TRANSPOWER

Appendices for Draft Security of Supply Assessment 2026

System Operator

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Contents

Appendix 1: Margin Assessment Methodology

A1.1 Margin Assessment Methodology

The Margin Assessment Methodology is outlined in the Security Standards Assumptions Document (SSAD)[1] published by the Electricity Authority (the Authority).

A1.1.1 Winter Energy Margins Assessment

There are two winter energy margins. The New Zealand Winter Energy Margin (NZ-WEM) is calculated as:

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

The South Island Winter Energy Margin (SI-WEM) is calculated as:

$$SIWEM = \left(\frac{SouthIsland\ expected\ energy\ spply + expected\ HVDC\ transfer\ south}{South\ Island\ expected\ energy\ demand} - 1\right) * 100\%$$

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.

Table 1 and Table 2 define the components in the above formulae.

Table 1 Summary of the New Zealand Winter Energy Margin components

Component	Comprises	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	Appendix 4 sets out thermal deratings due to fuel availability
	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[2]
	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

Component	Comprises	Description
	Other generation (GWh)	Expected winter energy available from co-generation[3], 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)	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 grid exit point (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% to allow for voluntary demand response These reductions include voluntary demand response resulting from high spot prices or retailer pricing initiatives. However, reductions in demand as a result of savings campaigns or forced rationing are excluded

Table 2 : Summary of the South Island Winter Energy Margin components (where different to above)

Component	Comprises	Description
Expected HVDC transfers south (GWh)	HVDC (GWh)	Expected winter HVDC transfers received in the South Island We have assumed that the North Island will be able to supply the South Island with at most 480 MW of average power transfer over winter, as specified in the SSAD. This equates to a total of 2,108 GWh of energy transfer over the 183-day winter period. This energy transfer is dependent on the North Island having the required surplus energy available. To allow for this restriction, we have used the lesser value of 2,108 GWh or the net North Island energy surplus. We have increased the maximum southward energy transfer in the HVDC upgrade sensitivity.
	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 the South Island

A1.2 North Island Winter Capacity Margin Assessment

The North Island Winter Capacity Margin (NI-WCM) is calculated as:

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

For the purposes of calculating winter capacity demand and winter capacity supply, winter is defined as the period from 1 April to 31 October between 7 am and 10 pm.

Table 3 defines the components in the above formula.

Table 3 Summary of the North Island Winter Capacity Margin components

Component	Comprises	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	Reviewed and updated the coal and gas capacity factors as discussed in A3.8 below. The updated gas derating is 2% and coal derating is at 4%. The SSAD specifies a 3% derating for all thermal generation. This SSAD value is still used for diesel generators.
	Thermal generation fuel supply availability deratings	No thermal deratings due to fuel availability are applied except for low gas supply sensitivity, as discussed in Appendix 4
	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 derated 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 The Waikato hydro scheme is derated by 60 MW to account for the impact of chronological flow constraints

Component	Comprises	Description
	Other generation (MW)	The capacity contributions of solar, wind, run-of-river hydro, co-generation and geothermal generation assumed for the NI-WCM are determined from historical generation at peak periods Generation output for the 200 trading periods with highest demand is collected. This is then analysed to determine the average contribution of solar, wind, run-of-river hydro, co-generation 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: 85.8% • co-generation: 51.5% • large-scale solar: 4.3% • wind: 29.3% For batteries, this assessment assumes a capacity contribution of 60% for those with storage durations of 2 hours or less, and 80% for those with storage durations of anything greater.
North Island and South Island expected demand (MW)	North Island and South Island 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 North Island 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

Component	Comprises	Description
	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 (South Island supply capacity minus South Island peak demand) is constrained by the capability of the HVDC as specified in the SSAD.

Appendix 2: Demand Forecasting Modelling

A2.1 Introduction

Winter energy and peak demand forecasts are developed in the demand forecasting modelling suite (the modelling suite) 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[1], as Figure 1 shows. The modelling suite can forecast average demand, in MW, at each 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 does not 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.

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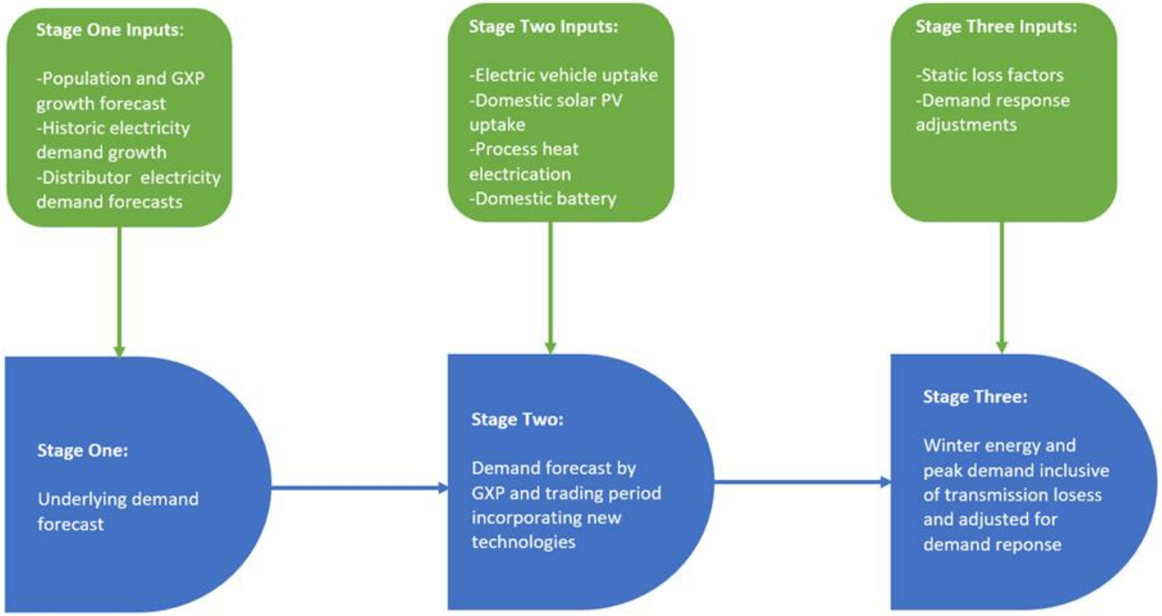
[1] This process is similar to that used in the 2025 SOSA.

Figure 1: A high-level diagram of the three-stage demand forecasting process



A2.1.1 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.

A2.1.2 Stage Two: Add Changes in Demand from New Technologies

In this stage, demand changes for electric vehicle charging, domestic solar photo voltaic (PV), domestic batteries and process heat electrification are added in, considering the regional, seasonal and sectoral impact of these technologies. Consideration is given to how some technologies alter the demand for electricity within a typical day. For example, we assume that smart[2] electric vehicle charging will be set up to charge electric cars during periods of low demand—acting to 'fill-in' demand troughs.

While the demand forecasts consider embedded generation, only the uptake of domestic solar PV is forecast[3]. Other types of embedded generation are assumed to remain at current levels, as derived from historic market information[4].

Inputs to this stage include forecast uptake rates of new technologies (see Table 4). Outputs from this stage are forecast demand—and its components—broken down by GXP and half-hourly trading period. Further details of the profiles associated with the new technologies, and demand forecasting in general, can be found in the report and appendices of Transpower's paper Whakamana i Te Mauri Hiko[5].

A2.1.3 Stage Three: Calculate Winter Energy and Capacity Demand

For this final stage, the forecast winter energy and peak demand are calculated.

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[6].

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

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[2] In this context, smart electric vehicle charging refers to technology that avoids electric vehicle charging in peak demand or high price periods.

[3] Domestic solar PV could increase as the number of households increase, and as a greater proportion of households adopt solar PV.

[4] Adjustments are made for other embedded generation if we are informed of changes by distributors or customers.

[5] Whakamana i Te Mauri Hiko

[6] This calculation of winter peak demand (also called the H100 demand) for use in the winter capacity margin calculation is specified in the SSAD.

both embedded generation and grid connected generation. Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor. Sections A2.6 and A2.7 detail demand response adjustments.

A2.2 Reference Case and Demand Sensitivities

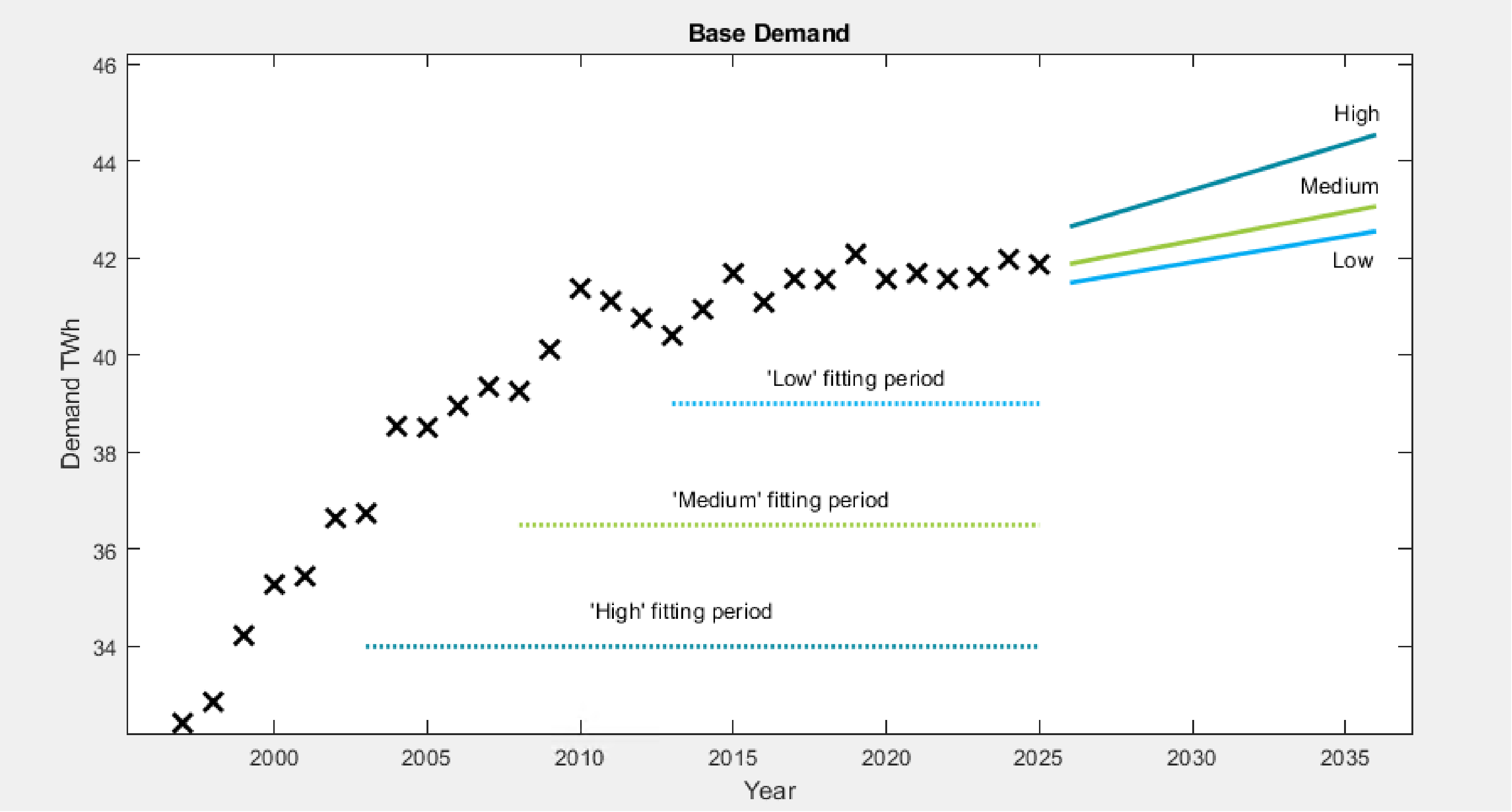
The modelling suite can be run to generate forecasts covering a range of different scenarios. The scenarios can include different base growth of peak and energy (Stage One) and different uptakes of new technologies (Stage Two). This year's annual security of supply assessment includes a 'medium demand' scenario, being utilised for the reference case, as well as 'low demand' and 'high demand' scenarios, which will be applied as sensitivities to the reference case. The medium demand scenario is modelled on 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 Table 4).

The three scenarios differed in the way that new step loads were treated. Previous SOSA scenarios included all step loads in each scenario. Further information collected by the grid owner included likelihood estimates for connection of new step loads, and each scenario was treated differently. The Low demand scenario only included step loads that EDBs indicated as certain or near-certain, the Medium demand scenario included step loads that were had a 50% likelihood and the High demand scenario included step loads that were more uncertain (>10% likelihood). This approach has resulted in an increased diversity across the three demand scenarios.

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. Figure 2 shows the base demand and the regression periods.

Figure 2: The base energy demand for the reference case and demand growth sensitivities derived from different regression periods



A2.3 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. The low process heat assumption has also been adjusted down to align with the 'business as usual' scenario. Table 4 sets out a summary of the scenario assumptions relating to Whakamana i Te Mauri Hiko. Distributed battery uptake and the effect on demand and peak is small in the forecast horizon. Distributed battery uptake for the reference case and demand growth sensitivities are similar to the Whakamana i Te Mauri Hiko 'mobilise to decarbonise' scenario.

