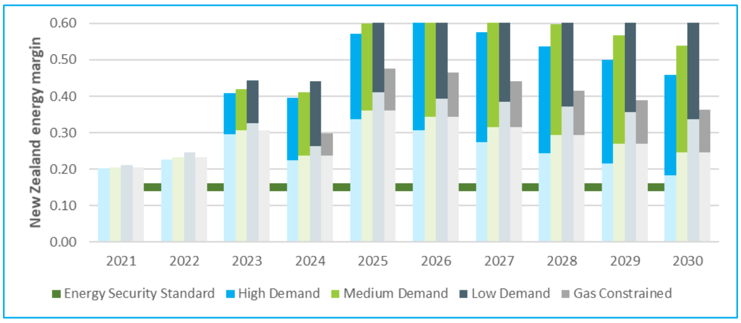

Figure 2a: NZ energy margin assessment results

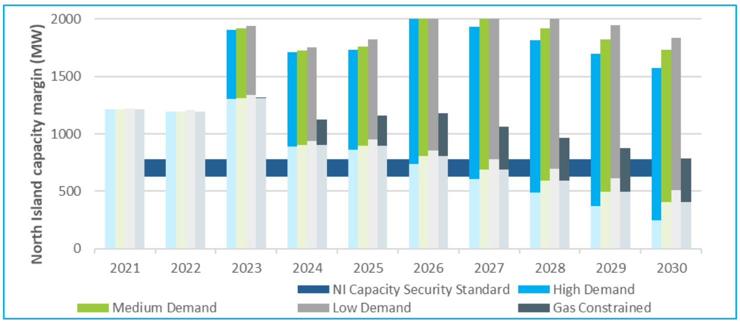

Figure 3b: North Island capacity margin assessment results (MW)

6 Significant new renewable supply required to displace existing thermal generation

For this year's assessment, at the request of the Electricity Authority, we looked at the impact on margins of increasing the proportion of renewable generation as of 2030. We investigated five thermal generation scenarios, which consider progressively lesser amounts of thermal generation. For each of these thermal generation scenarios we estimated how much additional supply would be required from renewable generation and other technologies to maintain margins above security standards.

This analysis shows that significant new renewable supply additions will be required to displace existing thermal generation, increase the proportion of renewable energy beyond 90%, and maintain efficient levels of supply reliability. New supply additions will need to include projects – and possibly technologies - that are not yet being actively pursued.

Using our 'Medium Demand' scenario as a reference, to displace all thermal generation and achieve 100% renewable generation (regardless of hydro inflows) by 2030 would require progressing new supply projects that could contribute at least 5,300 GWh of winter energy and 1,700 – 1,900 MW of winter capacity.

7 Consultation Process

Consultation on the assessment closed on 5 October 2021[2] . The final report will be published by 29 October 2021, including responses to any submissions made.

[2] The System Operator's draft 2021 Security of Supply Annual Assessment: https://www.transpower.co.nz/system-operator/stakeholder-interaction/invitation-comment-draft-security-supply-annual-assessment

TRANSPOWER

Security of Supply Annual Assessment 2021

System Operator

Version: 1.0

Date: September 2021

Version	Date	Change
1.0	September 2021	First release

IMPORTANT

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Contents

1.0
Executive Summary

1.1 Executive Summary

Overview

For all our scenarios, existing and committed generation should be able to maintain New Zealand winter energy margins above the security standard through to 2030. These results hold for most sensitivities that we apply to our scenarios.

In contrast, new supply projects will need to be built in the latter half of this decade for all scenarios to ensure North Island winter capacity margins are maintained above the security standard. Except for our 'Gas Constrained' scenario there is enough new supply projects that have already been consented – and could potentially be built - to maintain margins at the required level. Our 'Gas Constrained' scenario restricts new generation to exclude gas generation. For this scenario the pipeline of new supply projects is much reduced, and if no new supply projects are identified, future capacity margins will be susceptible to changes in supply or demand. Sensitivity analysis of North Island winter capacity margins shows that new supply projects will be required to be built earlier for possible changes to thermal generation or demand.

Looking at the impact on margins of increasing the proportion of renewable generation as of 2030, we investigate five thermal generation scenarios, which consider progressively lesser amounts of thermal generation. This assessment shows that significant new renewable supply additions will be required to displace existing thermal generation, increase the proportion of renewable energy beyond 90% and maintain efficient levels of supply reliability.

Introduction

This document is Transpower's annual medium-term security of supply assessment. It provides a 10-year view (2021 to 2030) of the balance between supply and demand in the New Zealand electricity system.

The assessment presents three margins that, together, cover the key security of supply risks for the New Zealand electricity system; the New Zealand and South Island winter energy margins and North Island winter capacity margin. The winter energy margins assess whether it is likely that there will be an adequate level of generation and HVDC transmission capacity to meet expected electricity demand across the winter months. The North Island winter capacity margin assesses whether it is likely there will be adequate generation and HVDC transmission capacity to meet peak winter North Island demand.

Margins are compared against security standards, set by the Electricity Authority.

Scenarios

Our scenarios cover a plausible range of futures and have remained largely consistent with those used in 2020. Three of our scenarios 'Low Demand', 'Medium Demand' and 'High Demand' explore varying rates of electricity demand growth. Each scenario has a different rate of uptake of electrification and distributed energy resource technologies, consistent with Transpower's Whakamana i Te Mauri Hiko modelling.

We also include a fourth scenario, ‘Gas Constrained’. This uses ‘Medium Demand’ growth rates but assumes no new gas generation. This represents an environment where the incentives for new gas generation are lacking.

All scenarios assume the NZAS Smelter at Tiwai (‘Tiwai’) closes at the end of 2024 and that TCC is decommissioned at the end of 2023. Gas and coal are de-rated in 2021 and 2022 to reflect gas supply constraints, following the unexpected decline in production from the Pohokura gas field. Finally, we assume the third Rankine unit is available for dry year cover only and contributes just to energy margins.

Sensitivities

Sensitivities allow us to explore uncertain - though possible - changes in supply and demand. Each sensitivity can be applied to each scenario, and include:

TCC remains: The 350 MW Taranaki Combined Cycle (TCC) power station is not decommissioned as anticipated at the end of 2023 and remains in operation through to at least 2030.

Dry year reserve: The operation of a small number of ‘baseload’ thermal generation units is changed so that they only provide dry year reserve from 2027 onwards, perhaps in response to greater quantities of renewable generation. Winter capacity margins are reduced by 480 MW. Winter energy margins remain unaffected.

Delayed build times: Commissioning dates for all new generation is delayed by one year.

Transmission pricing: Peak demand increases for a short time as the electricity sector adjusts to a change in peak transmission pricing. Peak demand goes up by 304 MW in 2022 and returns to forecast levels by 2024.

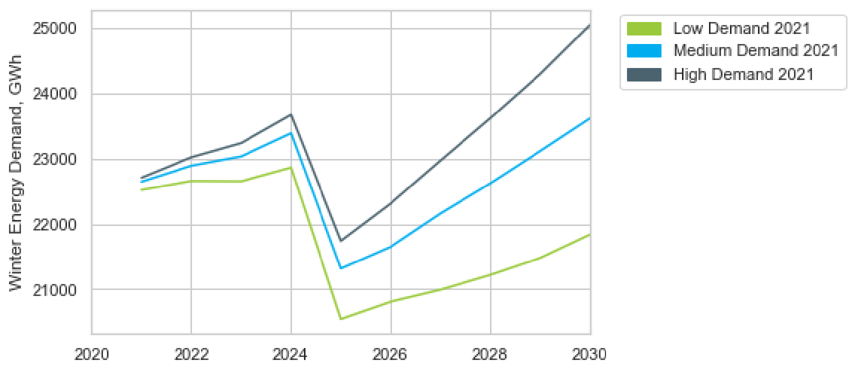
Demand step changes: New industrial facilities result in a material step change in baseload demand. We assume 100 MW is added to South Island demand in 2023 and 100 MW is added in the North Island demand in 2024.

Tiwai remains: Tiwai remains operational until at least the end of 2030.

Assumptions

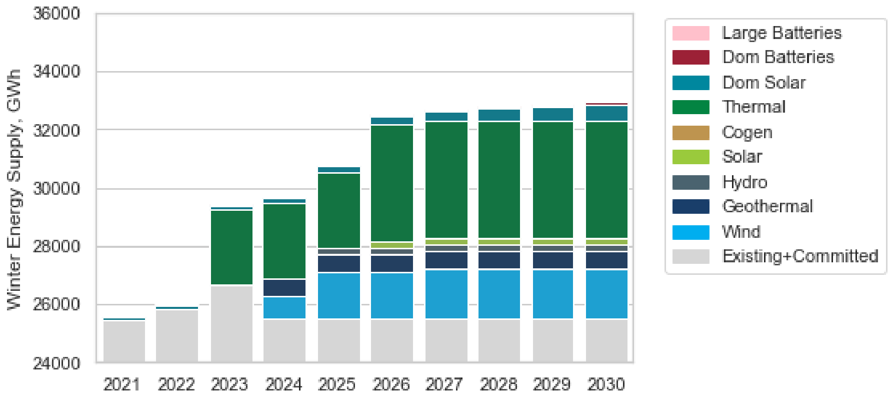
Demand forecasts are based on Transpower’s demand forecast used for transmission and strategic planning. Winter energy demand forecasts are shown in Figure 1.

Figure 1: NZ winter energy demand for all scenarios



Supply assumptions - that is for existing generation and potential new projects – are provided in confidence by generators and presented in aggregate in Figure 2.

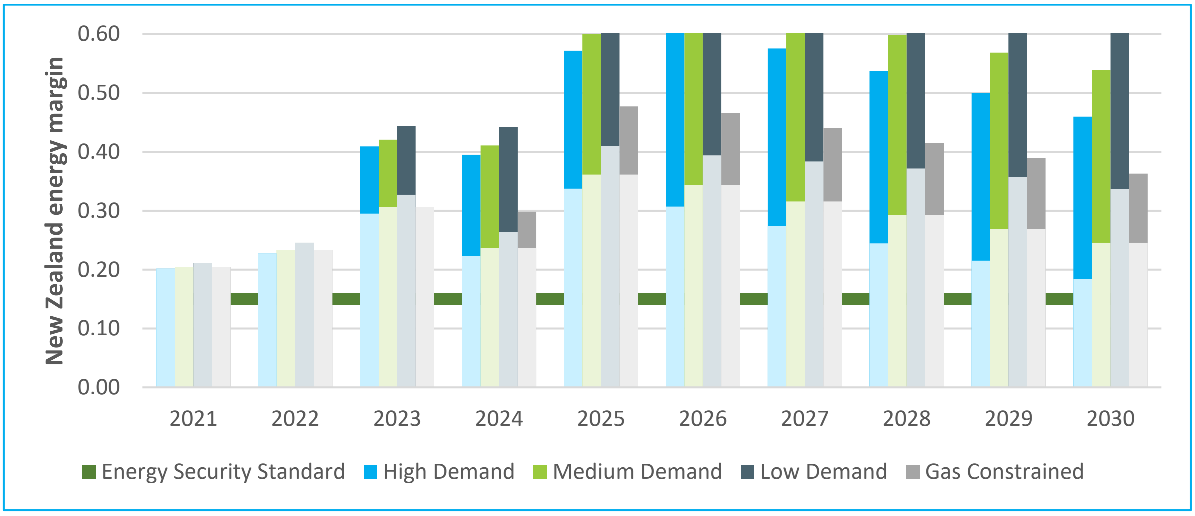
Figure 2: NZ winter supply: Modelled new supply projects



New Zealand winter energy margins

For all our scenarios, existing and committed generation should be able to maintain New Zealand winter energy margins above the security standard through to 2030. There is a significant upwards step change in winter energy margins in 2025, as a result of Tiwai closing. Figure 3 shows these results. For each scenario, the lower, light bands are existing or committed generation. The upper, dark bands are new supply projects that could be built.

Figure 3: NZ winter energy margins for all scenarios



For our 'Medium Demand' scenario, New Zealand winter energy margins are resilient to most of our sensitivities. For our Tiwai Remains sensitivity, margins only fall below security standards in 2029. If we combine our Tiwai Remains and Demand Step Changes sensitivities margins fall below the security standard in 2027. This combination of scenarios is unlikely though: incentives to develop new sources of demand pre-2024 are likely to be less if Tiwai signals that it may remain in operation.

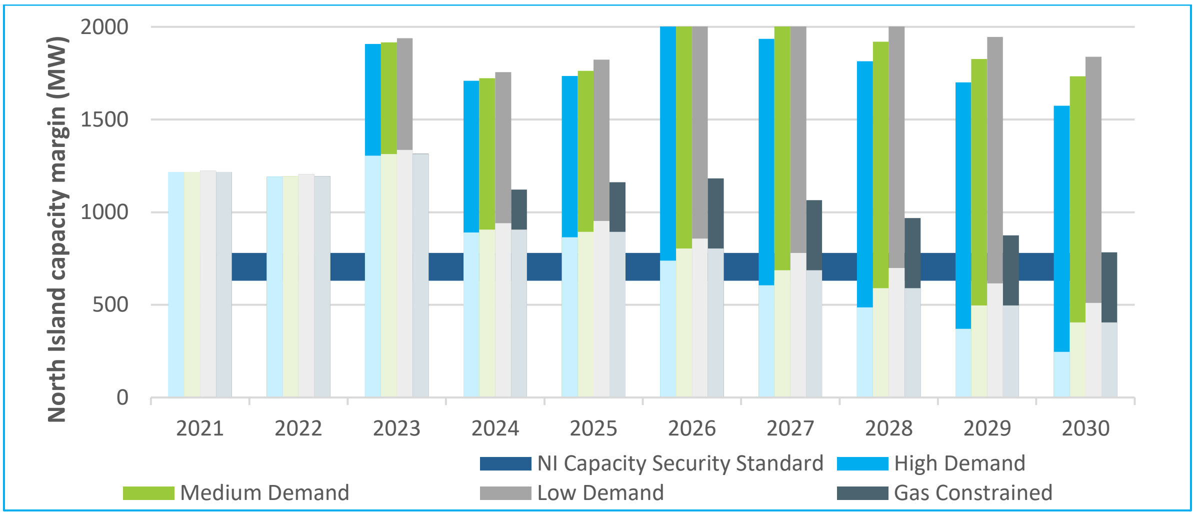
North Island winter capacity margins

North Island winter capacity margins, with existing and committed generation, fall below the security standard between 2027 to 2029, depending on the scenario's assumed winter peak demand growth rate. Tiwai closure has less of an impact on North Island winter capacity margins. This is because South Island capacity contributions, post-Tiwai closure, are constrained by the current capacity of the HVDC.

Except for our 'Gas Constrained' scenario, consented new supply projects alone are adequate to maintain margins above the security standard throughout the assessment period. For the 'Gas Constrained' scenario, the pipeline of new supply projects is much reduced. From 2025 onwards new supply projects that are consented could potentially contribute 154 MW of winter capacity. This would not be enough to maintain margins through to 2030. To build resiliency to changes in supply or demand new projects would need to be identified and developed for this scenario in the second half of this decade.

On the evening of 9 August 2021 record high peak demand and unexpected supply shortages lead to demand curtailment. Our North Island winter capacity margin analysis assumes all thermal generation is able to contribute its full capacity and that peak demand is assessed as the average of the top 200 demand period over winter morning and evening peaks. In contrast, on 9 August market conditions were such that not all thermal generation was available and peak demand was well above the average of the top 200 demand peaks. For more discussion refer to the cover note to this report.

Figure 4: NI winter capacity margins for all scenarios

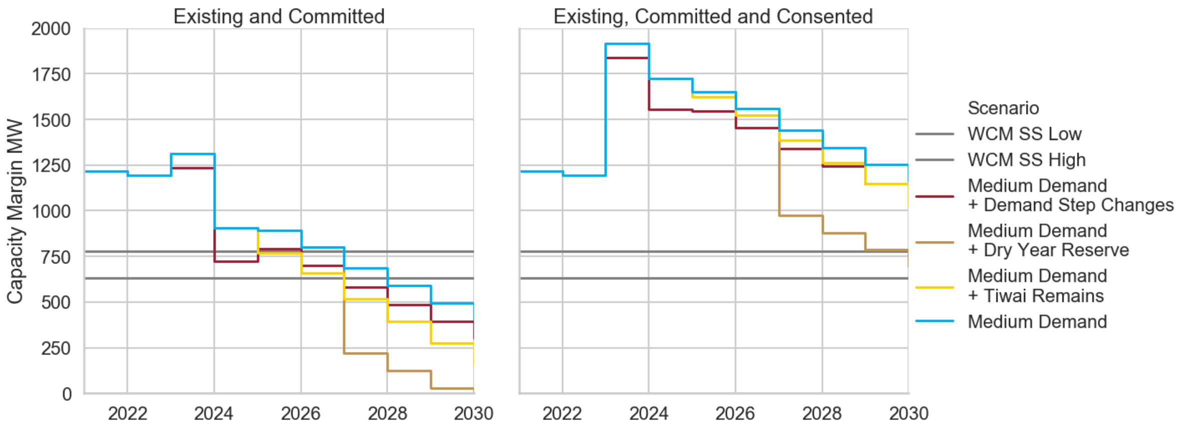


North Island winter capacity margins are comparatively sensitive to changes in thermal generation or demand. For example, taking the 'Medium Demand' scenario as a reference, the *Tiwai Remains*, *Demand Step Changes* and *Dry Year Reserve* sensitivities all require new supply projects to be built one year earlier, by 2026.

For these sensitivity results, there is enough consented new supply projects to ensure adequate levels of reliability. The Dry Year Reserve sensitivity, though, would be challenging. To maintain minimum security standards at least 691 MW of winter capacity would need to be built by 2030, this equates to 91% of known consented supply projects.

Figure 5 shows results for the sensitivities discussed above. Each stepped line shows North Island winter capacity margins for a different sensitivity. The left chart shows margins with existing and committed generation. The right chart shows margins with consented and on-hold new supply projects.

Figure 5: NI winter capacity margins, Medium Demand scenario, Demand Step Changes, Dry Year Reserve and Tiwai Remains Sensitivities



Although not shown in Figure 5, for the *Transmission Pricing* sensitivity margins remain above the security standard within the time frame (2023 – 2024) where changes in transmission pricing are assumed to affect winter peak demand. This applies to all scenarios.

North Island winter capacity margins are more susceptible to demand or supply changes in part due to the type of generation projects that are currently being actively progressed. Over half of this capacity is wind generation, which contributes a relatively smaller amount to North Island winter capacity margins than to the winter energy margins.

Changes from last year

Winter energy and capacity margins have improved from last year's results primarily as the closure of Tiwai is now included in all our scenarios. Other changes include several significant generation projects due to be commissioned over the next two to three years (~680 MW of installed capacity by 2025) and the departure of TCC at the end of 2023.

Margins with increasing proportions of renewable energy

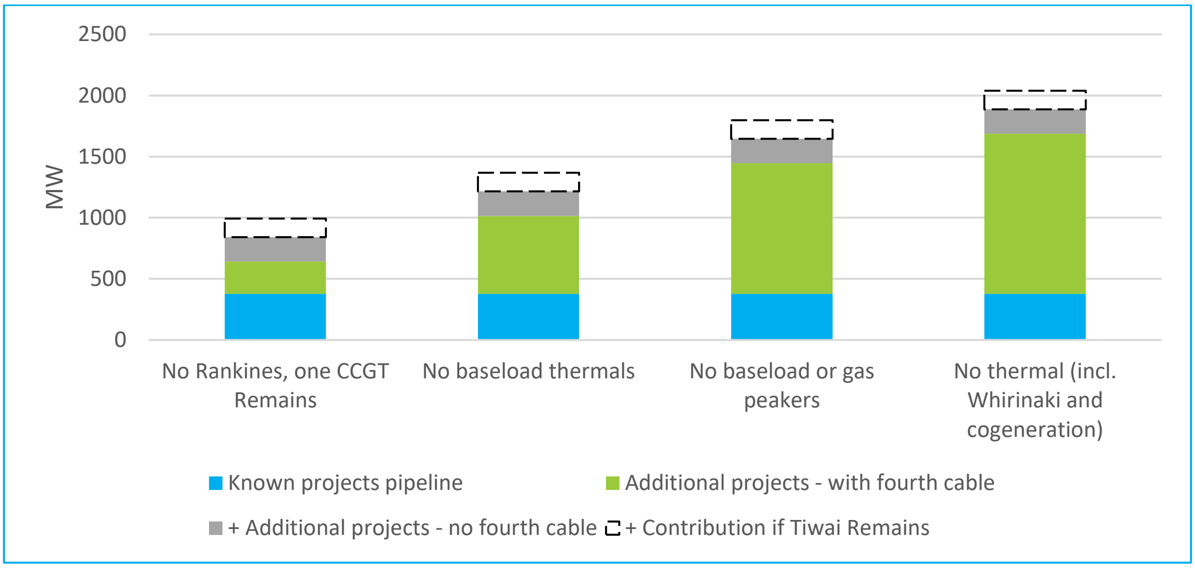
For this year's assessment we look at the impact on margins of increasing the proportion of renewable generation as of 2030. We investigate five thermal generation scenarios, which consider progressively lesser amounts of thermal generation. For each of these thermal generation scenarios we estimate how much additional supply would be required from renewable generation and other technologies to maintain margins above security standards.

This assessment shows that significant new renewable supply additions will be required to displace existing thermal generation, increase the proportion of renewable energy beyond 90%, and maintain efficient levels of supply reliability. New supply additions will need to include projects – and possibly technologies - that are not yet being actively pursued.

Using our 'Medium Demand' scenario as a reference, to displace all thermal generation and achieve 100% renewable generation (regardless of hydro inflows) by 2030 would require progressing new supply projects that could contribute at least 5,300 GWh of winter energy and 1,700 - 1,900 MW of winter capacity.

Figure 6 shows new North Island supply additions required for each of our thermal generation scenarios in order for North Island winter capacity margins in 2030 to be above the upper security standard. The blue bars show potential contributions that could come from known renewable projects in our pipeline. The green bars show the contribution that would be required from new renewable supply projects not yet being actively considered or developed. The grey bar shows the potential reduction in contributions that could be achieved if the HVDC capacity was upgraded by 200 MW. The dotted outlined bars show the additional contribution required if Tiwai remains.

Figure 6: Additional capacity contribution from NI projects required in 2030 to meet the 780 MW security standard



2.0
Background

2.1 Background

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 the Security of Supply Forecasting and Information Policy and the Emergency Management Policy. These include:

- assessment of Electricity Risk Curves and Stimulated Storage Trajectories over a one to two year time period
- short-term monitoring and information provision, such as the weekly reporting of hydro levels relative to the Electricity Risk Curves
- implementation of emergency measures where necessary
- Grid capability assessment to meet demand over the next three years, published as Transpower's System Security Forecast
- capacity assessment for the current year, available in Transpower's New Zealand Generation Balance assessment.

3.0
Methodology, Scenarios and Sensitivities

3.1 Methodology

3.1.1 Winter Margins

This assessment provides a medium-term view of the balance between supply and demand in the New Zealand electricity system. It forecasts:

- The winter energy margins, for New Zealand and the South Island. These are winter energy supply, in gigawatt-hours (GWh), divided by winter energy demand, in GWh. The margins are expressed as a percentage of total demand.
- The North Island winter capacity margin[1]. This is the sum of North Island supply capacity less the expected peak demand plus surplus South Island supply capacity able to be sent via the HVDC link to the North Island. The margin is expressed as a megawatt (MW) value.

Winter is defined as the period from April to October for the North Island winter capacity margin, and April to September for the winter energy margins. Thermal generation is assumed to be available and operating at its maximum capacity, with adjustments for installed capacity and, for energy margins only, fuel supply availability.

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

In the context of this assessment the term *supply* includes grid connected generation, embedded generation, hydro storage and batteries.

3.1.2 Security Standards

Security standards are defined by the Electricity Authority ('the 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, where the expected cost of shortage is equal to the expected cost of new generation.

