Security and Reliability Council

The system operator's 2017 annual assessment of security of supply

28 March 2017

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

Background

The Security and Reliability Council (SRC) functions under the Electricity Industry Act 2010 (Act) include providing advice to the Electricity Authority (Authority) on security of supply matters.

The Act also mandates that Transpower is the system operator and is responsible for managing security of supply emergencies and publishing forecasting of security of supply. Short-term forecasting is achieved by the system operator's risk meter and hydro risk curves in the case of energy security, and by the New Zealand Generation Balance report in the case of capacity security. Forecasting of medium-term energy and capacity security is achieved through the system operator's annual assessment of security of supply (annual assessment).

The purpose of this paper is to provide the SRC with a copy of the system operator's 2017 annual assessment and ask questions that may help to establish whether the SRC has advice to offer the Authority.

The security standards represent an efficient level of generation

The key standards set by the Authority are:

- a winter energy margin for New Zealand (NZ-WEM) of 14-16% greater than forecast energy consumption
- a winter energy margin for the South Island (SI-WEM) of 25.5-30% greater than forecast energy consumption
- a winter capacity margin for the North Island (WCM) of 630-780 MW greater than forecast peak demand (in MW).

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

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. 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.

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

The Authority has also opted to provide assumptions that the system operator must use when preparing the annual assessment.[1] These assumptions are published in the Security Standards Assumptions

[1] The reasons for this decision were to ensure consistency and provide transparency. Results against the margins should be calculated in a way that is consistent with the derivation of the margins. Sufficient information about the methodology and input assumptions should be provided for the Authority and other stakeholders to have confidence that results are being calculated appropriately.

Document (SSAD).[2] 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.

The Authority will consider when to schedule an update to the security margins and the SSAD

The security margins and the SSAD were last updated in 2012. Since then, there have been significant changes that are likely to affect the inputs to the calculation of the security margins:

- transmission investments including Pole 3 of the HVDC
- expansion of geothermal and wind generation
- retirement of the Otahuhu and Southdown thermal generators
- reductions in the amounts of frequency-keeping and instantaneous reserve procured
- improved estimates of the value of lost load.

The SSAD will need to be updated to reflect whatever assumptions get used in any revised security margins. 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 Authority will consider including an update of the security margins and the SSAD in its 2017-18 work programme.

Points to consider when interpreting the results

The annual assessment scenarios do a good job of illustrating the sensitivity of results against the margins to a few key assumptions. Any reader of the annual assessment should keep the following points in mind while interpreting the results.

The further out a scenario models, the greater the uncertainty

Obviously, analysing the year ahead is more accurate than analysing the tenth year out and there is a spectrum of certainty in between. This is visible in the difference between 'Existing & committed generation' results and 'Existing & committed, plus high, medium and low probability generation' results. The difference is non-existent in 'year one' and very large in 'year ten'.

The main reason for the difference is the size and uncertainty of the generation development project 'pipeline'.[3] This difference is influenced by other assumptions over time, particularly assumptions about annual growth in demand for electricity.

Scenarios highlight a range of possible results

The system operator models a variety of different scenarios in the annual assessment, but does not assign any probabilities to these possible outcomes. While the 'base case' scenario represents some sort of a midpoint, it should not be inferred that this scenario is known to be more or less likely than any other.

Furthermore, the model prescribed for the annual assessment is, by necessity, an over-simplification of a complex system. In reality, the events that would cause a scenario to actually occur would in turn influence the timing and likelihood of further generation development. For example:

[2] Available from http://www.ea.govt.nz/operations/wholesale/security-of-supply/security-of-supply-policy-framework/security-standards-assumptions/

[3] As discussed in section 4.2 of the attached annual assessment.

- retaining the Huntly Rankine units beyond 2022 will incentivise the deferral of other generation investment
- the closure of Tiwai would incentivise deferral of other generation investment[4]
- higher or lower demand growth would, respectively, incentivise or disincentivise generation development.

Accordingly, readers of the annual assessment should regard the scenarios as simple snapshots that almost entirely disregard feedback effects of the scenario assumptions altering the generation build likelihoods. As the system operator notes in the annual assessment, "it should be noted that a number of factors influence generation investment decisions and therefore these numbers are a guideline only." Furthermore, because these 'guideline' numbers originate with generation companies, all of their assumptions are unknown and may differ significantly from the system operator's base case (let alone all the other scenarios these numbers are used in).

There are three variables that have major effects on results

There are three variables that create the largest differences in modelling results: whether Genesis Energy's Huntly Rankine units operate beyond 2022; whether or not New Zealand Aluminium Smelters' (NZAS) Tiwai Point closes; and the difference between low and high demand scenarios.

When the Huntly Rankine units are modelled as exiting the market, this shows up as a large step-change between 2022 and 2023 in the results of all scenarios (except the 'Huntly Rankine units retained' scenario). A side-effect of modelling the Huntly Rankine units in this way is that the commitment of the units beyond 2022 is treated differently to the pipeline of potential generation that the Rankine units appear to be competing with. Rather than being assigned a probability of being retained (high/medium/low), the Rankine units are excluded entirely after 2022.

The closure of Tiwai Point would have a substantial impact on all of the NZ-WEM and SI-WEM scenarios, but negligible impact on WCM.

When demand is modelled as growing by 2% every year (the high demand scenario) versus modelled at no growth (the low demand scenario), the difference in results is major in later years. Figures 1 and 2 overleaf show demand for, and consumption of, electricity from 2004-2017.

The SRC may wish to consider the following questions.

Q1.	What further information, if any, does the SRC wish to have provided to it by the secretariat?
Q2.	Does the SRC consider that the annual assessment provides an adequate representation of generation adequacy against the security margins? Does the SRC have any recommendations for improvements?
Q3.	Does the SRC consider that generation companies would be reasonably able to estimate meaningful generation build probabilities based on the system operator's scenarios?
Q4.	What advice, if any, does the SRC wish to provide to the Authority?

[4] The system operator has attempted to mimic one significant market dynamic: it models a scenario where Tiwai closes and the Huntly Rankine units are withdrawn, as the former could precipitate the latter.

Figure 1: Total consumption of electricity 2004-2017

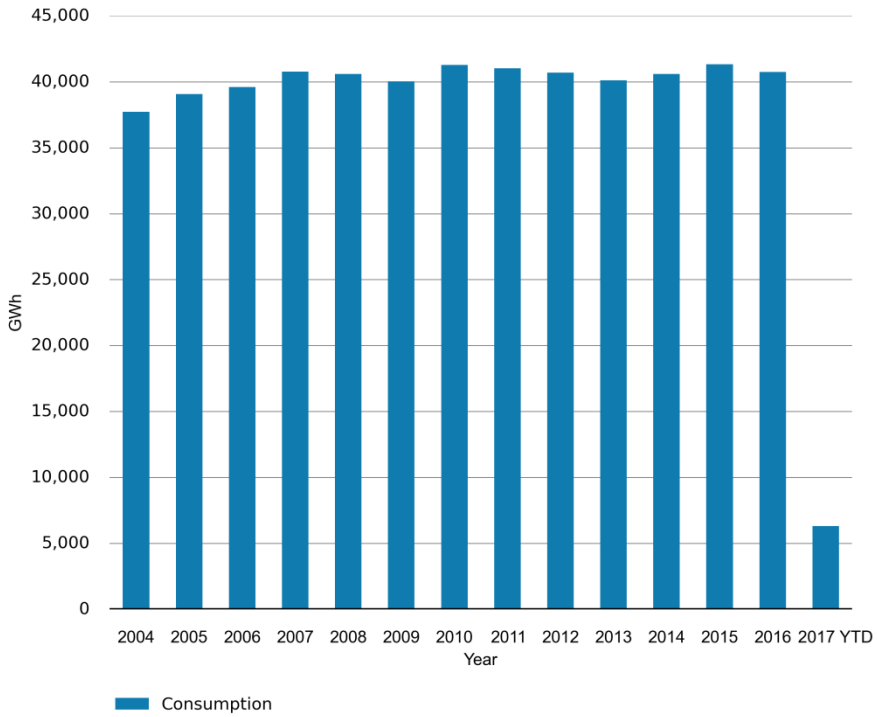
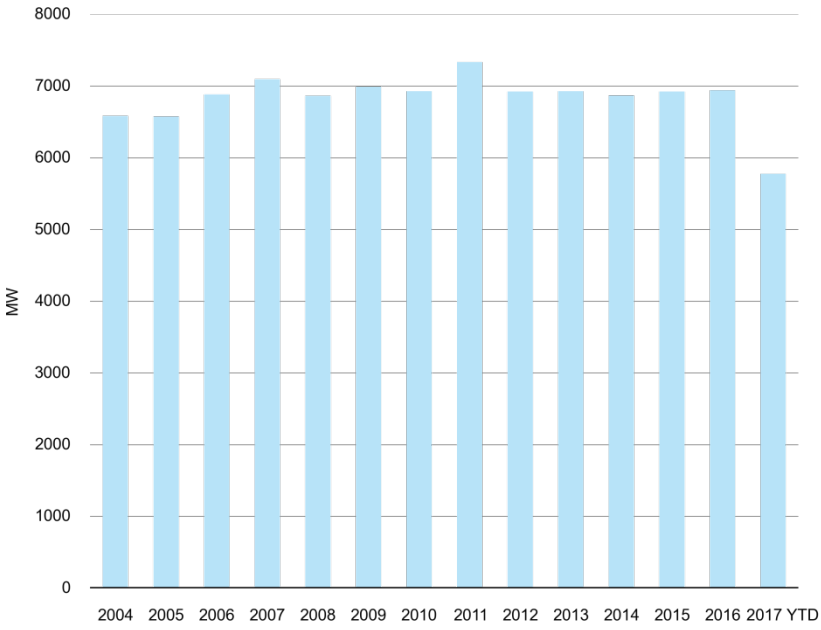


Figure 2: Total demand for electricity 2004-2017



Security of Supply
Annual Assessment 2017

Transpower New Zealand Limited

February 2017

Keeping the energy flowing




TRANSPOWER

Version[1]	Date	Change
1.0	19/01/2017	Draft for industry review

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

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

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1 EXECUTIVE SUMMARY

Transpower publishes an annual, medium to long-term security of supply assessment. This assessment provides a ten-year view (2017 to 2026) of security of supply metrics for a range of supply and demand scenarios. These metrics enable industry stakeholders to compare the risk of supply shortages both between scenarios and over time in order to inform risk management and investment decisions.

The 2017 base-case assumptions are based on Transpower's demand forecast, including continued demand from New Zealand Aluminium Smelter (NZAS), Huntly Rankine units being decommissioned at the end of 2022, and investor (generator) advice of new generation options under consideration.

In the base-case, the security of supply measures[2] are forecast to remain above or within their respective security standards[3] until at least 2018.

From 2018, some modest investment in generation will need to commence, with significant investment required after 2022 to maintain the security standards throughout the assessment period. However, in the event NZAS closes (and the Huntly Rankine units are decommissioned in 2022), only modest investment in new generation would be required to maintain the standards.

The results of all scenarios indicate the level of investment required to maintain the winter energy margin is sensitive to the ongoing availability of the Huntly Rankine units in the medium to long-term. The ability to meet the winter capacity margin is also sensitive to ongoing availability of the Huntly Rankine units though it is not affected by NZAS load.

The new generation options reported this year are comparable to those options reported last year. Overall, there has been a small increase in new generation.

The 2017 Annual Assessment shows a significant increase in all three security margins for the period from 2019 to 2022, in comparison to the 2016 assessment results. This is due to the delayed decommissioning of the Huntly Rankine units.

[2] The set of metrics include three measures; the New Zealand and South Island Winter Energy Margins (WEMs) and North Island Winter Capacity Margins (WCMs). The energy margins assess whether it is likely there will be an adequate level of generation demand and south transmission capacity to meet to meet expected electricity demand in extended dry periods. The capacity margin assesses whether it is likely there will be adequate generation and north transmission capacity to meet peak North Island demand.

[3] Electricity Authority Defined Security Standards. It is important to note that falling below the standards does not equate to electricity shortage. It simply implies that investment in new generation would be an economically rational exercise according to the winter margin assessment.

2 ABBREVIATIONS

Term	Description
The Code	The Electricity Industry Participation Code 2010 sets out industry participant responsibilities and duties
Authority	Electricity Authority
GXP	Grid Exit Point. This is the boundary between the national grid and the distribution networks
H100	A measure based on the highest 100 hours (or 200 half hours). For example, H100 North Island demand is the expected average of the highest 100 hours of demand in winter.
SoSFIP	Security of Supply Forecasting and Information Policy
SSAD	Security Standards Assumption Document
WEM	Winter Energy Margin
WCM	Winter Capacity Margin

3 BACKGROUND

3.1 SECURITY STANDARDS AND INTERPRETATION

Transpower, as the system operator, must prepare and publish a security of supply assessment that enables interested parties to compare projected winter energy and capacity margins over the next five or more years. The margins that define the security of supply standards used in this assessment, are determined by the Electricity Authority (the Authority) and are documented within the Code.[4] The Authority derived the margins in 2012 using a probabilistic analysis[5]. The analysis sought to determine:

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

The current security of supply standards are:

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

The Authority suggests that assessed margins should be interpreted as:

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

Assessed WEMs should be interpreted in a similar fashion.

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

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

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

4 KEY ASSUMPTIONS

4.1 FRAMEWORK

The Authority's Security Standards Assumptions Document (SSAD)[6] is the basis for the Security of Supply Annual Assessment methodology and the assumptions used in our modelling. We have evaluated the assumptions and, where appropriate, included scenarios to assess the sensitivity of the margins to different assumptions. This year we have also received feedback regarding the scenarios and included a new scenario which assumes Huntly Rankine closures with the loss of NZAS load.

The main input assumptions used in this assessment were:

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

For the complete set of supply and demand assumptions refer to the appendices (Sections 9 and 10). The methodology for the calculation of WEMs and WCMs is in Sections 5.1 and 6.1.

Furthermore, we are working with the Authority to review the SSAD. Any changes to the assumptions will be incorporated in a future Annual Assessment.

4.2 GENERATION ASSUMPTIONS

4.2.1 Existing Generation Assumptions

Assumptions about generation were largely based on information received from the major generators on a confidential basis. Some publicly available information is also used.

All existing generation is expected to remain operationally available throughout the assessment period with the exception of generation with a publicly notified decommissioning date.

For example, in the Base-case we assume two coal-fired Huntly Rankine units are available for the derivation of the WEMs and WCMs up to, and including, winter 2022. From winter 2023 onwards it is assumed no Huntly Rankine units will be available[7] There is a scenario that assesses the impact of these two units remaining in service.

Existing generation is subject to normal limitations (for example, variability of intermittent generation, dependence of hydro plants on inflows, and outage rates of thermal and hydro plants).

We also assume thermal fuel, or operational limitations, will not constrain production of electricity, with the exception of Whirinaki diesel generator. Whirinaki's energy contribution is treated as limited to 15 GWh per year for the calculation of the WEMs.

See Section 9 for further details on base-case assumptions about existing generation.

[6] http://www.ea.govt.nz/dmsdocument/14134

[7] For more information see https://www.genesisenergy.co.nz/web/genesis-energy/genesis-news-item/-/asset_publisher/SXj7PCBceFc2/content/genesis-energy-limited-gne-–-rankine-units-operational-life-extended?_101_INSTANCE_SXj7PCBceFc2_read_more=true

4.2.2 New Generation Assumptions

Information provided by generators about new generation development has been aggregated for publication to preserve confidentiality. This assessment covers the period from 2017 to 2026. There are currently no projects classified as committed so Transpower cannot disclose any detailed information on future generation options.

New generation development options under consideration by investors may or may not proceed for a variety of reasons. We have asked potential investors to indicate the likelihood of the investment proceeding. New generation projects have been allocated to four categories: committed, high probability, medium probability, and low probability. Each scenario includes four cases.

- Existing and committed generation only
- Existing, committed and high likelihood generation
- Existing, committed, high and medium likelihood generation
- Existing, committed, high, medium and low likelihood generation.