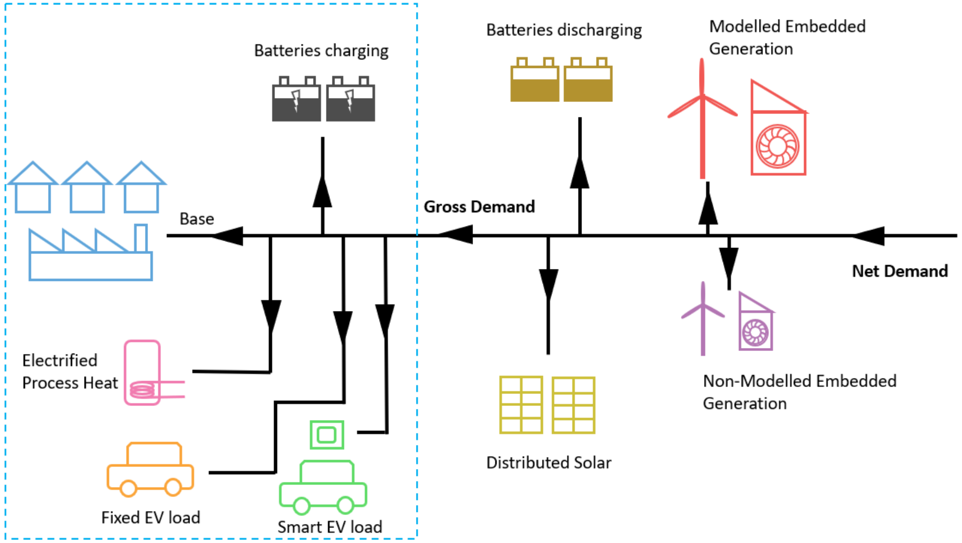
Table 4: Technology uptake rates mapped to Whakamana i Te Mauri Hiko scenarios

Demand scenarios	Whakamana i Te Mauri Hiko scenario	Description
Low demand (sensitivity)	A blended mix of business as usual and measured action with approximately 10% greater electric vehicle uptake	Some electrification of transport and process heat fails to emerge as compared to the medium and high demand sensitivities. This may reflect stalled technology development or regulatory settings not achieving their intended goals. It could also be consistent with a future where other alternatives to decarbonisation are pursued, such as forestry abatement.
Medium demand (reference case)	Accelerated electrification with approximately 25% greater electric vehicle uptake	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 (sensitivity)	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. While this scenario has more domestic solar uptake, it has little impact on reducing the winter peak demand.

A2.4 Forecast

The modelling suite is required to separate out the gross and the net demand; for example, 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. Figure 3 illustrates different types of supply and demand. We have used the convention that all power is pointing towards the load or generator, thus giving any generation as a negative load.

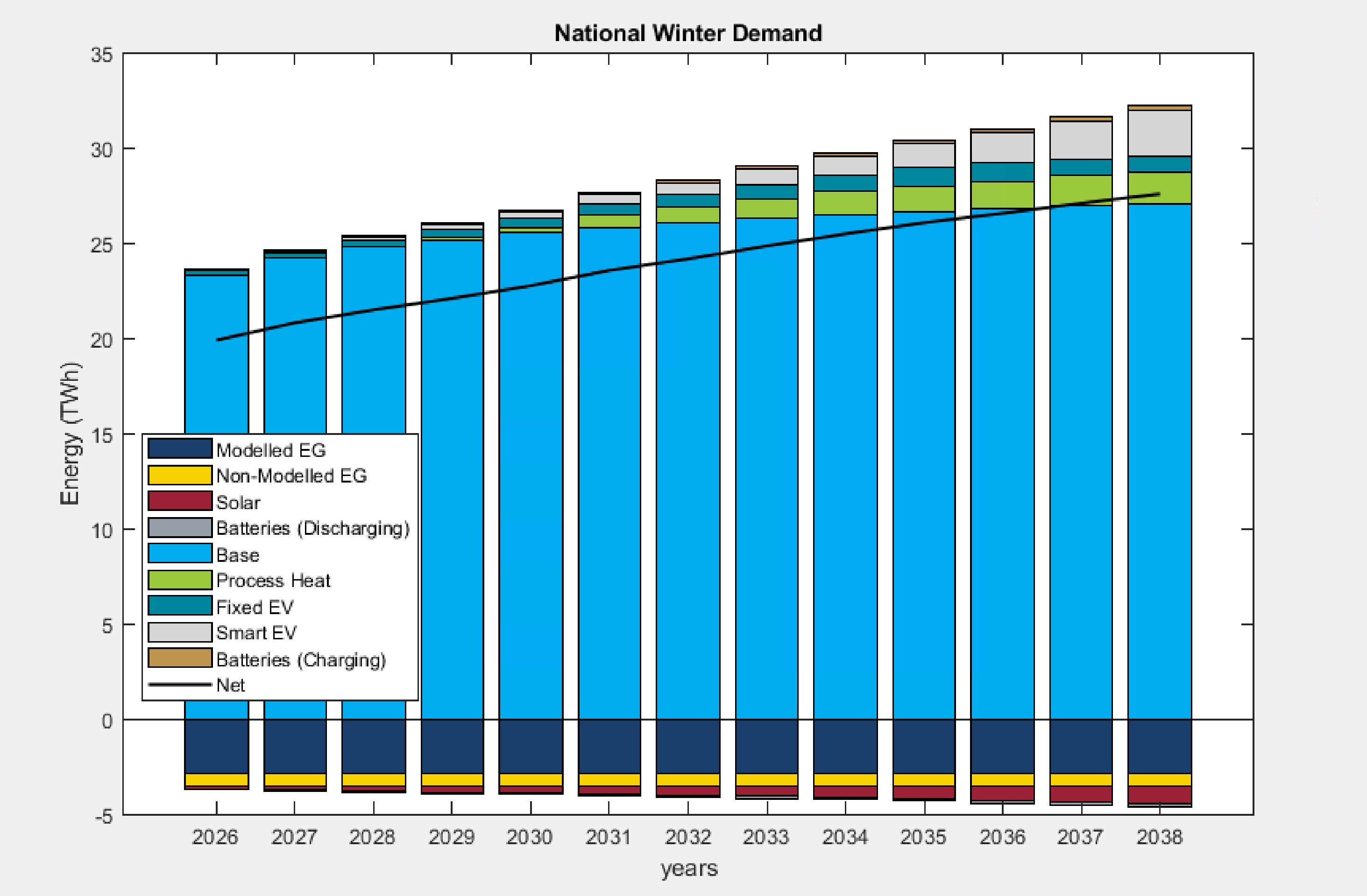
Figure 3: The components of Stage Two and the different components of embedded generation



A2.5 Winter Energy Demand

Forecast energy demand is reported for each island and the nation for every month. Energy demand can then be isolated for ‘winter’, which in this case is from 1 April to 30 September. Figure 4 shows the growth of New Zealand winter energy demand. It also shows the individual components that make up the gross demand, fixed and smart electric vehicle charging, electrification of process heat and batteries charging. Winter energy 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 Operations team.

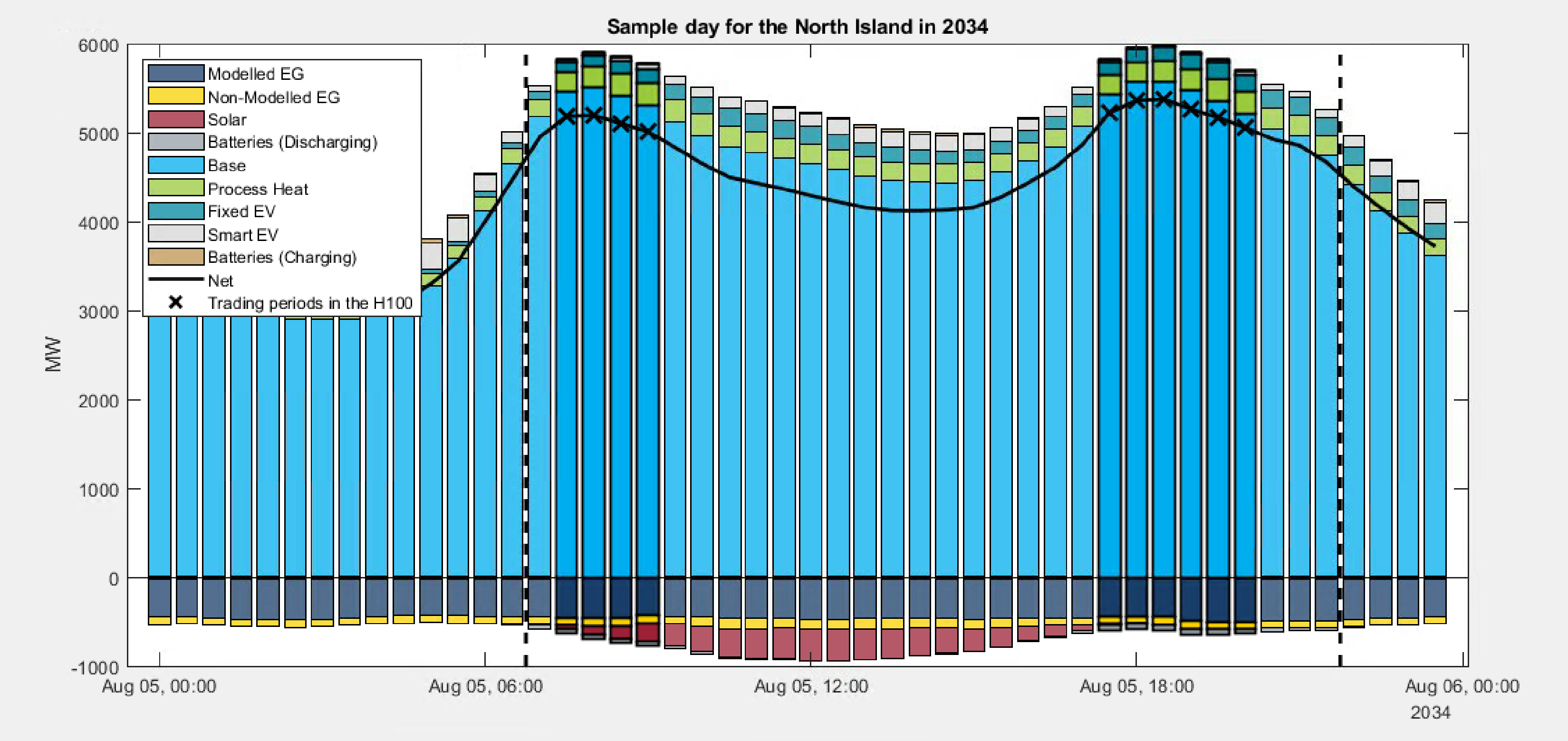
Figure 4: New Zealand winter energy demand. The different types of embedded generation are shown



A2.6 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 1 April to 31 October, and daytime is from 7am to 10pm. Figure 5 shows a sample day for the North Island; 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 Operations 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—that is, base demand, electric vehicle charging, electrification of process heat and batteries charging—are also shown.

A2.7 Winter Energy and Peak Demand Forecasts

Figure 6 shows forecast winter energy and peak demand as used in this analysis as well as a comparison to the demand forecasts used in the 2025 Security of Supply Assessment (SOSA). 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[7]. The medium demand forecast is the one assumed in our reference case.

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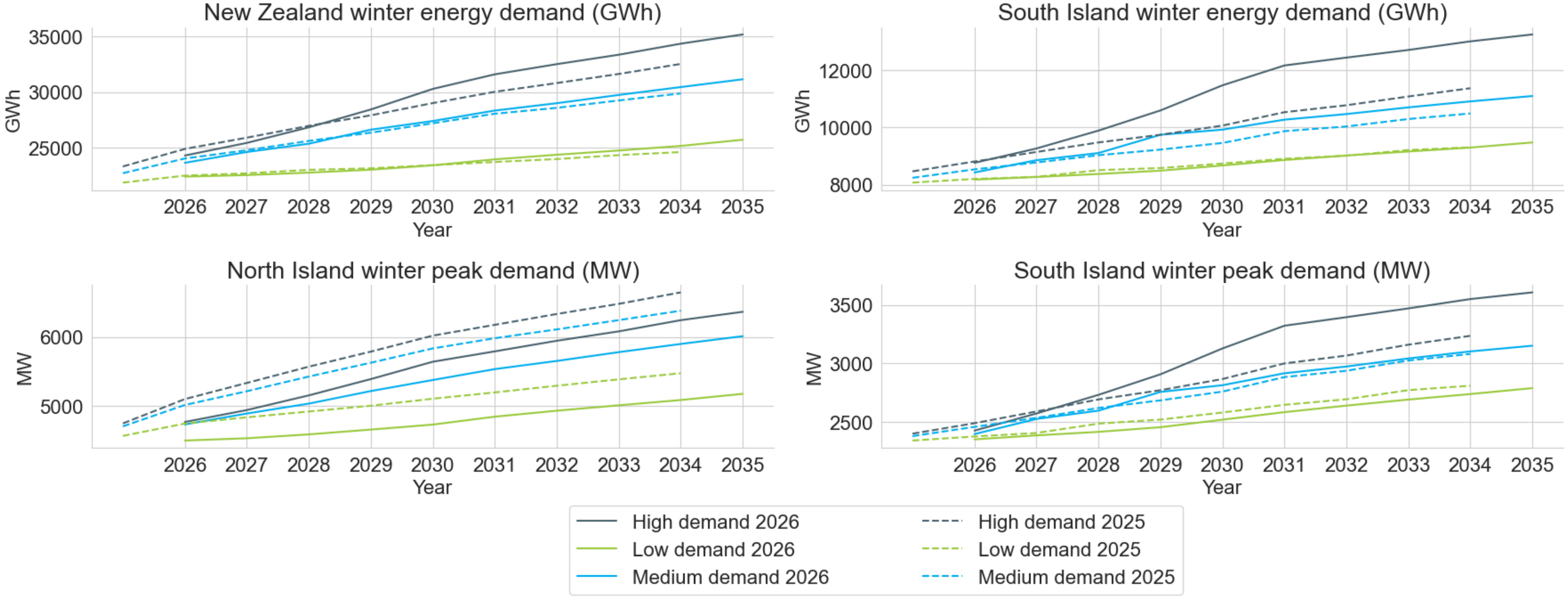
[7] Demand response assumptions are based on the SSAD. This specifies 2% demand response in the winter energy margin calculation and 176 MW when calculating the winter capacity margin.