The current security standards specified in the Code are:

- a New Zealand winter energy margin of 14-16%.
- a South Island winter energy margin of 25.5-30%.
- a North Island winter capacity margin of 630-780 MW.

[1] 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, the actual margin observed would be available, but not dispatched generation, and reserves required.

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

3.1.3 Our Assessment

Our assessment evaluates margins and compares these against the Authority's security standards. This is done for both existing generation and the pipeline of new supply projects that could be potentially built. The objectives of the assessment are to understand:

- when, and under what circumstances, margins will fall below security standards if no new supply projects are built (other than those already committed).
- whether the pipeline of new supply projects is adequate to maintain security standards assuming a stable investment environment and adequate market incentives.

We do not attempt to forecast when or if new supply projects will be progressed. Our assessment considers multiple scenarios and sensitivities.

3.2 Scenarios and Sensitivities

3.2.1 Scenarios and Sensitivities Defined

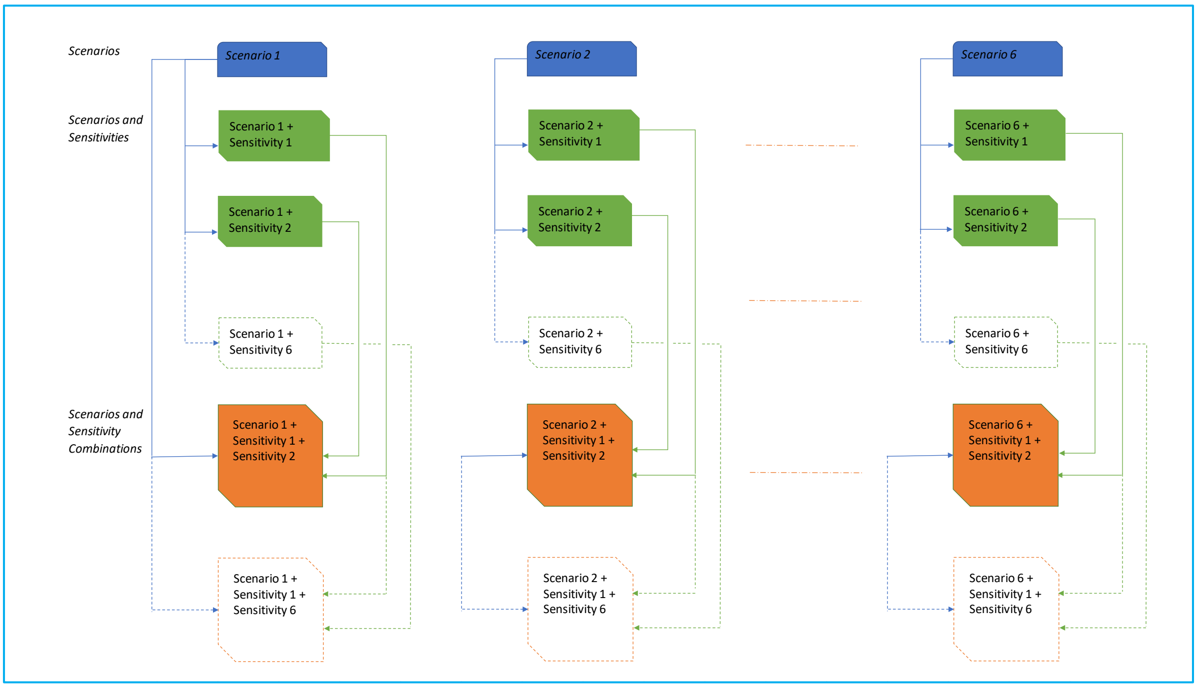
Scenarios are intended to provide a plausible range of futures for forecasting our security margins.

Sensitivities allow us to explore uncertain changes in supply and demand. Sensitivities may include one-off events, such as a generation asset decommissioning, or may be used to show the impact of inaccuracies in our assumptions, such as a generic delay in project commissioning dates.

Each sensitivity can be applied to each scenario, the relationship between the two is shown in Figure 7 below. Sensitivities are designed to be mutually exclusive so that they may be combined (although some combinations may be unlikely). The potential combination of scenarios and sensitivities is large, and this report only considers a subset of these combinations in detail.

We do provide results for all combinations of scenarios and sensitivities via our webtool. We believe this is important. Stakeholders should be free, and may be better placed, to make their own decisions as to which scenarios and sensitivities they should have more regard to than others.

Figure 7: Diagram showing relationship between scenarios and sensitivities



3.2.2 Scenarios

Low Demand, Medium Demand and High Demand scenarios

Three of our scenarios explore varying rates of electricity demand growth. Each scenario has a different 'underlying' demand growth rate (for winter energy only) and a different rate of uptake of electrification and distributed energy resource technologies.

The underlying demand growth rate is intended to cover changes in electricity efficiency and intensity, sectoral shifts in energy demand, and growth of population and the economy. We use the same underlying demand growth rate for each scenario's winter peak demand forecast. We vary the underlying demand growth rate for each scenario's winter energy demand forecast, this ensures a reasonable spread of demand for our scenarios across the assessment time frame.

New technology uptake rates consider transport electrification (electric vehicles), process heat electrification and growth in domestic solar photo voltaic generation ('solar PV') and batteries. Each scenario considers a different rate of uptake for these technologies leveraging Transpower's Whakamana i Te Mauri Hiko modelling.

Gas Constrained scenario

Our fourth scenario considers a future where no new gas generation is commissioned until at least the end of 2030. This represents an environment where incentives for investment in new gas generation are lacking, whether due to high relative costs or reduced investment in upstream gas infrastructure.

3.2.3 Scenario Assumptions

All scenarios include the following assumptions:

Potential future generation

As in previous year's, future new supply projects will be based on information provided by market participants on a confidential basis.

Tiwai exit

We assume that the NZAS Smelter at Tiwai ('Tiwai') will close at the end of 2024. We assume a 'hard exit', with no ramp down in demand from the smelter up to and including 2024.

TCC decommissioning

We assume that TCC power station will be decommissioned at the end of 2023, consistent with the owner's publicly announced expectations[2].

Gas supply

Our scenarios assume that gas generators will have access to enough gas to contribute to security margins at their maximum available capacity, from 2023 until at least the end of the decade.

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[2] See here for more information.

Thermal generator installed capacity is de-rated for 2021 and 2022 to reflect gas supply constraints from the Pohokura gas field. The basis for these assumptions is provided in Appendix 3.

Third Huntly Rankine Unit

We assume that one out of three Huntly Rankine units is available for dry year cover only. Therefore, this unit only contributes to energy margins. The other two Huntly Rankine units are assumed to contribute to both energy and capacity margins.

HVDC capacity

Our scenarios assume that the HVDC will not be upgraded through to 2030. The capacity of the HVDC is described in the Authority's 'Security Standards Assumptions Document'.

3.2.4 Supply Side Sensitivities

TCC Remains

The 350 MW Taranaki Combined Cycle (TCC) power station is not decommissioned as anticipated at the end of 2023 and remains in operation through to at least 2030. This could be in response to an unanticipated increase in demand or, less likely, low cost gas.

Dry year reserve

The operation of a small number of 'baseload' thermal generation units is changed so that they only provide dry year reserve from 2027 onwards, perhaps in response to greater quantities of renewable generation. This sensitivity tests the impact of what would happen if these generators are not available to contribute to short term, unanticipated, supply shortages (unrelated to hydrology). Existing thermal generation installed capacity will be reduced by 480 MW when calculating the North Island winter capacity margin. As this capacity will still be available for dry year reserve, it will still be included when calculating both winter energy margins.

Delayed build times

This sensitivity explores the impact of delaying the commissioning dates for all new generation by one year. This sensitivity is intended to cover a range of possible eventualities. For example, new generation may be delayed due to transmission constraints, resource consent issues or investment uncertainty.

3.2.5 Demand Side Sensitivities

Transmission pricing

Peak demand increases for a short time as the electricity sector adjusts to a change in peak transmission pricing.

The revised Transmission Pricing Methodology is due to remove Regional Coincident Peak Demand charges, a component of transmission interconnection charges. This will come into effect from August of this year and will remove a direct price incentive for Transpower customers (distributors and directly connected consumers) to control load at peak times.

We anticipate that this will result in an increase in peak demand. This increase is likely to be muted, given that existing load control activities will still be used to manage local distribution constraints or spot market exposure. We also anticipate that this increase in peak demand will be temporary. Arrangements will eventually be made to take advantage of any underutilised load control facilities to, for example, manage wholesale risk or local transmission constraints.

Based on a survey of distributors and an analysis of directly connected consumer demand, we estimate that peak demand may increase (from forecast levels) in 2022 by 236 MW in the North Island and 68 MW in the South Island. In 2023, this increase in winter peak demand is reduced by 50%, and in 2024 we assume winter peak demand returns to forecast levels.

Demand step changes

There is a material step change in base load demand. This sensitivity explores the potential impact of new industrial sources of demand such as data centres, other new industries or electrification of process heat demand. We assume 100 MW is added to South Island demand in 2023 and 100 MW is added in the North Island demand in 2024.

Tiwai remains

This sensitivity considers the impact of Tiwai remaining in operation until at least the end of 2030. This could happen, for instance, if operations at the smelter continued to be commercially viable.

4.0

Assumptions

4.1 Demand Assumptions

4.1.1 Forecasting Approach

Winter energy and capacity demand forecasts are developed by Transpower's Grid Investment and Modelling team and align with those used for transmission planning and strategic planning. They are developed following a three-step process (Figure 8):

Stage one: Forecast underlying demand growth rate

This stage forecasts the underlying demand growth rate. Inputs to this forecast include expected changes in population and Gross Domestic Product, historic demand growth rates and demand forecasts from distributors.

Stage two: Add changes in demand from new technologies

In this stage we add in demand changes for electric vehicle charging, domestic solar PV, domestic batteries and process heat electrification. We consider the regional, seasonal and sectoral impact of these technologies. We also consider how some technologies alter the demand for electricity within a typical day. For example, smart[3] electric vehicle charging will be set up to charge electric cars during periods of low demand – acting to 'fill-in' demand troughs.

While our forecasts consider embedded generation, only the uptake of domestic solar PV is forecast. Other types of embedded generation are assumed to remain at current levels, as derived from historic market information.

Inputs to this stage include forecast uptake rates of new technologies, see below. Outputs from this stage are forecast demand - and its components - broken down by GXP and half hourly trading period.

Stage three: Calculate winter energy and capacity demand

For this final stage we calculate forecast winter energy and peak demand.

Winter energy demand is calculated by summing the stage two forecast demand, over each GXP in both islands, and over each winter half hour period. Winter peak demand is calculated by averaging the stage two forecast demand, over each island, and over the highest 200 half hours of winter daytime demand.

Forecast winter energy and peak demand, as used in our assessment, is on a gross basis, includes transmission losses and is adjusted for demand response. Gross demand can be thought of as the total demand seen by the national grid and distribution networks. It is the demand served by both embedded generation and grid connected generation. Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor. Demand response adjustments are detailed in Appendix 2.

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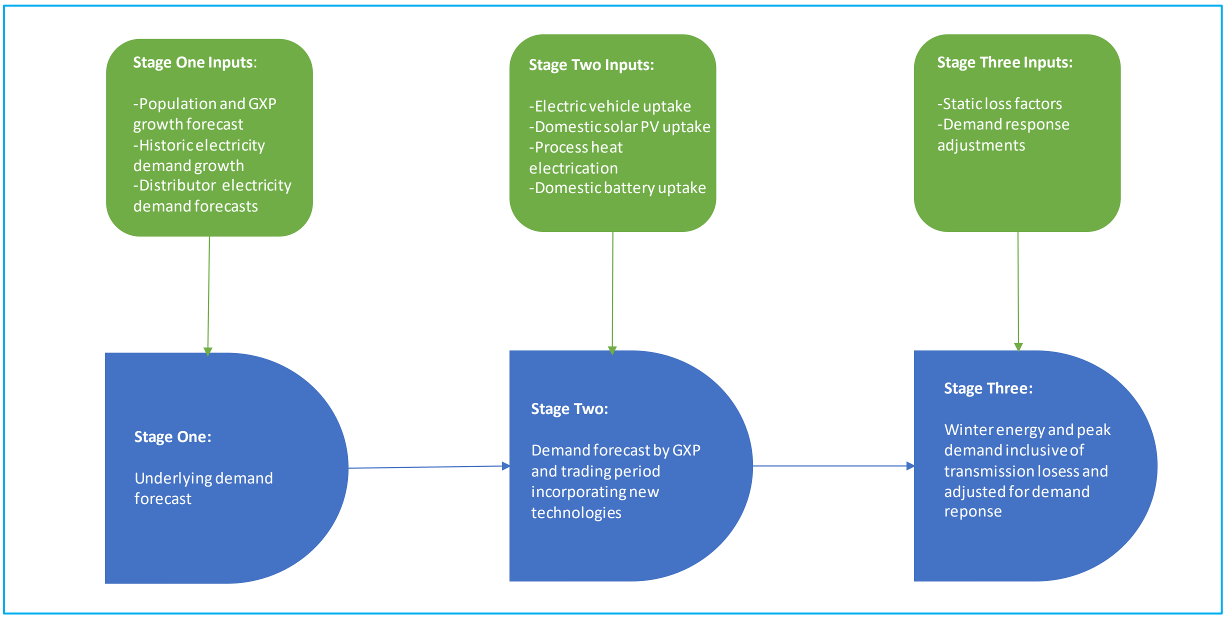
[3] Where in this context smart electric vehicle charging refers to technology that avoids electric vehicle charging due peak demand or high price periods.

Figure 8: Diagram of demand forecasting process



4.1.2 New Technology Uptake Rates

New technology uptake rates leverage the work from Whakamana i Te Mauri Hiko and vary for each scenario as shown in Table 1:

Table 1: Technology uptake rates mapped to Whakamana i Te Mauri Hiko scenarios

Scenario	Whakamana i Te Mauri Hiko Scenario	Description
Low Demand	A blended mix of Business as Usual and Measured Action	Significant electrification of transport and process heat fails to emerge. This may reflect stalled technology development or if regulatory settings do not achieve their intended goals. It could also be consistent with a future where other alternatives to decarbonisation are pursued, such as forestry abatement.
Medium Demand and Gas Constrained	Accelerated Electrification	Technology uptake rates represent a realistic yet aspirational scenario for the New Zealand economy and electricity industry. This will require integrated, coordinated planning and action from across the economy and government.
High Demand	Mobilise to Decarbonise	There is a much stronger and more urgent response to climate change. It is not the rate of development of technologies that will change

		under this scenario, but rather the strength of the decarbonisation effort.

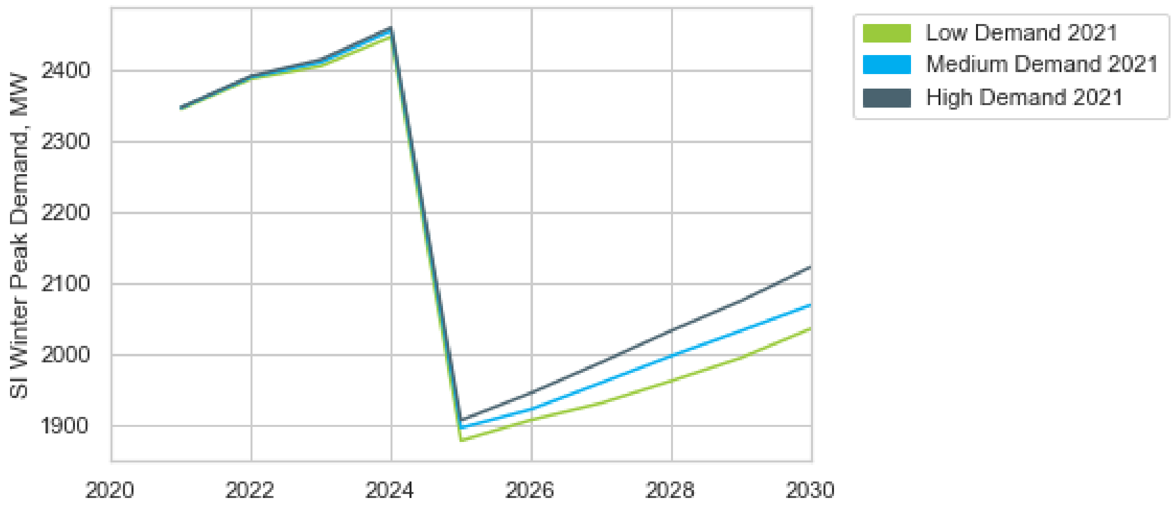
4.1.3 Forecasts

Figure 9 shows forecast winter energy and peak demand as used in the analysis. The demand shown is gross, includes transmission losses, but excludes demand response. While demand response is not shown below, it is included in our margin analysis.

Our forecasts incorporate recent demand reductions or anticipated demand reductions at the Norske Skog's Tasman pulp and paper mill at Kawerau and Refining New Zealand's Marsden Point Refinery.

The step change in demand in 2025 is due to Tiwai closing at the end of 2024.

Figure 9: Winter energy and peak demand

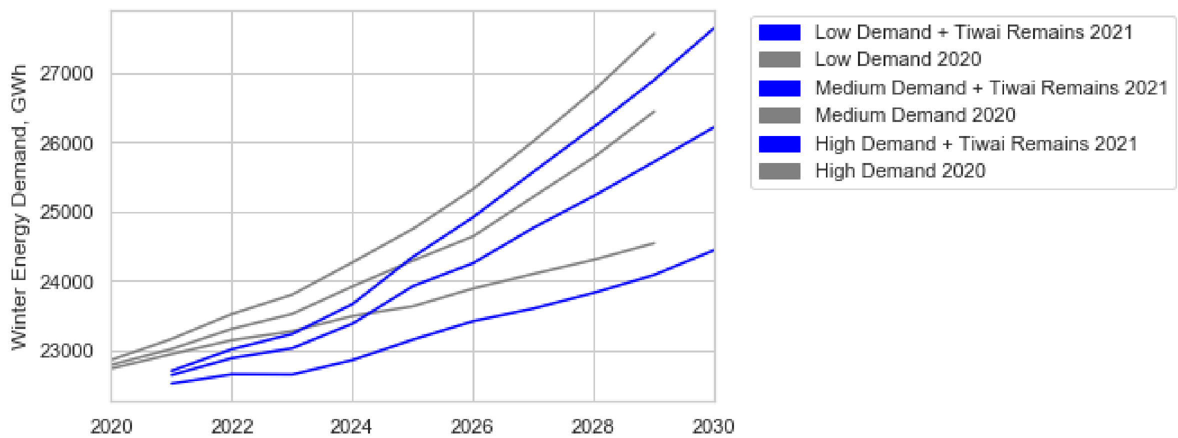


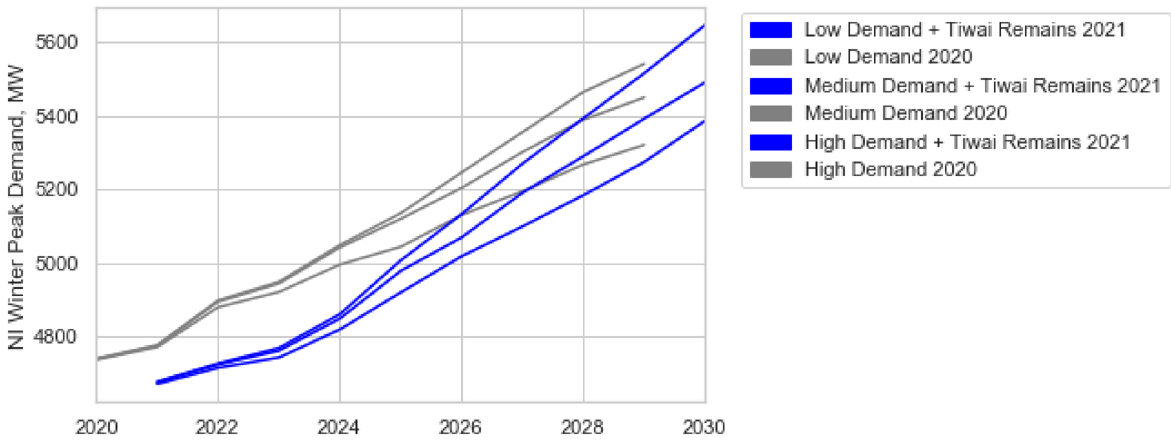
Comparison with last year's assessment

The charts in Figure 10 compare this year's and last year's assessment forecasts. This year's forecasts have shifted to the right and are lower, more so for the first half of this decade. These changes reflect:

- an adjustment to the underlying energy demand forecast due to COVID-19 effects, the forecast was adjusted so that it grew from the 2019 demand, as if it was repeated in 2020
- a reduction to underlying peak demand forecast of 90 MW due to an updated forecast of industrial peak demand
- lower forecast electric vehicle load, approximately 50% in 2030 for the Medium Demand scenario
- slower uptake of electric vehicle smart charging resulting in faster peak growth in 2021
- lower forecast domestic solar PV growth reduction, approximately 30% in 2030 for the Medium Demand scenario.

Figure 10: Winter energy and peak demand



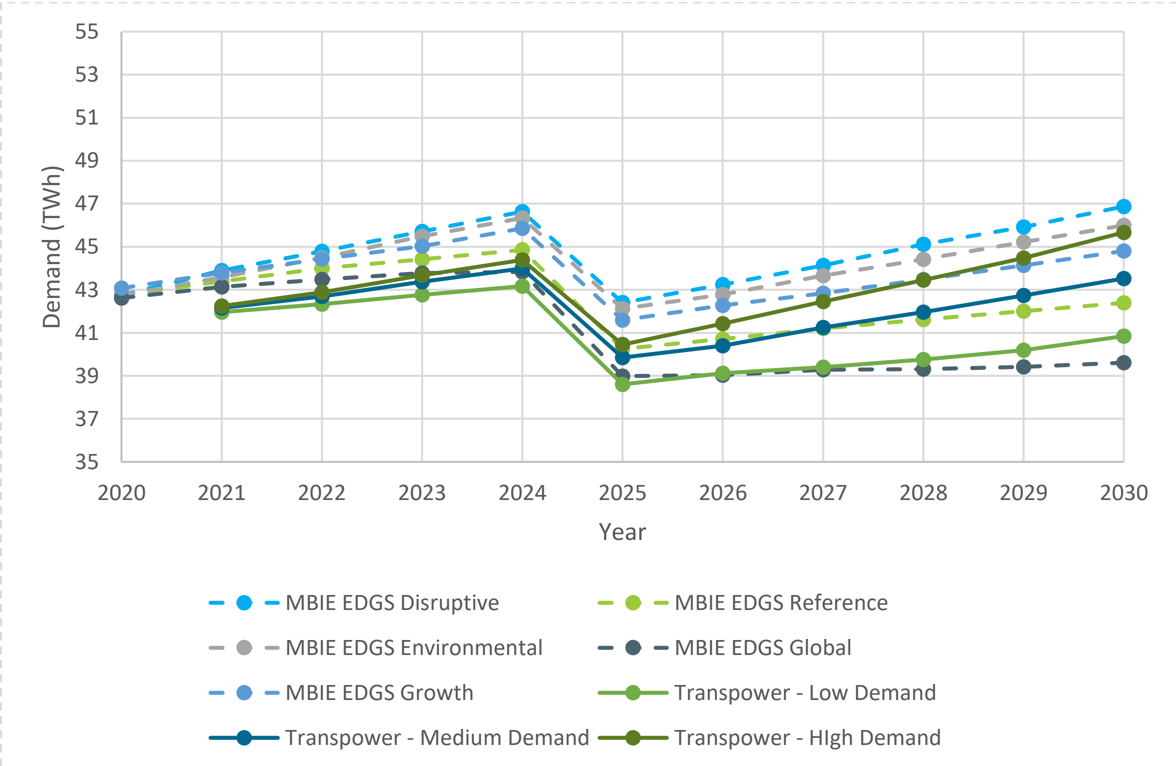


Comparison with Ministry of Business, Innovation and Employment's forecasts

Figure 11 shows annual energy demand for our scenario forecasts (solid lines) compared to the Ministry of Business, Innovation and Employment's (MBIE's) electricity demand and generation scenario forecasts published in 2019 (dashed lines). MBIE prepares an independent set of scenarios that enable the Commerce Commission to assess Transpower's planning proposals for future capital investment in the electricity transmission grid. MBIE's forecasts have been adjusted for Tiwai closure in 2024.