High, medium and low likelihood generation is classified based on responses to our industry survey. Broadly speaking each classification represents a 75%, 50% or 25% likelihood of generation projects going ahead respectively. However, it should be noted that a number of factors influence generation investment decisions and therefore these numbers are a guideline only.

Investors did not indicate expected commissioning dates for a number of new generation projects. This assessment has adopted a twofold classification system:

- where generation has a planned commissioning date, this date is used and generation is treated as a *dated project*
- where generation does not have a planned commissioning date, then assumed commissioning dates of 2022 and 2024 for medium and low likelihood projects are used respectively, and the generation is treated as a *non-dated project*.

In the presentation of all results, including WEMs, WCMs and any supporting information, distinction is made between results or information that include only dated generation projects and results or information that includes all generation projects.

Figure 1 and Figure 2 show the expected energy and capacity contributions from new generation in aggregate form. Each graph shows contributions by the generator's fuel type, the expected commissioning year, the likelihood of the project and in which island the generation is based.

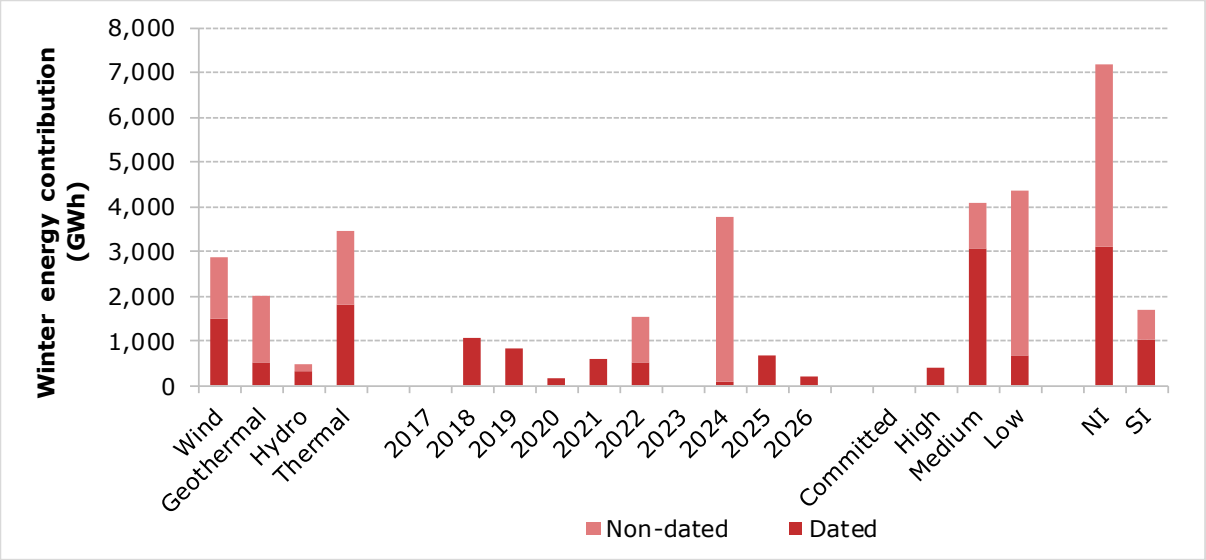

Figure 1: Winter Energy Contribution from New Generation

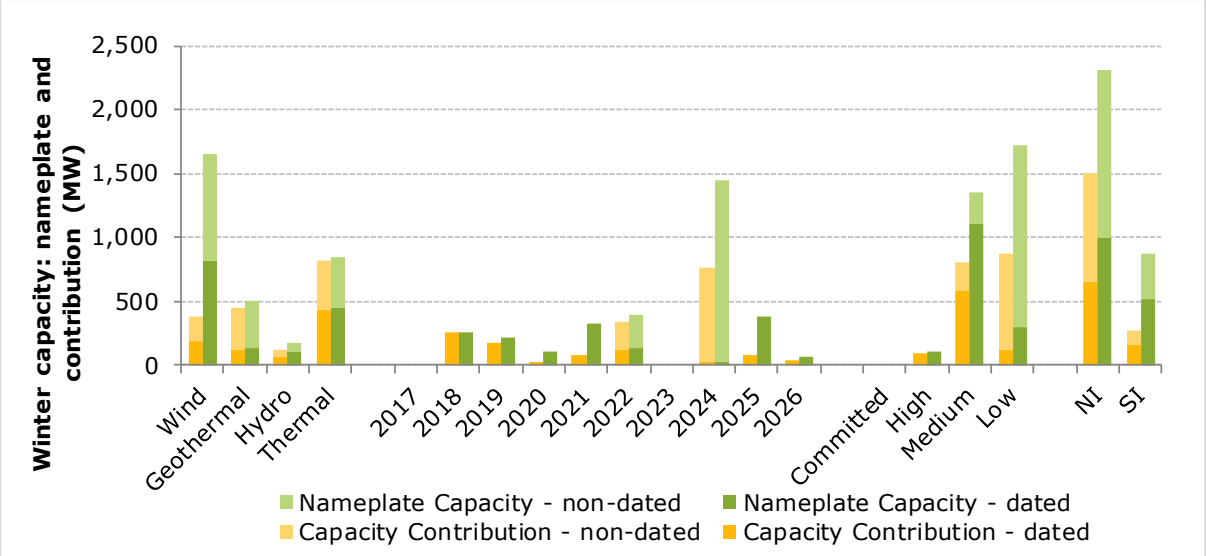

Figure 2: Winter Capacity Contribution from New Generation

See Section 9 for further details on base-case assumptions about new generation.

4.2.3 Comparison of New Generation Assumptions

The total amount of new generation reported is in Figure 3 and Figure 4. Overall, there is a small increase in new generation. The total energy contribution of future generation has increased from 7,834 GWh in 2016 to 8,877 GWh in 2017. Similarly, the expected capacity contribution from future generation has increased from 1,494 MW in 2016 to 1,774 MW in 2017.

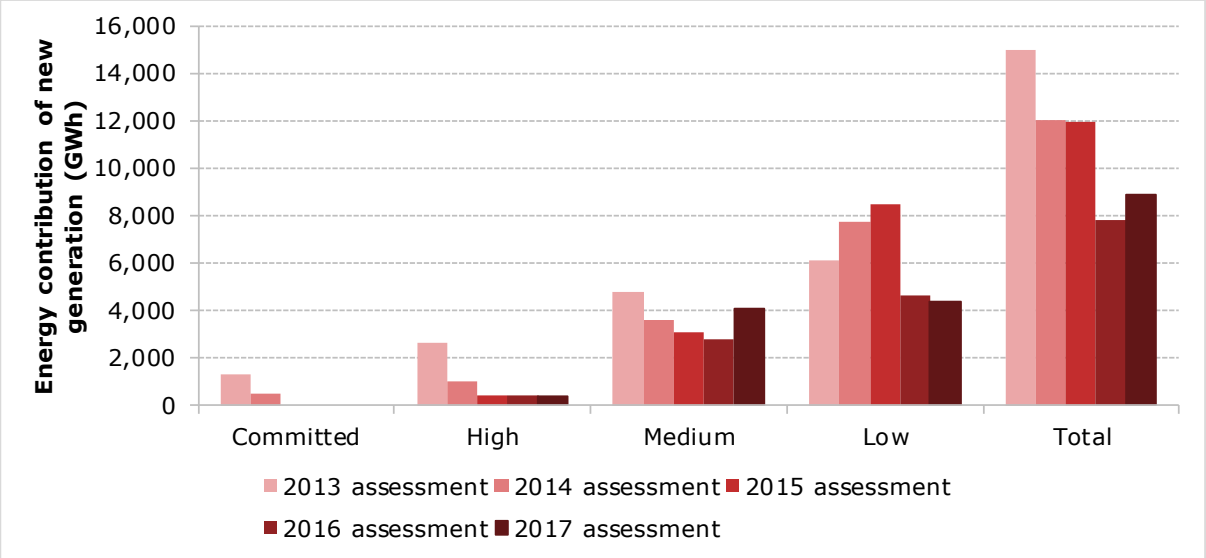

Figure 3: Energy Contribution of New Generation – 2017 Annual Assessment compared with previous annual assessments

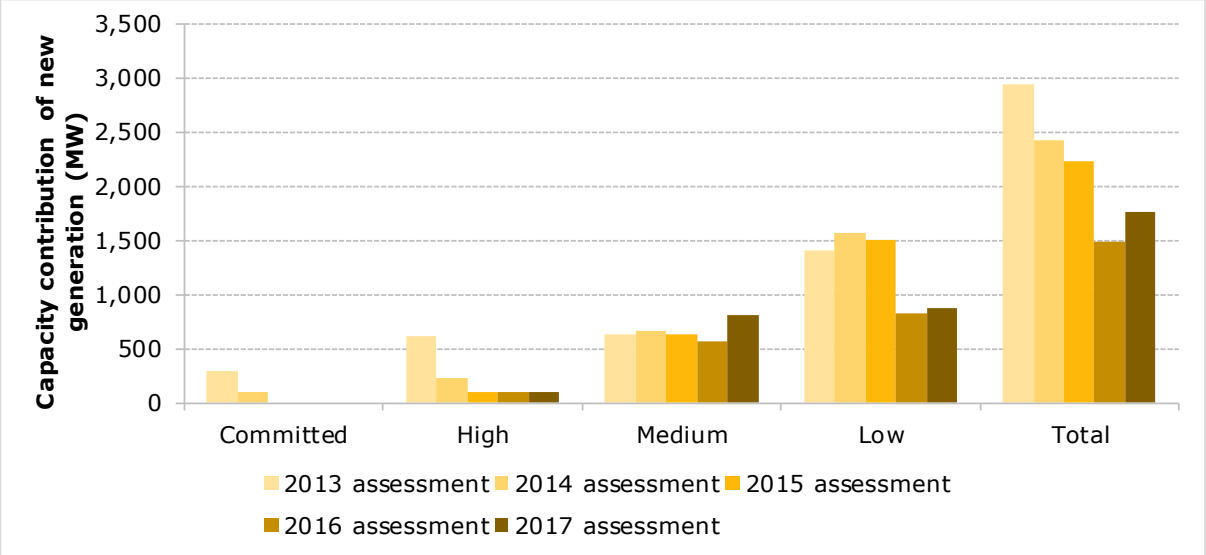

Figure 4: Capacity Contribution of New Generation – 2017 Annual Assessment compared with previous annual assessments

4.3 DEMAND FORECAST ASSUMPTIONS

This assessment uses Transpower's 2016 long-term electricity demand forecast. This forecast is demand for electricity at the Grid Exit Point (GXP). Ideally, any security of supply assessment should include all major sources of generation, and the demand served by these generators, where possible.

Therefore, in this assessment the following modifications have been made to the base demand forecast:

- demand served by embedded generation has been added onto the demand forecast
- transmission losses have been explicitly estimated and added to the demand forecast.

Figure 5 and Figure 6 show expected peak and energy demand out to 2027 and include high and low demand sensitivity scenarios.

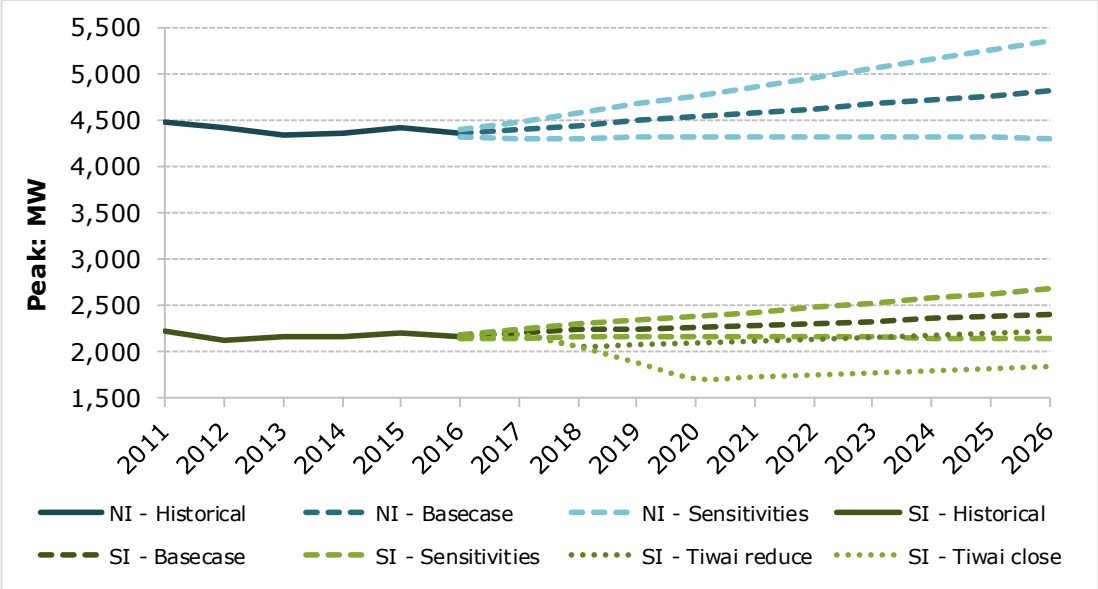

Figure 5: Expected peak demand

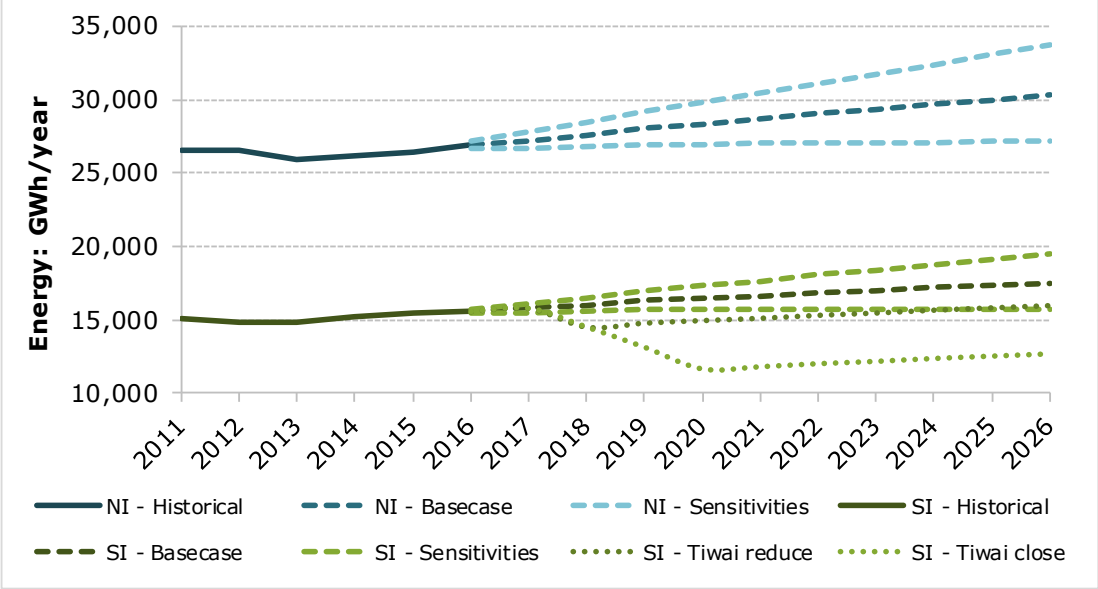

Figure 6: Expected energy demand

See Section 10 for more detailed assumptions about the electricity demand forecast used in the base-case scenario.

4.4 INTER-ISLAND TRANSMISSION ASSUMPTIONS

Inter-island transmission assumptions are required for the assessment of the South Island WEMs and the North Island WCMs. This assessment assumes HVDC capability will be the combined capability for Pole 2 and Pole 3 for all scenarios.

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

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

See Section 9 for detailed assumptions about inter-island transmission.

4.5 SCENARIOS

Assessed energy and capacity margins are sensitive to assumed availability of generation (existing and new), demand, and HVDC capability. This assessment considers a range of scenarios to assess the implications of different assumptions.