Figure 6: New Zealand winter energy, North Island winter peak and South Island winter peak demand forecasts compared to equivalent figures in the 2024 Security of Supply Assessment



Appendix 3: Supply Assumptions

A3.1 Information Sources

We obtain information on existing and proposed new supply projects from generation companies on a confidential basis.

A3.2 Winter Energy and Capacity Supply Contributions

Winter energy and capacity supply contributions include generation from both grid connected and embedded generation. Table 5 shows how contributions are evaluated for different types of generation.

Table 5: Evaluating winter energy and capacity contributions

Resource type	Energy contribution	Capacity contribution
Fossil-fuel thermal generation	Installed capacity, derated for outages, and multiplied by the number of winter hours	Installed capacity, derated for outages
Controlled hydro	Generation based on average hydro inflows over the historic record	Installed capacity, derated 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 29.3% for wind and 4.3% for large-scale solar, which is based on historical winter peak contributions. Likewise for other resources.

Resource type	Energy contribution	Capacity contribution
Grid-connected batteries (BESS)	No energy contribution assumed[8]	Installed capacity, multiplied by a resource specific winter peak contribution factor[9] A 60% winter peak contribution is used for BESS with a storage capacity of 2-hours or less, and 80% for anything greater.
Smaller embedded generation (excluding domestic solar PV)	As per historic market information. No forecast changes are assumed unless information is provided by customers on changes	As per historic market information. No forecast changes are assumed unless information is provided by customers on changes
Domestic solar PV and batteries[10]	As per the demand forecast	As per the demand forecast

A3.3 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 three supply pipeline stages as shown in the table below.

Our SOSA 2026 survey required each respondent to provide us with its own assessment of the likelihood of the potential investment proceeding. We also tested that assessment against other sources of information including Transpower's published grid connection pipeline information. A potential investment is assessed as "likely" to proceed in the 10-year modelled period if it has at least a 75% chance of proceeding.

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[8] Grid connected batteries will both inject power into and consume power from the grid. The net efficiency loss will result in a net load on the system. Our assessments based on grid-connected battery supply was an expected increase in load of ~0.1%. Given this small effect, we have assumed no significant impact on the net load in this year's assessment.

[9] We have kept our assumptions around battery capacity contribution same as the previous year SOSA (2025). See Appendix 6.2 for details.

[10] Both the domestic solar PV and batteries included in the demand forecast are done at a regional level and include regional diversities. No further deratings are applied to these forecasts.

Table 6: Supply pipeline stages

Stage	Short description	Long description
Stage 1	Existing and committed	Includes: • Existing assets • Committed investments for which a final decision to invest has been made.
Stage 2	Stage 1 + consented and likely	Includes: • Existing assets • Committed investments for which a final decision to invest has been made • Potential investments that are consented and likely to proceed but a final decision to investment is yet to be made.
Stage 3	Stage 2 + consent likely to be sought	Includes: • Existing assets • Committed investments for which a final decision to invest has been made. • Potential investments that are consented and likely to proceed but a final decision to investment is yet to be made. • Potential investments that are not consented and consent is likely to be sought within the next two years.

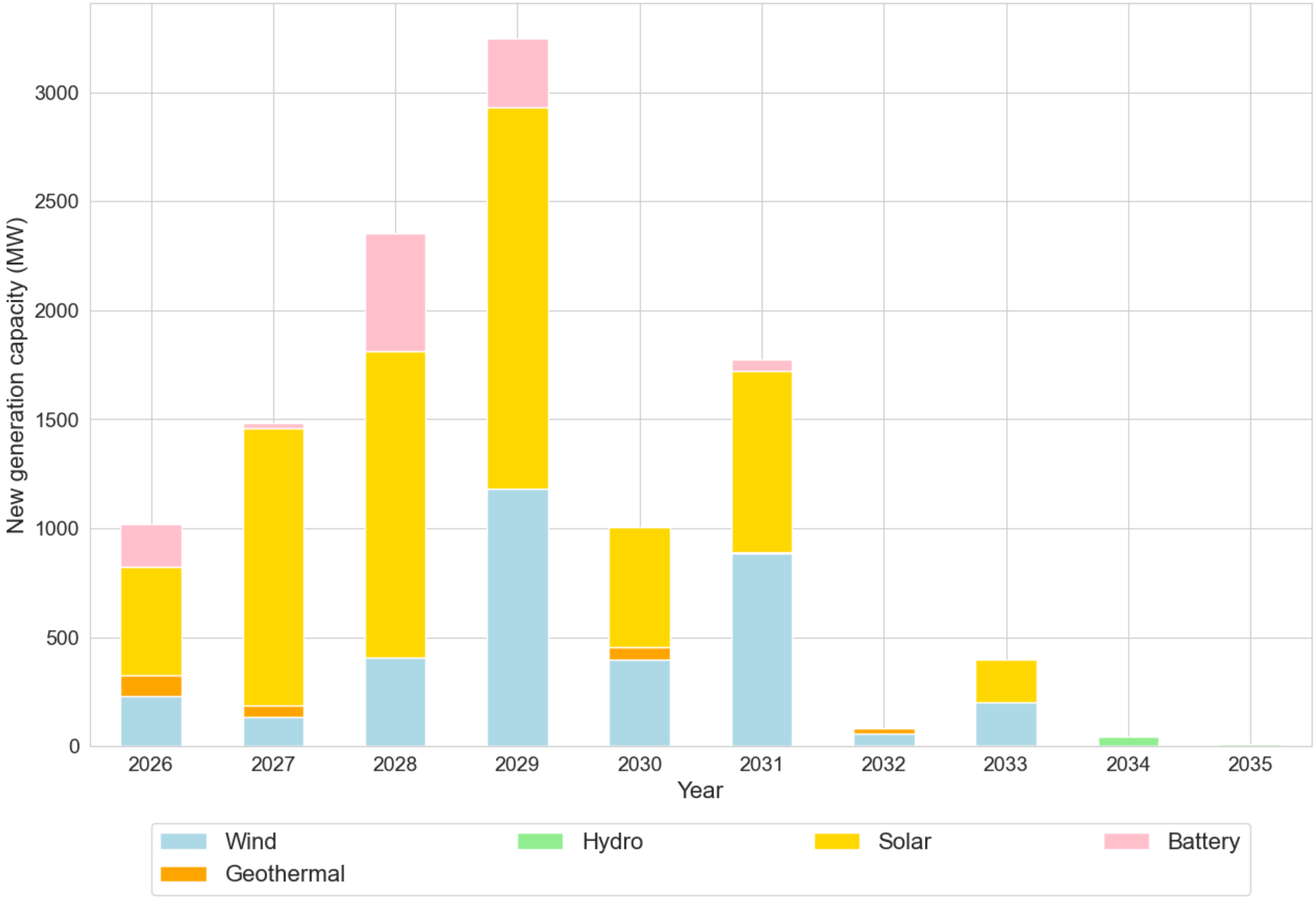
The commissioning dates for each of the new supply projects is determined as the first winter period following the date provided by the generation company on a confidential basis. If a date was not provided for a project, we use an estimated earliest build date. The earliest dates at which a new supply project could potentially become available is based on the type of project and its development stage (outlined in Table 7). Our earliest build dates are an estimate of when generation could potentially be built at a given point in the future. New supply projects will most likely be progressed only when the market conditions justify investment. Delays may occur for a variety of reasons, including plant availability, logistics and transmission requirements. It is also possible that projects may be expedited to respond to market conditions. It is possible therefore that actual build dates for a given new supply project could differ from our estimated earliest build date.

Table 7: Proposed new supply project earliest build dates by project type and development category

	Stage 1: Existing and committed	**Stage 2: Consented and likely**	**Stage 3: Consent likely to be sought**
Fossil-fuel thermal	Estimated build date	2028	2031
Geothermal	Estimated build date	2029	2032
Onshore Wind	Estimated build date	2029	2032
Hydro	Estimated build date	2030	2033
Solar (large scale)	Estimated build date	2028	2031
Battery	Estimated build date	2028	2031

Figure 7 shows proposed new supply project additions by year (including earliest build year, where used).

Figure 7: Proposed new supply project timeline for the reference case



A3.4 Winter Energy Supply and Capacity

Figure 8 shows assumed winter energy supply and capacity. The grey bars show existing and committed generation. The coloured bars show the pipeline of new supply projects for supply pipeline Stages 1, 2 and 3. Each coloured bar represents cumulative new supply projects for a given fuel type and year.

Figure 8: Winter energy and peak supply pipeline

A3.5 Inter-Island Transmission Assumptions

Our assessment of the SI-WEM found that North Island energy supply can meet some of the South Island's energy demand. We have 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[11].

Similarly, our assessment of the NI-WCM found that some South Island generation capacity can meet some North Island demand. 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.

We consider a sensitivity with an HVDC upgrade which allows a greater contribution from South Island generation to the NI-WCM[12]. Figure 9 shows the estimated increase in the contribution of South Island generation to the NI-WCM. The maximum contribution to the NI-WCM with the HVDC upgrade is estimated to be 1103 MW[13].

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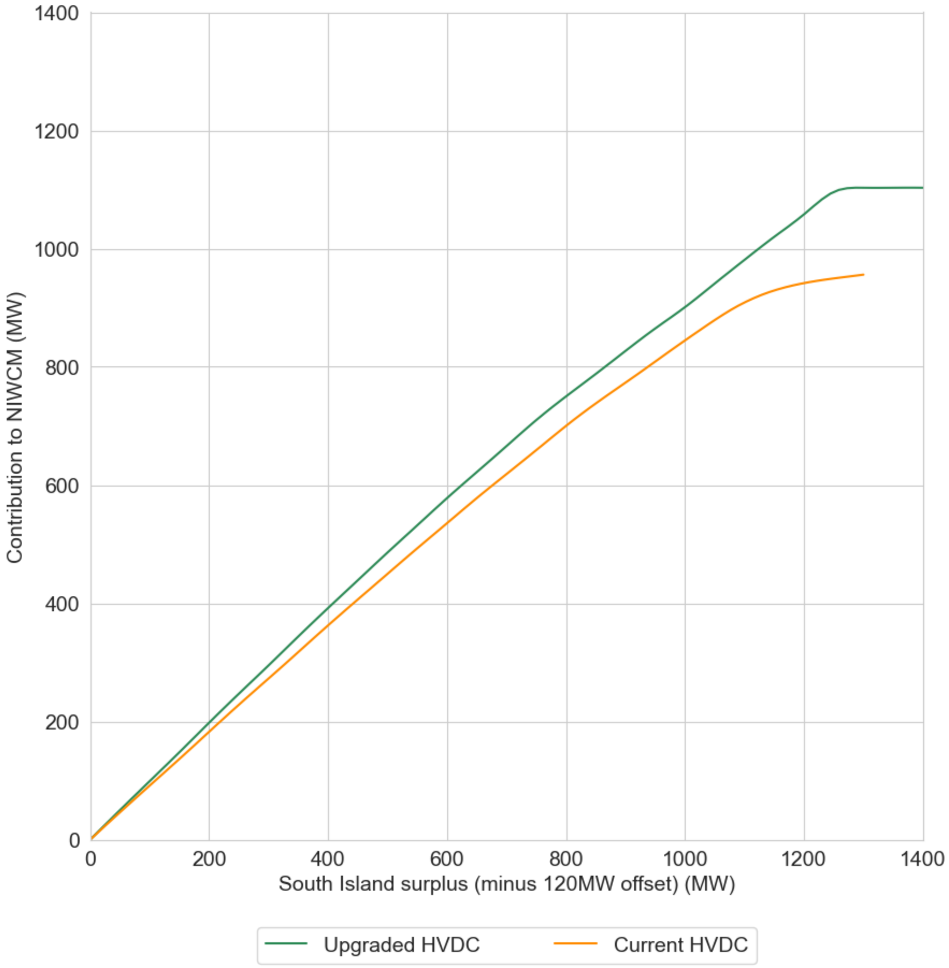
[11] Energy surplus in the North Island is calculated by subtracting North Island demand from available North Island supply.

[12] This is the upgrade including a fourth HVDC cable.