Broadly speaking, our scenarios fall within MBIE's set of scenarios. For some MBIE scenarios forecast demand is higher. This is in part due to anticipated demand growth in 2020 which did not eventuate due to COVID-19 related disruptions.

Figure 11: Energy demand forecasts combined to MBIE's forecasts

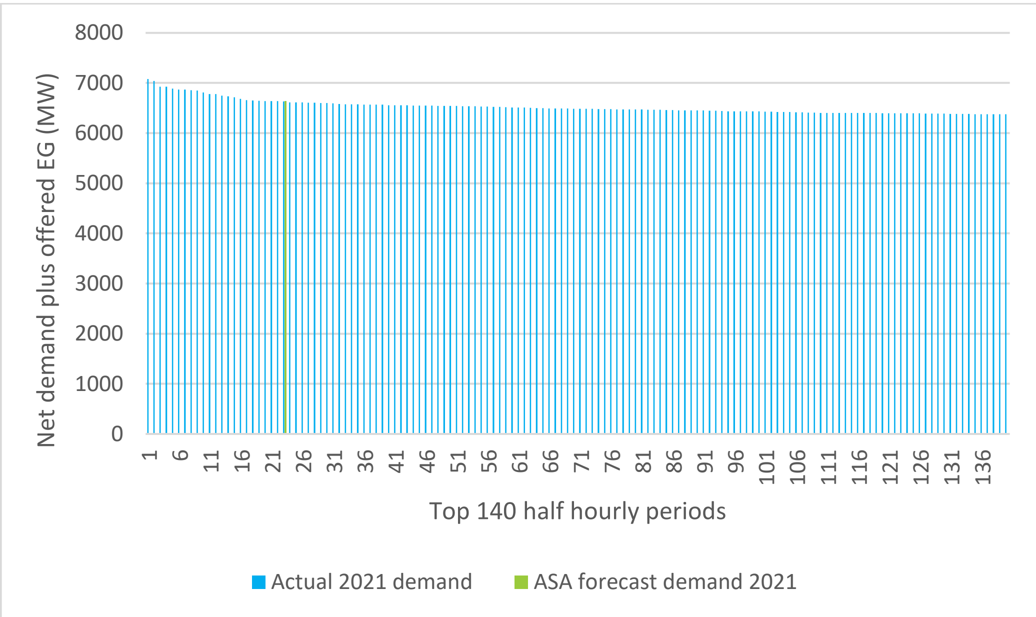


Comparisons with this year's actual to-date winter peak demand

On the evening of 9 August 2021 there were record levels of demand across New Zealand. Winter peak demand, as used in this assessment, uses the average of the highest 200 half hours of winter daytime demand. Despite the spike in demand on 9 August, actual winter peak demand to date for this year is tracking to our forecast winter peak demand.

Figure 12 shows the highest 140 actual half-hourly New Zealand demand periods for the 2021 winter period to date. Demand shown is net grid imports plus offered embedded generation and average actual demand over the 140 periods is 6,526 MW. For the purposes of calculating winter peak demand, winter is from 1 April – 31 October. We look at the highest 140 half hourly periods to roughly adjust for the remaining two months of winter to come in 2021. Forecast winter peak demand (adjusted so that the comparison is on a like for like basis) for 2021 is comparable at 6,630 MW.

Figure 12: New Zealand actual peak demand: Highest140 half hourly periods



4.2 Supply Assumptions

4.2.1 Information Sources

Information on existing and proposed new supply projects are obtained from generation companies on a confidential basis.

4.2.2 Winter Energy and Capacity Supply Contributions

Winter energy and capacity supply contributions include generation from both grid connected and embedded generation. Table 2 shows how contributions are evaluated for different types of generation.

Table 2: Evaluating winter energy and capacity contributions

Resource type	Energy contribution	Capacity contribution
Thermal generation	Installed capacity, de-rated for outages, and multiplied by the number of winter hours.	Installed capacity, de-rated for outages
Controlled hydro	Generation based on average hydro inflows over the historic record	Installed capacity, de-rated for outages
Other major sources of generation This includes all generation offered into the spot market (with a handful of exceptions)	Installed capacity, multiplied by the expected capacity factor, and then multiplied by the number of winter hours. The expected capacity factor is as reported by generation companies supplemented by historic market information	Installed capacity multiplied by a resource specific winter peak contribution factor. The 'resource specific winter peak contribution factor' is 25% for wind and based on historical winter peak contributions for other resources
Smaller embedded generation (except for domestic solar PV)	As per historic market information. No forecast growth assumed.	As per historic market information. No forecast growth assumed.
Domestic solar PV and batteries	As per the demand forecast	As per the demand forecast

4.2.3 New Supply Projects

Proposed new supply projects have been aggregated to preserve confidentiality. To give a broad indication of the likelihood that development will proceed we have allocated each new supply project into four categories:

- Consented and proceeding (i.e. committed)
- 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 earliest dates at which a new supply projects could potentially become available is based on the type of project and its development category. This is shown in Table 3. New supply project additions by their earliest build year are also shown in Figure 13.

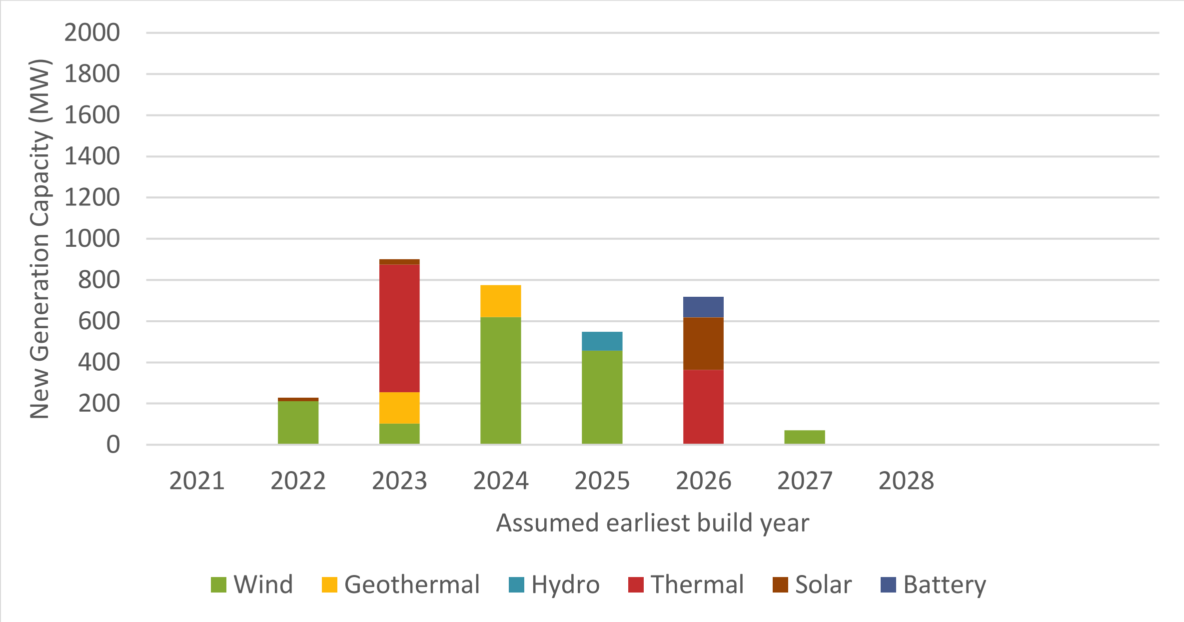
Table 3: New supply project, earliest build dates by project type and development category

	Committed	Consented and on hold	Consented, on hold, requires consent revision	Not consented
Thermal	Estimated build date	2023	2024	2026
Geothermal	Estimated build date	2024	2025	2027
Wind	Estimated build date	2024	2025	2027
Hydro	Estimated build date	2025	2026	2028
Solar (large scale)	Estimated build date	2023	2024	2026
Battery	Estimated build date	2023	2024	2026

The above timeframes allow us to project the size of the pipeline of new supply projects at a given point in the future. They are not intended to forecast what will be built. New supply projects will most likely be progressed only when the market conditions justify investment. It is possible therefore that actual build dates for a given new supply project will be many years later than our earliest build date.

Our earliest build dates are an estimate. Delays may occur for a variety of reasons, including due to plant availability, logistics, and transmission requirements. It also possible that projects may be expediated to respond to market conditions.

Figure 13: New supply project timeline for Low, Medium and High Demand scenarios (domestic solar and batteries not shown)



4.2.4 Winter Energy Supply and Capacity

Assumed winter energy supply and capacity are shown in Figure 14. The grey bars show existing and committed generation. The coloured bars are our forecast of the pipeline of new supply projects. Each coloured bar represents cumulative new supply projects for a given fuel type and year. Again, the pipeline of new supply projects shown is what *could potentially* be built at a given point in the future.

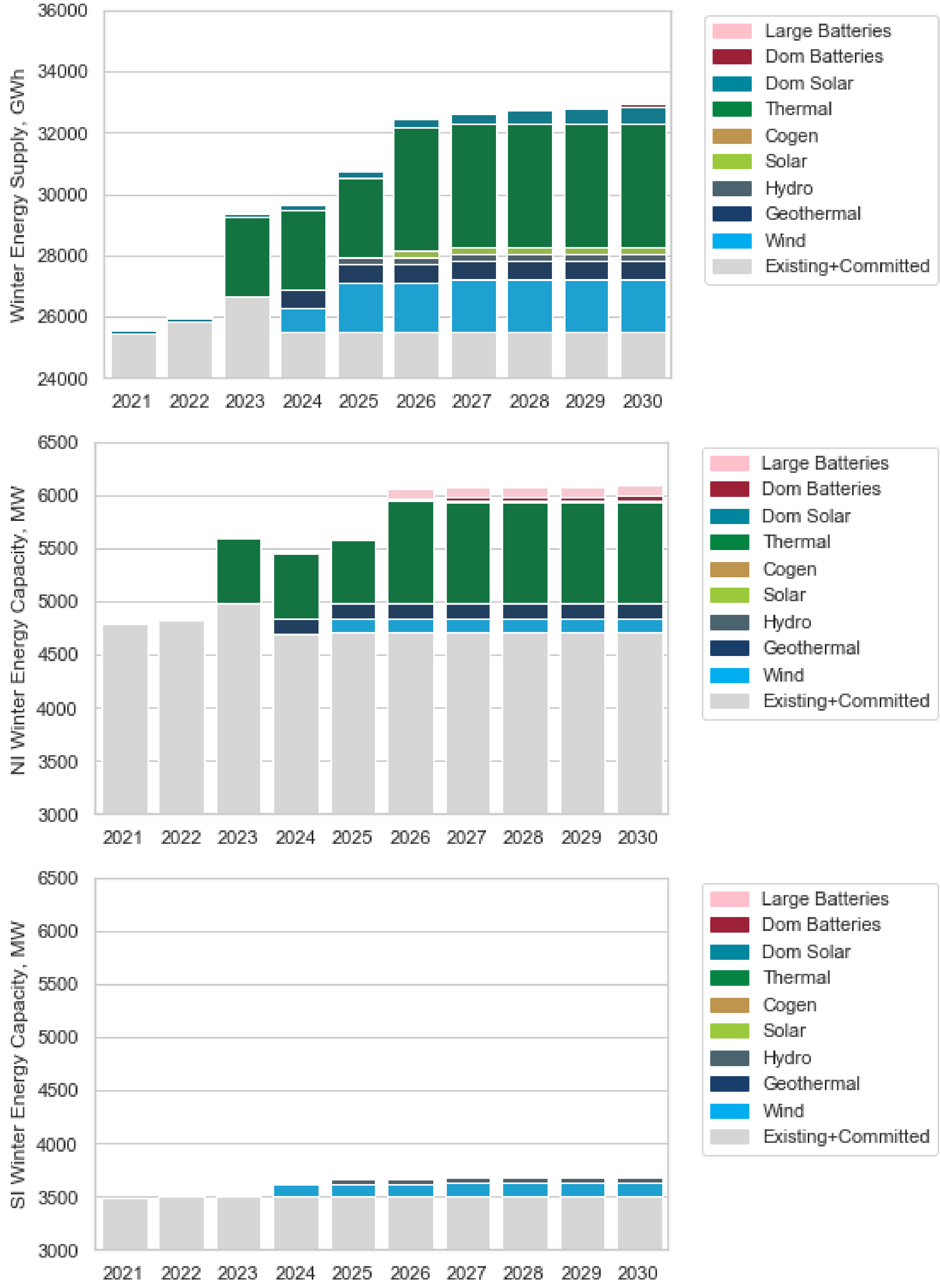
4.2.5 Inter-Island Transmission Assumptions

North Island energy supply can meet some of the South Island's energy demand in the assessment of the South Island winter energy margins. 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[4].

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

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

Figure 14: Winter energy and peak supply (storage and de-ratings excluded)



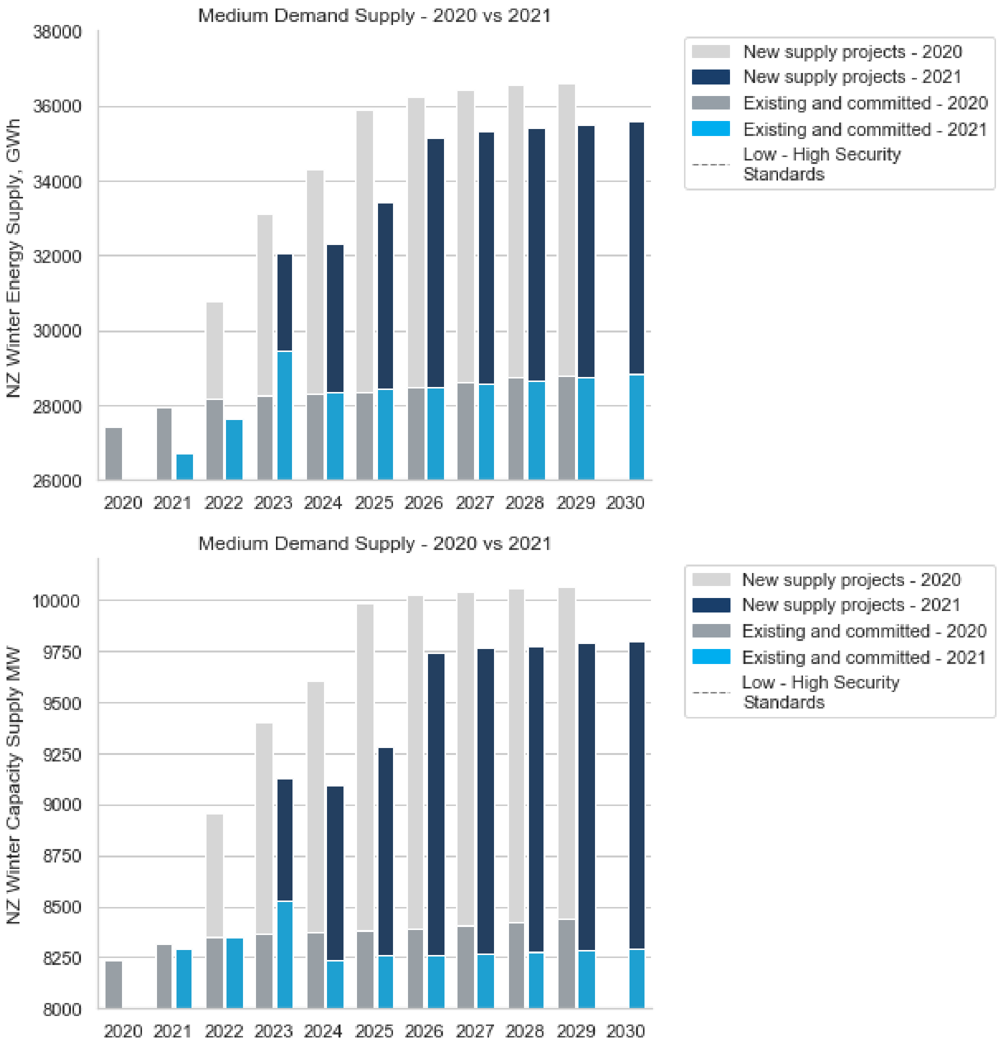
4.2.6 Changes in Supply from Last Year’s Assessment

Changes in winter energy and capacity supply assumptions compared to last year’s assessment are shown in Figure 15.

Winter energy and capacity supply increases in 2023, reflecting new supply projects due to be commissioned over the next two to three years. This increase is largely reversed in 2024 with the departure of TCC. Post 2023 winter energy supply from existing and committed generation is almost the same for this year’s assessment. Post 2023 winter capacity supply from existing and committed generation is, though, less for this year’s assessment. This difference between post 2023 winter energy and capacity supplies indicates that committed new supply projects in aggregate contribute greater quantities of energy than capacity.

The volume of new supply projects has decreased slightly (comparing the top light grey bars for last year’s assessment and the top dark blue bars for this year’s assessment). As new supply projects have been progressed to implementation, they have not been fully replaced within the overall pipeline of new supply projects.

Figure 15: Winter energy and capacity supply as compared to last year’s assessment



4.2.7 Thermal Fuel Availability

Gas and coal availability

Gas supply availability for gas generation has been assessed by estimating a dry year gas supply margin out for the next ten years. This margin calculates the average daily difference for gas supply and demand (across all gas users) during a dry year emergency. The margin assumes that the Huntly Rankines are operating on coal and that there will be a material substitution of gas demand from industrial processing to electricity gas generation. The analysis is presented in full in Appendix 2.

Gas supply assumptions use confidential information from gas producers for 2021 - 2022 and Ministry of Business Innovation and Employment statistics for later years.

Dry year gas supply margins indicate:

- gas supply will be constrained for 2021 – 2022 and there will be insufficient gas to supply all gas generators if they are to operate at their maximum capacity
- from 2023 onwards, there is likely to be enough dry year gas supply subject to continued ongoing investment in this sector, including the development of potentially recoverable contingent reserves.

Coal availability has been assessed based on assumed coal stockpiles, domestic coal purchases and foreign coal imports.

On this basis we have de-rated winter energy contributions from thermal generation for 2021 – 2022 as shown in Table 4. We assume that supply constraints are unlikely to affect the capability of generation plant to meet short-term winter morning and evening peaks. For this reason, winter capacity contributions from thermal generation have not been de-rated.

The above thermal derating methodology and assumptions has been aligned to ensure consistency with our Electricity Risk Curves.

Table 4: Winter energy thermal deratings

Year	Winter Energy De-rating (GWh)
2021	1508
2022	978

Diesel availability

Consistent with our Electricity Risk Curves, Whirinaki's winter energy contribution is limited to 60 GWh, reflective of fuel delivery logistics.

5.0

Results

5.1 Overview and Summary

This Section presents our assessment results.

In summary, assessed winter energy margins do not suggest that there will be significant security risks over the next ten years for all our scenarios. Energy margins can be maintained above security standards with existing and committed generation. This contrasts with North Island winter capacity margins. Capacity margins with existing and committed generation fall below the security standard in the latter half of the decade for all scenarios.

Our scenario results should be viewed with a degree of caution. The scenarios, by design, do not consider possible material changes in supply and demand. The impact of such changes is presented in this section by considering a range of sensitivities to our Medium Demand scenario. We show that there are circumstances where margins can be materially eroded bringing forward the need for new supply.

It is likely that there will be enough new supply projects that could potentially be built to ensure adequate levels of supply reliability for all scenarios. The size of pipeline of new projects is, though, considerably eroded for our Gas Constrained scenario. If this scenario were to eventuate, it is likely additional new projects will need to be identified and developed into viable future supply options.

With no new supply, in general, the gap between forecast margins and the corresponding security standard is likely to reduce for North Island winter capacity margins ahead of New Zealand winter energy margins. This general result is as found in last year's assessment. North Island winter capacity margins are more susceptible to demand or supply changes in part due to the type of generation projects that are currently being actively progressed. Over half of this capacity is wind generation, which contributes a relatively smaller amount to winter capacity margins than to winter energy margins.

5.2 Chart Interpretation

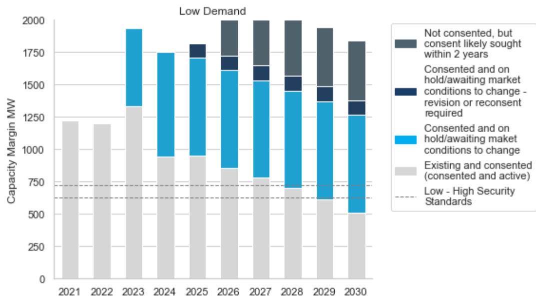
Our assessment results are shown using two types of charts, one to show margins for an individual scenario and one to show the scenarios with a range of sensitivities.

5.2.1 Individual Scenario Results

Individual scenario results are shown with a chart in the format of Figure 16. Each chart presents three key pieces of information:

- The security standard is represented by a horizontal grey dotted line on the charts. This is a reference to compare the margins against. Security standards are set by the Authority as upper and lower margins that represent an efficient level of reliability.
- The margins calculated with 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 contributed by existing and committed generation decreases.
- The margins with new supply projects added. That is, the margins if all known new supply projects options are built (assuming some practical limitations on lead times). This is represented by the series of blue coloured bars on the charts.

Figure 16: Example chart, showing North Island capacity margins for the Low Demand Scenario



We can draw conclusions from this chart by first looking at whether margins with existing and committed generation fall below the security standards. We then assess the adequacy of the pipeline of new supply projects to meet the security standards in the future. If there is a significant volume of new supply projects 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.

5.2.2 Comparing Scenarios with Sensitivities

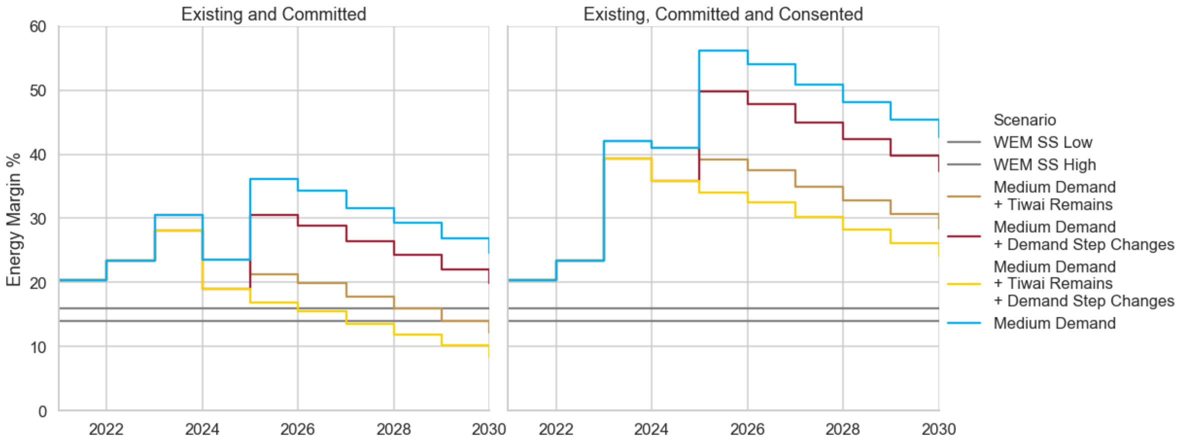
Scenario sensitivities are shown with a chart in the format of Figure 17.

The chart on the left shows the margin with existing and committed generation for a scenario and one or more sensitivities. Margins are shown as stepped lines - and display the same information as the grey bars in the individual scenario result charts (discussed above). The blue line always denotes the scenario, other colours are used to denote sensitivities.