The Base-case uses the generation assumptions described in sections 4.2, the Base-case demand forecast identified in section 4.3, and the inter-island transmission capability described in section 4.4.

Table 1 describes the change to assumptions for each of the following scenarios:

- Huntly Rankine units retained
- NZAS closure
- NZAS closure and Huntly Rankine units decommissioned
- High demand
- Low demand
- Delayed build
- Reduced generation availability
- Limited south transfer

The Authority recently decided to amend the Code so that distributed generation that does not efficiently defer or reduce grid costs will no longer receive Avoided Cost of Transmission (ACOT) payments under regulated terms. This change will progressively come into effect during 2018 and 2019[8]. The Authority is also proposing to change the Transmission Pricing Methodology.

Both changes may have an impact on winter capacity from 2019. The Authority engaged Concept Consulting to assess the potential impact[9].. Concept Consulting's analysis suggests the impact on the winter capacity margin is similar to the high demand scenario[10]. See Section 6.2.5 for further details.

[8] *http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-part-6-dg-pricing-principles/consultations/#c15998*

[9] *http://www.ea.govt.nz/dmsdocument/21578*

[10] The impact of the Authority's final amendments to the distributed pricing principles may not be as severe as that assumed in the Concept report. We will include the impact in subsequent assessments.

Table 1: Sensitivity scenarios

Scenario	Affects Energy	Affects Capacity	Rationale	Assumptions Made
Huntly Rankine units retained	Yes	Yes	In April 2016 Genesis Energy publically announced its intention to delay the planned decommissioning of the remaining Huntly Rankine units from 2019 to 2022. This scenario explores the situation where the Huntly Rankine units remain available after 2022.	Huntly Rankine units are not decommissioned at the end of 2022 and are available for the entire duration of the assessment (2017-2026).
NZAS closure	Yes	Yes	NZAS aluminium smelter may reduce its output or shutdown.	NZAS reduces load in stages beginning in 2018 until it shuts down in 2020.
NZAS closure and Huntly Rankine units decommissioned	Yes	Yes	NZAS aluminium smelter may reduce its output or shutdown. As a consequence, available generation may reduce.	NZAS reduces load in stages beginning in 2018 until it shuts down in 2020. Huntly Rankine units are decommissioned at the end of 2020.
High demand	Yes	Yes	Demand may exceed the base-case forecast.	+1% demand growth pa on base-case. This is equivalent to an average growth rate of 2.00% pa.
Low demand	Yes	Yes	Demand may fall below the base-case forecast.	-1% demand growth pa on base-case. This is equivalent to flat demand (i.e. an average growth rate 0.00% pa)
Delayed Builds	Yes	Yes	Generation investment may be delayed due to market conditions or physical, technical or regulatory limitations.	Projects, other than committed, are uniformly delayed by 1 year.
Reduced generation availability	Yes	Yes	This scenario explores the sensitivity of the WCMs and WEMs to a reduction in electricity supply. This scenario is designed to indirectly account for internal and external influences that may reduce the output of electricity generation. External influences include effects such as shifting rainfall patterns due to climate change and reduction in geothermal field pressure. Internal influences include effects such as statistical errors in historical generation data and forecast errors for new generation. This reduced supply is equivalent to removing the expected energy contribution of McKee from the South Island winter energy margin calculation, or Stratford from the New Zealand winter energy margin. In terms of capacity, it is the equivalent of removing the capacity contribution of one Huntly Rankine unit.	In the calculation of energy margins, all non-thermal generation energy contribution is reduced by 5%. In the calculation of capacity margins, all non-thermal generation capacity factors are reduced by 5%.
Limited south transfer	Yes (only South Island WEMs)	No	The base-case assumption is that southward transfer can rise to an average of 480 MW – but various factors can combine to prevent this. During June-August 2008, the average net southward transfer over the HVDC link was approximately 300 MW. Although this limit may no longer be relevant this scenario is still considered to be meaningful as it illustrates the sensitivity of the South Island WEMs to limited HVDC transfer.	Inter-island transfer is limited to 1,314 GWh in the South Island WEMs (equivalent to an average of 300 MW).

5 ENERGY MARGIN ASSESSMENT

5.1 METHODOLOGY

The assessment of Energy Margins follows the methodology set out in the SSAD. There are two metrics:

The New Zealand Winter Energy Margin:

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

The South Island Winter Energy Margin:

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

Components to these equations are described in Table 2 and Table 3.

Table 2: Summarising the New Zealand WEM components

Component	Comprises of	Description
New Zealand expected energy supply (GWh)	Thermal GWh	Maximum expected thermal generation available to meet winter (1 April to 30 September) energy demand allowing for forced and scheduled outages, available fuel supply and operational and transmission constraints.
	Mean Hydro GWh	Expected winter (1 April to 30 September) hydro generation based on mean inflows and expected 1 April start storage of 2,750 GWh.
	Other GWh	Expected winter (1 April to 30 September) energy available from cogeneration[11], geothermal and wind generation based on long-run average supply.
New Zealand expected energy demand (GWh)	NZ Energy Demand GWh	Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).

Table 3: Summarising the South Island WEM components

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

[11] 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.

5.2 ENERGY MARGIN RESULTS

This section summarises the results of the WEM assessment, based on the input assumptions summarised in Section 4 and described in detail in the appendices (Sections 9 and 10).

Forecasts of the New Zealand WEMs and South Island WEMs from 2017 – 2026 under the base-case scenario are shown in Figure 7 and Figure 8. Sensitivity results are presented following the base-case results.

In summary:

- In the base-case scenario, the New Zealand and South Island WEMs are forecast to remain above or within the security standard until 2018 and 2021 respectively with existing and committed new generation.
- In all scenarios, with the exception of the high demand and reduced generation scenarios, existing and committed new generation provide sufficient energy to keep the New Zealand and South Island WEMs above or within the respective security standards until the end of 2018 and 2022 respectively.
- With the addition of high and medium probability generation there would be sufficient generation (based on the information made available to Transpower) to maintain WEMs within the range of the security standards in all scenarios except the high demand and reduced generation scenarios.
- The New Zealand and South Island WEMs in the 2017 Security of Supply Annual Assessment are comparable to those derived in the 2016 Security of Supply Annual Assessment with the exception of the period 2020 to 2022. This is due to the delayed decommissioning of the Huntly Rankine units.

5.2.1 Scenario: Base-case

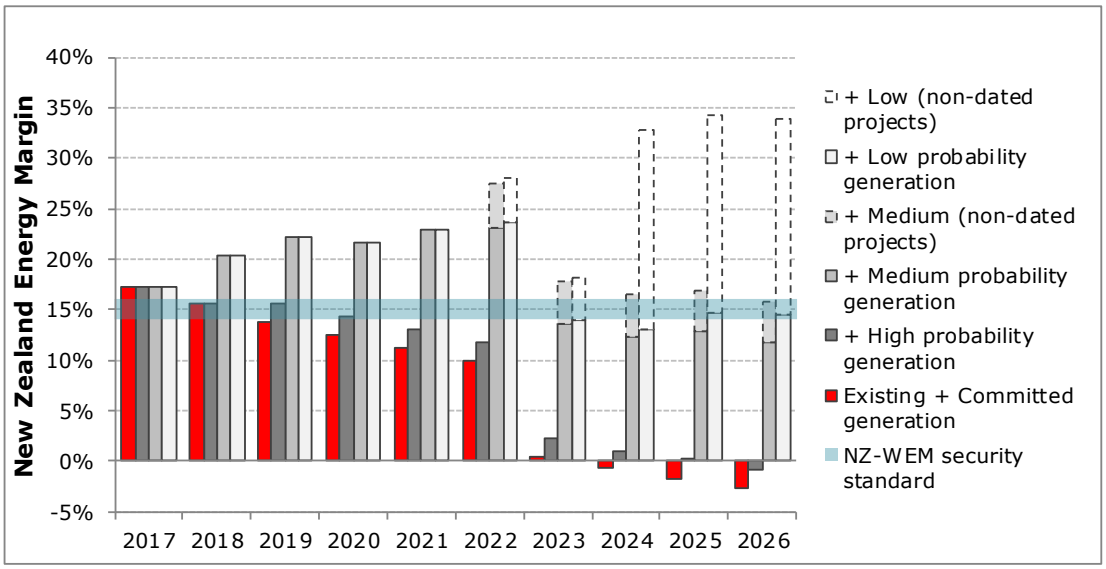

Figure 7: New Zealand Winter Energy Margin 2017 to 2026 – Base-case

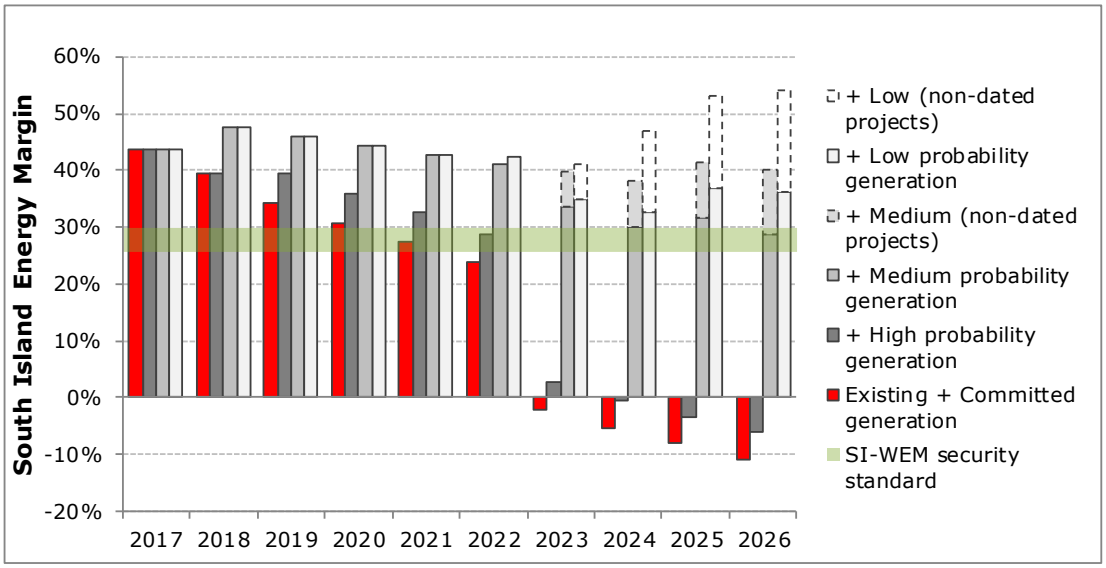

Figure 8: South Island Winter Energy Margin 2017 to 2026 – Base-case

- In the base-case scenario, the New Zealand and South Island WEMs are forecast to remain above or within the security standards until 2018 and 2021 respectively, with existing and committed generation.
- To continue to meet the New Zealand winter energy security of supply standard increasing levels of new generation would be required:
  - the high probability generation (or equivalent) would need to be commissioned prior to the winter of 2020
  - increasing levels of medium probability generation would be required prior to the winters of 2021 and 2022
  - after decommissioning of the Huntly Rankine units at the end of 2022 most if not all medium probability, including non-dated projects, would be required through 2023 to 2026
- To meet the South Island winter energy security of supply standard high probability generation would need to be commissioned by the winter of 2022. After 2022, investment in medium probability generation would be required to compensate for the decommissioning of the Huntly Rankine units.

5.2.2 Scenario: Huntly Rankine units retained

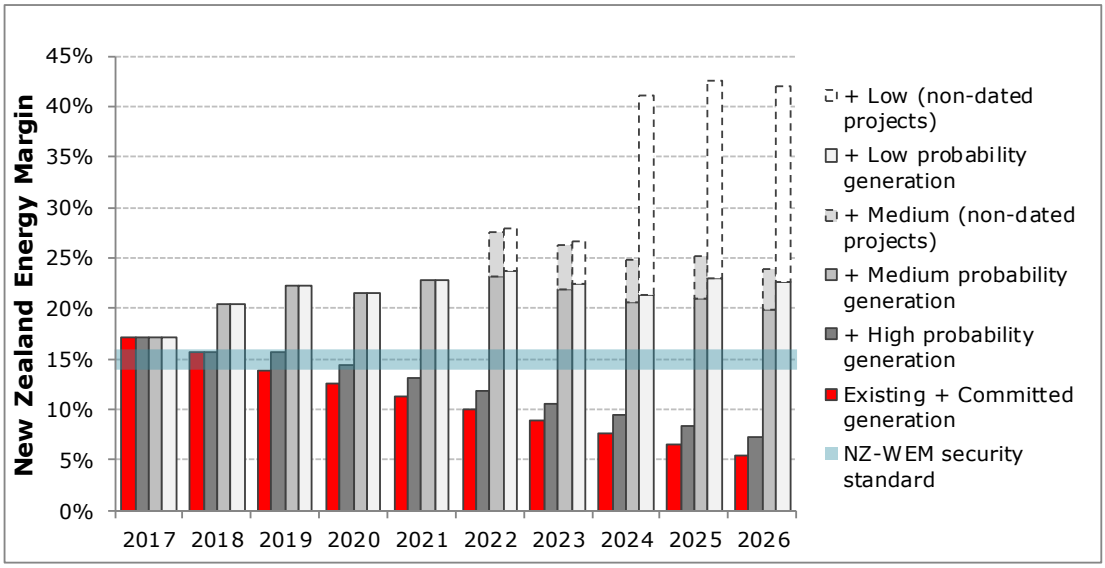

Figure 9: New Zealand Winter Energy Margin 2017 to 2026 – Huntly decision reversal scenario

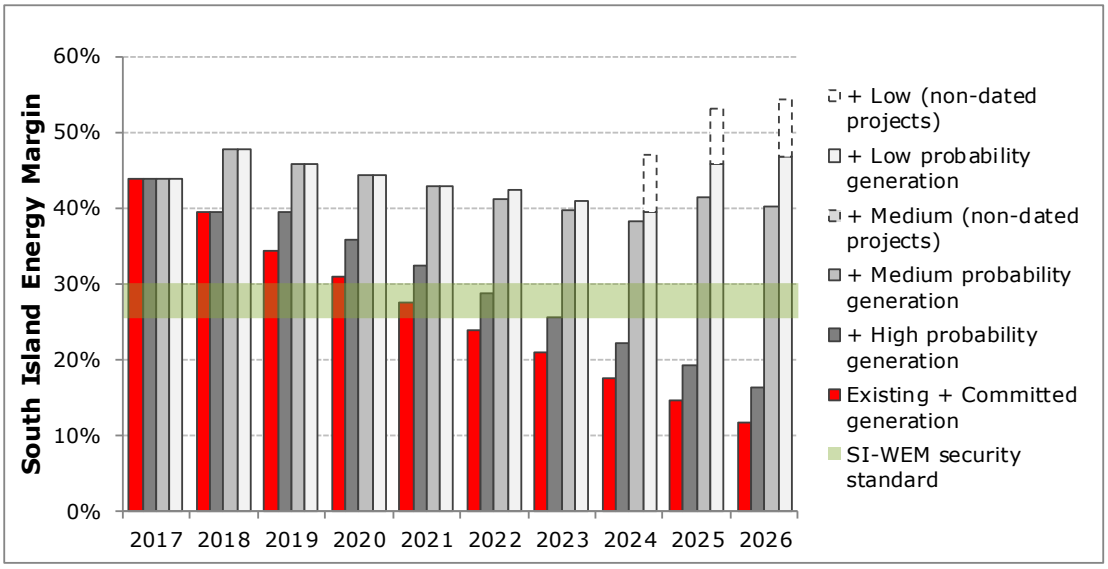

Figure 10: South Island Winter Energy Margin 2017 to 2026 – Huntly decision reversal scenario

- In this scenario the Huntly Rankine units are assumed to be available for the duration of the assessment.
- Despite retaining the Huntly Rankine units the New Zealand and South Island WEMs are forecast to fall below the security of supply standard in 2019 and 2022, respectively.
- Investment in high and some medium probability generation projects would still be required from 2020 to maintain the winter energy security of supply standard.