[13] The maximum contribution with the HVDC upgrade is based on the estimated maximum received power on a single pole (after accounting for losses) plus 400 MW (to account for estimated North Island reserves required to cover the largest North Island risk).

Figure 9: South Island contribution to North Island winter capacity margin for reference case and HVDC upgrade sensitivity



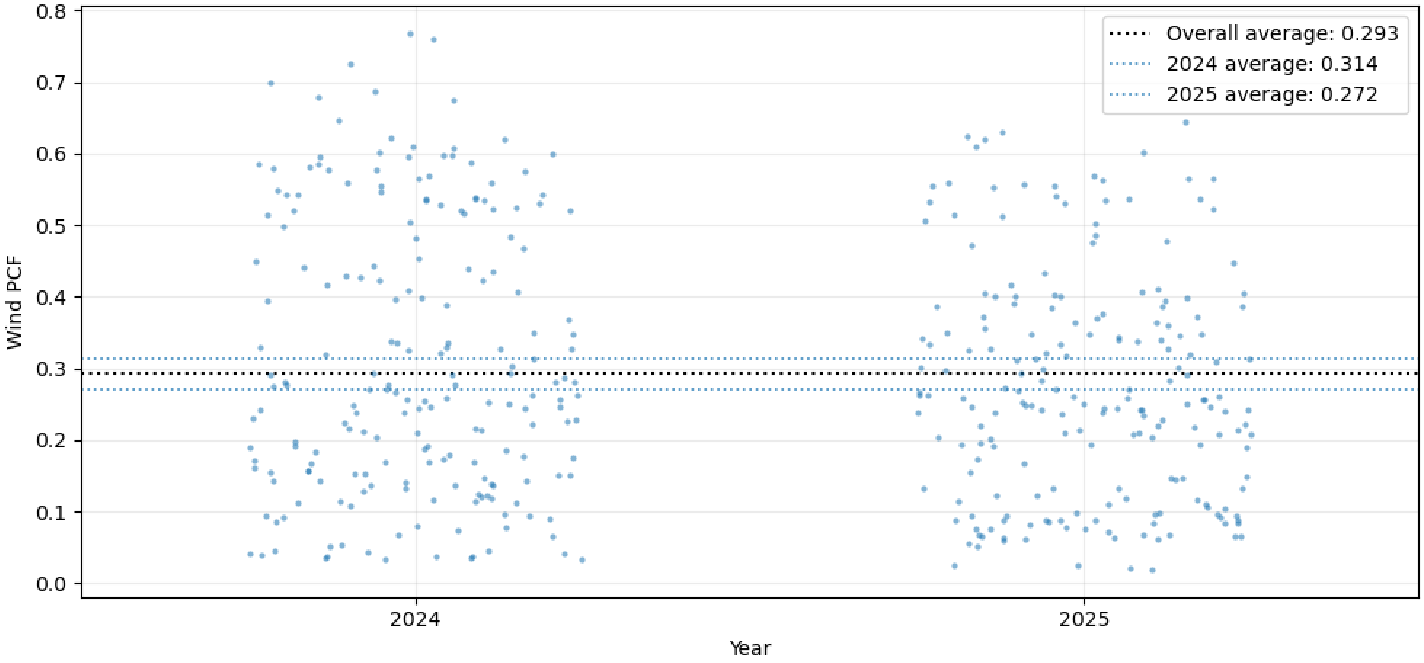
A3.6 Updated wind peak capacity factor

We have updated the wind peak capacity factor to 29.3% in this year's SOSA, a slight increase from the 25% assumed last year. This adjustment is based on our analysis of average of observed wind generation during the top 200 highest half hour demand peaks in 2024 and 2025, where we found the average capacity factor to be approximately 31.4% and 27.2% respectively.

Figure 10 shows the distribution of observed wind capacity factors over top 200 trading period demand peaks for year 2024 and 2025.

We simulated wind generation output using Renewable Ninja from 1980-2014 and compared simulated wind generation output against actuals for 2024. We found that simulated values provided a higher capacity factor of 37% versus actual observation of 31.3%. The simulated wind generation relies on theoretical turbine power curves applied to historical weather data and do not account for outages, constraints or pricing effects, which would result in a lower capacity factor. Relying on actuals ensures an operationally grounded baseline for SOSA 2026, while calibrating the simulated datasets to reflect these operational biases will be explored.

Figure 10: Observed Wind Capacity Factor during Historical Peaks



A3.7 Updated solar peak capacity factor

We have updated the solar peak capacity factor to 4.3% in this year's SOSA, a slight decrease from the 5.4% assumed last year. This adjustment is based on our analysis of average of observed solar generation during the top 200 highest half hour demand peaks in 2024 and 2025, where we found the average capacity factor to be approximately 1.49% and 7.14% respectively.

Figure 11 shows that solar generation could potentially contribute over 10% of its installed capacity on average to morning peaks but has a minimal impact on evening peaks. Given the large amount of planned investment in solar generation, this would significantly improve morning peak capacity security, but taking an average capacity factor across both mornings and evenings could result in an optimistic assessment of evening capacity security. This suggests that there could be value in assessing morning peak capacity security and evening peak capacity security separately.

Based on this analysis, it is assumed there will be a 0% contribution from solar to the NI-WCM under the constrained operational capacity sensitivity in the 2026 SOSA. This assumption is due to the low contribution from solar generation during evening peak periods, as well as fact that the majority of high winter demand peaks are evening peaks (as shown in Figure 12 for top 200 peaks of year 2024 and 2025).

Similar for wind, we also compared simulated solar generation output against actuals for 2024 and found simulated values provided a higher capacity factor (10.7%) versus actual observation of 1.5%. We've used capacity factors based on actual generation rather than simulated for SOSA 2026 using an average over 2024 and 2025 to reduce variability a single year sample. We will reassess this as additional years and solar generation capacity comes online.

Figure 11: Observed Solar Capacity Factor during Historical Peaks

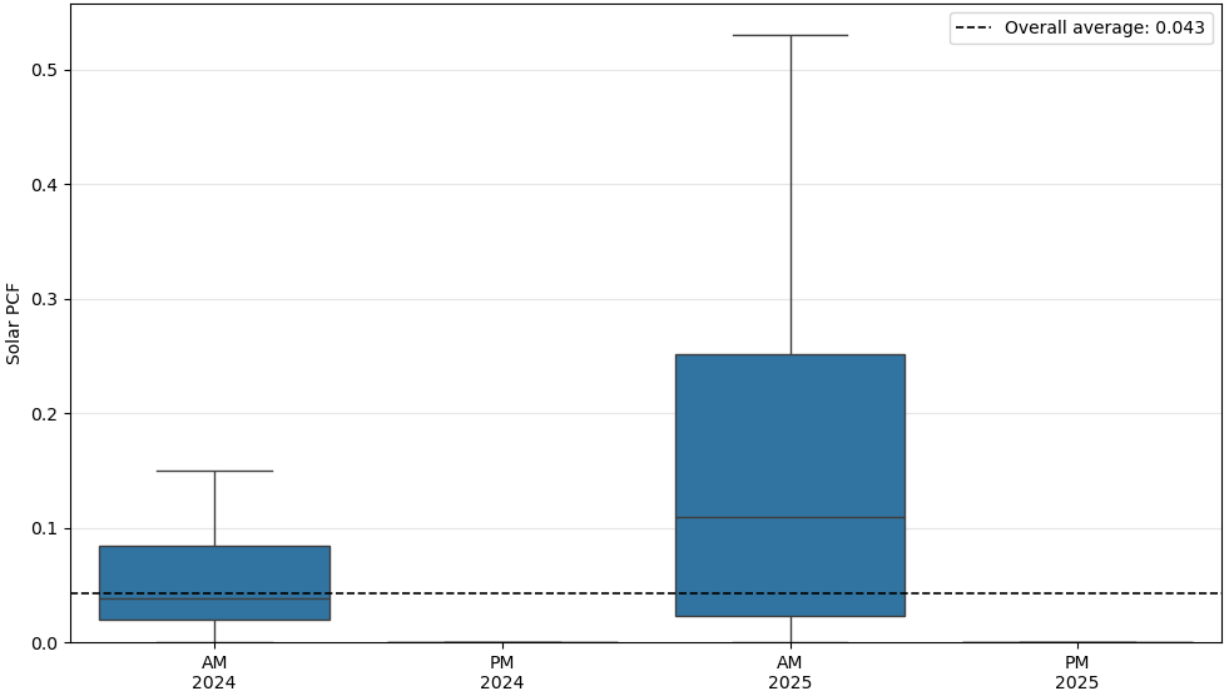
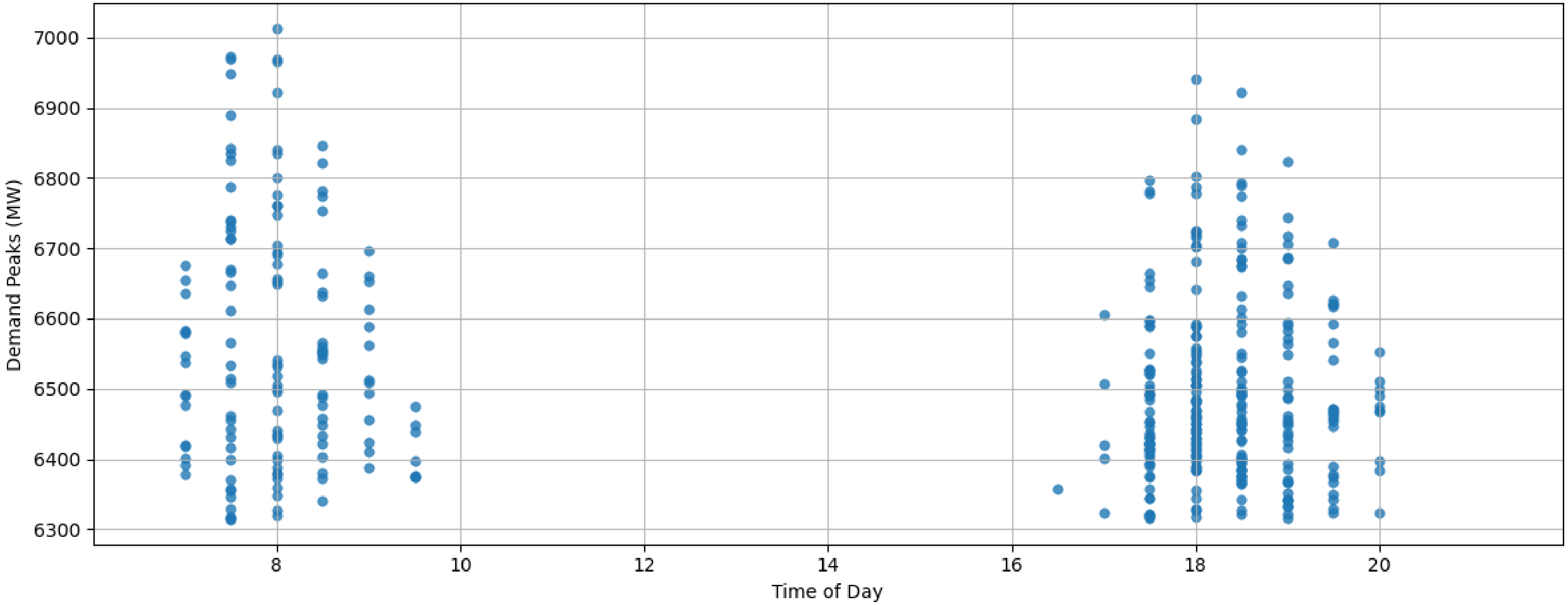


Figure 12: Distribution of Highest 200 Trading Periods in 2024 & 2025 by Time of Day



A3.8 Updated thermal peak capacity factor

To determine the thermal peak capacity contribution, we have analysed historical market offer data cross-referenced with actual unit outage records across the top 200 winter peak demand periods. This methodology provides an empirical approach to estimate the availability of the thermal fleet during peak load periods. The approach relies primarily on submitted market offers excluding extreme scarcity pricing tranches to establish a baseline of synchronised, firm capacity.

To address instances of economic deference, where a physically capable unit is not committed due to low wholesale prices, a market-referenced potential model is applied. If a unit offers 0 MW but is not on a recorded outage, its potential capacity is retained for security purposes unless the nodal clearing price exceeds the unit's marginal cost sourced from EA Trading Conduct Reports[14]. When prices exceed marginal cost and a unit remains at 0 MW, it confirms a physical inability to respond to market stress (such as cold-start latency or undisclosed fuel limits), and the capacity is excluded. Furthermore, the methodology explicitly accounts for out-of-market strategic reserves (such as Huntly Firming agreements) by treating them as firm capacity when physically healthy, while gas-peaking units are strictly capped by empirical fuel-delivery limits. The resulting peak capacity factor reduces the effects of short-term commercial dispatch behaviour, to capture the physical availability of the thermal units.

A3.9 Battery peak capacity factor

To determine the battery peak capacity contribution, we have analysed the operational data from the Rotohiko battery over winter peaks. This provides sufficient dataset spanning two full previous winters, whereas Ruakākā battery has only a partial winter of operational history (although both exhibit similar operational behaviour, as shown in weekly insight[15]. The methodology relies on market offers submitted inherently accounting for real-world availability, including both planned and forced outages. To address the energy-limited nature of battery, a dynamic state-of-charge (SoC) model is applied. Anchored to its market offer, battery's available energy is strictly depleted by cleared energy during sustained peaks, mathematically constraining its capacity once exhausted. The resulting peak capacity factor using empirical market behaviour aligns closely with the previous year's SOSA assumptions following observation of other jurisdictions [16].