The chart of the right shows the same information for margins with existing, committed and consented (on hold / awaiting market conditions to change) supply projects.

Both charts also show the upper and lower security standards – these are the grey solid horizontal lines.

Figure 17: Example chart, showing New Zealand energy margins for the Medium Demand Scenario with the Tiwai Remains and Demand Step Changes Sensitivities



5.3 Winter Energy Margin Results

5.3.1 New Zealand Winter Energy Margin Scenario Results

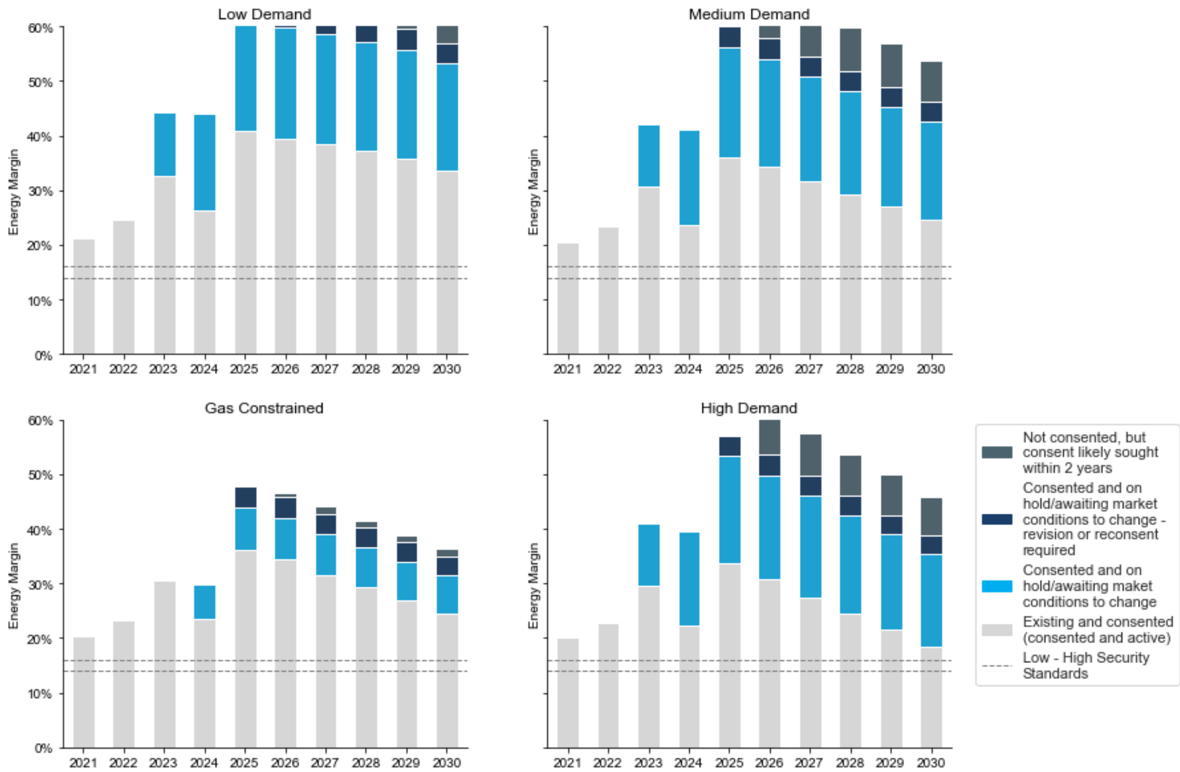
New Zealand winter energy margin results for each scenario are shown in Figure 18 below.

For all our scenarios, existing and committed generation should be able to maintain New Zealand winter energy margins above the security standard through to 2030. There is a significant upwards step change in margins in 2025, as a result of Tiwai closing. The impact of the smelter remaining open is covered below.

The Gas Constrained scenario shows a comparatively large reduction in the available pipeline of projects. For example, in 2025, new consented supply projects are reduced by 79% compared to the Medium Demand scenario. This implies that for this scenario there will be less new supply options to handle possible future changes in demand or supply (of the type covered by our sensitivities).

New Zealand winter energy margins are relatively low in 2021 – 2021 due to the thermal de-ratings imposed to reflect gas supply constraints.

Figure 18: NZ winter energy margin scenario results



5.3.2 South Island Winter Energy Margin Scenario Results

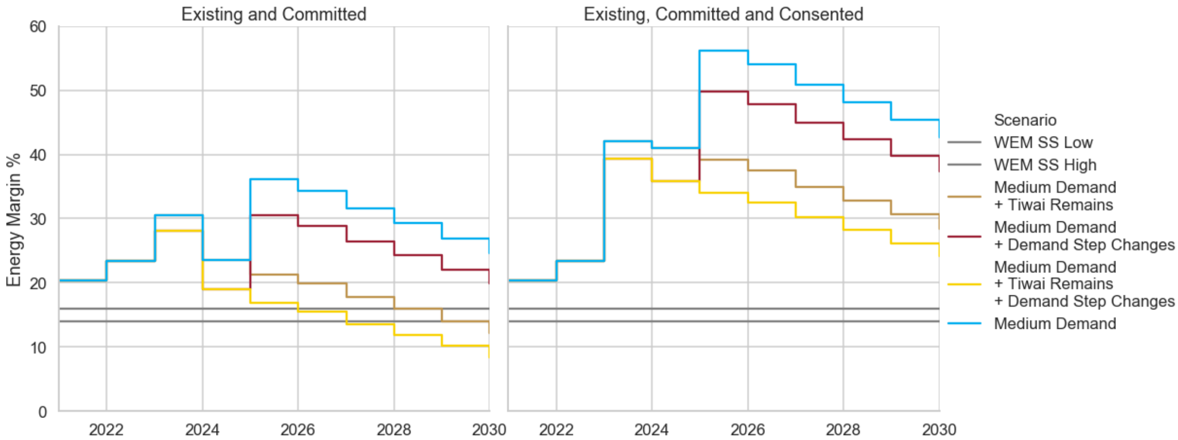
South Island energy margins are comparatively much higher than New Zealand energy margins and do not pose significant medium-term security risks. Appendix 4 presents South Island energy margin results.

5.3.3 New Zealand Winter Energy Margin Sensitivities

In this section we present New Zealand winter energy margins for selected Medium Demand scenario sensitivities. Sensitivities for other scenarios are shown in Appendix 5.

Figure 19 shows results for the Medium Demand scenario for the Tiwai Remains and Demand Step Changes sensitivities (and their combinations). The Demand Step Changes sensitivity is where 200 MW of demand is added over 2023 – 2024.

Figure 19: Medium Demand scenario NZ winter energy margins, with Tiwai Remains and Step Changes in Demand sensitivities



New Zealand winter energy margins are resilient to most of our sensitivities. For our Tiwai Remains sensitivity, margins only fall below security standards in 2029. If we combine our Tiwai Remains and Demand Step Changes sensitivities margins fall below the security standard in 2027. This combination of scenarios is unlikely though: incentives to develop new sources of demand pre-2024 are likely to be less if Tiwai signals that it may remain in operation.

5.4 Winter Capacity Margin Results

5.4.1 North Island Winter Capacity Margin Scenario Results

North Island winter capacity margin results for each scenario are shown in Figure 20.

North Island winter capacity margins, with existing and committed generation, fall below the security standard between 2027 to 2029, depending on the scenario's assumed winter peak demand growth rate. Tiwai closure has less of an impact on North Island winter capacity margins. This is because South Island capacity contributions, post-Tiwai closure, are constrained by the current capacity of the HVDC.

The total volume of new supply projects – including those that have yet to obtain a resource consent - is adequate to maintain margins above the security standard throughout the assessment period for all scenarios. For the High Demand, Medium Demand and Low Demand scenarios, margins could be maintained just with new supply projects that have already been consented.

For the 'Gas Constrained' scenario, the pipeline of new supply projects is much reduced. From 2025 onwards new supply projects that are consented could potentially contribute 154 MW of winter capacity. This is not enough to maintain margins above the security standard through to 2030. To build resiliency to changes in supply or demand new projects will need to be identified and developed for this scenario in the second half of this decade.

The amount of new supply projects required by 2030 for each scenario is shown in Table 5.

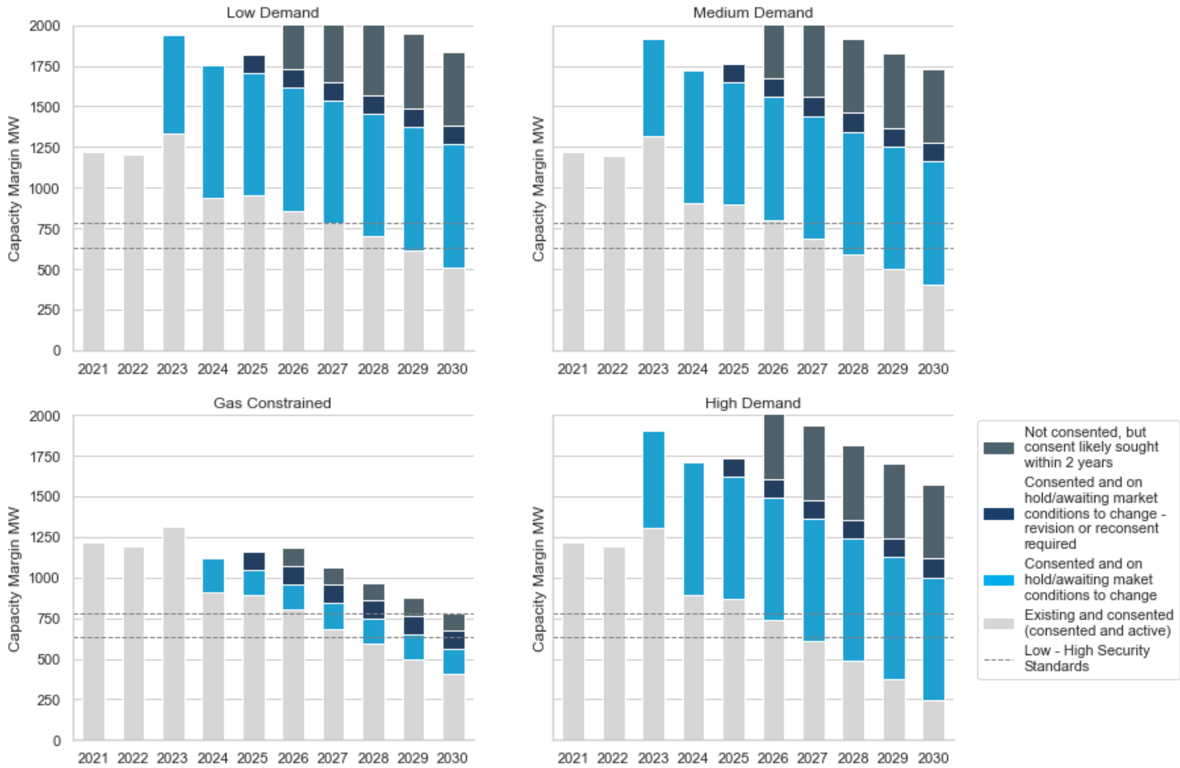
Table 5: New winter capacity required by 2030 to maintain minimum security standards

Scenario	New winter capacity required to maintain minimum security standard by 2030 (MW)	As a % of all new supply projects*	As a % of consented new supply projects*
Low Demand	120	9%	16%
Medium Demand	225	17%	30%
Gas Constrained	225	59%	146%**
High Demand	385	29%	51%

**Excluding South Island projects that are HVDC constrained*

*** For the Gas Constrained scenario there are insufficient consented new supply projects able to maintain North Island winter capacity margins in 2030*

Figure 20: North Island winter capacity margin scenario results



5.4.2 North Island Winter Capacity Margin Sensitivities

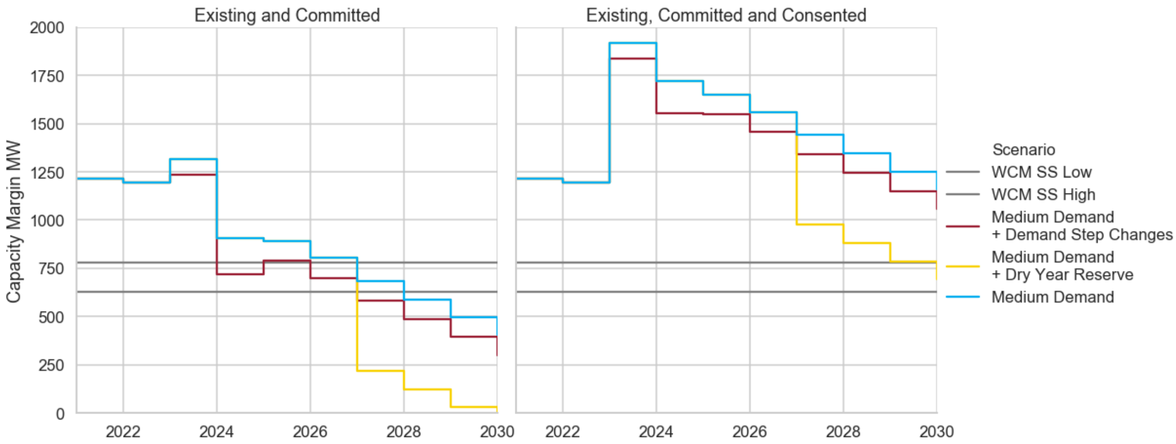
In this section we present North Island winter capacity margins for selected Medium Demand scenario sensitivities. Sensitivities for other scenarios are shown in Appendix 5.

Dry year reserve and demand step changes

Figure 21 shows North Island winter capacity margins for the Medium Demand scenario, with the Dry Year Reserve and Demand Step Changes sensitivities. The Dry Year Reserve sensitivity considers 480 MW of thermal generation being available only for dry year reserve - and unable to contribute to capacity at all times - from 2027 onwards.

With both sensitivities, North Island winter capacity margins with existing and committed generation fall below the security standard one year earlier, in 2027. Margins drop significantly for the Dry Year Reserve sensitivity. Currently consented new supply projects would be adequate to maintain efficient levels of reliability for either sensitivity. The Dry Year Reserve sensitivity would be challenging and, perhaps, illustrates the difficulties of transitioning to greater quantities of renewable generation. To maintain minimum security standards for this sensitivity at least 691 MW of winter capacity would need to be built by 2030, this equates to 91% of known consented supply projects.

Figure 21: Medium Demand scenario NI winter capacity margins, with Dry Year Reserve and Step Changes in Demand sensitivities



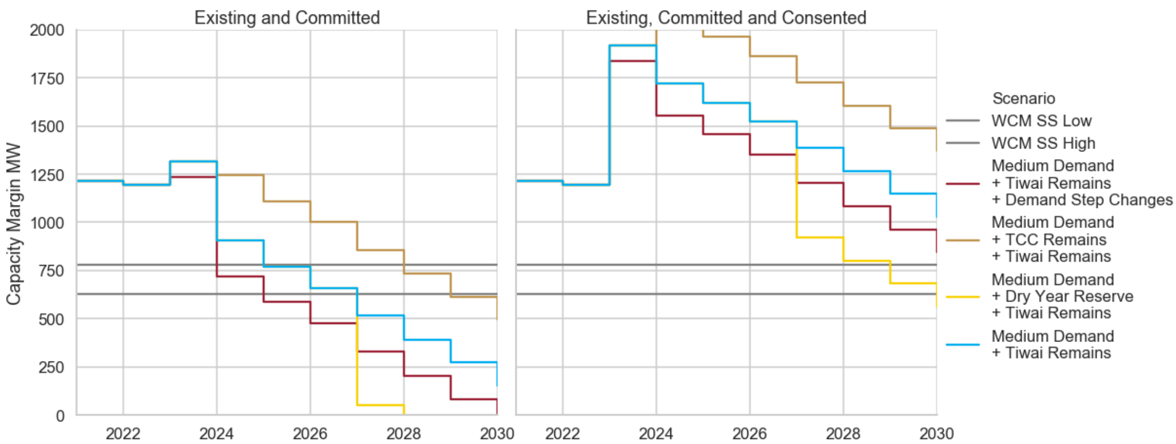
Tiwai remains

Figure 22 shows the impact of Tiwai remaining in operation post-2024. We have combined the Tiwai Remains sensitivity with each of the Demand Step Changes, Dry Year Reserve and TCC Remains sensitivities. The TCC Remains sensitivity considers the impact of this power station remaining in operation post 2023.

If Tiwai remains this has the overall impact of lowering North Island winter capacity margins post-2025. Winter capacity margins with existing and committed generation fall below security margins for all presented sensitivities; even if TCC remains in operation. The Demand Step Changes sensitivity is our worst case, though less likely sensitivity combination. For this sensitivity combination new supply projects would need to be built as early as 2024.

A greater proportion of our pipeline of new projects will be required to maintain efficient levels of reliability. For our challenging Dry year Reserve sensitivity, our pipeline of new supply projects still has enough options to maintain security standards, however the current stock of consented projects would need to be expanded.

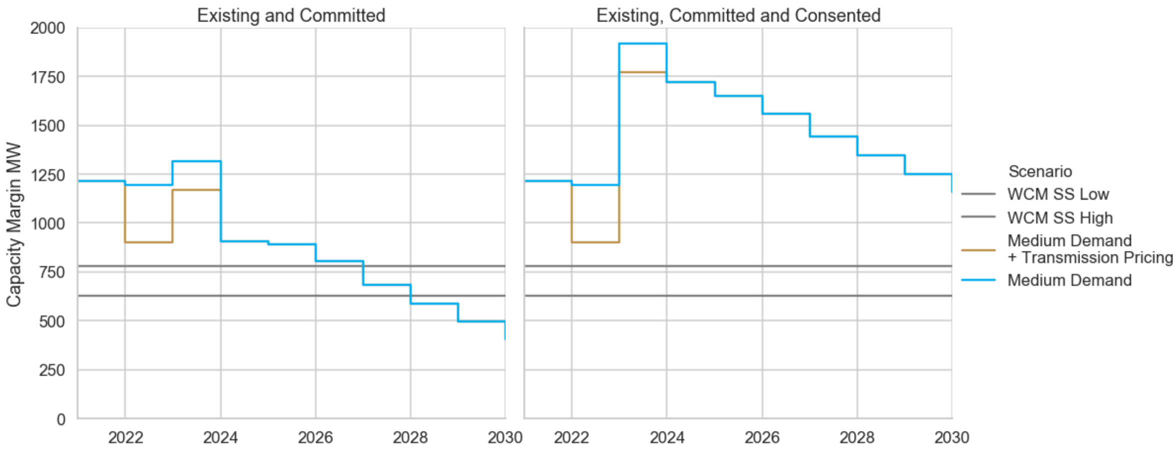
Figure 22: Medium Demand scenario and sensitivities NI winter capacity margins – Tiwai Remains



Transmission pricing

Figure 23 shows North Island winter capacity margins for the Medium Demand scenario, with our Transmission pricing sensitivity. Winter capacity margins are forecast to dip materially in 2022, although remain above security standards. While margins fall below the security standard, the timing remains unchanged from our reference Medium Demand scenario.

Figure 23: Medium Demand scenario and Transmission Pricing sensitivity NI winter capacity margins

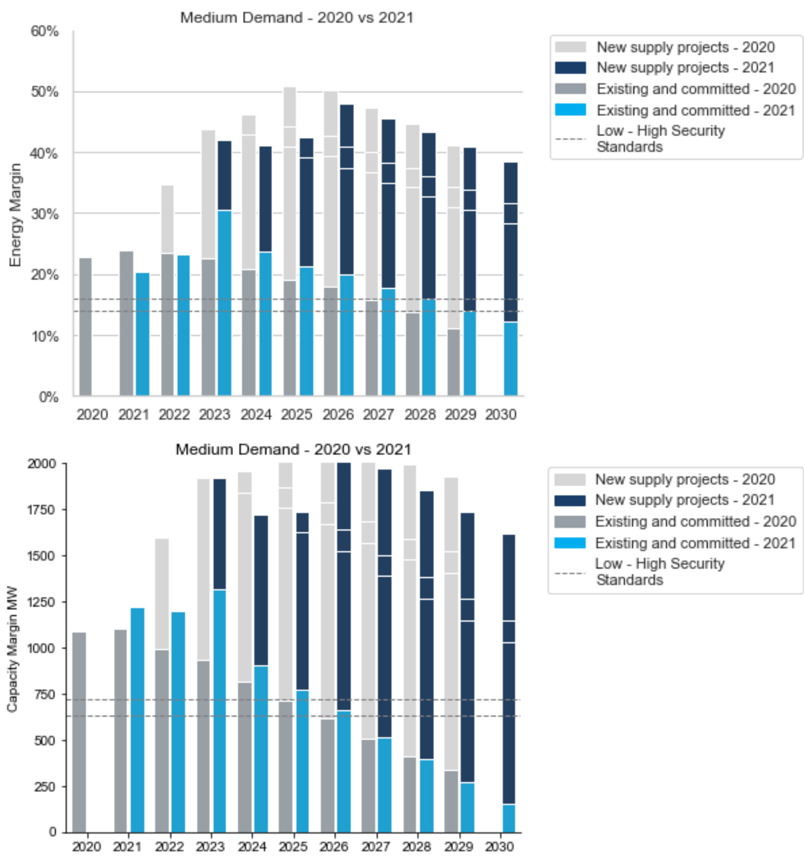


5.5 Comparison with Last Year's Assessment

New Zealand winter energy and capacity margins have improved compared to last year's assessment. After closure of Tiwai at the end of 2024 energy margins have made substantial gains. This is less so for North Island capacity margins due to the HVDC constraining surplus South Island generation.

Figure 24 compares New Zealand winter energy margins and North Island winter capacity margins for the Medium Demand scenario. For this year's results we have used our Tiwai Remains sensitivity so that the comparison is on a like for like basis. Differences in margins are driven by the loss of TCC at the end of 2023. The reduction in margins following the departure of TCC is partly offset by new generation projects expected to be commissioned over the next two or three years.

Figure 24: Comparison of margins with last year's assessment – Tiwai Remains sensitivity used for 2021



6.0
Maintaining security margins with greater proportions of renewable generation

6.1 Overview and Summary

In this section we look at the impact on margins of increasing the proportion of renewable generation as of 2030. Our approach is to investigate five thermal generation scenarios, which consider progressively lesser amounts of thermal generation. For each of these scenarios we estimate the contribution from renewable generation and other technologies that would be required to maintain margins above security of supply standards.

This analysis is exclusively focused on security of supply, we have not investigated economic or technical issues outside of this brief. Consistent with our margin forecasts, presented in Section 5.0 we do not attempt to forecast or otherwise determine the likelihood of whether any these scenarios could occur.

This assessment shows that significant new supply additions will be required to displace existing thermal generation, increase the proportion of renewable energy beyond 90%, and maintain efficient levels of supply reliability. New supply projects will need to include projects – and possibly technologies - that are not yet being actively pursued.

For the purposes of this chapter thermal generation refers exclusively to generation that is fuelled by either diesel, natural gas or coal[5].

[5] We do not discount future supply options that may utilise in some form thermal generation technologies that are carbon zero.