5.2.3 Scenario: NZAS closure

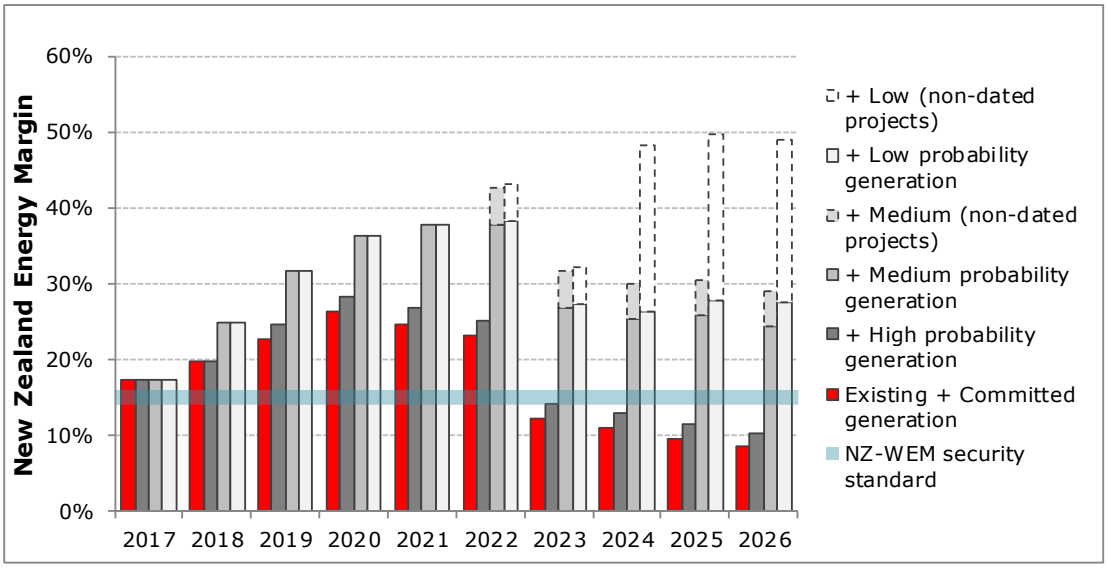

Figure 11: New Zealand Winter Energy Margin 2017 to 2026 – NZAS closure

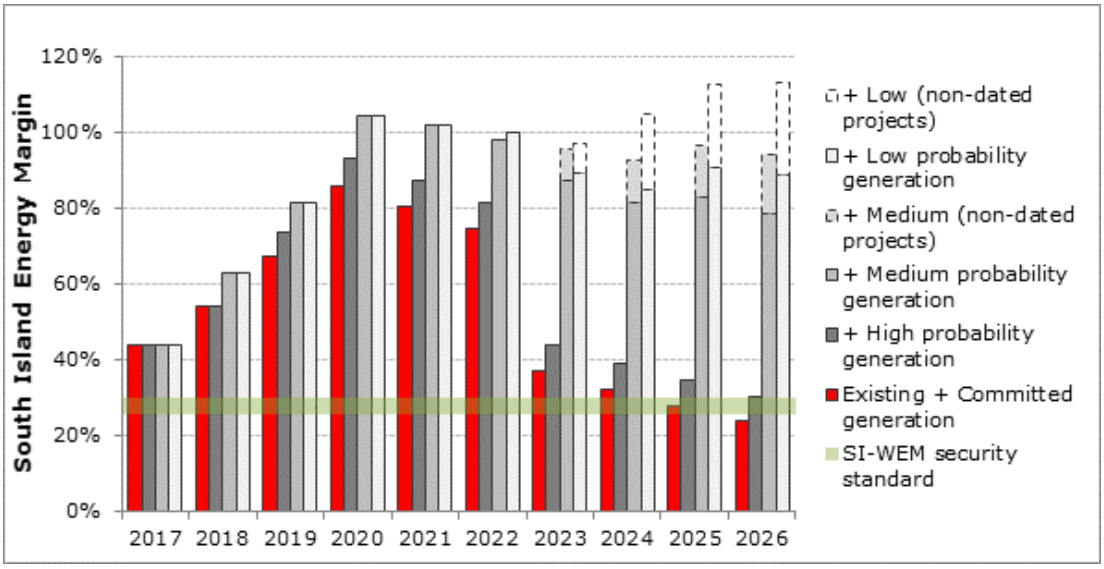

Figure 12: South Island Winter Energy Margin 2017 to 2026 – NZAS closure

- In this scenario, NZAS is assumed to reduce load in stages beginning in 2018 until closure in 2020.
- This scenario increases the WEMs compared to the base-case. However, without generation investment the New Zealand WEM is still forecast to fall below the security of supply standard in 2023, following decommissioning of Huntly Rankine units.

5.2.4 Scenario: NZAS closure and Huntly Rankine unit decommissioned in 2020

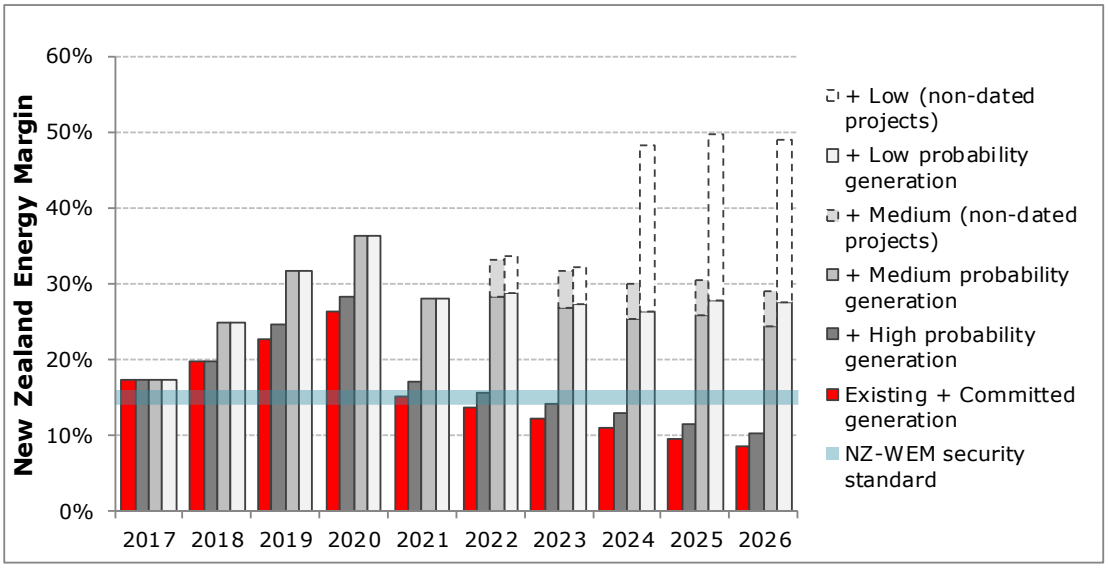

Figure 13: New Zealand Winter Energy Margin 2017 to 2026 – NZAS and Huntly closures

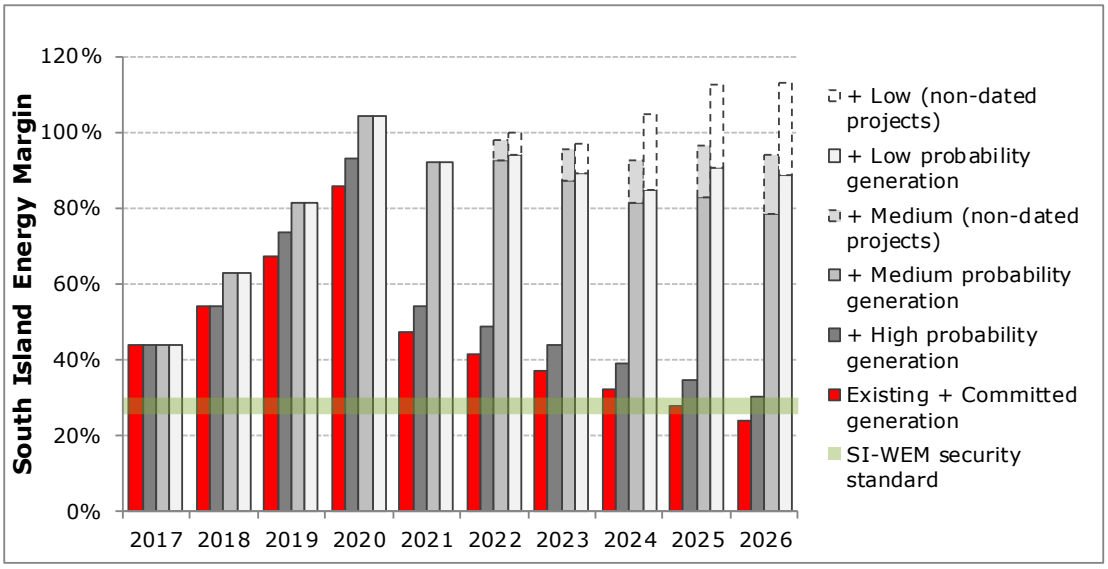

Figure 14: South Island Winter Energy Margin 2017 to 2026 – NZAS and Huntly closures

- In this scenario, NZAS is assumed to reduce load in stages beginning in 2018 until closure in 2020. The Huntly Rankine units are assumed to be decommissioned at the end of 2020.
- The NZAS and Huntly closure scenario increases the New Zealand and South Island WEMs compared to the base-case from 2018 onwards. Without generation investment the New Zealand WEM is still forecast to fall below the security of supply standard in 2022.

5.2.5 Scenario: High demand

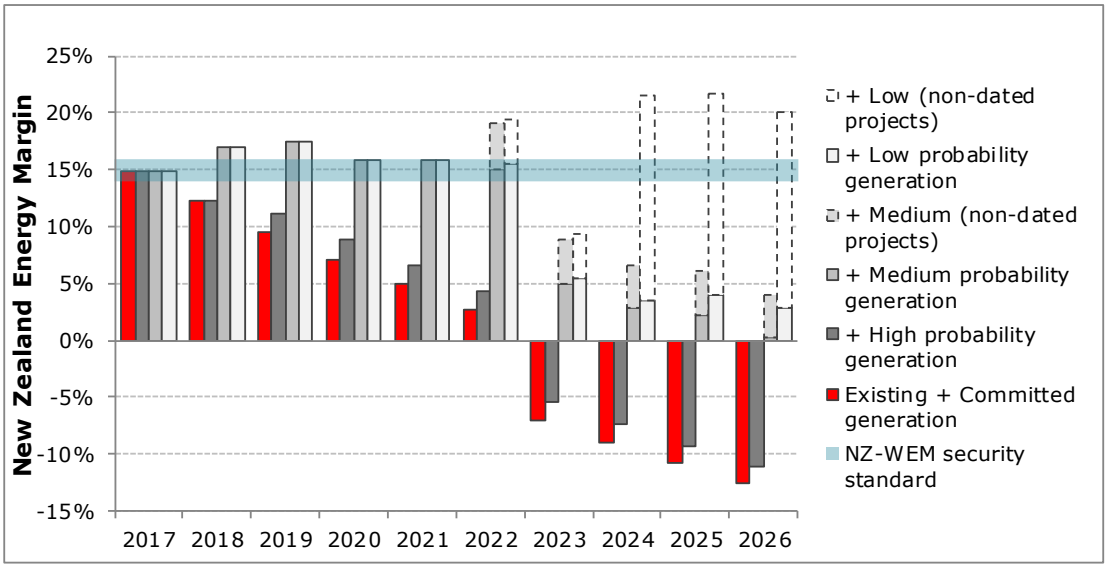

Figure 15: New Zealand Winter Energy Margin 2017 to 2026 – High demand scenario

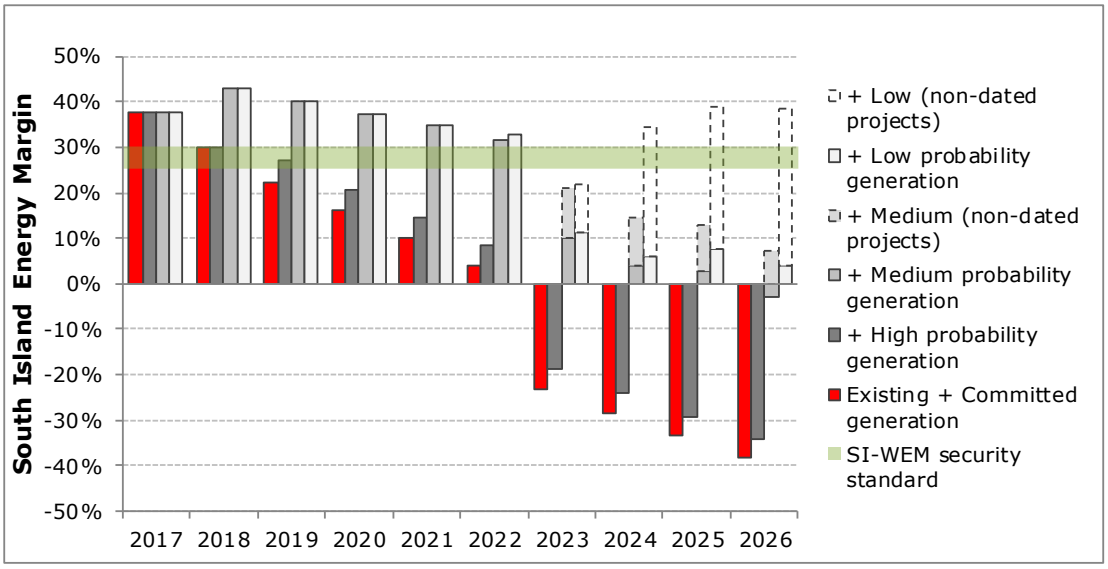

Figure 16: South Island Winter Energy Margin 2017 to 2026 – High demand scenario

- In this scenario, demand growth is increased by 1% per annum. This is equivalent to an average growth rate of 2.00% pa.
- The high demand scenario significantly reduces the WEMs compared to the base-case. Margins are forecast to become negative from 2023 onwards if there is no new generation investment and Huntly Rankine units are decommissioned as announced.