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[14] https://www.ea.govt.nz/data-and-insights/trading-conduct-reports/

[15] Market Operations Weekly Report

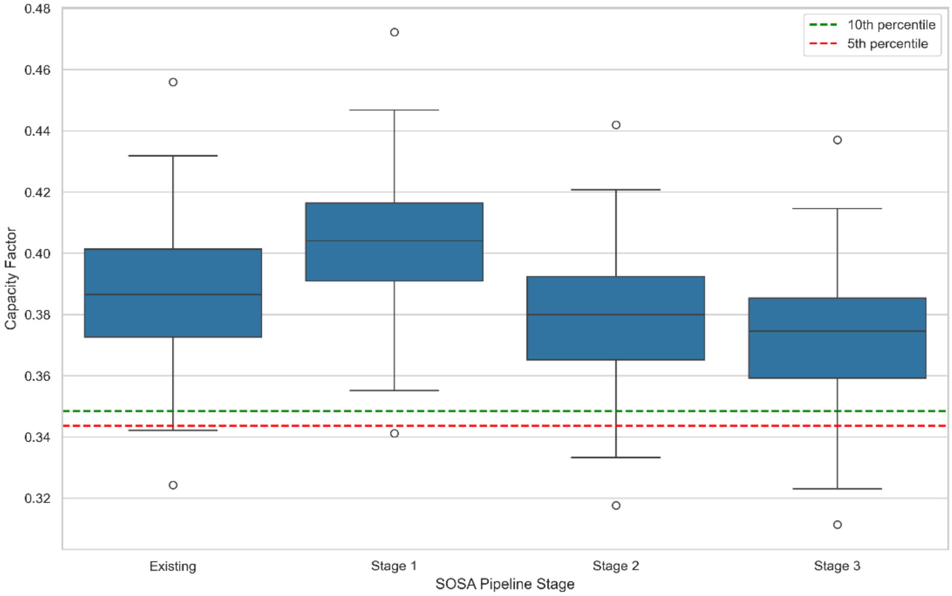
[16] AEMO ESO Report

A3.10 Wind and solar generation variations across winter

While wind and solar generation across winter is more reliable than their output during peak load periods, there is still some variation. The charts below shows the potential variation of wind and solar generation[17] during the winter months (April to September). It also shows the 5th and 10th percentile outputs of the existing fleet.

Here we see that the mean wind generation of the existing fleet over winter is 38.6% of its installed capacity. A 10% reduction in this mean is ~35%. This is below the 10th percentile of existing wind generation output across winter.

Figure 13: Distribution of wind generation over winter months



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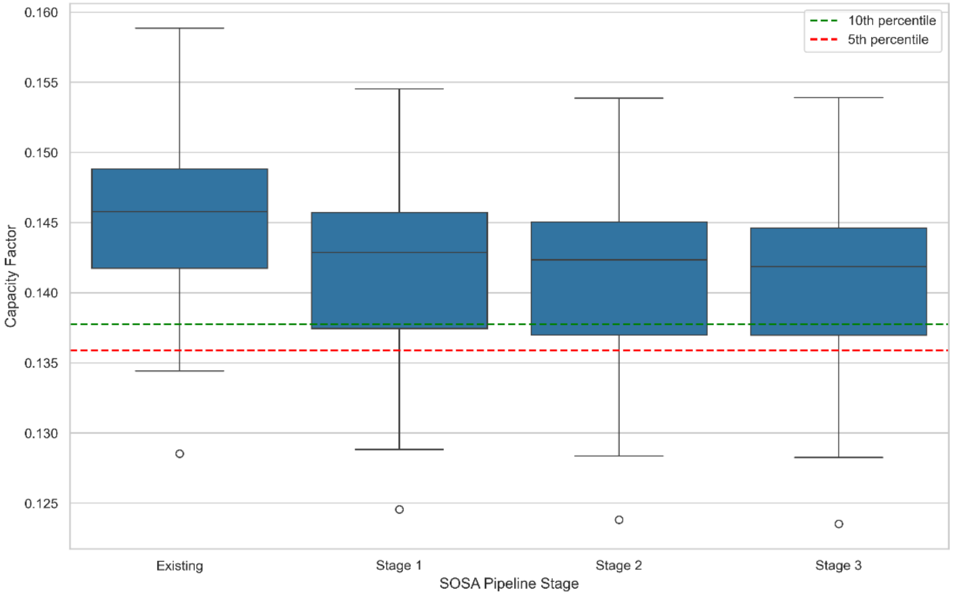
[17] This data is based on analysis from supply pipeline for the 2025 SOSA. We have not updated this analysis with the SOSA 2026 pipeline of wind and solar generation however we do not expect this to change significantly.

The chart below shows the mean solar generation of the existing fleet over winter is 14.5% of its installed capacity. A 10% reduction in this mean is ~13%. This is below the 5th percentile of existing solar generation output across winter.

Figure 14: Distribution of solar generation over winter months



Appendix 4: Thermal Fuel Availability

A4.1 Gas Supply Availability

A4.1.1 Gas supply forecast

Figure 15 shows the gas supply forecasts used for the SOSA. These are in average TJ/day produced over the winter period (1 April to 30 September).

- Confidential information from gas producers is used for 2026–2027.
- The reference case, low and very low gas supply sensitivity use forecasts from Enerlytica[18] for 2028-2035.
- The high gas supply forecast is based on an assumption aligned with the proposed requirements from an LNG facility. We have used the requirements based on public information of potential deliverability under a potential LNG import regime (12PJ over any 3-month period[19]).

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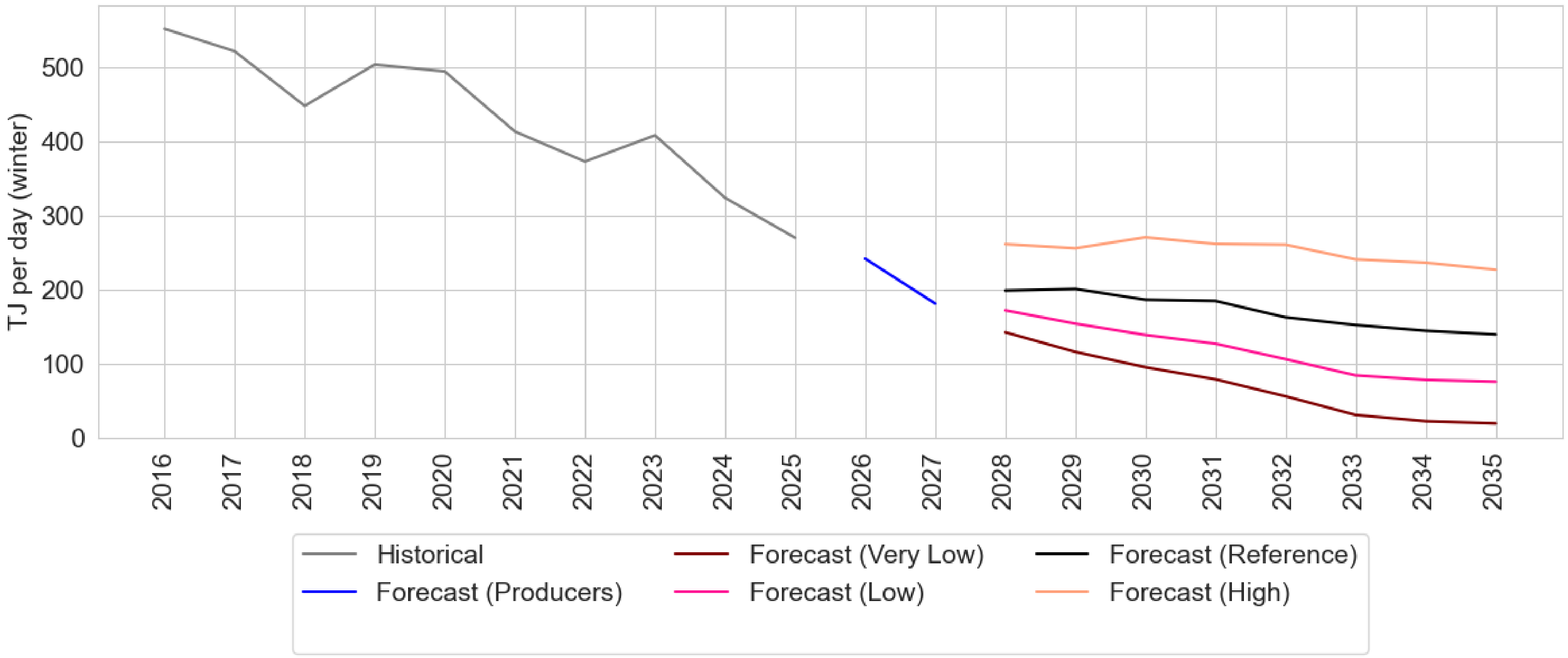
[18] Enerlytica "NZ Gas Supply Quarterly Forecasts". Research Portal | Enerlytica (paywalled)

[19] See paragraph 35 here (Government Investment in Dry Year Risk Cover: Consideration of an LNG Import Facility)

Figure 15: Gas production forecasts



A4.1.2 Dry year gas supply margin

To evaluate gas supply adequacy, we estimate a dry year gas supply margin for the next 10 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:

- Huntly Rankine units are operating on coal or some other fuel that is not gas, and have enough fuel to contribute to energy margins at their maximum available capacity[20];
- all gas generators operate at their maximum available capacity unless limited by fuel supply;
- gas demand for users other than gas generators is estimated using forecasts of industrial exits[21], gas demand forecasts aligned with those from the Gas Industry Company (GIC) as well as information provided by the Commerce Commission on expected future demand from gas distribution businesses[22];
- For our Reference case we assume that gas supply availability for generation reflects both Methanex and Ballance Agri-Nutrients' Kapuni sites shutting production in 2027 at the same time as the Enerlytica medium gas forecast assumes the Maui gas field will exit. We've also modelled forecast reductions in other industrial, commercial and residential gas usage
- other than this reduction in gas demand due to fuel substitution, there is no material reallocation of gas from major industrial gas users to gas generators during dry years;
- at the start of winter on 1 April, the Ahuroa Gas Storage facility contains an amount of gas equal to its average 1 April storage level[23]; and
- the Taranaki Combined Cycle (TCC) gas power plant is not available (decommissioned) in SOSA 2026.

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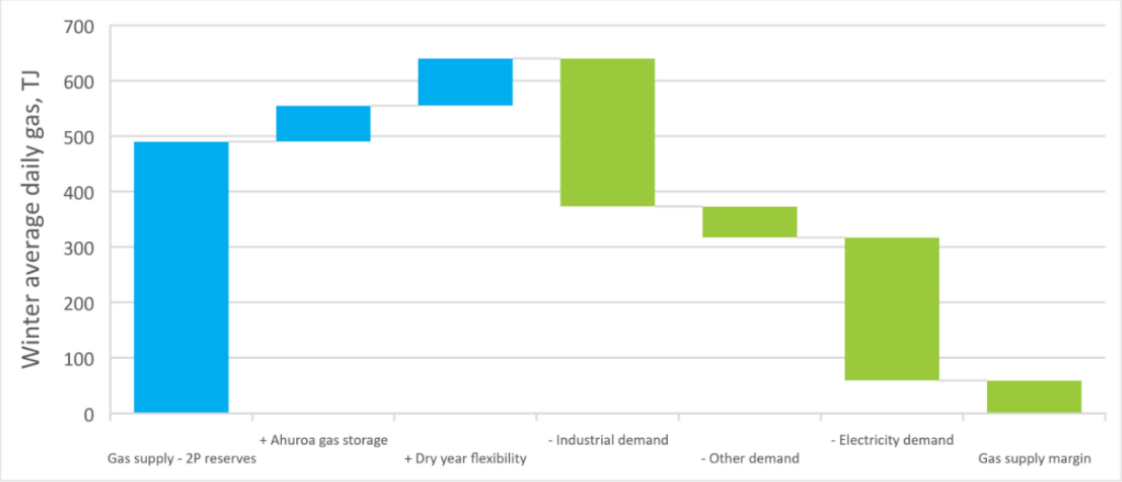
[20] In this appendix, "maximum available capacity" means maximum capacity minus an allowance for outages. Our assessment indicates this is a reasonable assuming a start coal stockpile of 600kT at the start of winter, which is the basis for the Commerce Commission approved Strategic Energy Reserve Huntly Firming Option agreement. Potential limitations (including fuel) that could limit Rankine output are assessed by the *reduced Rankine availability* sensitivity.

[21] In our Reference case, we assume Methanex and Ballance exit in 2027

[22] See 2026-GIC and Concept Consulting-Gas-demand-projections-to-feed-into-the-default-price-quality-path-DPP-regulation-of-gas-distribution-businesses-22-August-2025-v2.pdf

[23] An alternative would be to assume AGS is full at the start of winter (1-April). We felt this was too optimistic for gas storage capability to support a dry winter for each of the next 10 years. In recent dry winters (2021 and 2024), AGS was below average (2.4 PJ) and above average (4.3 PJ) respectively.