6.2 Thermal Generation Scenarios

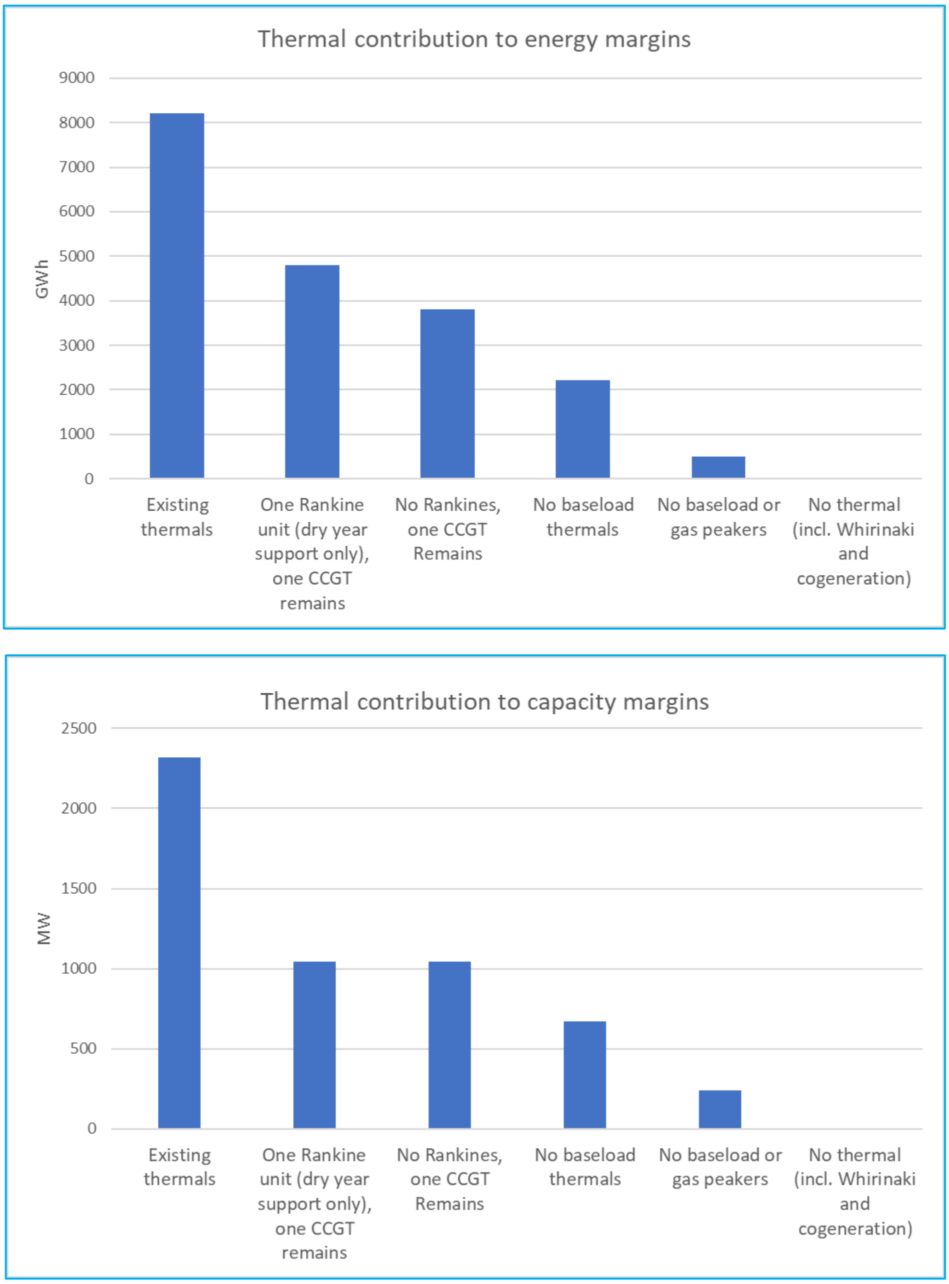
We have developed five thermal generation scenarios, described below, that consider progressively less thermal generation than current levels. These thermal generation scenarios should not be interpreted as indicating a potential or likely pathway to higher proportions of renewable generation. It is possible that the pathway to higher proportions of renewable generation will involve step changes in thermal generation that by-pass or vary from the thermal generation scenarios that we have considered.

Table 6: Thermal generation scenarios

Scenario	Description
One Rankine unit (dry year support only), one CCGT remains	One Huntly Rankine unit remains for dry year support. We assume that this Rankine unit will not contribute to winter capacity margins. The CCGT at Huntly and all other existing thermal generation are available to contribute to winter energy and capacity security margins.
No Rankine units, one CCGT remains	All Huntly Rankine units have been decommissioned. The CCGT at Huntly continues to contribute to winter energy and capacity security margins.
No baseload thermals	The CCGT and all Rankine units at Huntly have been decommissioned
No baseload or gas peakers	Only gas cogenerators and the Whirinaki diesel open cycle gas turbine remain
No thermal incl. Whirinaki and cogeneration	There is no gas, coal or diesel thermal generation

The relative contributions to winter energy and capacity margins for each thermal generation scenario are shown in Figure 25 below. There is a significant step change down from existing levels of contribution for even the first scenario.

Figure 25: Thermal contributions to security standards



6.3 Security Margin Impacts

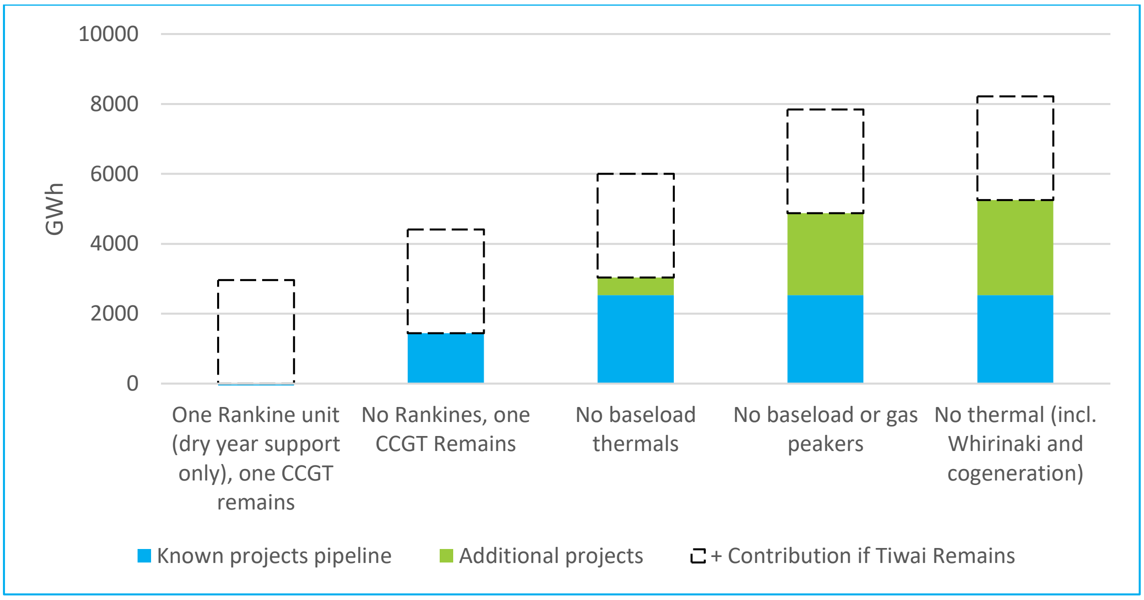
6.3.1 Winter Energy Margins

Figure 26 presents the additional contribution to New Zealand winter energy margins that would be required from new supply projects to maintain margins above the upper security standard in 2030. These contribution calculations use the Medium Demand scenario. The bottom blue bars show potential contributions from known renewable projects in our pipeline. This includes all projects regardless of their current resource consent status. The middle green bars show the levels of contribution required from projects that are not yet being actively considered. This is how much we must increase our new supply projects pipeline by. We also show – as the top dotted bars – the impact of Tiwai remaining.

For the 'no base load thermals' scenario - and others with less thermal generation - the pipeline of new supply projects will need to be expanded to maintain margins above the security standard. To put the likely quantities involved into perspective, the 'no base load thermals' scenario would need an additional ~3,000 GWh of additional projects, of which ~507 GWh would be from projects not yet actively pursued. A 200 MW geothermal power station would be able to provide ~775 GWh of winter energy, roughly a quarter of the winter energy contribution required for this scenario.

While we have not investigated the feasibility of expanding the current supply project pipeline, we do understand that these projects are just a subset of the resources available in New Zealand that could potentially be used to generate electricity.

Figure 26: Additional energy contribution required in 2030 to meet the 16% security standard



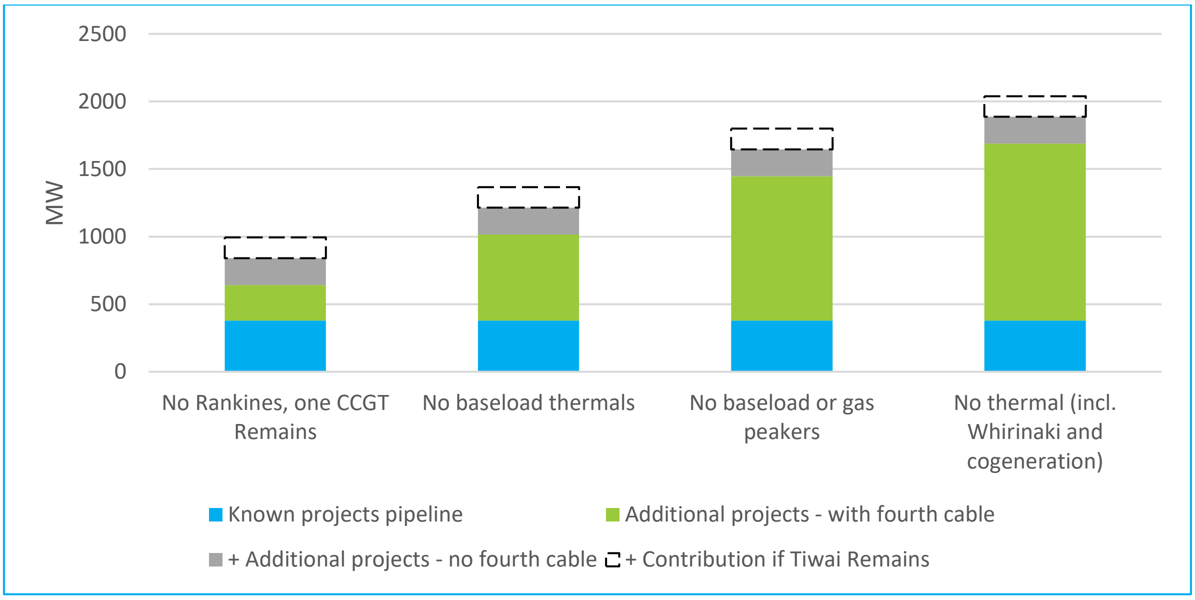
6.3.2 Winter Capacity Margins

Figure 27 presents the additional contribution to North Island winter capacity margins that would be required from new North Island projects to maintain winter capacity margins above the upper North Island winter capacity margin security standard in 2030. We use the same format as above to designate contributions from known renewable and battery projects in our pipeline and from projects that are not yet being actively considered.

The extent to which South Island generation can contribute to North Island winter capacity margins is limited by the capacity of the HVDC. For our assessment of capacity margins, we assume that the current Northward capacity of the HVDC is constrained to ~950 MW. If a fourth cable is added to the HVDC, as described in the 2020 Transmission Planning Report, this would add a further 200 MW of capacity[6]. The grey bar in Figure 27 shows the estimated potential reduction in required contributions that could be achieved if the HVDC were upgraded with a fourth cable.

For all scenarios the pipeline of known projects will need to be expanded to maintain margins above the security standard. This is consistent with our winter capacity margin forecasts presented Section 4.0. Other technologies, besides traditional forms of renewable generation, may need to be considered if the required level of contributions to maintain security standards are to be achieved.

Figure 27: Additional capacity contribution from NI projects required in 2030 to meet the 780 MW security standard



HVDC capacity

For our reference Medium Demand scenario, even with a fourth HVDC cable, there is still 'un-used' surplus generation in the South Island that could be used to meet North Island peak demand in 2030. HVDC capacity and assumed South Island surplus generation are shown visually in Figure 28.

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[6] Along with any other required grid upgrades to support a greater quantity of Northwards transfer across the HVDC.

Surplus South Island generation would be substantially reduced if Tiwai remained or if its load were replaced after its closure.

Figure 28: HVDC capacity and South Island Surplus Generation Capacity in 2030

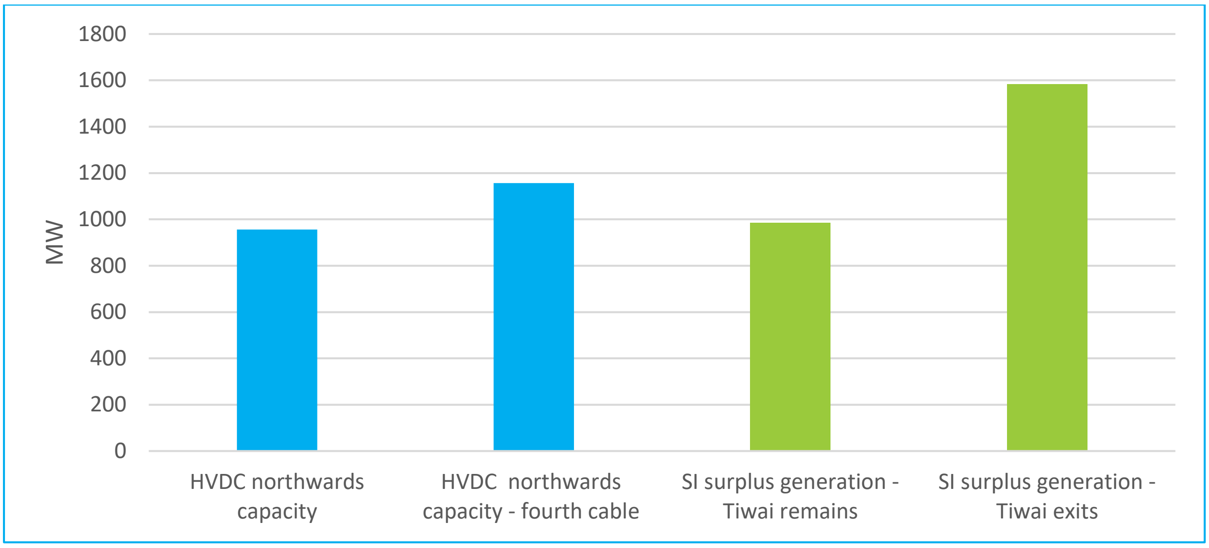
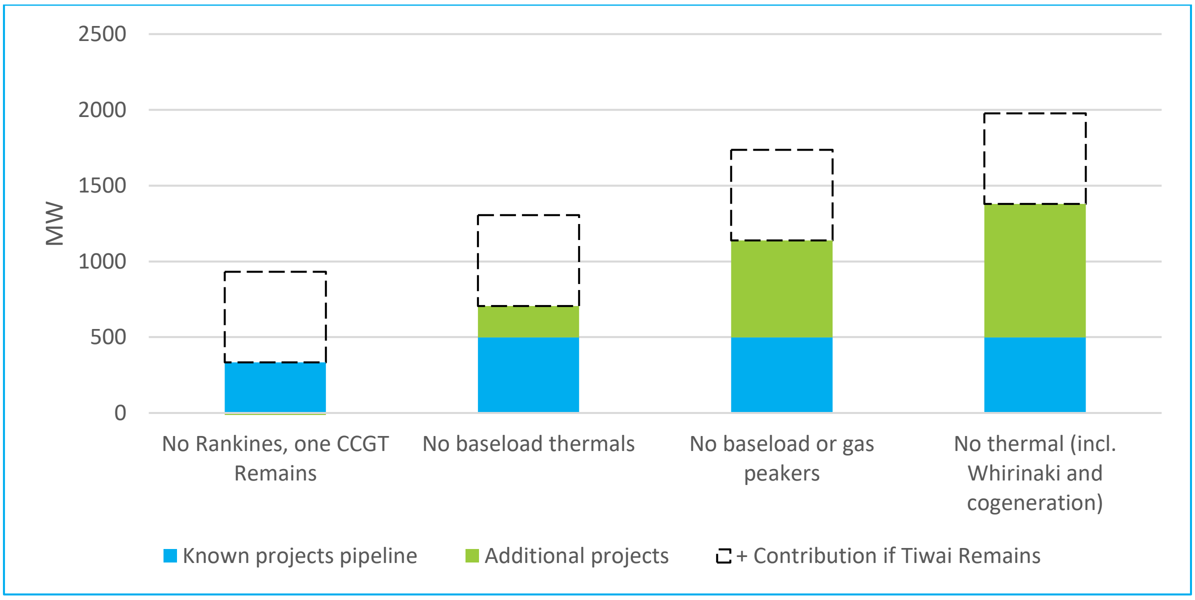


Figure 29 below shows the potential impact on the winter capacity margin if the HVDC were upgraded with a fourth cable and convertor[7]. Such an HVDC upgrade is not considered in the 2020 Transmission Planning Report and is discussed here for illustrative purposes only. Additional contributions to North Island winter capacity margins are for new supply projects across both Islands. The benefits to North Island capacity margins will be considerably reduced if either Tiwai remains or if its load were replaced after its closure.

Figure 29: Additional capacity contribution from national projects required in 2030 to meet the 780 MW security standard: No HVDC constraint



[7] Along with any other required grid upgrades to support a greater quantity of Northwards transfer across the HVDC.

6.3.3 The New Zealand Battery Project

The government's New Zealand battery project has the objective of "… providing comprehensive advice on the technical, environmental, and commercial feasibility of pumped hydro and other potential energy storage projects". The project will investigate, amongst other options, the Lake Onslow pumped hydro scheme. The Interim Climate Change Commission indicated that this scheme "would provide for a pumped hydro station of about 1,000 MW to be built and storage capacity of around 5,000 GWh".

The relative contribution that this project could make to our 'No thermal incl. Whirinaki and cogeneration' is shown in Table 7. As can be seen, Lake Onslow could potentially make a substantial contribution to New Zealand energy margins. Its contribution to North Island capacity contributions will be constrained by the future Northwards capacity of the HVDC and changes in South Island demand.

Table 7: Potential Contribution from Lake Onslow to Security Margins – Medium Demand Scenario

Margin	Contribution	Contribution as % required to maintain upper security standard
New Zealand winter energy	~5000 GWh (lake full at the end of summer)	~95%
North Island winter capacity - *With no HVDC upgrade and Tiwai closure in 2024*	0 MW	0%
North Island winter capacity - *With HVDC upgraded with a 4th cable and Tiwai remains*	~290 MW	~14%

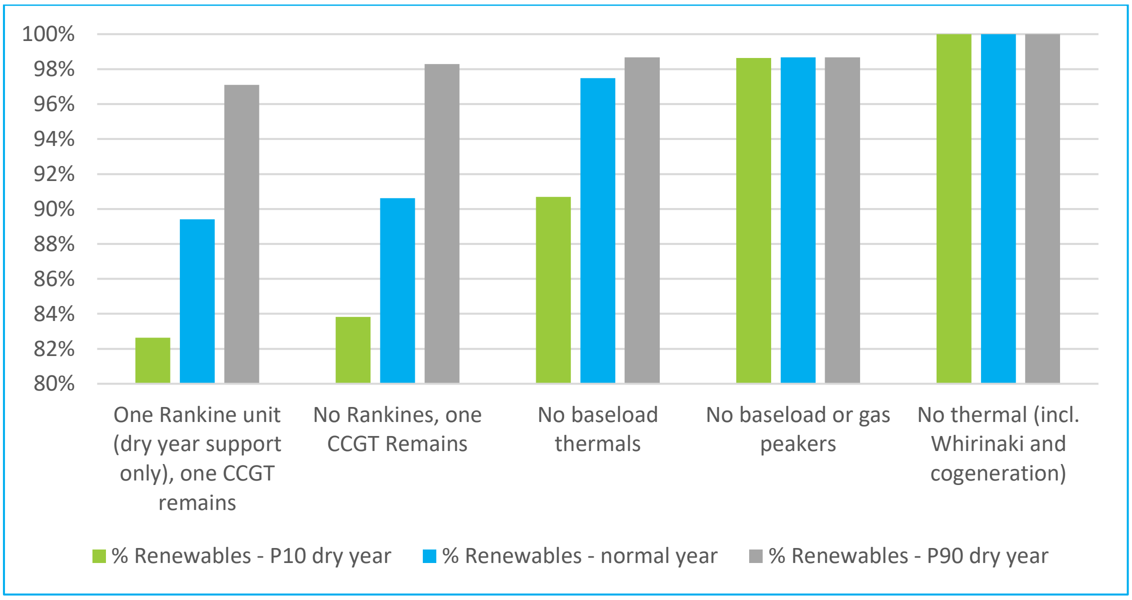
6.4 Renewable Generation Percentage Estimates

Figure 30 shows indicative estimated renewable generation percentages for each thermal generation scenario. Renewable generation percentages are shown for a normal year (blue bar), dry year (P10, green bar) and wet year (P90, grey bar) hydrological year. The estimated renewable generation percentages are for our Medium Demand scenario. The amount of renewable generation assumed for each thermal generation scenario is equal to that required to maintain New Zealand winter energy margins *at* the upper security standard.

If only renewable generation is used to maintain energy security standards this implies a level of renewable generation 'over build' for the 'no Rankine units, one CCGT remains' scenario and other scenarios with less thermal generation. This means for wet years the amount of renewable generation capacity will be greater than required to meet demand.

Except for the 'no thermal, incl. Whirinaki and cogeneration' thermal generation scenario we assume the maximum amount of renewable generation (produced in a given year) is constrained by gas cogeneration. This type of generation is likely to operate on a 'must run' basis given that it likely to also generate process heat for its host industrial facility.

Figure 30: Indicative, estimated renewables percentages: Medium Demand scenario and as required to maintain a 16% security standard



There are limitations to our estimates.

The use of alternative technologies, such as pumped storage or large industrial demand response, have not been taken account in our analysis and these would alter our P10 and P90 estimates. These alternative technologies may also help to reduce the quantity of renewable generation over build required.

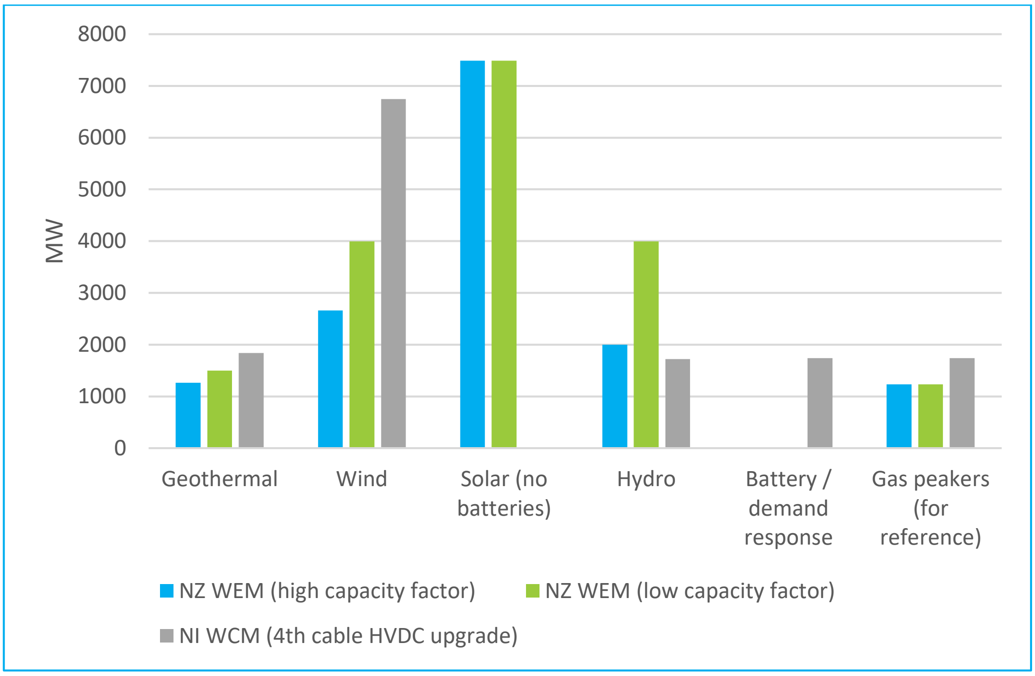
The amount of new renewable generation that we assumed would not be sufficient to maintain winter capacity margins above security standards. It is uncertain as to how winter capacity margins would be maintained for each thermal generation scenario. If renewable generation over build was found to be a favoured option, then this would increase the renewable generation percentages that we show below.