5.2.6 Scenario: Low demand

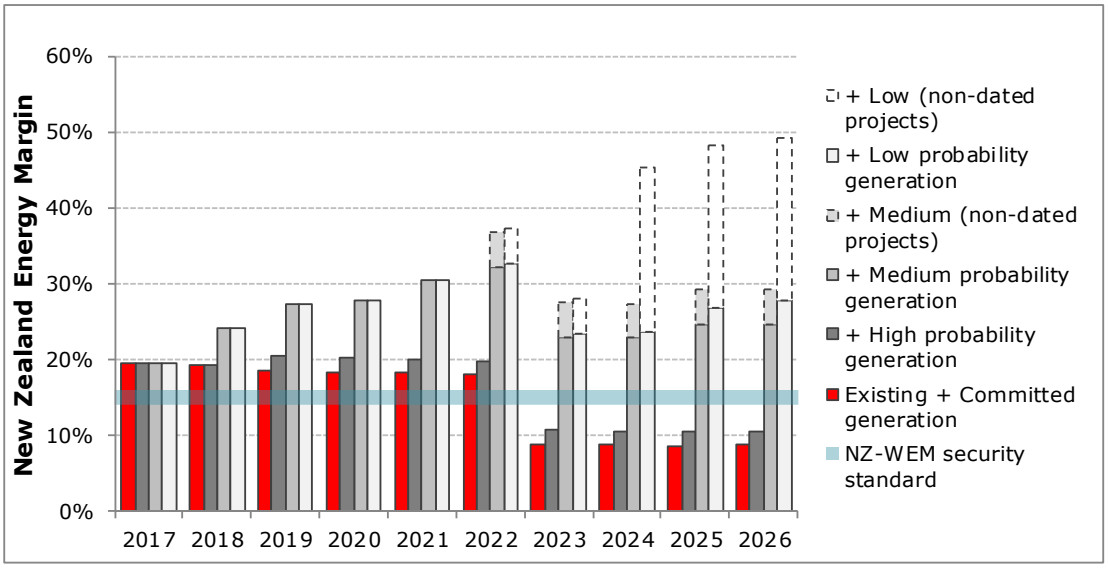

Figure 17: New Zealand Winter Energy Margin 2017 to 2026 – Low demand scenario

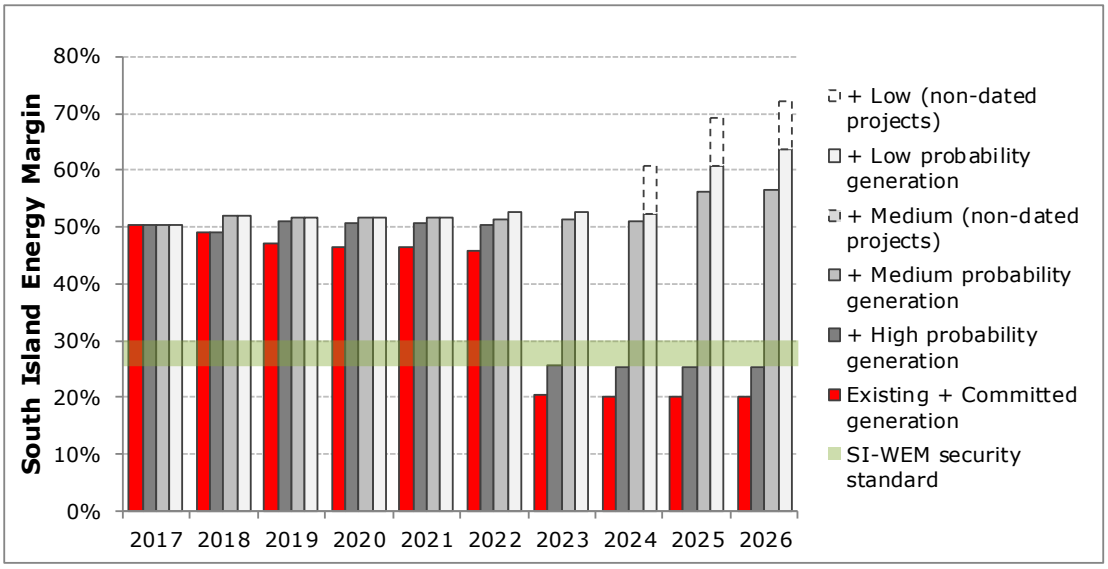

Figure 18: South Island Winter Energy Margin 2017 to 2026 – Low demand scenario

- In this scenario, demand growth is reduced by 1% per annum. This is equivalent to flat demand (i.e. an average growth rate of 0.00% pa).
- The low demand scenario increases the WEMs compared to the base-case. Margins are forecast to remain above or within the security standard until 2022.

5.2.7 Scenario: Delayed build

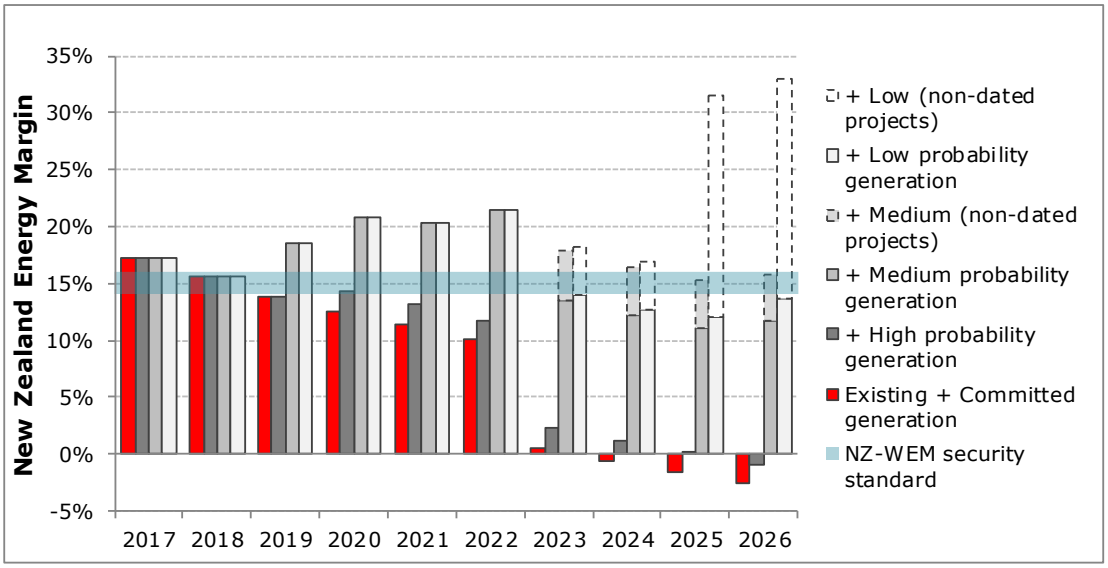

Figure 19: New Zealand Winter Energy Margin 2017 to 2026 – Delayed build scenario

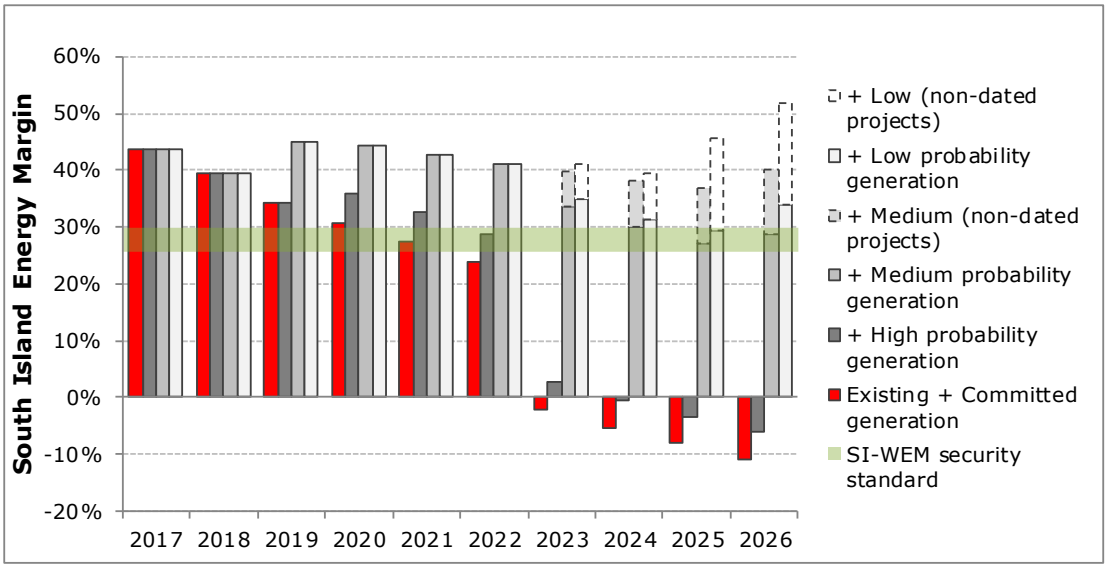

Figure 20: South Island Winter Energy Margin 2017 to 2026 – Delayed build scenario

- In this scenario, projects (other than committed) are uniformly delayed by 1 year.
- The results of the delayed build scenario are comparable to the base-case. With no additional investment, the New Zealand and South Island WEMs are forecast to remain above or within the security standard until 2018 and 2021 respectively.
- However, with inclusion of all medium and high probability generation investment, margins are forecast to remain above or within the standard throughout the assessment period.

5.2.8 Scenario: Reduced generation

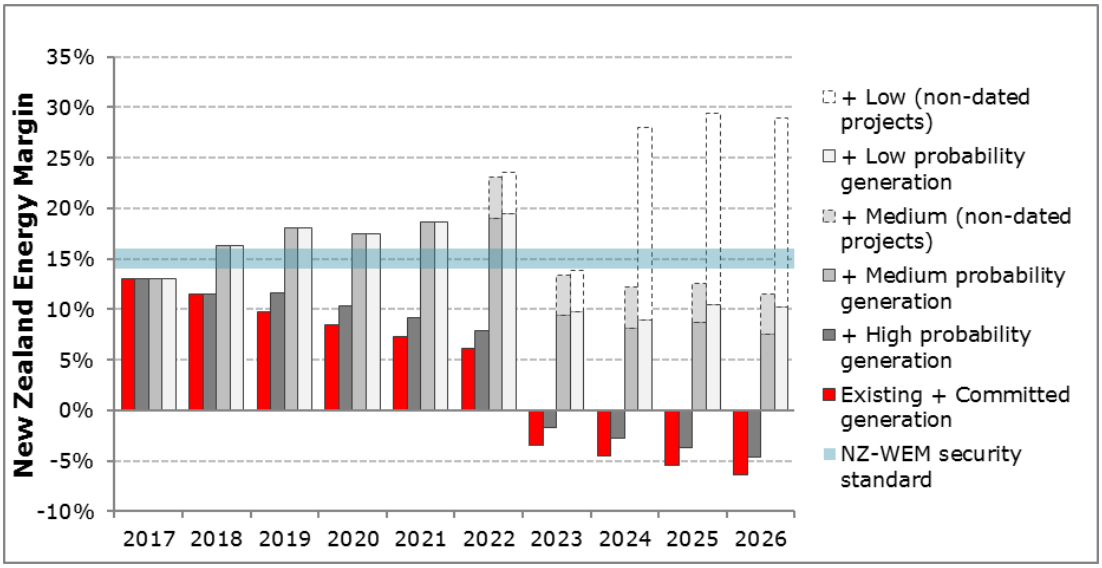

Figure 21: New Zealand Winter Energy Margin 2017 to 2026 – Reduced generation scenario

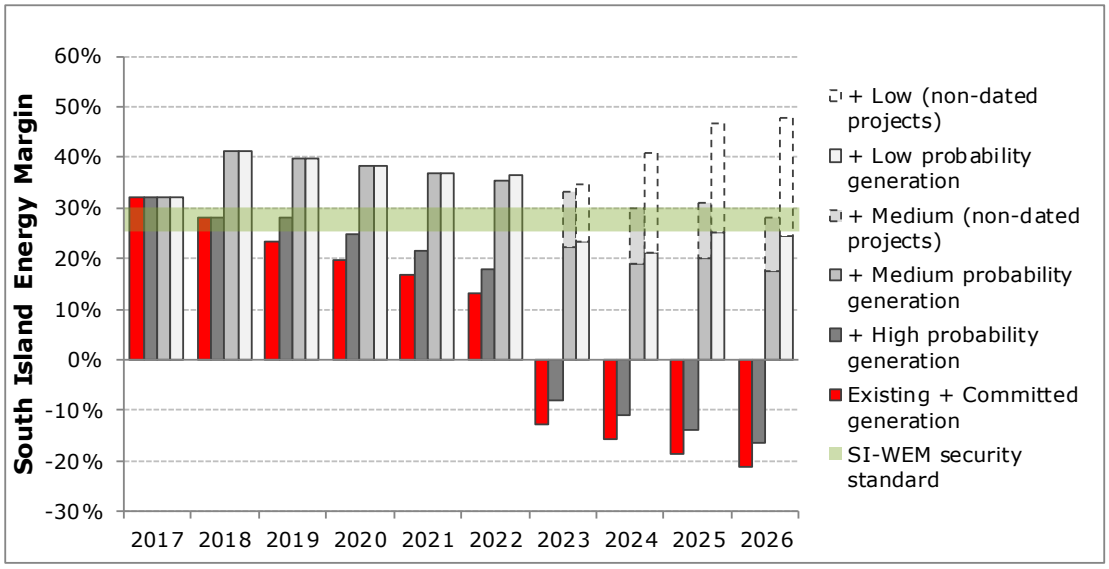

Figure 22: South Island Winter Energy Margin 2017 to 2026 – Reduced generation scenario

- In this scenario the energy contribution of all non-thermal generation is reduced by 5%. This is the equivalent to removing the expected energy contribution of McKee from the South Island WEM calculation, or Stratford from the New Zealand WEM calculation.
- The reduced generation scenario significantly reduces the WEMs compared to the base-case. In this scenario the New Zealand and South Island WEMs are forecast to fall below the security standard in 2017 and 2019 respectively.

5.2.9 Scenario: Limited HVDC transfer south

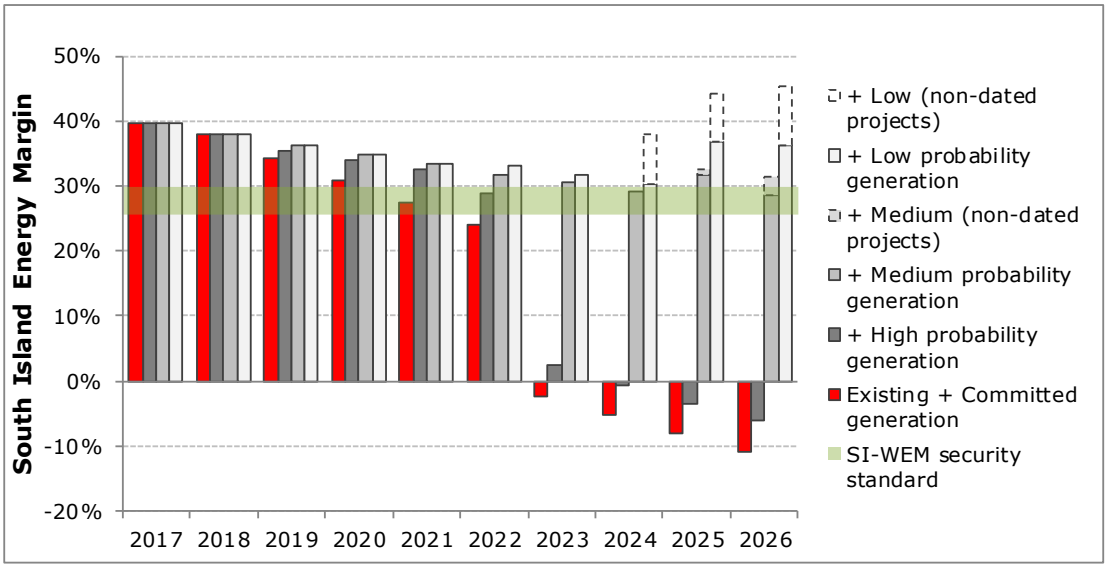

Figure 23: South Island Winter Energy Margin 2017 to 2026 – Limited HVDC south scenario

- In this scenario, HVDC transfer is limited to 1,314 GWh for the calculation of the South Island WEM.
- The limited HVDC transfer south scenario reduces the South Island WEM compared to the base-case. However, as in the base-case the margin is forecast to fall below the standard from 2022 until the end of the assessment period.

6 CAPACITY MARGIN ASSESSMENT

6.1 METHODOLOGY

The assessment of Winter Capacity Margin follows the methodology set out in the SSAD. There is a single metric; the North Island Winter Capacity Margin:

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

The input factors that comprise the WCM calculation are summarised in Table 4.

Table 4: Summarising the North Island WCM Components

Component	Comprises	Description
North Island expected capacity (MW)	NI Thermal MW	Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages, available fuel supply and operational and transmission constraints.
	NI Hydro MW	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and de-rated to account for energy and other constraints which affect output during peak times.
	NI Other MW	Expected winter peak generation from geothermal, wind, cogeneration and uncontrolled hydro scheme generation.
North Island expected demand (MW)	NI Peak Demand MW	Expected average of the highest 200 half hours (or 100 hours) of demand in winter inclusive of losses. This is referred to as H100 NI demand.
	NI Demand Response and Interruptible Load MW	Expected demand response and interruptible load over the highest 200 half hours of demand during winter peak. This is subtracted from NI Peak Demand to calculate NI expected demand.
Expected HVDC transfer north	South Island MW	The net amount of MW the South Island can supply to the North Island during peak periods. This is a similar calculation to above (supply capacity minus H100 NI demand); however, also takes into account HVDC transfer capability.

6.2 CAPACITY MARGIN RESULTS

This section summarises the results of the North Island WCM assessment, based on the input assumptions summarised in Section 4 and described in detail in the appendices (Sections 9 and 10).