Figure 16: Example gas supply margin calculation: business as usual



A4.1.3 Reference Case

Under our reference case assumptions, we expect that in all assessment years gas generators will be limited in their dry year energy output due to limited gas availability. This section outlines the gas supply assumptions we use in the reference case and the resulting deratings applied to winter energy supply from gas generators.

We first estimate dry year gas supply margins under the following assumptions:

- gas supply to 2027 is equal to our forecast based on confidential information from gas producers;
- gas supply from 2028 to 2035 is equal to Enerlytica's "Mid" scenario forecast[24]; and
- There is reallocation of gas from major industrial gas users to electricity generation during a dry year emergency, i.e. we model gas demand response like that seen from Methanex in winter 2024 (2 month shutdown).

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[24] This is based on the Enerlytica 2026 Q1 forecast.

- We also assume Methanex and Balance exit ahead of winter 2027.

Figure 17 shows dry year gas supply margins for the reference case. A positive margin would indicate sufficient gas availability to run all gas generation at its maximum available capacity during a dry winter. Based on gas production forecasts, we expect a negative margin in all assessment years, and as such we have derated the contribution from gas generators to energy margins as shown in Figure 18.

Figure 17: Dry year gas supply margins—reference case

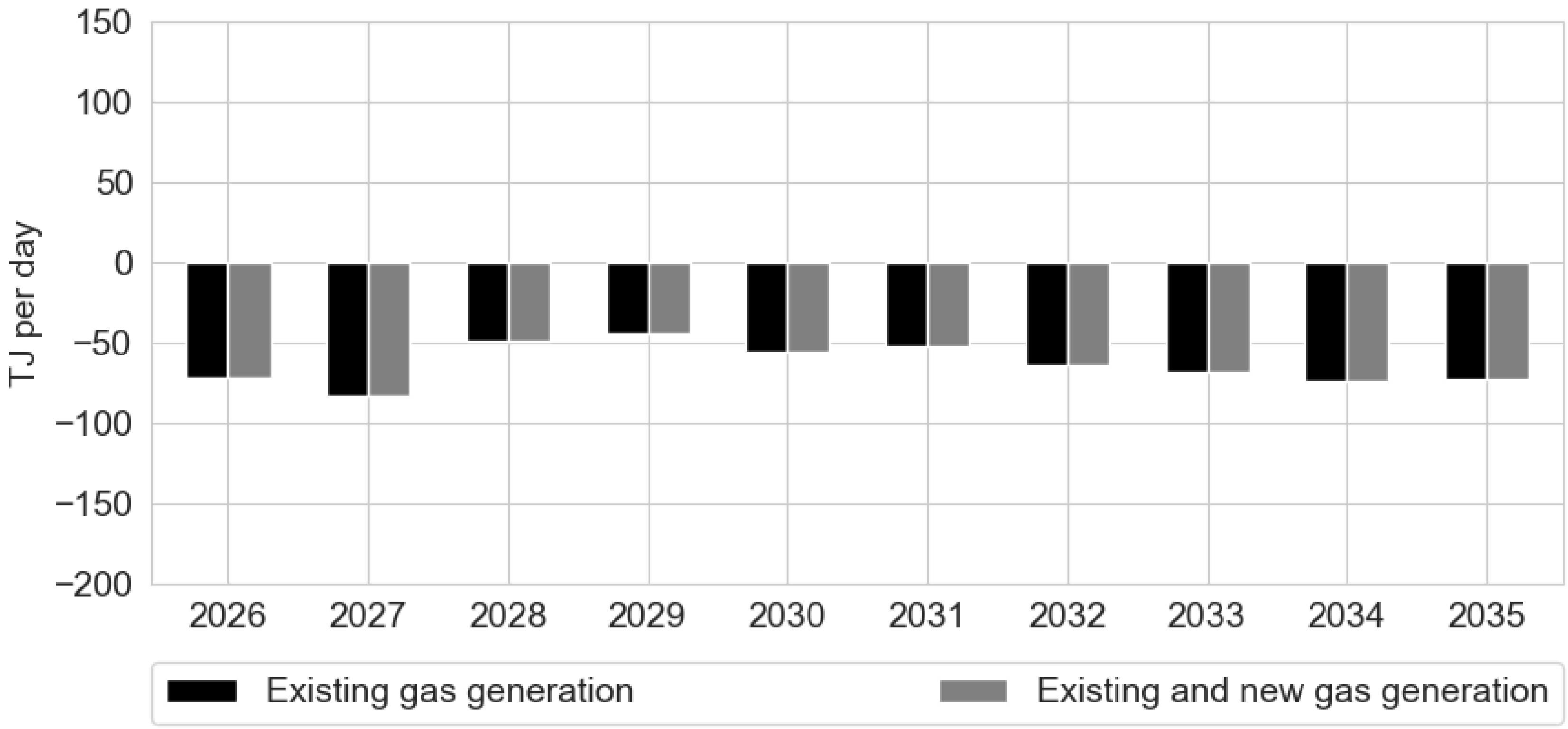
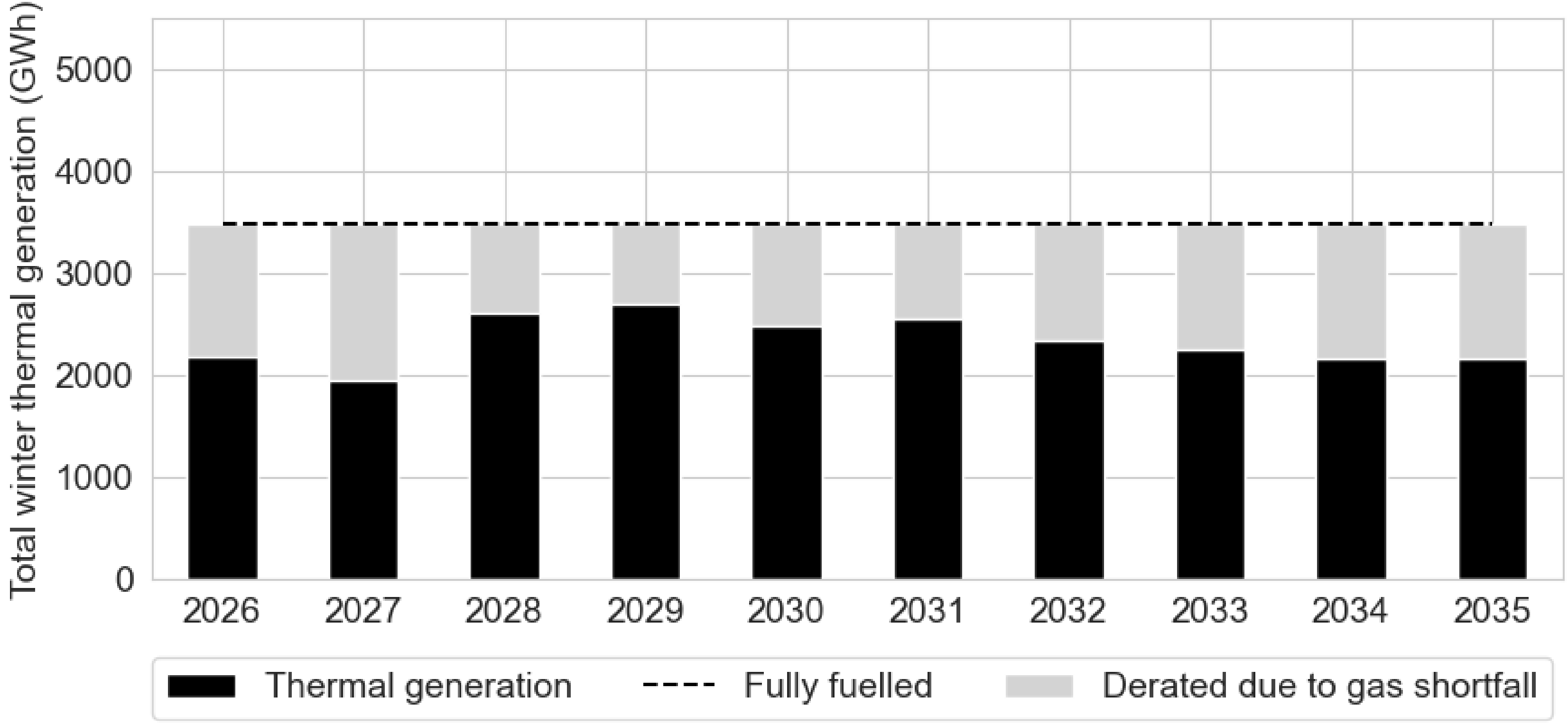


Figure 18: Dry year electricity generation from gas—reference case with existing gas generation



A4.1.4 Deratings

In the reference case and all sensitivities, deratings are applied to gas-fuelled generators in order of decreasing efficiency (less efficient plant derated before more efficient plant). The availability of gas for co-generation will largely depend on how the supply of gas is allocated to existing industrial gas users, which is beyond the scope of this assessment. Therefore, we have applied no deratings to gas co-generation plant in the reference case or any sensitivities.

A4.1.5 Low Gas Supply Sensitivity

Our *low gas supply* sensitivity looks at a future where domestic gas production declines substantially over the 2028-2035 period, consistent with a future where there is minimal investment in existing or new gas fields. This sensitivity is intended to show a pessimistic outcome for domestic gas production over the coming decade.

To estimate dry year gas supply margins for the *low gas supply* sensitivity, we have used the same assumptions as for the reference case, except that for the years from 2028 onwards the Enerlytica low gas production forecast is used in place of the reference gas forecast. We do not assume any additional reduction in non-electricity gas demand in this sensitivity, except for the same allowance for fuel substitution from gas to electricity that is used in the reference case. So it is possible for the available gas from production and storage withdrawals to drop below the level of modelled non-electricity demand, leaving nothing for electricity generation. This happens from 2028 onwards, resulting in zero contribution to energy or capacity from gas generators in those years in this sensitivity.

Figure 19 shows forecast dry year supply margins for the low gas supply sensitivity. As in the reference case, dry year gas supply margins are negative for all years of the assessment horizon.