6.5 Maintaining Margins with High Proportions of Renewables

6.5.1 Scale of the challenge

Displacing thermal generation will be challenging. To give an idea of the scale of this challenge - for our 'no thermal, incl. Whirinaki and cogeneration' thermal generation scenario - Figure 31 below shows the hypothetical amount of capacity required for different technologies assuming that technology was used solely to maintain margins. This is for illustrative purposes only, a mix of technologies will be deployed to achieve higher levels of renewable generation.

Figure 31: Hypothetical amount of capacity required for different technologies – Medium Demand Scenario with HVDC 4th Cable Upgrade – For illustrative purposes



6.5.2 Technology options to maintain margins

The known pipeline of projects is dominated by traditional forms of renewable generation. As we transition away from a reliance on thermal generation other technologies, listed in Figure 32, may start to contribute to maintain a secure electricity system.

Figure 32: Non-thermal technology options to improve energy or capacity margins

To improve **energy** margins:

- Renewable generation
- Demand response at scale – industrial or commercial facilities able to turn down production in dry years
- Energy storage at scale – including pumped hydro storage
- 'Dispatchable' generation using renewable or zero carbon fuels (e.g. biomass, hydrogen, biodiesel)

To improve capacity margins:

- Renewable generation
- Demand response
- Grid or embedded batteries – providing reserves or energy during peaks
- Interruptible load – to free up generation used for reserves
- HVDC upgrades – to use surplus South Island generation
- Pumped hydro storage
- 'Dispatchable' generation using renewable or zero carbon fuels (e.g. biomass, hydrogen, biodiesel)

TRANSPOWER

Appendices for Security of Supply Annual Assessment 2021

System Operator

Version: 1.0

Date: September 2021

Version	Date	Change
1.0	September 2021	First release

IMPORTANT

Contact Details

Email: system.operator@transpower.co.nz

Contents

Appendix 1: Margin Assessment Methodology

1.1 Margin Assessment Methodology

1.11 Winter Energy Margins Assessment

There are two winter energy margins. The New Zealand 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:

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

For the purposes of calculating winter energy demand and winter energy supply winter is defined as the period from 1 April through to 30 September.

The components in the above formulas are defined in Tables 1 and 2.

Table 1: Summarising the New Zealand winter energy margin components

Component	Comprises of	Description
New Zealand expected energy supply (GWh)	Thermal Generation GWh	Maximum expected thermal generation available to meet winter energy demand allowing for forced and scheduled outages, fuel supply availability and operational constraints
	Thermal Generation Forced and Scheduled Outages	5.4% for combined cycle gas turbines and 6.7% for coal-fired Huntly units
	Thermal Generation Fuel Supply Availability Deratings	Thermal deratings due to fuel availability are provided in main report, Section 4
	Thermal Generation Operational Constraint Deratings	Thermal generation has been reduced by 92 GWh in the North Island to reflect spinning reserve and frequency keeping requirements[1]

[1] This is different than that suggested in the Electricity Authority's Security Standards Assumption Document. 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 Electricity Authority has

	Mean Hydro generation GWh	Expected winter hydro generation based on mean hydro inflows over the historic record
	Hydro storage at 1 April	Hydro storage at the start of winter is 2,750 GWh
	Other Generation GWh	Expected winter energy available from cogeneration[2], geothermal generation, wind generation, solar generation, embedded generation and batteries based on information from generation companies and supplemented by market information. Domestic solar generation and domestic battery generation is as derived for the winter energy demand forecast.
New Zealand expected energy demand (GWh)	NZ Energy Demand GWh	Expected winter energy demand on a gross basis, inclusive of transmission losses and adjusted for demand response. Where gross demand includes embedded generation.
	Transmission Losses	Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor of 3.5 % for New Zealand
	Demand Response	Winter energy demand has been reduced by 2 per cent to allow for voluntary demand response. These reductions include voluntary demand response resulting from high spot prices or retailer pricing initiatives. Reductions in demand as a result of savings campaigns or forced rationing are, though, excluded.

Table 2: Summarising the South Island winter energy margin components (where different to above)

Component	Comprises of	Description
Expected HVDC transfers south (GWh)	HVDC GWh	Expected winter HVDC transfers received in the South Island. It is assumed that the North Island will be able to supply the South Island with 2,101 GWh (480 MW average transfer) 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

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.

[2] 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.

		restriction the lesser value of 2,101 GWh or the net North Island energy surplus is used.
	Hydro storage at 1 April	Hydro storage at the start of winter is 2,400 GWh
	Transmission Losses	A static loss factor of 4.5 % is used for South Island

1.12 North Island Winter Capacity Margin Assessment

The North Island Winter Capacity Margin is calculated as:

$$\begin{aligned} NI\ WCM = {} & North\ Island\ expected\ capacity - North\ Island\ expected\ demand \\ & + expected\ HVDC\ transfer\ north\ (function\ of\ SI\ capacity - SI\ demand) \end{aligned}$$

For the purposes of calculating winter energy demand and winter energy supply winter is defined as the period from 1 April to 31 October.

The components in the above formula are defined in Tables 3.

Table 3: Summarising North Island winter capacity margin components

Component	Comprises of	Description
North Island expected capacity (MW)	Thermal Generation MW	Installed capacity of thermal generation allowing for forced and scheduled outages, fuel supply availability and operational constraints
	Thermal Generation Forced and Scheduled Outages	3% for all thermal generation
	Thermal Generation Fuel Supply Availability Deratings	No thermal deratings due to fuel availability are applied
	Thermal Generation Operational Constraint Deratings	No thermal deratings due to operational constraints are applied
	Hydro Generation MW	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and de-rated to account for operational constraints

	Hydro Generation Forced and Scheduled Outages	2% for all controllable hydro generation
	Operational Hydro Generation Deratings	Matahina, Patea and Tokaanu are derated by 13 MW, 5 MW and 20 MW respectively to account for their limited short-term storage. Waikato hydro scheme is derated by 60 MW to account for the impact of chronological flow constraints.
	Other Generation MW	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. Assumed contributions to winter peak demand, as a percentage of capacity are: • Flexible run-of-river hydro: 81.2% • Inflexible run-of-river hydro: 72.0% • Geothermal: 91.7% • Cogeneration: 61.0% For wind generation, this assessment assumes a wind capacity contribution of 25 per cent as defined in the SSAD. For large scale solar generation and batteries, this assessment assumes a capacity contribution of 5% and 97% respectively. This will be further refined as actual operational data is obtained.
North Island and South Island expected demand (MW)	NI and SI peak demand MW	Expected average of the highest 100 hours of demand in winter inclusive of losses, by Island. This is referred to as H100 NI demand. Demand is gross, inclusive of transmission losses and adjusted for demand response.
	Transmission Losses	Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor of 2.88% within the North Island, and 4.88% within the South Island
	Demand Response	An allowance of 176 MW is made for demand response and interruptible load in the North Island at peak times. No allowance is made for South Island peak-time demand response or interruptible load.
Expected HVDC transfer north	South Island MW	The net amount of MW the South Island can supply to the North Island during peak periods. Surplus supply (SI supply capacity minus SI peak demand) is constrained by the capability of the HVDC as

		defined in Electricity Authority's Security Standards Assumption Document.

Appendix 2: Demand Forecasting Modelling

2.1 Demand Forecasting Modelling

Purpose

This appendix describes the demand forecasting modelling suite ('the modelling suite') used by Transpower's Grid Investment and Modelling team to forecast winter energy and peak demand.

Introduction

The modelling suite can forecast average demand, in MW, at each Grid Exit Point (GXP) and each half hour trading period. Having a modelling suite that produces this level of detail provides a mechanism for modelling the effect of solar Photo Voltaic (PV), batteries and 'smart' charging of electric vehicles at a daily profile level. The full set of profiles also assists in producing a wide variety of outputs for different purposes such as a forecast of winter peak demand. While the security margin assessment doesn't require GXP or regional level detail, we use the full capabilities of the modelling suite to produce the forecast.

The modelling suite can produce different scenarios with different assumptions for base energy growth, base peak growth or different uptakes of new technologies.

Two stage approach

To account for future levels of demand growth to be different to historic levels and to be able to satisfy all the requirements of the modelling suite we have developed a two-stage forecasting method illustrated in Figure 1. The two-stage approach provides a convenient 'break' in the modelling suite for a variety of reasons, the outputs of the first stage can provide:

- A measure of base growth for energy and peak demand.
- A convenient place to bring in external forecasts of energy and peak demand (this feature if not used for winter energy and peak demand forecasts).

The outputs of stage one does not contain any half-hourly profile data. The peak is separated by season and year, and by nation, island and region. The energy outputs are by year, and nation and island. A simple flow chart for this process in shown in Figure 1. The customer forecasts at the GXP level are an important part of this process.

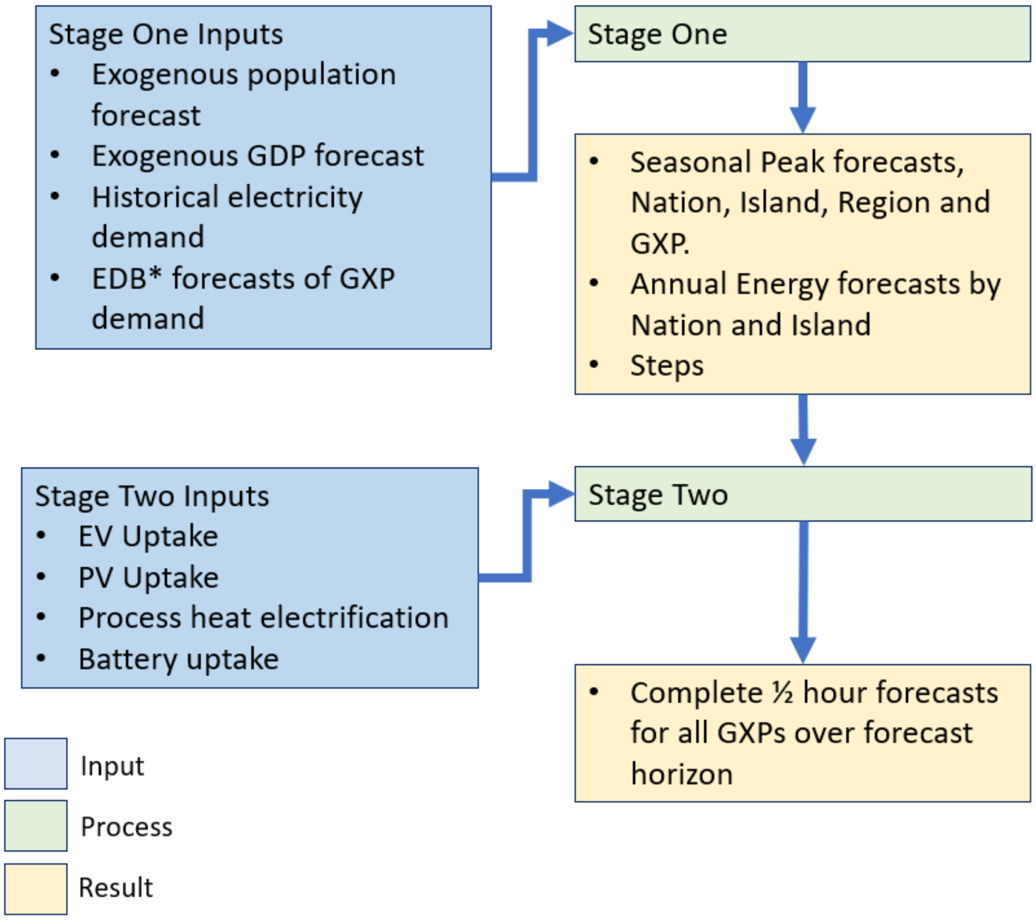
Generating base profiles

Base profiles are initially generated from historical data and scaled to match the stage one peak and energy growth. A reconciliation process is used, at the trading period level, to best preserve the hierarchy of the stage one forecasts.

Adding in new technologies

The new technologies added in stage two; electric vehicle charging, domestic solar PV, domestic batteries and electrification of process heat will all have an associated daily profile. These profiles, which can be regional, seasonal and specific to new industries say, are added on to the base profile. Some new technologies, such as batteries and smart electric vehicle charging can respond to the existing profile and adapt their profiles to 'fill-in' any troughs. Further details of the profiles associated with the new technologies, and demand forecasting in general can be found in the report and appendices of Whakamana i Te Mauri Hiko[2].

Figure 1: A high level diagram of the two-stage process, the first stage produces a hierarchy of seasonal peak and annual energy values of the forecast horizon, stage two creates complete half hourly profiles at every GXP over the forecast horizon. *EDB is an Electricity Distribution Business.



Embedded generation

Other than domestic solar PV and domestic batteries, there is no forecast growth of embedded generation in our suite. Historical embedded generation profiles are used to model the effect on the forecast profiles at the GXP level.

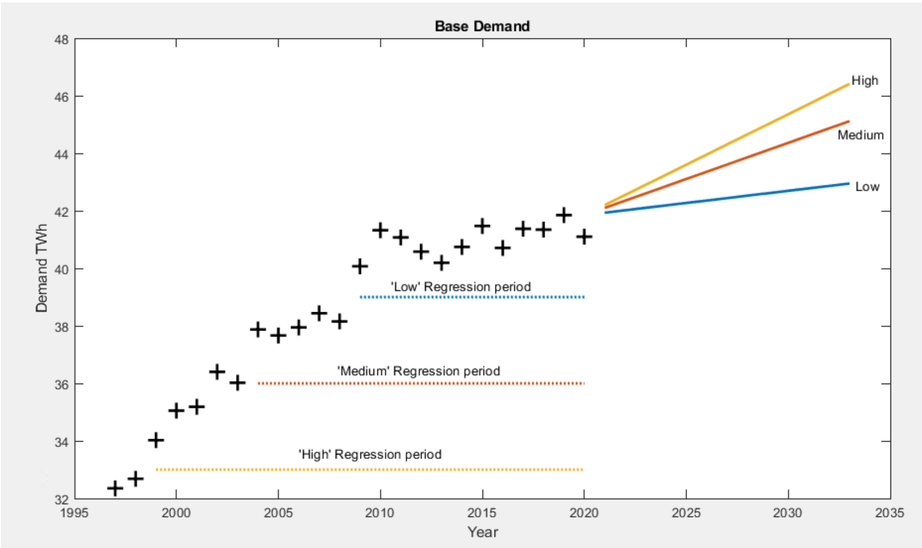
Scenarios

The modelling suite can be run to generate forecasts covering a range of different scenarios. The scenarios can include different base growth of peak and energy (stage 1) and different uptakes of new technologies (stage 2). This year's annual security of supply assessment includes 'Low Demand', 'Medium Demand' and 'High Demand' scenarios. The Medium Demand scenario is modelled on the Whakamana I Te Mauri Hiko's 'Accelerated Electrification' scenario.

The base peak growth is not varied within the scenarios, the final peak will grow by virtue of the growth of new technologies across the different scenarios. New technology uptake rates for each demand scenario, including domestic solar PV and batteries, are based on different Whakamana I Te Mauri Hiko scenarios (see below).

The base energy growth rate for each scenario is achieved through an expected forecast based on different regression windows. A shorter regression window follows the recent trend of small growth while a longer regression window captures the larger historical growth. Such an approach is not perfectly robust but serves the purpose well here. The base demand and the regression periods are shown in Figure 2. The starting points of all the base energy forecasts are adjusted to converge at the 2019 demand. We consider 2020 demand as somewhat of an anomaly due to the effects of COVID-19.

Figure 2: The base energy demand for the three scenarios derived from different regression periods.



Input assumptions

The uptakes of the new technologies are largely based on Transpower's Whakamana I Te Mauri Hiko. One notable adjustment is that the expected demand increase due to electric vehicles has been brought forward. This is to reflect the increase expected heavy vehicle electrification due to a government pledge to decarbonise public transport bus fleet bus 2035[3]. A summary of the scenario assumptions relating to Whakamana i Te Mauri Hiko is shown below. Battery uptake and the effect on demand and peak is small in the forecast horizon. Battery uptake for all three scenarios are most similar to the Whakamana I Te Mauri Hiko mobilise to decarbonise scenario.

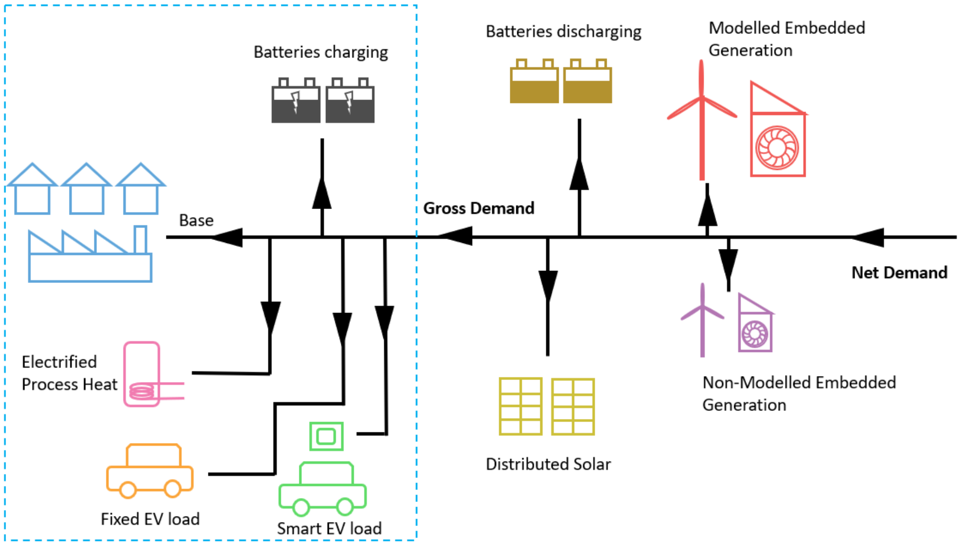
Table 4: Technology uptake assumption in relation to Transpower's Whakamana i Te Mauri Hiko scenarios

	Low	Medium	High
Process Heat	15% higher than Business As Usual	Accelerated Electrification	Mobilise to Decarbonise
Total EV Load[4]	Measured Action	Accelerated Electrification	Mobilise to Decarbonise
Solar[5]	Business as Usual	Accelerated Electrification	Mobilise to Decarbonise
Tiwai	Exiting end of 2024		

Forecast

The modelling suite is required to separate out the gross and the net demand, i.e. batteries are treated separately depending on whether they are charging or discharging. Furthermore, embedded generation is categorised as 'modelled', or 'non-modelled'. In almost all cases modelled embedded generation is larger generation offered into the wholesale market. Winter supply contributions for modelled embedded generation are based on confidential information provided by generation companies and supplemented by historic market information. Winter supply contributions for non- modelled generation are as derived by the demand forecast process. A graphic of different types of supply and demand is shown in Figure 3. We have used the convention that all power is pointing towards the load or generator, thus giving any generation as a negative load.

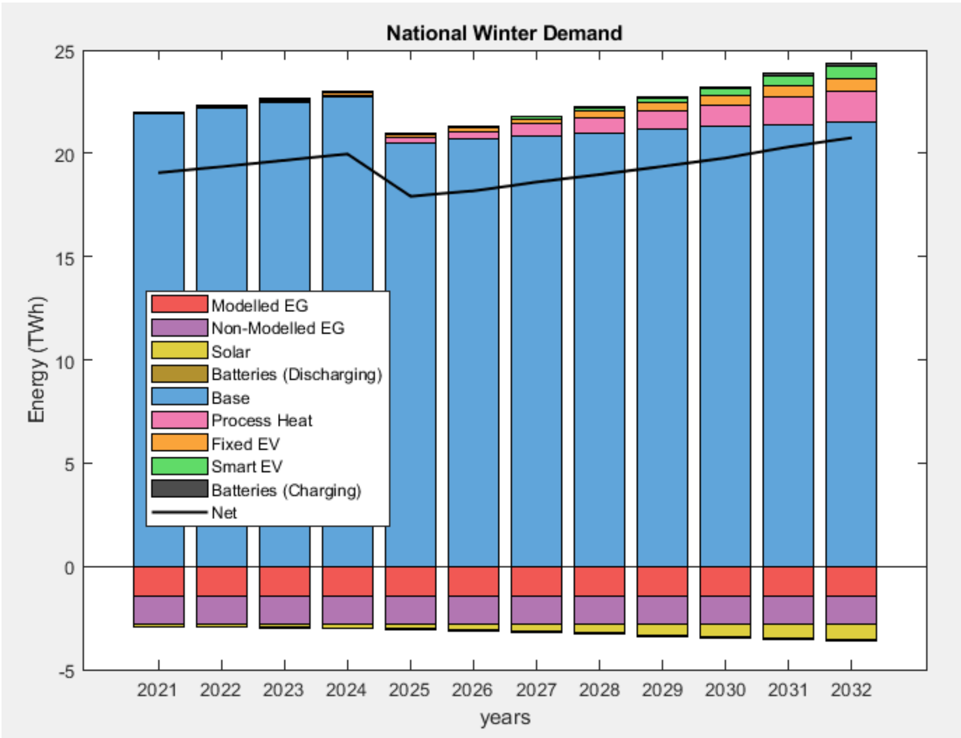
Figure 3: The component of stage two and the different components of embedded generation. In this diagram generation is treated as a negative load.



Winter Energy Demand

Forecast energy demand is reported for each island and the nation for every month. Energy demand can then be separated out into 'winter', which in this case is from 1 April to 30 September. The growth of New Zealand winter energy demand is shown in Figure 4. The individual components that make up the gross demand, fixed and smart electric vehicle charging, electrification of process heat and batteries charging, are also shown. Winter energy demand as used in the assessment included transmission losses and demand response. These are added in as a post processing step by the System Operator's market and business team.

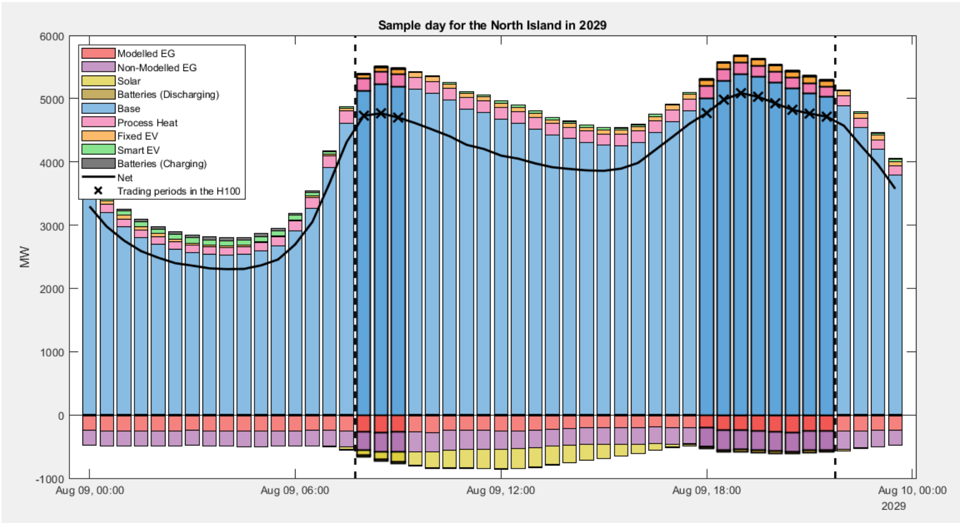
Figure 4: New Zealand Winter Energy Demand for the Medium Demand scenario. The different types of embedded generation are shown.



Winter Peak Demand

Winter peak demand is reported as 'H100' demand, that is, the average of the highest 200 net demand trading periods during winter daytime. For this definition 'winter' is from 1st April to 31st October and daytime is from 7am to 10pm. A sample day for the North Island is shown in Figure 5, the trading periods from this day which are part of the H100 are highlighted. Winter peak demand as used in the assessment includes transmission losses and demand response. These are added in as a post processing step by the System Operator's market and business team.