The forecast of the North Island WCMs from 2017 – 2026 under the base-case scenario is shown in Figure 24. Sensitivity results are presented following the base-case results.

In summary:

- In all scenarios existing and committed generation provides sufficient energy supply to keep the North Island WCM above or within the respective security standards until the end of 2020.
- With the addition of high and medium probability generation there would be sufficient generation (based on the information made available to Transpower) to maintain WCM within the range of the security standards in all scenarios, except high demand scenario[12].
- The North Island WCM in the 2017 Security of Supply Annual Assessment is comparable to that derived in the 2016 Security of Supply Annual Assessment with the exception of the period 2020 to 2022. This is due to the delayed decommissioning of the Huntly Rankine units.

6.2.1 Scenario: Base-case

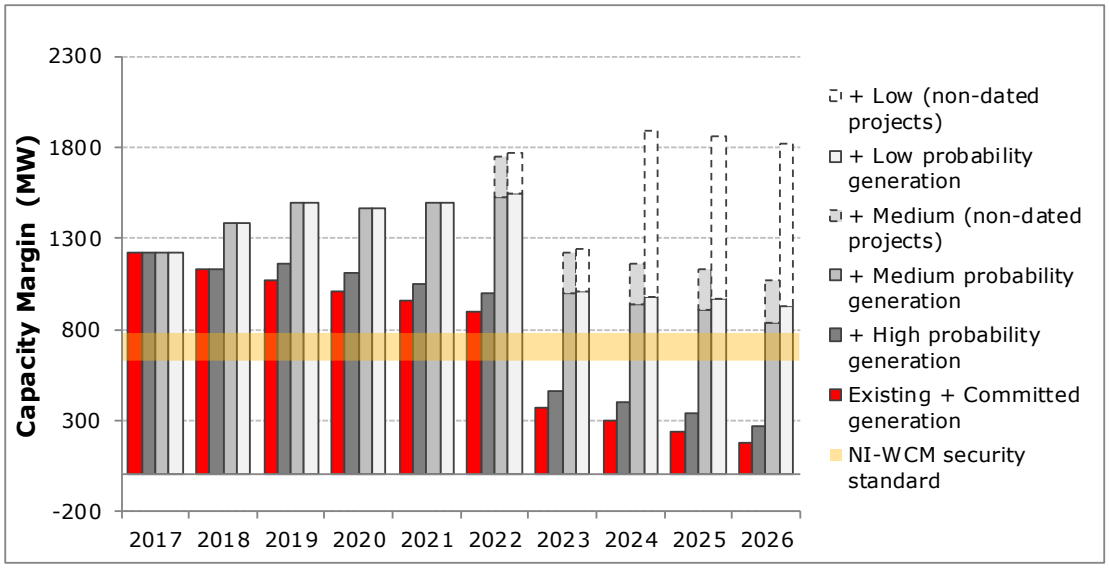

Figure 24: North Island Winter Capacity Margin 2017 to 2026 – Base-case

- In the base-case scenario, the North Island WCMs are forecast to remain above the security standard until 2022 with existing and committed generation.
- Following decommissioning of the Huntly Rankine units at the end of 2022 the North Island WCMs are forecast to reduce below the security standard. With no additional generation investment, the North Island WCMs are forecast to remain below the standard from 2023 until the end of this assessment period.

[12] From 2019 this scenario is representative of Concept Consulting's assessment of the potential impact of the revised distribution pricing principles and new transmission pricing methodology proposed by the Authority. Refer to Section 6.2.5.

6.2.2 Scenario: Huntly Rankine units retained

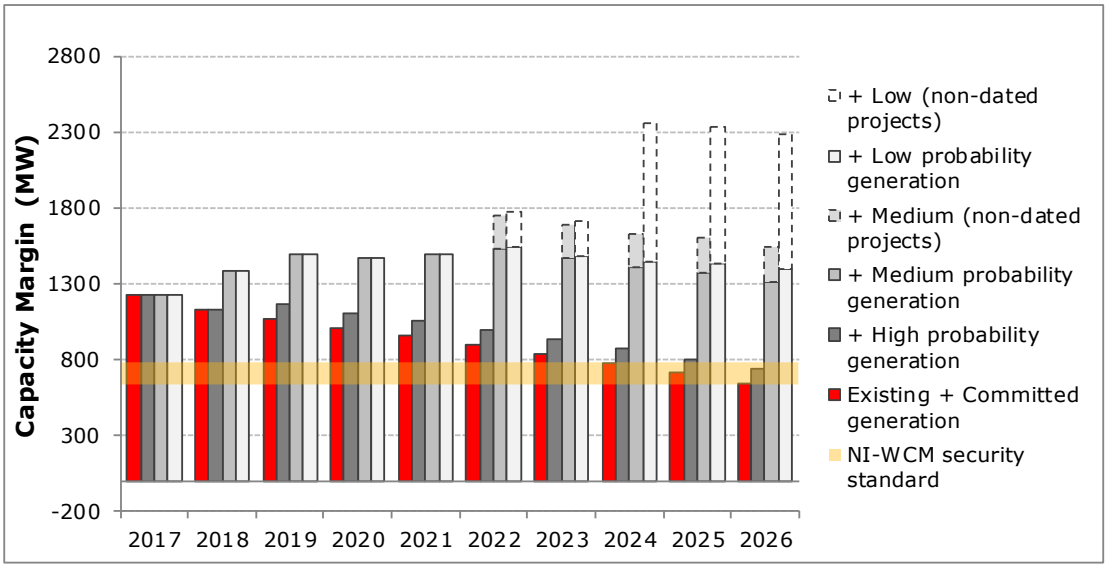

Figure 25: North Island Winter Capacity Margin 2017 to 2026 – Huntly Rankine units retained

- If the Huntly Rankine units were retained North Island WCMs would be expected to remain above or within the bounds of the security of supply capacity standard.

6.2.3 Scenario: NZAS closure

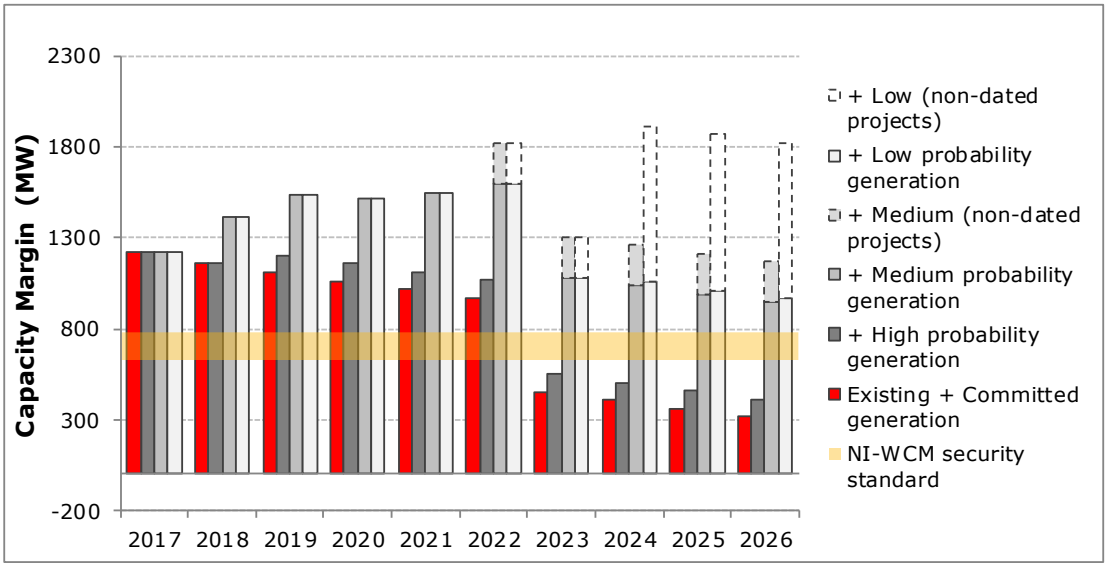

Figure 26: North Island Winter Capacity Margin 2017 to 2026 – NZAS closure

- In the NZAS closure scenario, the WCM is forecast to remain above or within the security standard until 2022. Note, the future of NZAS has little impact on the WCM calculation, unlike the WEM calculation.

6.2.4 Scenario: NZAS closure and Huntly Rankine units decommissioned in 2020

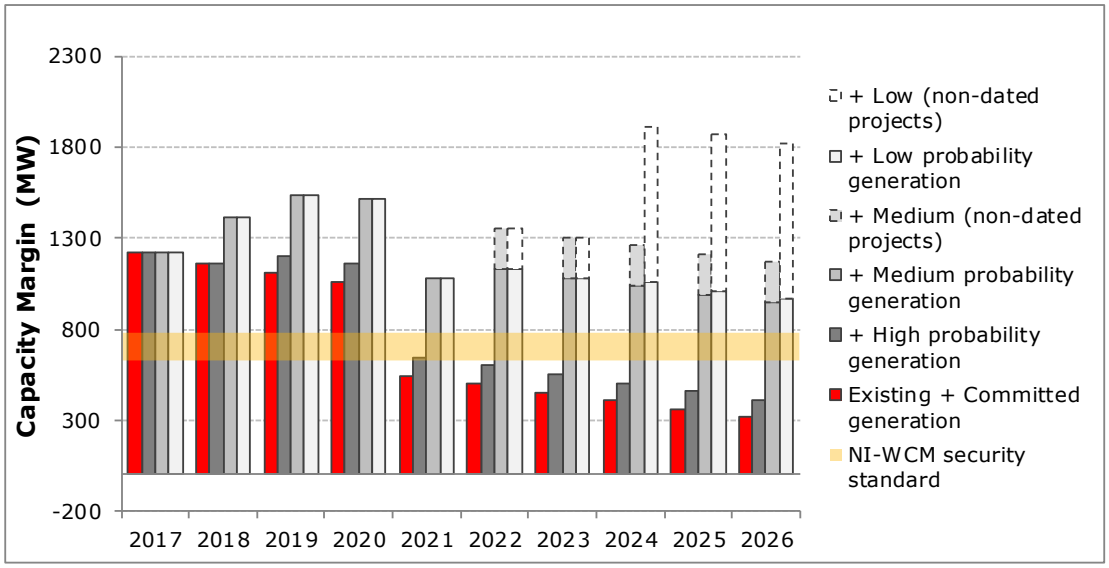

Figure 27: North Island Winter Capacity Margin 2017 to 2026 – NZAS and Huntly closure

- In the NZAS closure and Huntly decommissioning scenario the WCM is forecast to remain above or within the security standard until 2020. Although the future of NZAS has little impact on the WCM calculation, the Huntly decommissioning significantly reduces the WCM in 2021 and 2022.

6.2.5 Scenario: High demand

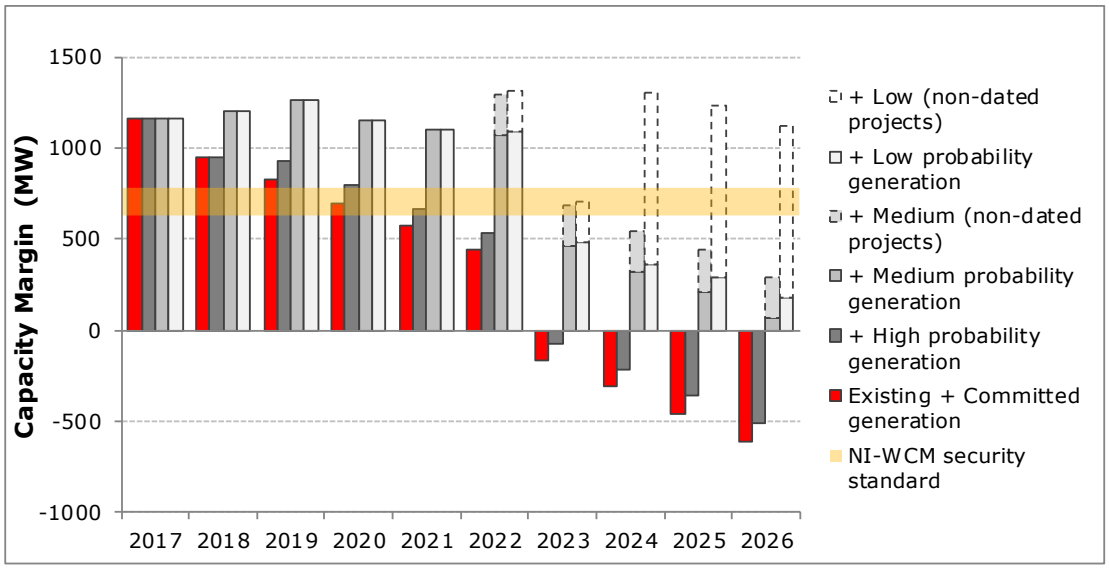

Figure 28: North Island Winter Capacity Margin 2017 to 2026 – High demand scenario

- The high demand scenario significantly reduces the North Island WCMs compared to the base-case. In this scenario the North Island WCMs are forecast to become negative if there is no new generation built (and Huntly Rankine units are decommissioned as announced).
- The Authority's proposal to remove ACOT payments may reduce distributed generation, increasing net demand. According to the recent Concept Consulting report, this decision, together with possible changes to the Transmission Pricing Methodology, may affect around 270MW of distributed generation and interruptible load, in aggregate. For clarity, Concept Consulting's estimate assumes that wholesale prices would remain unchanged, though in reality it would be reasonable to expect price increases that encourage distributed generation and interruptible loads

to remain available at peak times. Notwithstanding this, assuming the change is expected to be observed in 2019, impact to the capacity margin is similar to the high demand scenario which increases demand by 272 MW compared to the base-case.

6.2.6 Scenario: Low demand

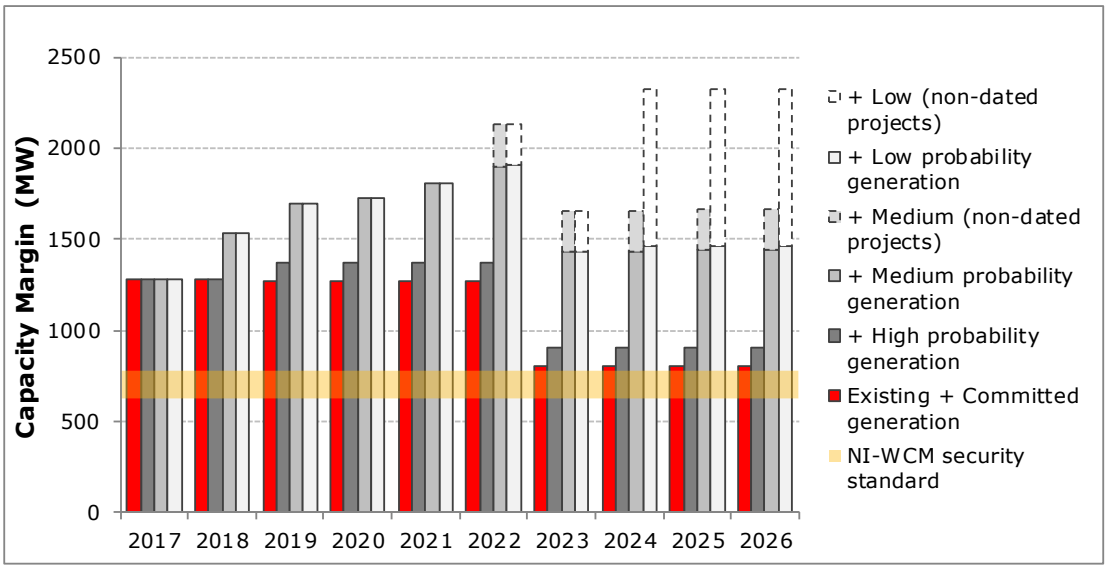

Figure 29: North Island Winter Capacity Margin 2017 to 2026 – Low demand scenario

- The low demand scenario significantly increases the North Island WCM compared to the base-case. In this scenario the margin is forecast to remain above or within the security standard throughout the assessment period.