Figure 19: Dry year gas supply margins—low gas supply *sensitivity*

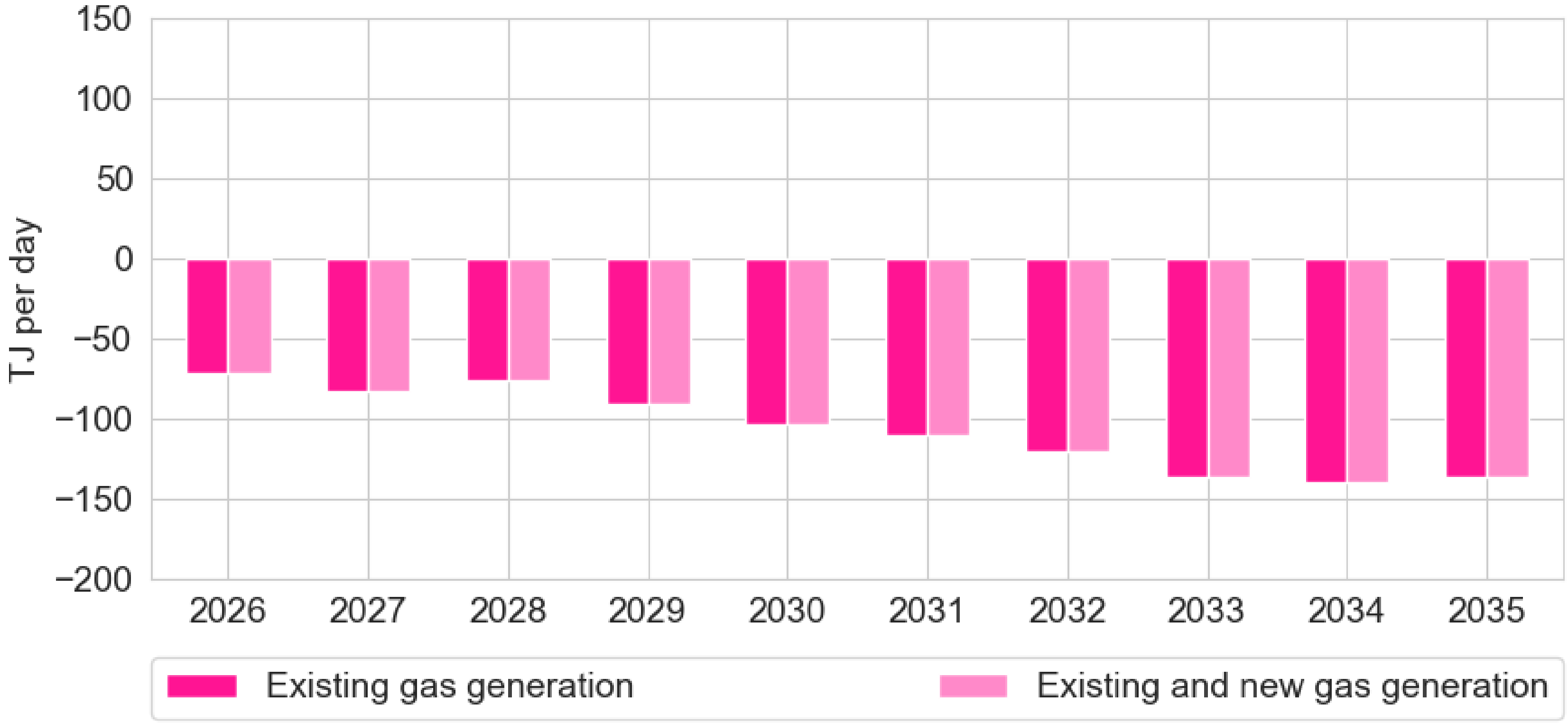
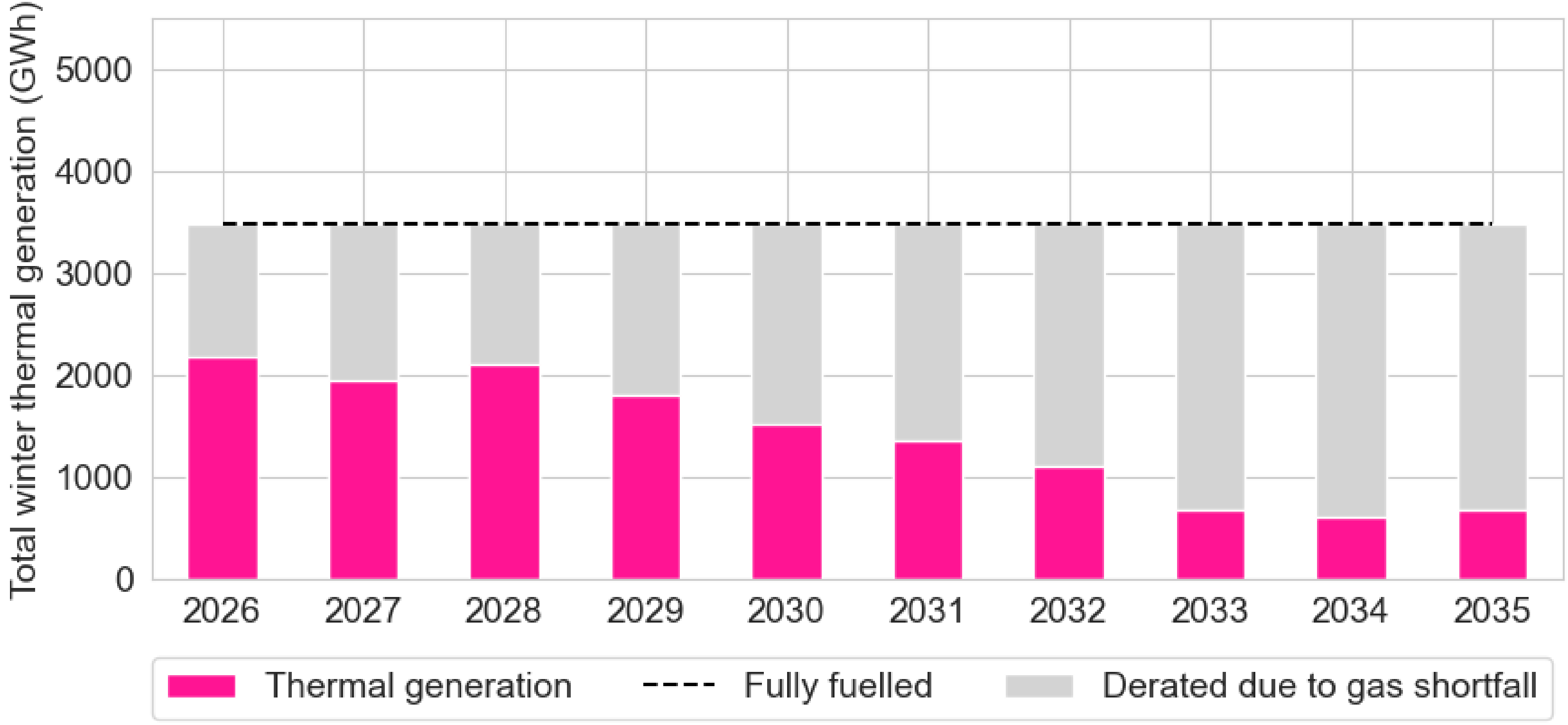


Figure 20 shows gas generation in the *low gas supply* sensitivity. In addition to calculating the energy deratings shown in Figure 18.

Figure 20: Dry year electricity generation from gas—low gas supply *sensitivity with existing gas generation*



A4.1.6 Very Low Gas Supply Sensitivity

Our *very low gas supply* sensitivity looks at a future where domestic gas production declines substantially over the 2028-2035 period, consistent with a future where there is minimal investment in existing or new gas fields. This sensitivity is intended to show a more pessimistic outcome for domestic gas production over the coming decade versus the low gas supply. For this sensitivity we use the Enerlytica base case forecast.

To estimate dry year gas supply margins for the *very low gas supply* sensitivity, we have used the same assumptions as for the reference case, except that for the years from 2028 onwards the very low gas production forecast described in section 4.1.1 is used in place of the reference gas forecast. We do not assume any reduction in non-electricity gas demand in this sensitivity, except for the same allowance for fuel substitution from gas to electricity that is used in the reference case.

If a low gas production scenario like this to actually play out, there would be significant value for capacity security in reallocating a small amount of gas from other uses to electricity generation in order to continue running peaker plants at a low capacity factor. 1PJ per year would be sufficient to run the gas peaking fleet at a 5% winter capacity factor.

Figure 21 shows forecast dry year supply margins for the very low gas supply sensitivity. As in the reference case, dry year gas supply margins are negative for all years of the assessment horizon.

Figure 21: Dry year gas supply margins-very low gas supply *sensitivity*

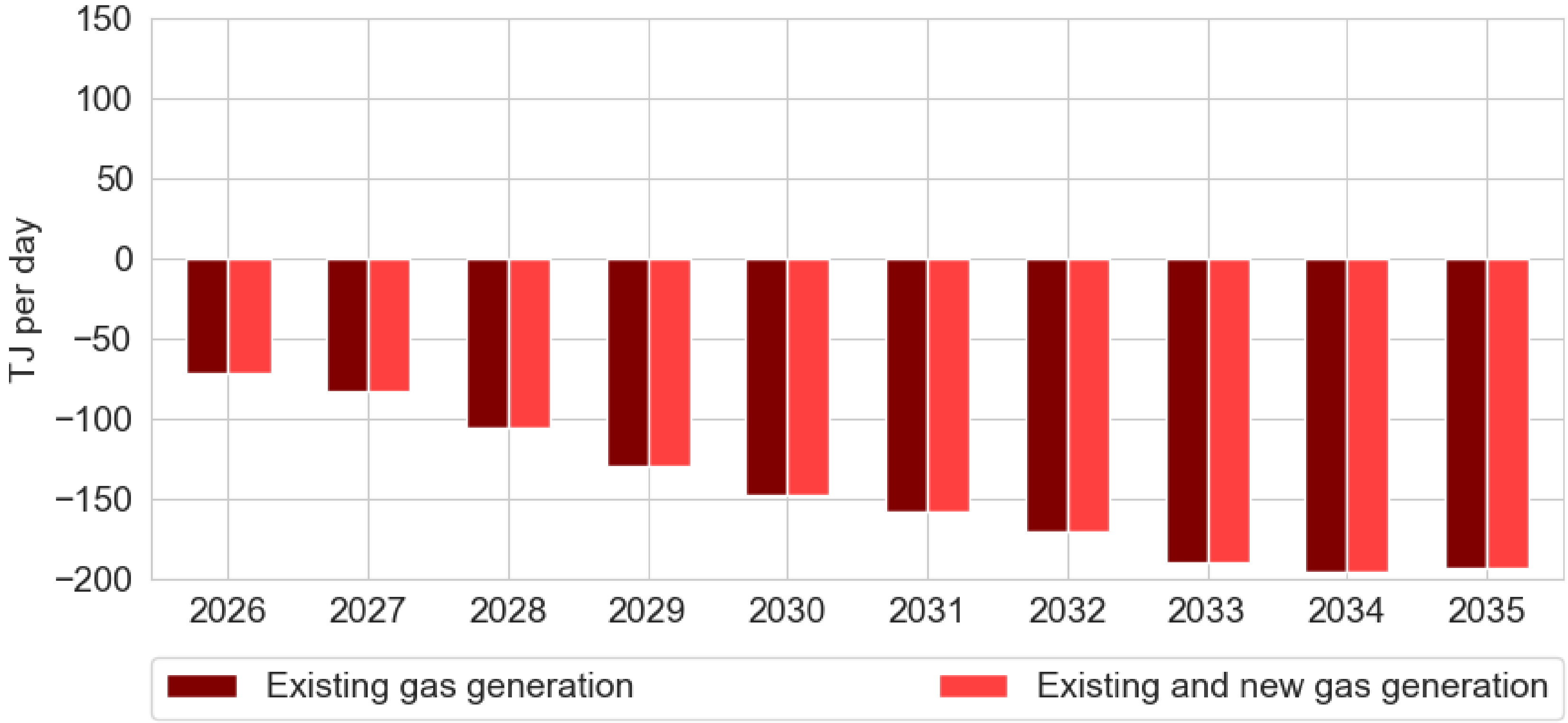
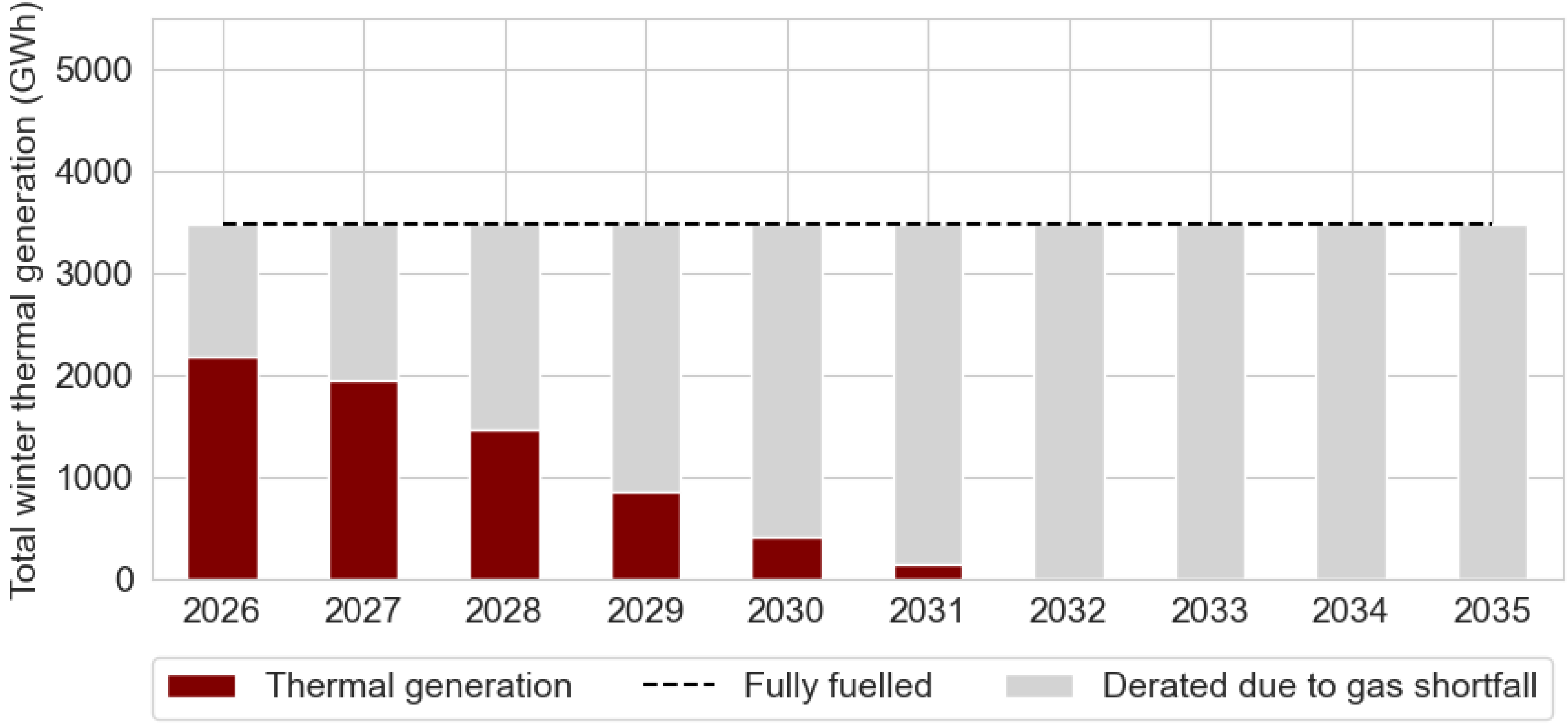


Figure 22 shows gas generation in the *very low gas supply* sensitivity. In addition to calculating the energy deratings shown in Figure 18, we assume that capacity will also be limited if the shortage of gas is severe enough. This results in winter capacity supply being derated by about 80 MW in 2030, and 330 MW in 2031, as shown in Figure 28. From 2032, there is no contribution from gas generators to either energy or capacity margins except for co-generation, which is not derated (see section A4.1.3 above).