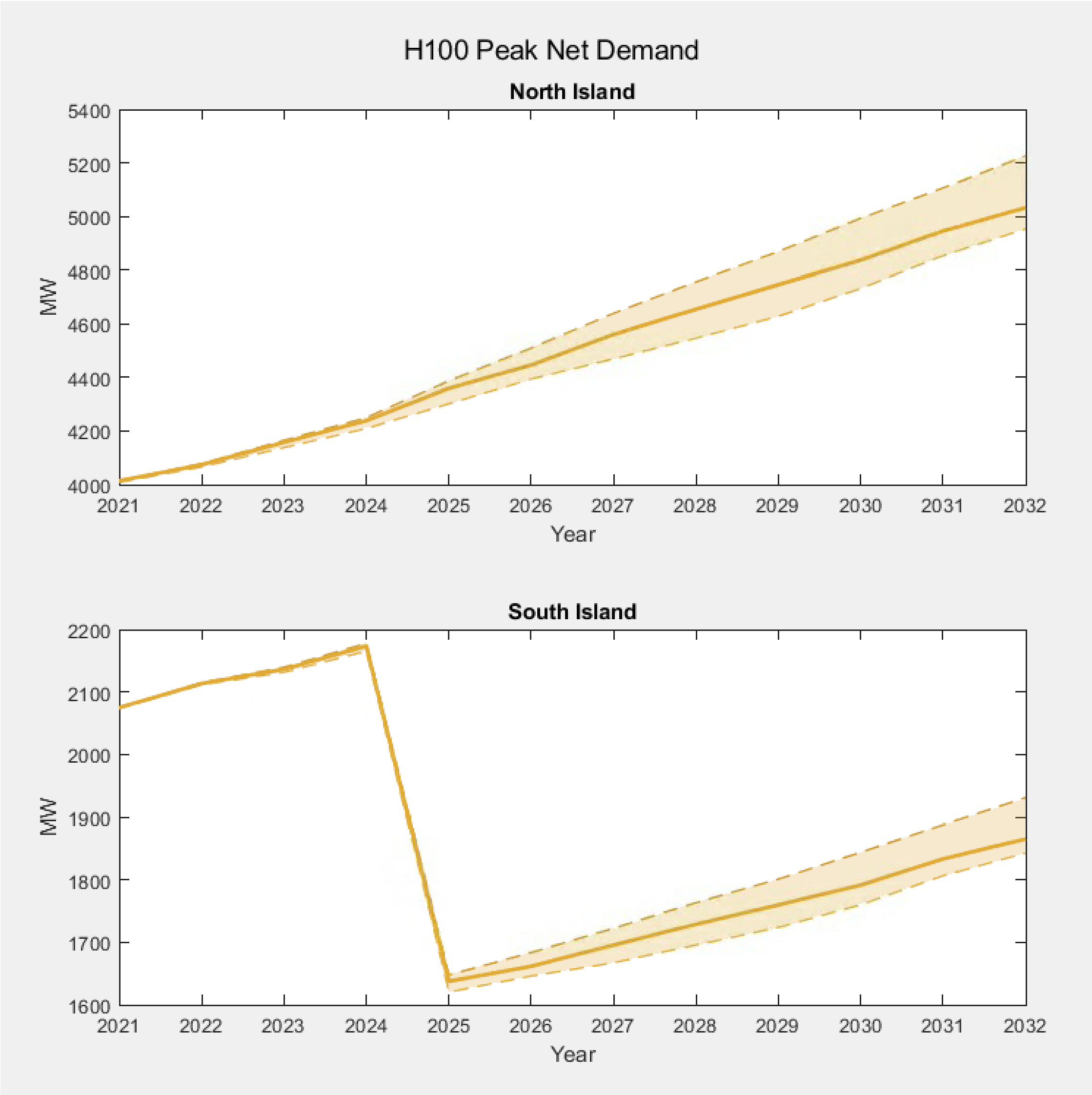
Figure 5: A sample day for Medium Demand forecast showing which trading periods are used for the H100. The EG contributions during these periods are also reported. The net demand used for the H100 analysis is denoted by the marker 'x' and the trading periods have thicker borders.



The separate embedded generation components are reported. The components that make up the gross, i.e. base demand, electric vehicle charging, electrification of process heat and batteries charging, are also shown.

Winter peak demand for both Islands, showing the extent of the 'Low', 'Medium' and 'High' Demand scenarios is shown in Figure 6.

Figure 6: Winter peak demand over the 'Low', 'Medium' and 'High' Demand scenarios



Appendix 3: Gas Supply Availability

3.1 Gas Supply Availability

3.11 Introductions

Our scenarios assume that gas generators will have access to enough gas to contribute to security margins at their maximum available capacity, from 2023 until at least the end of the decade. Gas generator installed capacity will be de-rated for 2021 - 2022, to reflect gas supply constraints from the Pohokura gas field. This section outlines the basis for these assumptions.

This analysis has been undertaken given:

- Stakeholder feedback.
- Some our largest gas fields have an end of life within 10-15 years.
- Potential for reduced incentives for further investment in gas exploration and development. Reasons for this may include restrictions on oil and gas exploration and higher carbon prices.

3.12 Dry Year Gas Supply Margin

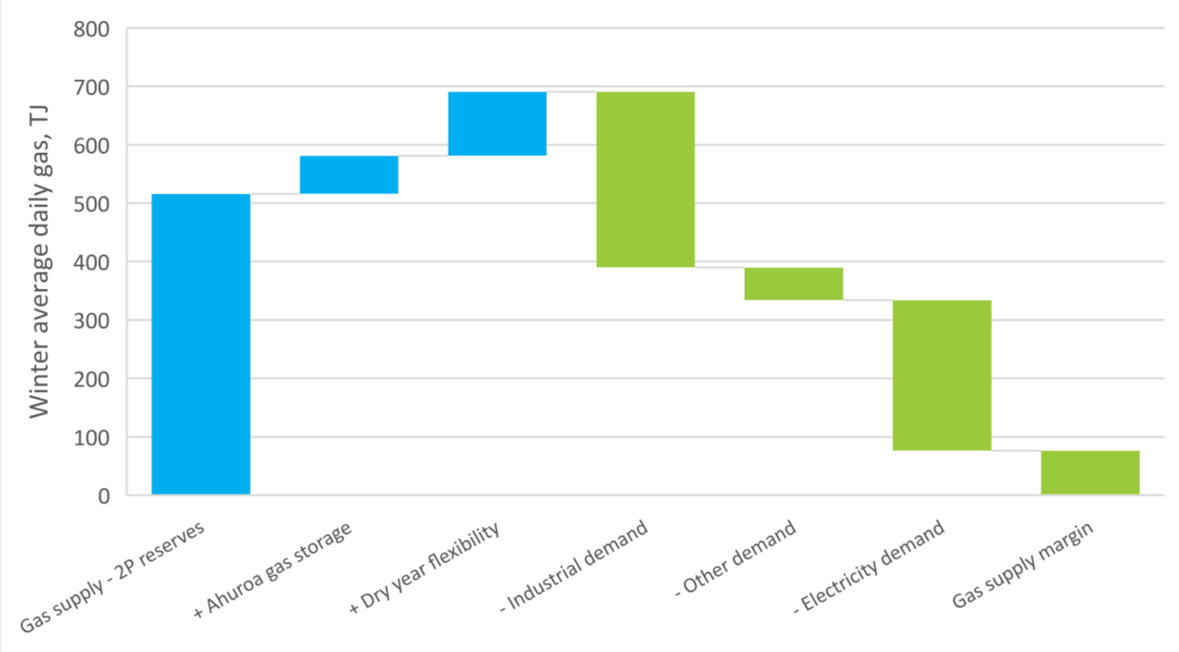
To evaluate gas supply adequacy, we estimate a dry year gas supply margin out for the next ten years. This margin is the estimated daily difference in gas supply and demand during a dry year emergency.

To estimate daily demand during a dry year emergency we assume:

- All gas generators operate at their maximum capacity, with an allowance for outages.
- There is a substitution of gas demand from major industrial gas users to gas generators during a dry year emergency. We have assumed that industrial gas users will reduce their demand, in aggregate, by 110 TJ /day.
- Gas demand for users other than gas generators is estimated using historical demand information, together with an allowance for future fuel substitution from gas to electricity.
- From 2023 onwards we assume the Ahuroa Gas Storage facility has enough gas stored to operate at its maximum extraction rate throughout a dry year emergency. For 2021 and 2022 gas storage is based on confidential information.
- TCC is decommissioned in 2024.

An example dry year gas supply margin is shown below, where gas production is as estimated for 2023.

Figure 7: Example gas supply margin calculation: 2023 Business as usual



3.13 Dry Year Gas Supply Margin Scenarios

Dry year gas supply margins have been estimated for the following three scenarios:

- **Business as usual**: Existing gas generation is available until at least the end of 2030. No new gas generation is commissioned.
- **New gas generation**: In the second half of this decade, an additional 200 MW of gas generation is commissioned in 2026 and a further 200 MW of this type of generation is commissioned in 2028.
- **Reduced demand flexibility**: Industrial gas users will reduce their demand, in aggregate, by 60 TJ/day . This assumes a much lower level of demand flexibility during a dry year emergency.

3.14 Dry Year Gas Supply Margin – Forecast 2P Reserves

We first estimate dry year gas supply margins with gas supply set equal to:

- Forecast production out to 2022, based on confidential information from gas producers.
- Forecast 2P reserves as published by the Ministry of Business Innovation and Employment (MBIE)[3].

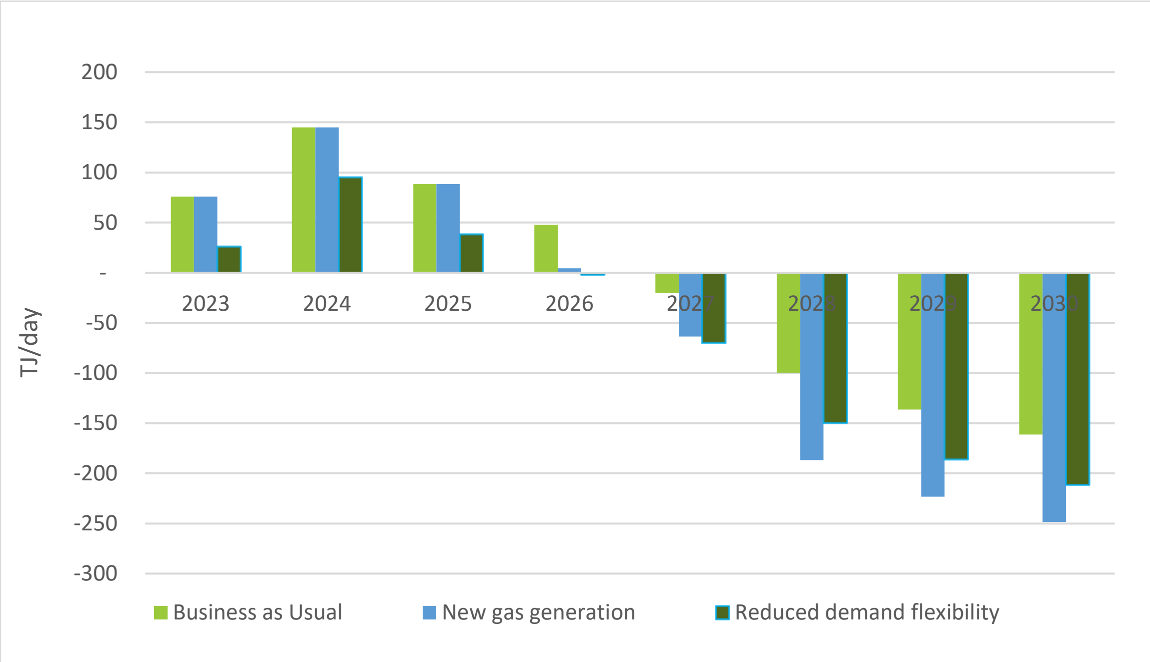
Reserves are known gas resources that are anticipated to be technically and commercially recoverable[4]. The 2P designation means that there is a 50% probability that the reserves will be recovered.

[3] As of January 2021, published here.
[4] A more comprehensive definition is available here.

Dry year gas margins are insufficient for 2021 and 2022, due largely to reduced gas production from Pohokura. For these years, we will de-rate the installed capacity of gas generators, consistent with other system operator security of supply modelling[5].

Dry year gas margins post 2022 are shown below. For our business as usual scenario, margins are adequate from 2023 out to at least 2026. For our reduced demand flexibility scenario, margins fall below zero one year earlier than our business as usual scenario, high lighting the importance of industrial gas user flexibility. For all scenarios further gas reserves will need to be accessed after 2026 to maintain adequate dry year gas supply margins. The new gas generation scenario shows that this date would most likely move forward if additional gas generation were built before 2024.

Figure 8: Dry Year Gas Supply Margins - 2P Reserves - From 2023



3.15 Contingent Gas Resources

Further investment in existing gas fields and facilities has the potential to unlock contingent gas resources and ensure ongoing gas supply security. Contingent gas resources are those which are potentially recoverable, but which are not currently considered to be commercially recoverable.

While it is unlikely that all contingent resources will be able to be developed in the future, they arguably provide a yard stick of potential future gas supply. In their report "Long term gas supply and demand scenarios – 2019 update", Concept Consulting assumed that, as a central estimate, 75% of 2C contingent resources could be developed.

We roughly estimate the approximate proportion of 2C contingent resources, as reported by MBIE, that would have to be developed in 2030 to ensure there is enough gas for gas generators during a dry year emergency. To do this we simple covert 2C contingent resources into an approximate daily

[5] See our 'Electricity Risk Curve Update Log' document for further detail. Available here.

supply quantity, by assuming that these resources would be recovered at a constant rate over a 15-year period.

We have received some feedback that the use of contingent resources in this manner may be overly optimistic. Following the same approach, we also use the difference between 3P and 2P reserves as a more conservative estimate of the possible future potential of existing gas fields. The 3P designation means that there is a 10% probability that the reserves will be recovered.

Scenario	Proportion of 3P – 2P reserves that must be developed by 2030 to ensure gas security (rounded to nearest 5%)	Proportion of 2C reserves that must be developed by 2030 to ensure gas security (rounded to nearest 5%)
Business as usual	~80%	~30%
New gas generation	~125%	~45%
Reduced demand flexibility	~105%	~40%

This analysis suggests that contingent gas resources could potentially provide enough gas for all three dry year gas supply margin scenarios. For our more conservative assessment, new resources would need to be developed before 2030 for our new gas generation and reduced demand flexibility scenarios.

3.16 New Discoveries

This analysis above takes account of gas reserves and contingent resources obtained from existing gas fields. Last year's successfully exploration campaign by OMV at Toutouwai demonstrates that there may still be potential for our gas reserves to increase from gas or oil exploration and development. This type of activity may, though, tail off as restrictions on this type of activity start to bind.

3.17 Conclusions

Leaving aside this year's production issues at Pohokura, our assessment suggests that there are enough gas reserves and contingent resources from existing gas fields to ensure on-going gas supply security for this decade. There is also the possibility that recent exploration activity may add to these resources. Development of these gas resources will require on-going investment and a market environment that will continue to be favourable for such investment[6]. Recent gas sector activity would suggest that the market environment, for now at least, is one where investment in existing gas fields is a commercially viable business opportunity.

[6] For more discussion on this topic, see here.

Our assessment of gas supply security for this decade:

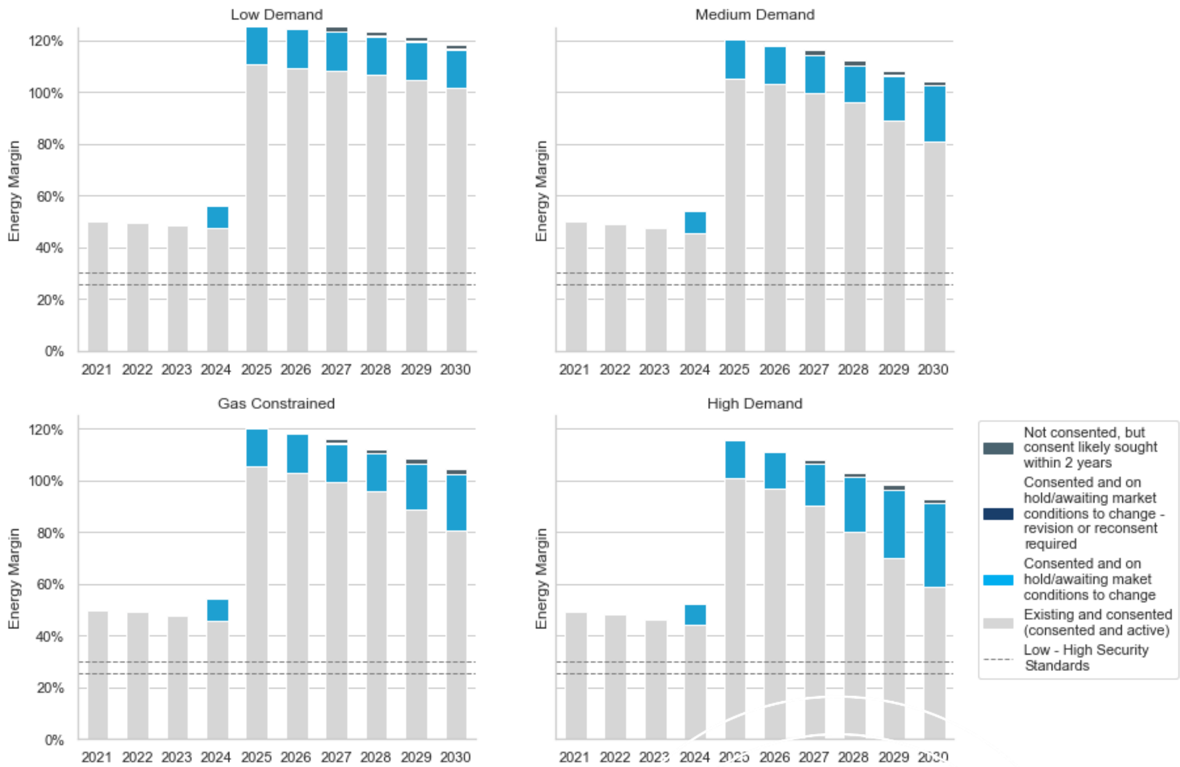
- Relies on publicly available information from MBIE.
- Assumes contingent gas reserves are a reasonable yardstick of the future potential of existing gas reserves. A more conservative approach, using the difference between 3P reserves and 2P reserves, indicates that gas supplies could tighten in the next half of this decade.
- Our new gas generation scenario stretches available known contingent reserves. For this year's Annual Security of Supply Assessment, we have not included an upper limit on new gas generation, this is something though that we may consider in the future.
- Depends on the level of demand flexibility from major industrial gas users during a dry year emergency. Reduced levels of demand flexibility will mean that either further gas resources or other forms of flexibility (i.e. gas storage) will need to be developed.

Appendix 4: South Island Energy Margin Results

4.1 South Island Energy Margin Results

South Island energy margins results are shown in the chart below. Existing and committed generation should be able to ensure efficient levels of supply availability, out to 2030, for all scenarios.

Figure 9: South Island energy margin results



Appendix 5: Further Sensitivity Results

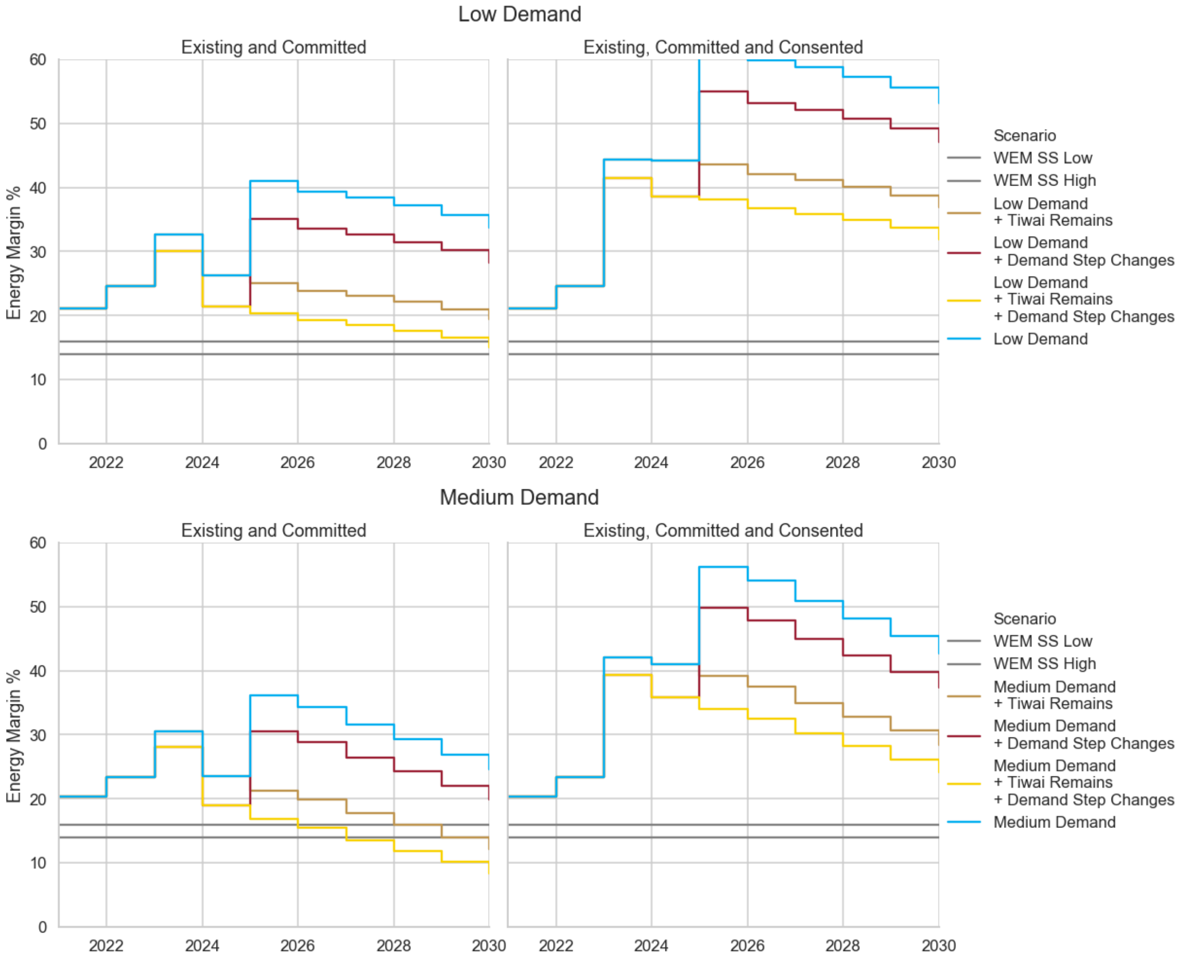
5.1 Further Sensitivity Results

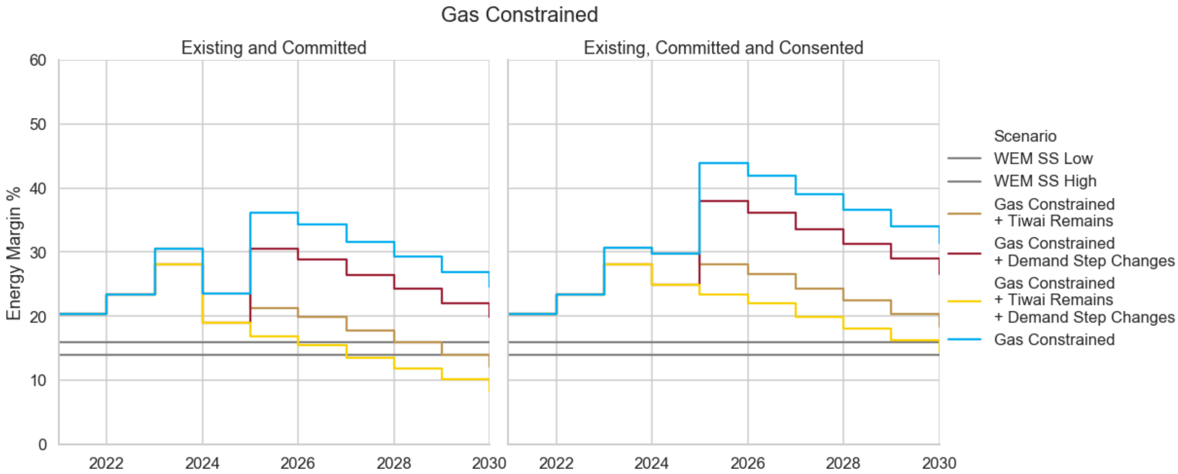
This Appendix presents selected sensitivity results for all scenarios.