6.2.7 Scenario: Delayed build

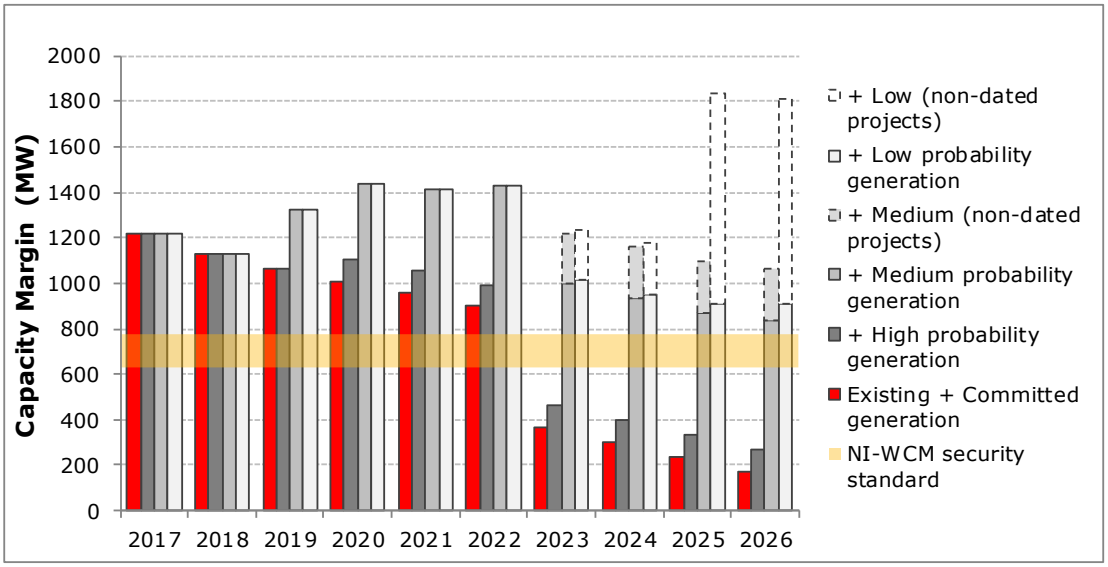

Figure 30: North Island Winter Capacity Margin 2017 to 2026 – Delayed build scenario

- The delayed build scenario is comparable to the base-case scenario.

6.2.8 Scenario: Reduced generation

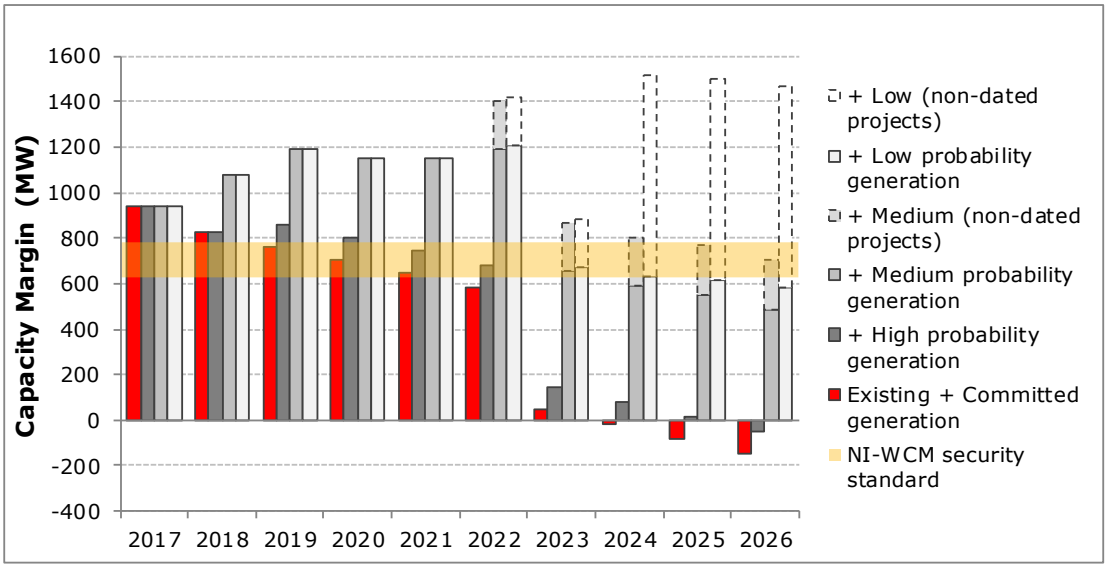

Figure 31: North Island Winter Capacity Margin 2017 to 2026 – Reduced generation scenario

- The reduced generation scenario is comparable to the high demand scenario.

7 CONCLUSIONS

7.1 ENERGY MARGIN CONCLUSIONS

The New Zealand and South Island WEMs are forecast to remain above or within the security standard until 2018 and 2021 respectively, with existing and committed new generation in the base-case scenario.

In the medium to long-term the WEM forecasts are sensitive to the future plans of the Huntly Rankine units, and, to a lesser extent, NZAS demand. The base-case scenario assumes the Huntly Rankine units will be decommissioned at the end of 2022. In this scenario the New Zealand and South Island WEMs are expected to fall below the security of supply standard for energy.

Significant generation investment would be needed to maintain energy margins within the security standards beyond 2022. However, in the scenario where each of the NZAS and Huntly Rankine units close in 2022 (the NZAS closure scenario), the margins fall only slightly below the standard in the second half of the ten-year analysis period.

7.2 CAPACITY MARGIN CONCLUSIONS

The North Island WCM is forecast to remain above or within the security standard until 2022, with existing and committed generation in the base-case scenario.

Similar to the WEMs, the medium to long-term outlook is sensitive to the future of the Huntly Rankine units. However, unlike the WEM forecasts the level of NZAS demand has little impact on the North Island WCM.

7.3 INTERPRETATION OF THE MARGINS AGAINST THE STANDARDS

The 2016 Security of Supply Annual Assessment indicated the New Zealand electricity system was in a period of oversupply at that time. The 2017 assessment indicates the New Zealand WEMs, South Island WEMs and North Island WCM are forecast to remain above or within the efficient level, as determined by the Authority standards, until at least 2018.

If demand grows as forecast, generation is decommissioned as announced, NZAS demand remains, and only high likelihood generation is built, then from 2022 all margins fall below security of supply standards, indicating the New Zealand electricity system will experience uneconomic levels of demand curtailment risk. However, with investment in medium and high probability generation, all three margins are forecast to remain above or within the security standards throughout the assessment period.

It is important to note in this assessment that our generation build assumptions are static and do not vary over time in response to events such as the Huntly units decommissioning. The extent and timing of investment required to maintain the security of supply standards will be largely determined by the decommissioning of the Huntly Rankine units and the level of demand at NZAS.

8 ADDITIONAL INFORMATION

8.1 OTHER TRANSPOWER SECURITY OF SUPPLY FUNCTIONS

Transpower performs other security of supply-related functions covered in the Security of Supply Forecasting and Information Policy and the Emergency Management Policy. These include:

- short-term monitoring and information provision, such as the weekly reporting of hydro levels relative to the Hydro Risk Curves[13]
- implementation of emergency measures where necessary, in accordance with the Emergency Management Policy, the System Operator Rolling Outage Plan, and the emergency provisions under Parts 7 and 9 of the Code.

8.2 OTHER RELATED WORK WITHIN TRANSPOWER

Transpower performs other security related functions which monitor and assess the generation and transmission capabilities of the New Zealand electricity system in the medium term.

For a more detailed assessment of the North Island winter capacity margin for the current year, refer to the New Zealand Generation Balance[14].

For a detailed assessment of grid capability to meet demand over the next three years, refer to the System Security Forecast[15].

8.3 INVITATION TO COMMENT

Transpower welcomes feedback on this report, including any additional information for analysis that may lead to this report being updated or any suggestions on the report structure and format. Comment and additional information may be given in confidence, if marked accordingly.

Please direct all responses to:

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Market Analyst, Market Operations
System Operations Division
Transpower NZ Limited.
PO Box 1021
Wellington 6140

Or email: *emily.calvert@transpower.co.nz*

[13] *http://www.systemoperator.co.nz/security-supply/sos-weekly-reporting/hydro-risk-curves*
[14] *http://nzeb.redspider.co.nz/*
[15] *https://www.transpower.co.nz/system-operator/key-documents/system-security-forecast*

9 Appendix 1: Detailed Supply Assumptions

9.1 Introduction

This appendix sets out the key supply assumptions used in the energy and capacity margin assessments. Many of the assumptions discussed are based on the SSAD published by the Authority.

9.2 Existing Generation

The following tables summarise the existing generation that is used in the model.

Embedded generation has been included for those embedded generators where there is historical dataset available[16].

Table 5: Existing North Island Supply

Plant	Type	MW	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
Aniwhenua	Hydro	25	58	15
Arapuni	Hydro	192	See Waikato scheme*	*
Aratiatia	Hydro	78	See Waikato scheme*	*
Atiamuri	Hydro	74	See Waikato scheme*	*
Glenbrook	Thermal - Cogen	74	207	42
Huntly Rankines	Thermal - Coal	486	1986	471
Huntly U5	Thermal - Gas	385	1595	373
Huntly U6	Thermal - Gas	48	199	47
Kaimai	Hydro	38	82	29
Kaitawa	Hydro	36	See Waikaremoana scheme*	*
Kapuni	Thermal - Cogen	25	86	14
Karapiro	Hydro	96	See Waikato scheme*	*
Kawerau	Geothermal	104	433	94
Kawerau Onepu	Geothermal	60	216	54
Kinleith	Thermal - Cogen	28	88	16
Mangahao	Hydro	42	69	25
Maraetai	Hydro	352	See Waikato scheme*	*
Matahina	Hydro	80	137	66
McKee	Thermal - Gas	100	414	97
Mill Creek	Wind	60	119	15
Mokai	Geothermal	112	418	101
Nga Awa Purua	Geothermal	135	565	121
Ngatamariki	Geothermal	83	358	75
Ohaaki	Geothermal	50	175	45
Ohakuri	Hydro	106	See Waikato scheme*	*

[16] Transpower's SCADA system was used to gather data on embedded generators. If no SCADA data was available for a generator it was not included in the supply calculation. Those embedded generators which are not included in the supply calculation will have the effect of reducing demand.

Plant	Type	MW	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
Patea	Hydro	32	53	26
Piripaua	Hydro	42	See Waikaremoana scheme*	*
Poihipi	Geothermal	55	222	49
Rangipo	Hydro	120	279	73
Rotokawa	Geothermal	35	125	31
Stratford Peaker	Thermal - Gas	200	829	194
Tararua I and II	Wind	67	135	17
Tararua III	Wind	93	175	23
Taranaki Combined Cycle	Thermal - Gas	377	1562	366
Te Āpiti	Wind	90	150	22
Te Huka	Geothermal	28	117	25
Te Mihi	Geothermal	166	669	149
Te Rapa	Thermal - Cogen	44	164	25
Te Rere Hau	Wind	49	58	12
Te Uku	Wind	64	104	16
Tokaanu	Hydro	240	357	216
Tuai	Hydro	60	See Waikaremoana scheme*	*
Waipapa	Hydro	54	See Waikato scheme*	*
Wairakei incl. binary	Geothermal	132	549	119
West Wind	Wind	142	255	35
Whakamaru	Hydro	100	See Waikato scheme*	*
Whareroa	Thermal - Cogen	70	200	40
Wheao	Hydro	24	50	18
Whirinaki	Thermal - Diesel	155	15	150

Table 6: Existing South Island supply

Scheme	Type	MW	Assumed Contribution to Energy Margins (potential GWh April - Sep)	Assumed Contribution to Capacity Margins (MW)
Aviemore	Hydro	220	See Waitaki scheme*	*
Benmore	Hydro	540	See Waitaki scheme*	*
Branch	Hydro	11	25	7
Clyde	Hydro	432	See Clutha scheme*	*
Cobb	Hydro	32	88	31
Coleridge	Hydro	39	126	38
Deep Stream	Hydro	6	12	5
Highbank/Montalto	Hydro	27	47	21
Kumara/Dillmans	Hydro	11	20	8
Mahinerangi Wind 1	Wind	36	52	8
Manapouri	Hydro	800	2691	784
Ohau A	Hydro	264	See Waitaki scheme*	*
Ohau B	Hydro	212	See Waitaki scheme*	*
Ohau C	Hydro	212	See Waitaki scheme*	*
Paerau/Patearoa	Hydro	12	27	7
Roxburgh	Hydro	320	See Clutha scheme*	*
Tekapo A	Hydro	27	See Waitaki scheme*	*
Tekapo B	Hydro	154	See Waitaki scheme*	*
Waipori	Hydro	84	88	64
Waitaki	Hydro	90	See Waitaki scheme*	*
Whitehill	Wind	58	89	13

* Energy and capacity contributions of this plant are detailed in the aggregated hydro schemes shown in Table 7

Table 7: Existing NZ controllable hydro supply

Scheme	Island	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
Waikato	NI	2313	1031
Waikaremoana	NI	242	135
Waitaki	SI	2766	1685
Clutha	SI	1413	737
Start storage	NI	350	n/a
Start storage	SI	2400	n/a

9.3 NEW GENERATION

The tables below list the aggregated quantities of new generation that is included in this assessment. This is the supporting data for Figure 2.

Table 8: New Generation Aggregated by Year

Year	Nameplate MW	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
2017	0	0	0
2018	263	1,072	254
2019	215	824	180
2020	100	184	25
2021	319	590	79
2022	390	1,527	346
2023	0	0	0
2024	1,445	3,798	766
2025	374	670	81
2026	72	211	44

Table 9: New Generation Aggregated by Type

Type	Nameplate MW	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
Wind	1,650	2,888	387
Geothermal	505	2,026	454
Hydro	180	485	115
Thermal	843	3,479	818

Table 10: New Generation Aggregated by Probability

Probability	Nameplate MW	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
Committed	0	0	0
High	100	414	97
Medium	1,357	4,083	808
Low	1,721	4,380	869

Table 11: New Generation Aggregated by Island

By Island	Nameplate MW	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Assumed Contribution to Capacity Margins (MW)
NI	2,303	7,171	1,508
SI	875	1,706	266

9.4 Other Generation Assumptions

9.4.1 Outage Modelling and De-ratings

To allow for forced and scheduled outages the following assumptions were made in the calculation of the New Zealand WEMs, South Island WEMs and North Island WCM. Unless otherwise stated these assumptions are as per the SSAD.

- For combined cycle gas turbine generators, a de-rating of 5.4% was applied to the nameplate capacity when calculating the New Zealand WEMs and South Island WEMs (net energy contribution factor of 94.6%). This assumption was also applied to open cycle gas turbines, although this application is not explicitly contained with the SSAD (the SSAD only refers to combined cycle gas turbine generation).
- For the Huntly Rankine units, a de-rating of 6.7% is applied to the nameplate capacity when calculating the New Zealand WEMs and South Island WEMs (net energy contribution factor of 93.3%).
- The New Zealand WEMs and South Island WEMs have been reduced by 303 GWh in the North Island to reflect spinning reserve and frequency keeping requirements.
- For all thermal generation a de-rating of 3.0% is applied to the nameplate capacity when calculating the North Island WCMs (net capacity contribution factor of 97.0%).
- For all controllable hydro generators, a de-rating of 2.0% is applied to the nameplate capacity when calculating the North Island WCMs.
- In addition to a 2.0% de-rating, the following further de-ratings are applied to account for limited short-term storage ability (these generators are *not* treated as run-of-river hydro).
    - Matahina de-rated by 13 MW for the North Island WCMs
    - Patea de-rated by 5 MW for the North Island WCMs
    - Tokaanu de-rated by 20 MW for the North Island WCMs.
- All other hydro stations (non-controllable) are treated as run-of-river and assumed to contribute either 60.6% or 76.2% of nameplate capacity to the North Island WCMs depending on the level of peaking ability observed in their historical generation datasets (see Section 9.4.2). These assumptions are derived using current data and are not contained within the SSAD.
- All geothermal generation is assumed to contribute 89.9% of nameplate capacity to the North Island WCMs (see Section 9.4.2). This assumption is derived using current data and is not contained within the SSAD.
- All North Island wind generation is assumed to contribute 24.7% of nameplate capacity. All South Island wind generation 21.7% of nameplate capacity to the North Island WCMs (see Section 9.4.2). These assumptions are derived from a national wind capacity contribution of 25.0% which is based on the recommendations contained within the SSAD. North and South Island wind generation values are derived by de-aggregating to an island level contribution using current data and are not explicitly contained within the SSAD.

Note it is also recommended in the SSAD, and has been assumed in previous versions of the annual assessment, that the Waikato hydro scheme be de-rated by 60 MW in the derivation of the North Island WCMs. However, after discussion with Mercury Energy it was determined this de-rating no longer applies and the net available capacity, including allowances for river constraints, is 1052 MW. Therefore, this assumption was not used in the derivation of the North Island WCMs. Removing this assumption directly increased the WCMs by 60 MW in all scenarios.

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

In the calculation of the North Island WCMs it was recommended by the Authority the national wind capacity contribution be in the range of 20-25% of nameplate capacity.

This assessment used a national wind capacity contribution of 25%. However, to derive the WCMs a national level contribution must first be de-aggregated into North Island and South Island capacity contributions.

The capacity contribution of run-of-river hydro, cogeneration, geothermal, North Island wind generation and South Island wind generation at the winter peak has been determined[17]. This is then compared to the New Zealand wind generation in order to de-rate the nameplate capacity of these generation types on the same basis and de-aggregate North and South Island wind capacity contributions. A significant difference was observed between some run-of-river hydro generators, and therefore two different classifications have been used: flexible and inflexible run-of-river.

These capacity contributions were derived from the outputs of each modelled plant during peak periods. This was then sorted to determine the distribution of capacity contribution for each generation type over this period. Figure 32 shows the percentage of time the capacity contribution of each generation type is greater than the corresponding level, based on this data.

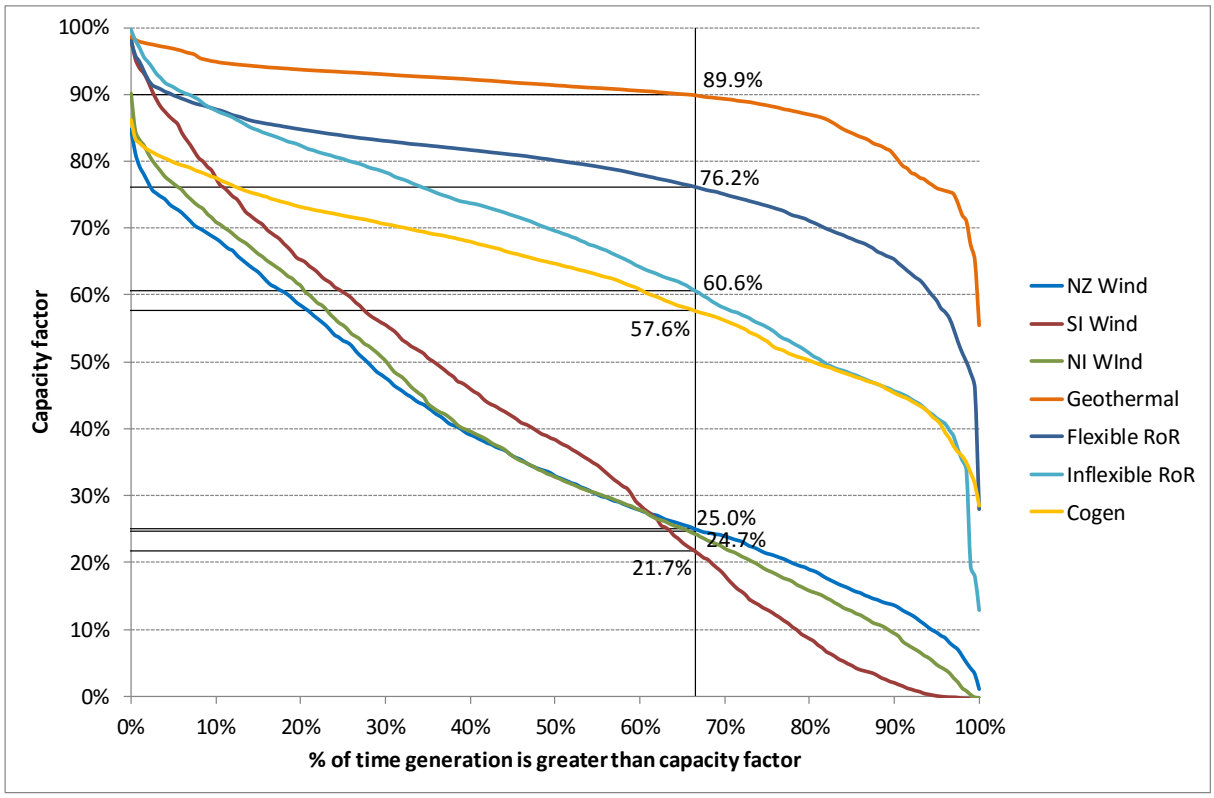

Figure 32: Capacity factor duration curves for wind, run-of-river hydro, geothermal, and cogeneration plant during peak periods.

Wind generation in New Zealand was shown to contribute greater than 25.0% of their nameplate capacity for 66.5% of the peak periods analysed. For 66.5% of the peak periods the following generation types contributed the given percentage of their nameplate capacity; North Island wind (24.7%), South Island wind (21.7%), flexible run-of-river hydro (76.2%), inflexible run-of-river hydro (60.6%), geothermal (89.9%) and cogeneration plants (57.6%). These values are used to de-rate nameplate capacity when calculating the North Island WCMs.

[17] Based on the 500 trading periods with the highest demand for each year historical data is available.

9.4.3 Thermal Fuel and Operational Limitations

It is assumed that thermal fuel, or operational limitations, will not constrain production of electricity, with the exception of the Whirinaki diesel generator. Whirinaki's energy contribution is limited to 15 GWh per year in the derivation of the WEMs.

This assumption is designed to reflect the limited fuel capacity of the plant. This limitation has the net effect of reducing the WEMs by directly reducing the amount of energy available during the winter period.

9.4.4 Start Storage

To account for start storage levels in the hydro catchments an amount of freely usable energy (GWh) is assumed. These assumptions are as per the SSAD. In the calculation of the WEMs the following values for start storage are used:

- The start storage level is 2,750 GWh in the New Zealand WEMs
- The start storage level is 2,400 GWh in the South Island WEMs.

9.5 TRANSMISSION

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

The base-case assumption in this assessment is that the HVDC capability will be the combined capability of Pole 2 and Pole 3.

9.5.1 HVDC: Southwards Flow

It is assumed that the North Island will be able to supply the South Island with 2,102 GWh (480 MW average transfer[18]) of energy during the winter period. Note that this energy transfer is dependent on the North Island having the required surplus energy available. To allow for this restriction the lesser value of 2,102 GWh or the net NI energy surplus, which is determined in the same way as the South Island WEMs, is used.

It should be noted that actual southward transfer during June-August in the 2008 dry year was less than that assumed above. The Winter Review[19] discusses reasons for this. This assessment includes a scenario with considerably lower southward transfer (300 MW compared with 480 MW).

This scenario may no longer be relevant in light of current HVDC capacity. Despite this, the scenario is meaningful as it illustrates the sensitivity of the South Island WEMs to HVDC transfer limits.

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

[19] *http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/consultations/security-of-supply-consultations/review-of-2008-winter/*

9.5.2 HVDC: Northwards Flow

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

The contribution of South Island capacity to North Island demand is a function of surplus capacity available in the South Island, which is determined in the same way as the North Island WCM. The function used in this process was derived using simulation analysis[20], taking account of:

- HVDC capacity
- transmission losses
- North Island instantaneous reserve requirements[21]
- the low probability of forced outages on the HVDC link.

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

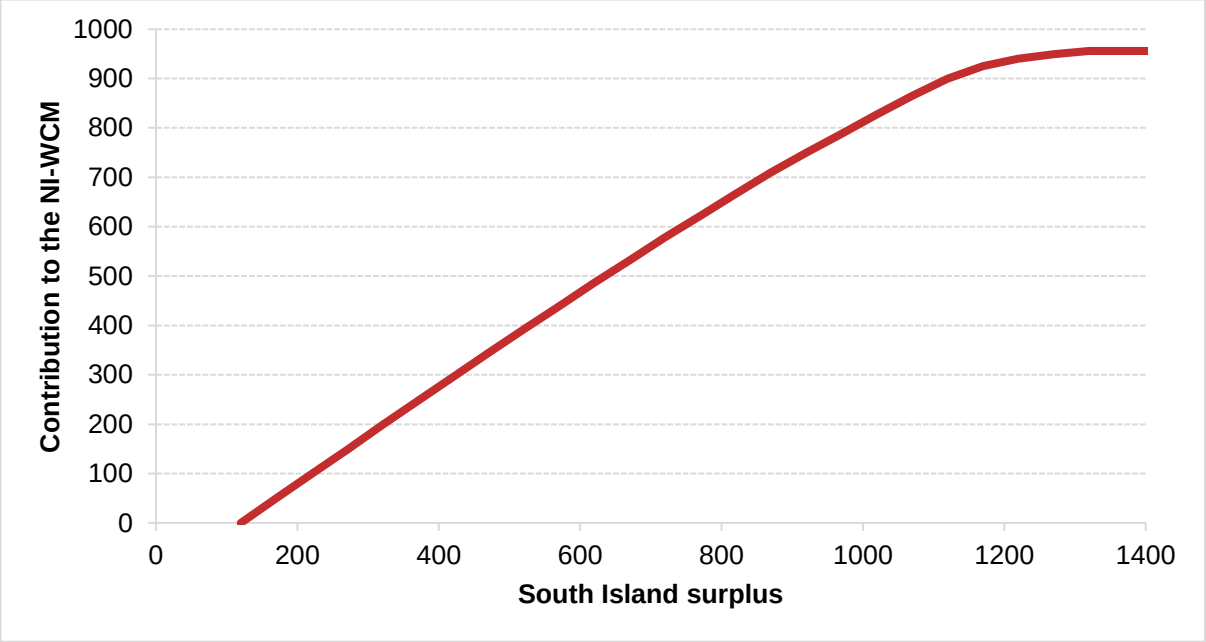

Figure 33: Relationship between South Island surplus and its contribution to the North Island WCMs

9.5.3 AC Transmission Assumptions

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

[20] Changes to the capability and operation of the HVDC such as the National Market for Instantaneous Reserves will impact this analysis. We are working with the Authority to review the SSAD, including the South Island Contribution Curve. Any changes to the assumptions will be incorporated in a future Annual Assessment.

10 Appendix 2: Detailed Demand Forecast Assumptions

10.1 Introduction

This appendix sets out the key demand assumptions used in the energy and capacity margin assessments.

This assessment based its demand forecast on Transpower's 2016 long-term electricity demand forecast, hereafter referred to as the underlying demand forecast. The underlying demand forecast does not include embedded generation as it is derived at GXP level. Therefore, some post-processing has been applied to allow for modelling of embedded generation, and account for transmission losses and demand response.

10.2 Treatment of Generation

The underlying demand forecast predicts demand at GXP level, with *all* embedded generation netted off. This approach is used internally as it best suits the purposes of modelling grid asset requirements. Ideally the Security of Supply Annual Assessment should include all electricity generation regardless of its connection status and therefore embedded generation has been grossed on to the underlying demand forecast wherever possible[22].

10.3 Specific Demand Assumptions

For energy margin calculations, the underlying demand forecast is adjusted by:

- grossing on transmission losses
- grossing on embedded generation
- allowing for demand response
- converting annual demand to winter demand.

These steps are carried out in the order outlined above. Transmission losses are only applied to net GXP demand, and demand response and conversion to winter demand are applied to gross demand (inclusive of transmission losses and embedded generation).

For all energy margin calculations winter demand (1st April – 30th September) is assumed to be 52.0% of average national annual demand, and 51.5% of South Island annual demand.

For capacity margin calculations the underlying demand forecast is applied proportionally to a known H100 demand value for 2016 (that is percentage growth rates are applied to determine 2017 onwards). This removes the need to adjust for embedded generation and transmission losses or convert from single highest peak demand to H100 peak demand. However, forecast demand is still adjusted to allow for demand response.

10.3.1 Demand Response

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

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

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

[22] Transpower's SCADA system was used to gather data on embedded generators. Where no historical SCADA data is available for a generator it was not included in the modelling.

10.3.2 Transmission Losses (for WEMs)

For the baseline year (2015) actual transmission losses are added onto net GXP demand. For all forecast years a historical linear relationship between demand and transmission losses is used to derive transmission losses, which are then added to the underlying demand forecast.

This is in contrast to a static percentage assumption that is recommended in the SSAD. This approach has been taken as it provides a more accurate baseline year, which has a flow on effect for all future years. The net effect of this assumption is to increase demand slightly (40-100 GWh) and therefore decrease the WEMs slightly.

10.3.3 H100 Demand (peak demand forecast)

The underlying demand forecast models the single highest half-hourly demand in a year. For the Security of Supply Annual Assessment, the Authority recommends use of the H100 demand, which is an average of the 100 highest hours (or 200 half hours) of demand falling between 7am and 10pm, 1st of April and 31st of October.

This assessment has derived an H100 demand that is consistent with the supply assumptions by determining demand for generation in 2016[23]. This is achieved by firstly identifying the H100 peak demand periods using aggregate data for the North and South Islands. Then, generation from each generator (that was modelled including embedded generation) during those peaks is aggregated to determine demand for generation for each of those peak periods. Finally, these aggregate values were averaged to determine a single H100 figure for 2016.

The percentage growth from the underlying demand forecast was then applied to the 2016 H100 figure to determine an H100 forecast out to 2026.

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

[23] Demand for generation is demand measured at the point of generation. This eliminates the need to adjust for embedded generation (measuring and aggregating all generation is modelling on the supply side) and transmission losses (these are implicitly included).

10.4 DEMAND DATA

10.4.1 Demand Data used for the 2017 Annual Assessment

The base-case energy demand is shown in Table 12.

Table 12: Base-case forecast of annual energy demand for generation

Calendar Year	North Island Demand		South Island Demand		New Zealand Demand	
	GWh	Δ%	GWh	Δ%	GWh	Δ%
2016	**26,948**		**15,594**		**42,542**	
2017	**27,237**	1.07	**15,817**	1.43	**43,055**	1.21
2018	**27,617**	1.40	**16,030**	1.35	**43,647**	1.38
2019	**28,028**	1.49	**16,315**	1.78	**44,343**	1.59
2020	**28,357**	1.18	**16,495**	1.10	**44,852**	1.15
2021	**28,683**	1.15	**16,654**	0.96	**45,337**	1.08
2022	**29,016**	1.16	**16,862**	1.25	**45,878**	1.19
2023	**29,327**	1.08	**17,023**	0.95	**46,350**	1.03
2024	**29,652**	1.11	**17,222**	1.17	**46,874**	1.13
2025	**29,971**	1.08	**17,385**	0.95	**47,356**	1.03
2026	**30,283**	1.04	**17,540**	0.89	**47,823**	0.99

The base-case annual H100 demand forecast is shown in Table 13.

Table 13: Base-case forecast of annual H100 demand for generation

Calendar Year	North Island Demand		South Island Demand (MW)	
	MW	Δ%	MW	Δ%
2016	**4,363**		**2,171**	
2017	**4,398**	0.81	**2,197**	1.19
2018	**4,446**	1.09	**2,238**	1.85
2019	**4,496**	1.14	**2,255**	0.75
2020	**4,543**	1.04	**2,272**	0.79
2021	**4,587**	0.97	**2,293**	0.89
2022	**4,631**	0.97	**2,313**	0.87
2023	**4,678**	1.01	**2,335**	0.97
2024	**4,724**	0.98	**2,358**	0.99
2025	**4,770**	0.98	**2,381**	0.99
2026	**4,816**	0.95	**2,405**	1.00

Note: these tables do not include the demand response or winter scaling adjustments.