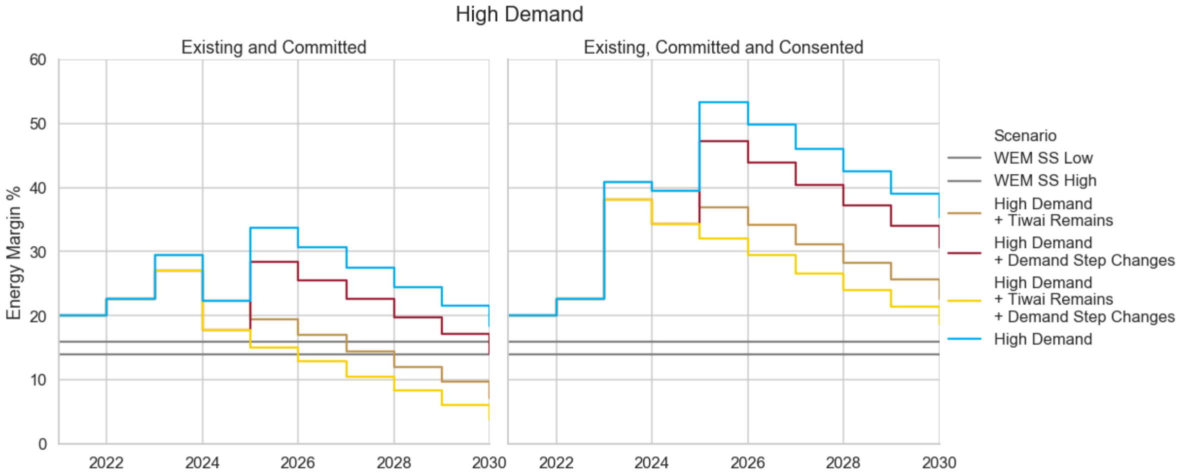
All sensitivity results can be viewed using the interactive charting tool on our website.

5.11 New Zealand Energy Margin Sensitivities

Tiwai Remains and Step Changes in Demand sensitivities

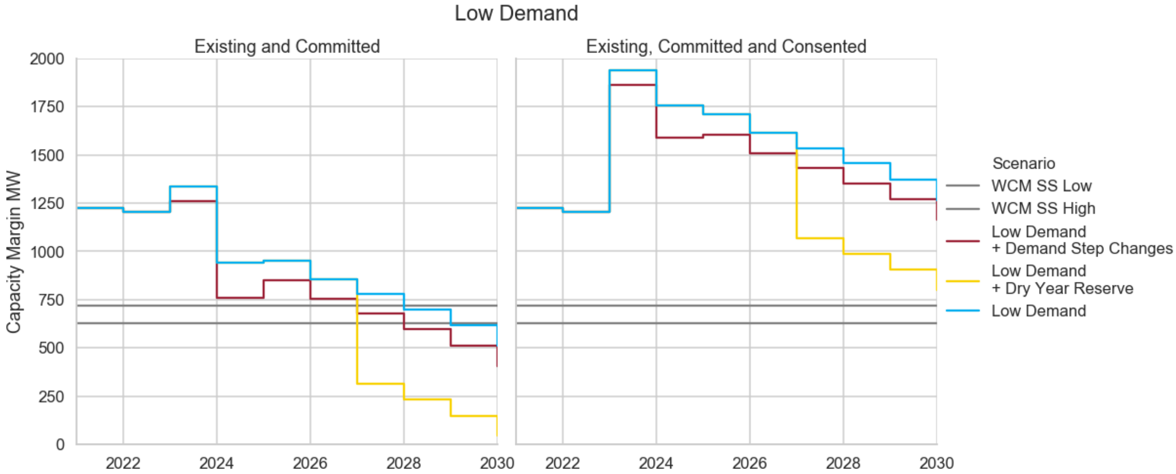


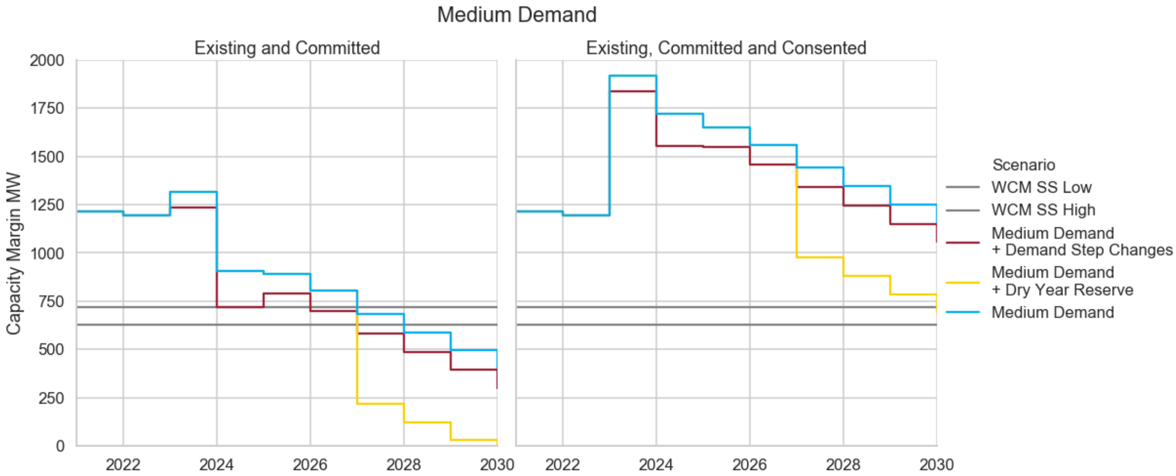


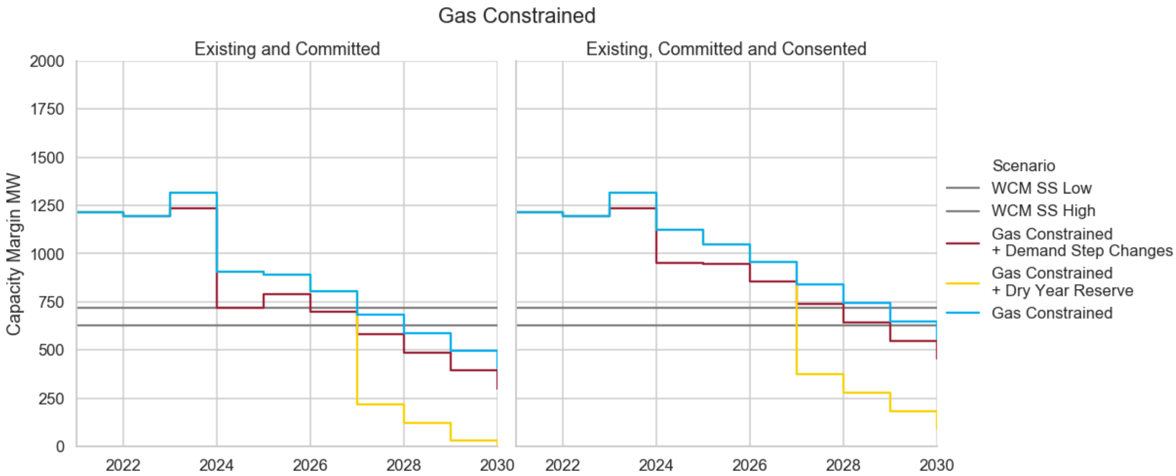


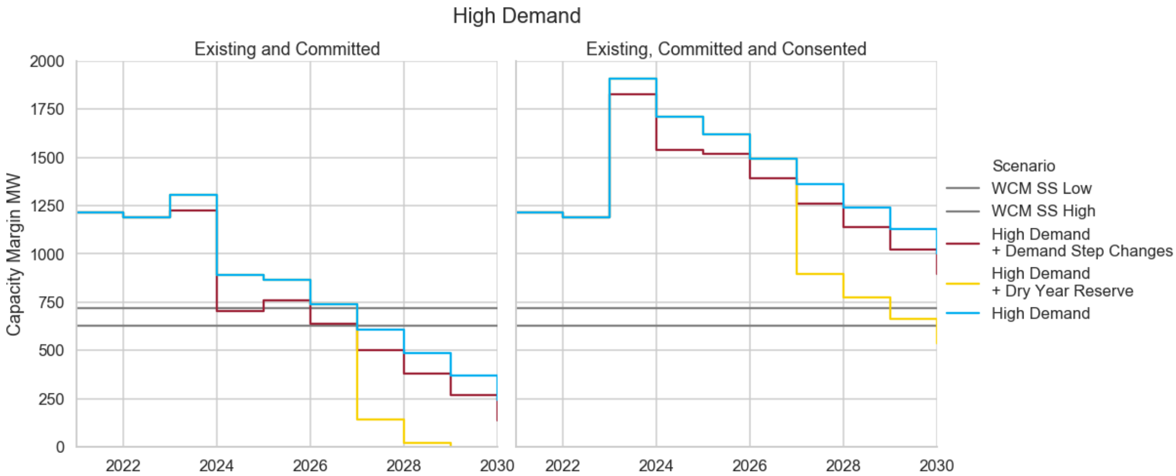
5.12 North Island Capacity Margin Sensitivities

Dry Year Reserve and Step Changes in Demand sensitivities

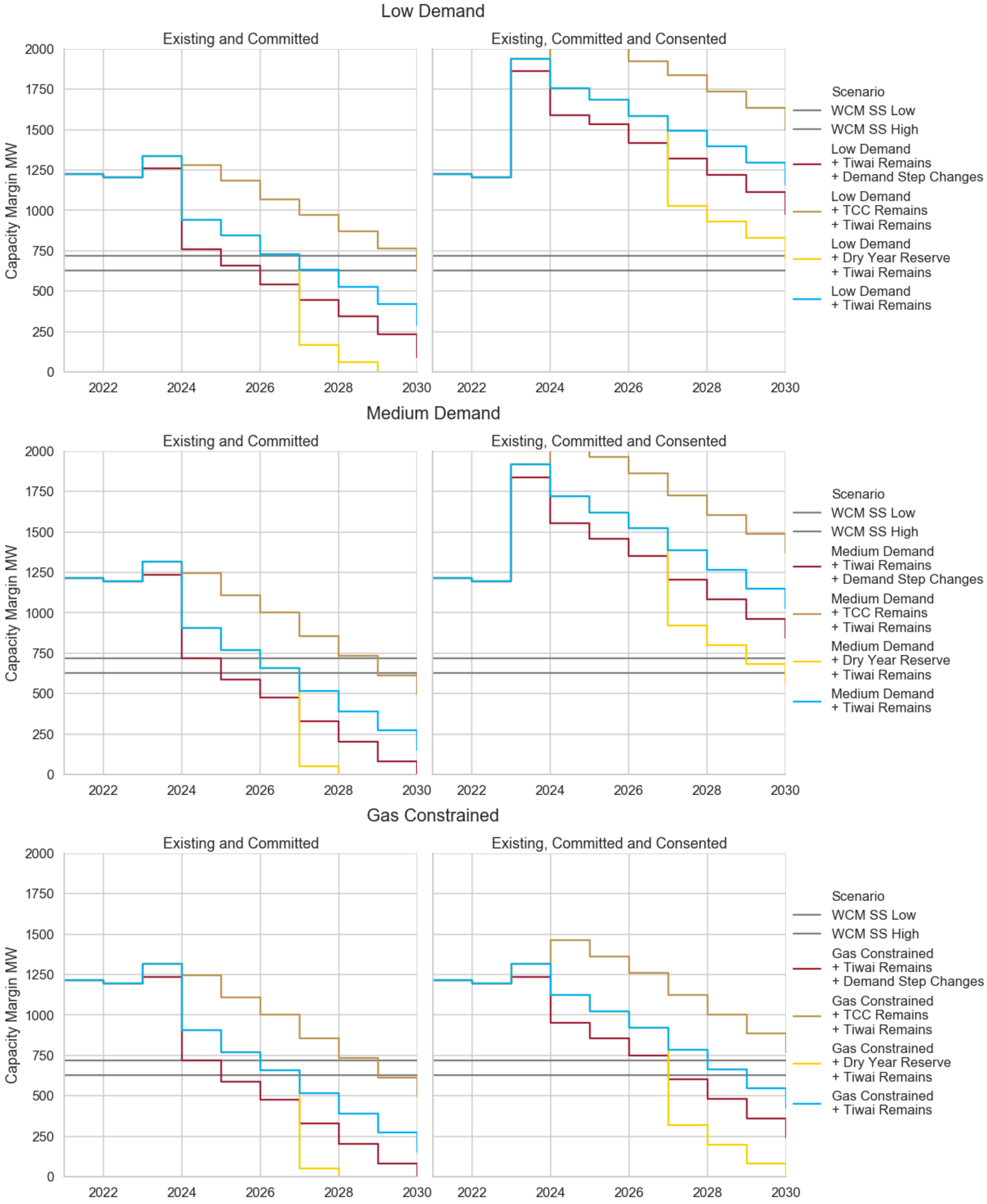


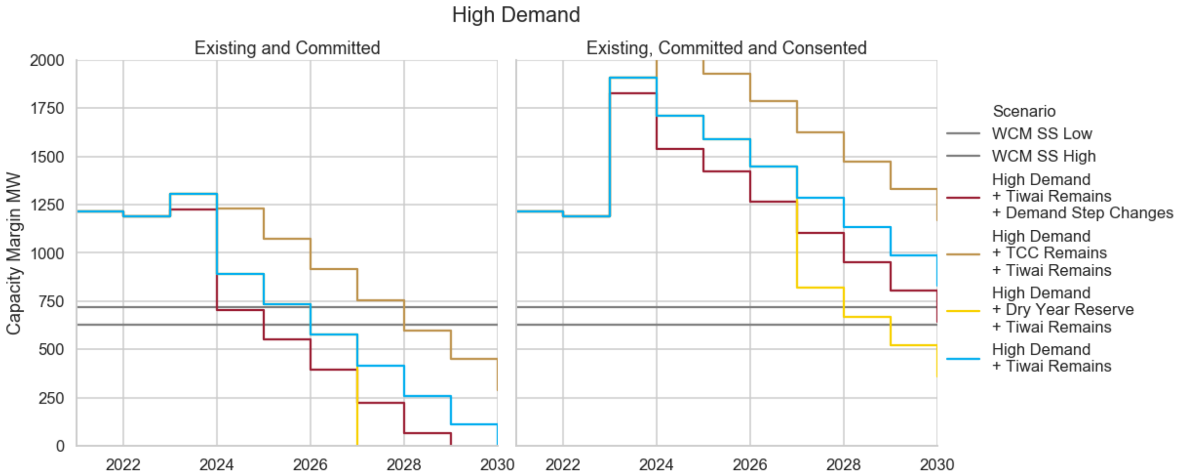

Medium Demand
Existing and Committed
Existing, Committed and Consented
Capacity Margin MW
2000
1750
1500
1250
1000
750
500
250
0
2022
2024
2026
2028
2030
Scenario
WCM SS Low
WCM SS High
Medium Demand
+ Demand Step Changes
Medium Demand
+ Dry Year Reserve
Medium Demand


Gas Constrained
Existing and Committed
Existing, Committed and Consented
Capacity Margin MW
2000
1750
1500
1250
1000
750
500
250
0
2022
2024
2026
2028
2030
Scenario
WCM SS Low
WCM SS High
Gas Constrained
+ Demand Step Changes
Gas Constrained
+ Dry Year Reserve
Gas Constrained

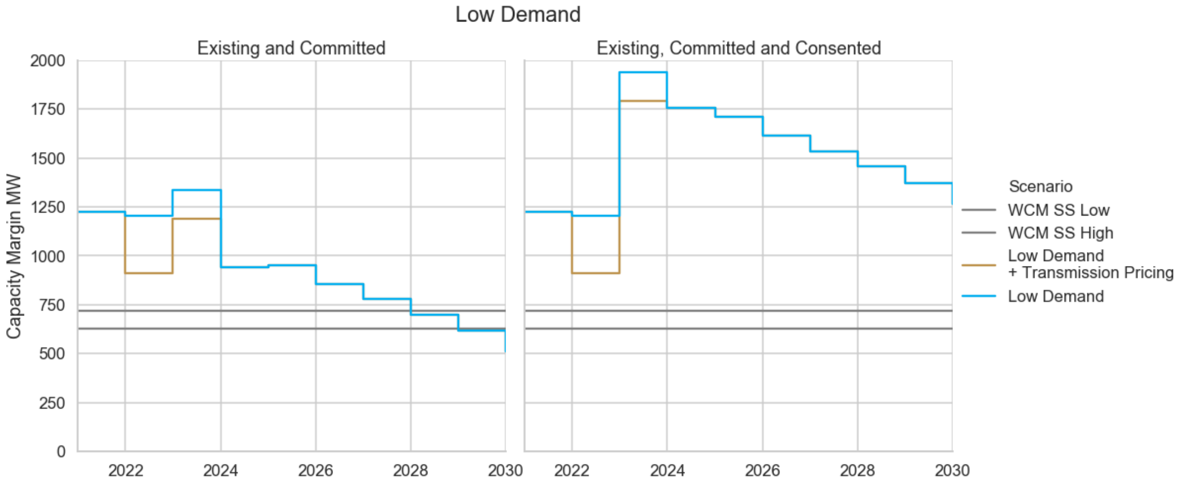

High Demand
Existing and Committed
Existing, Committed and Consented
Capacity Margin MW
2000
1750
1500
1250
1000
750
500
250
0
2022
2024
2026
2028
2030
Scenario
WCM SS Low
WCM SS High
High Demand
+ Demand Step Changes
High Demand
+ Dry Year Reserve
High Demand

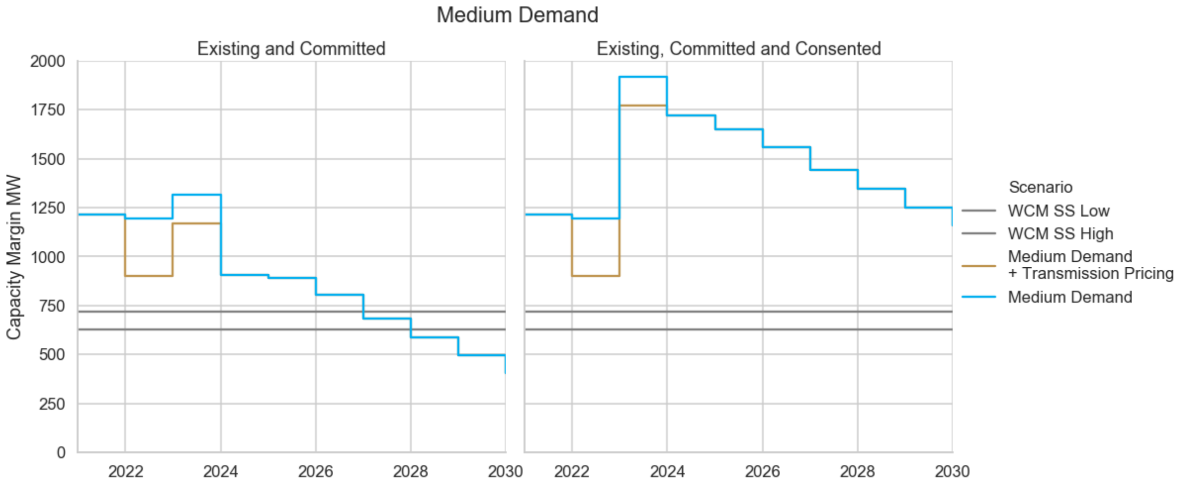
Tiwai Remains sensitivity and combined sensitivities

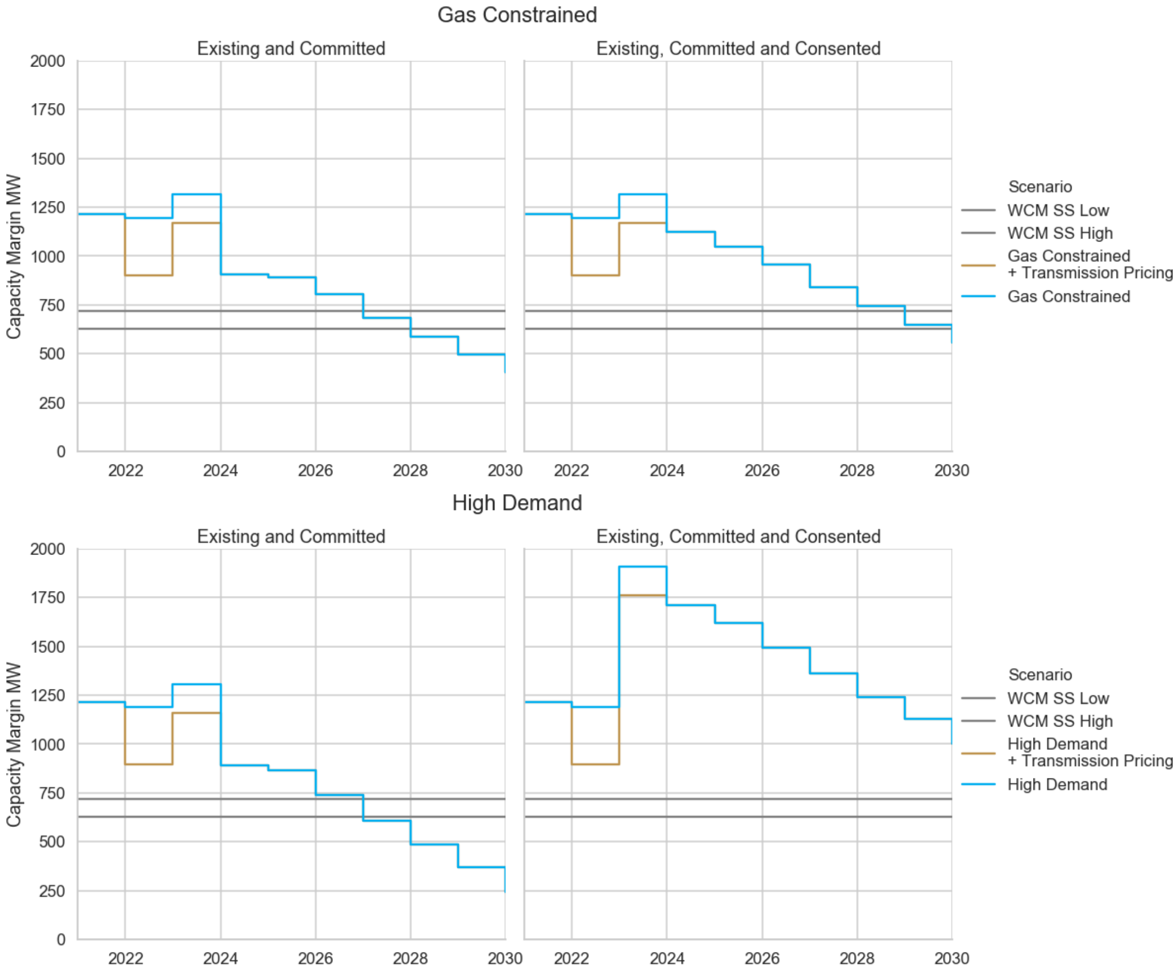




Transmission Pricing sensitivity






Gas Constrained
Existing and Committed
Existing, Committed and Consented
Capacity Margin MW
2000
1750
1500
1250
1000
750
500
250
0
2022
2024
2026
2028
2030
Scenario
WCM SS Low
WCM SS High
Gas Constrained
+ Transmission Pricing
Gas Constrained
High Demand
High Demand
+ Transmission Pricing

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