Figure 22: Dry year electricity generation from gas—very low gas supply *sensitivity with existing gas generation*



A4.1.7 High Gas Supply Sensitivity

Our *high gas supply* sensitivity is intended to explore the impact of additional gas availability for dry year electricity generation. Possible sources of additional gas are increased production from existing fields, LNG imports, further reduction in industrial gas usage, increased gas storage capacity, or a combination of these sources. What we model in this sensitivity is a significant increase in domestic gas availability from 2028 onwards, as shown by the "High" gas supply forecast shown in section 4.1.1. This is based on Enerlytica's "Medium" scenario forecast with an additional 24PJ available over winter (6 months)[25].

This sensitivity uses the same assumptions as the reference case except for changing the gas supply forecast. We do not assume any increase in non-electricity gas demand in this sensitivity, i.e. all of the additional gas is available for electricity generation in a dry year.

Figure 23 shows forecast dry year supply margins for the *high gas supply* sensitivity. With existing gas generators, margins in some years are positive, meaning all gas generators are able to run at their maximum available capacity.

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[25] This is based on the availability of 12PJ over a 3 month period as indicated in the requirements for an LNG facility.

Figure 23: Dry year gas supply margins—high gas supply *sensitivity*

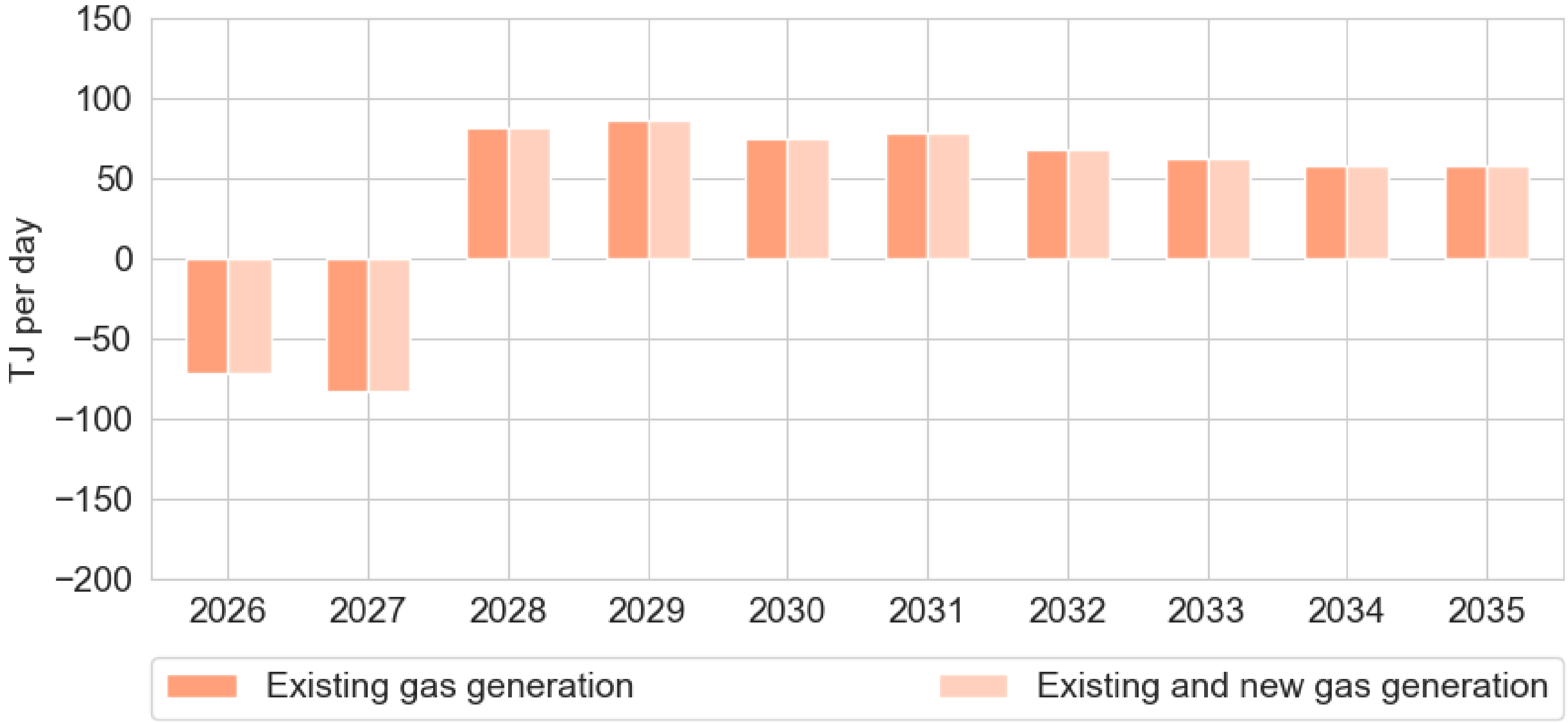
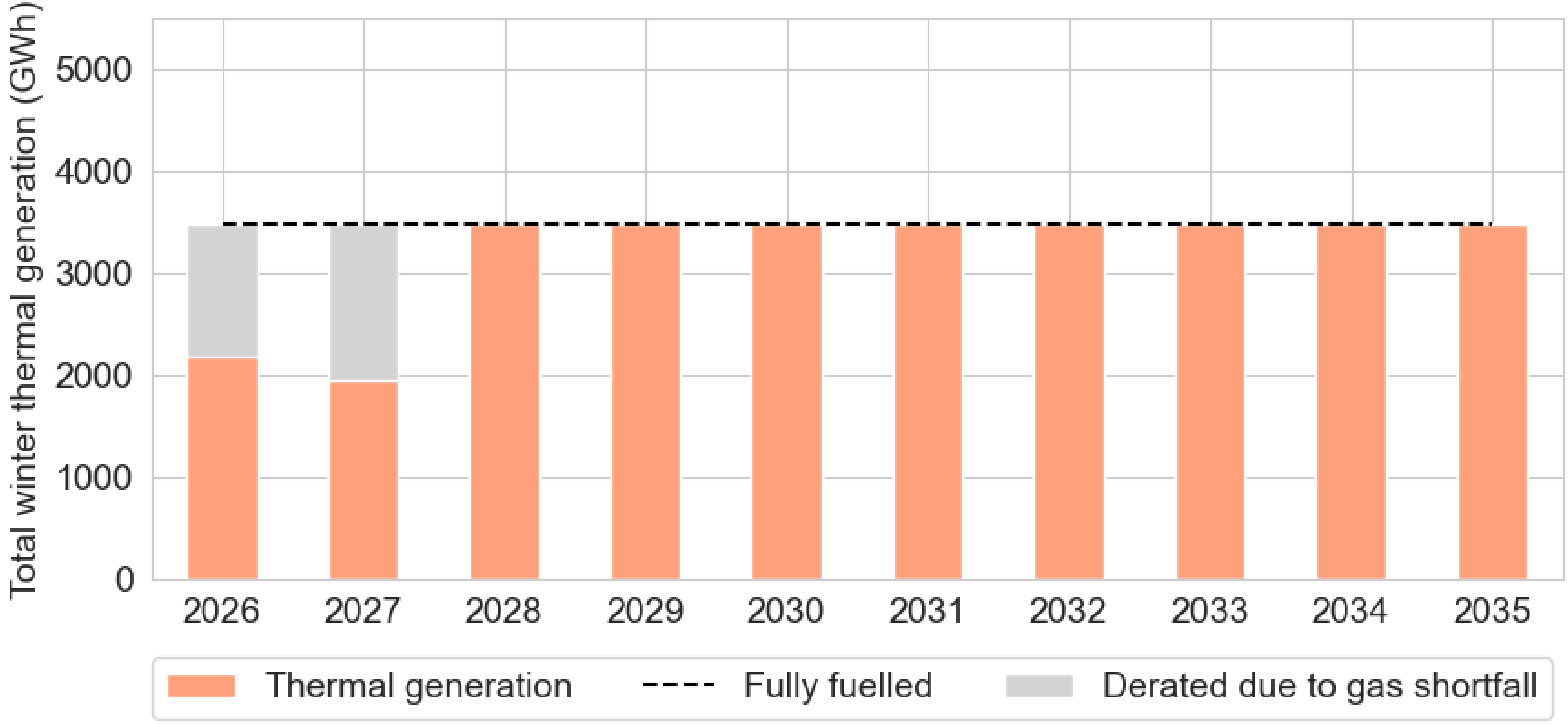


Figure 24 shows gas generation in the *high gas supply* sensitivity. From 2028 onwards (the year this sensitivity diverges from the reference case), deratings to energy supply from gas generators are minor. As in the reference case, there are no deratings to capacity supply from gas generators.

Figure 24: Dry year electricity generation from gas—high gas supply *sensitivity with existing gas generation*



A4.1.8 Coal and Diesel Availability

Coal

We have assessed coal availability based on assumed coal stockpiles, domestic coal purchases and foreign coal imports. We have assumed that the contribution from Huntly's Rankine units to winter energy margins is not constrained by fuel supply. The effect of possible coal fuel limitations is assessed by the *reduced Rankine availability* sensitivity.

Diesel

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

Appendix 5: Demand Response Sensitivity

A5.1 Demand Response Sensitivity Assumptions

The sensitivity explores the impact on the NI-WCM, NZ-WEM, and SI-WEM of increased uptake in demand response, in both the North and South Islands. The following NI-WCM – peak demand response section (5.1) outlines the analysis behind this sensitivity. No change have been made to this for the SOSA 2026 as we believe these assumptions are still sound. Market conditions in both winter 2024 and 2025[26] (high thermal unit commitment and reduced industrial demand due to low hydro storage levels) mean that 2024 and 2025 market data is of limited value in assessing how the market will behave during periods of capacity stress.

A5.1.1 NI-WCM – peak demand response

In 2023 there was on average about 200 MW of controllable load (a type of demand response) indicated to be available over peak periods with low residuals, as discussed in the Winter Review paper[27]. Figure 21 shows on average about 130 MW in the South Island and 75 MW in the North Island. These values have formed the basis of our assumption for this sensitivity, except we have assumed 100 MW in each island for simplicity. The amount of modelled demand response is then assumed to increase in proportion to peak demand growth from 2026 onwards.[28]

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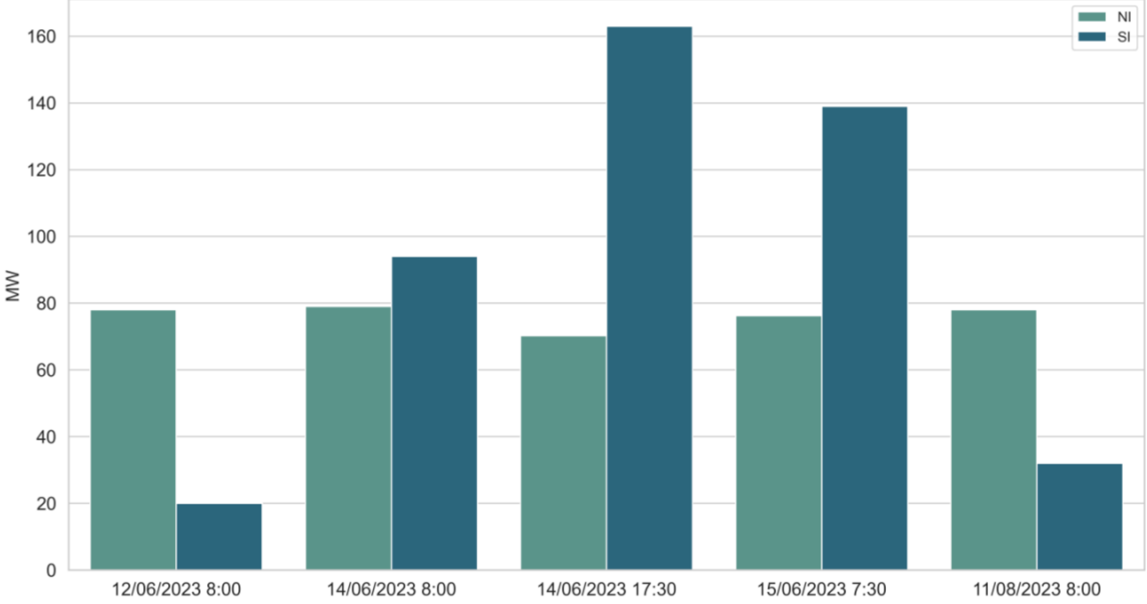
[26] See Winter Review 2025 and Winter Review 2024

[27] See Winter Review 2023 section 'Analysis of Winter 4' for more information on controllable load.

[28] The difference bids exercise with Electricity Distribution Businesses (EDBs) on 6 May 2025 to simulate "realistic" controllable load quantities for a low residual situation (which represents tight capacity situation), resulted in ~250 MW of difference bids being submitted.

Figure 25: Difference bids reflecting controllable load available over peak periods with low residuals in winter 2023



A5.1.2 NZ-WEM and SI-WEM – dry year demand response

In the reference case calculation of the NZ-WEM and SI-WEM, demand is reduced by 2% to account for normal demand-side response to electricity prices[29]. The *increased demand response* sensitivity assesses the impacts of a 2.5% reduction in national demand and 5% reduction in South Island demand due to demand response. This is to factor in growth in dry-year demand response initiatives, such as the long-term electricity supply agreement between New Zealand Aluminium Smelter (NZAS – Tiwai) and Meridian Energy, Contact Energy and Mercury. As further details of other demand-response contracts become available we will update our modelling to consider these impacts in future SOSAs.

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[29] As specified in Section 4 of the SSAD

Appendix 6: Detailed modelling results

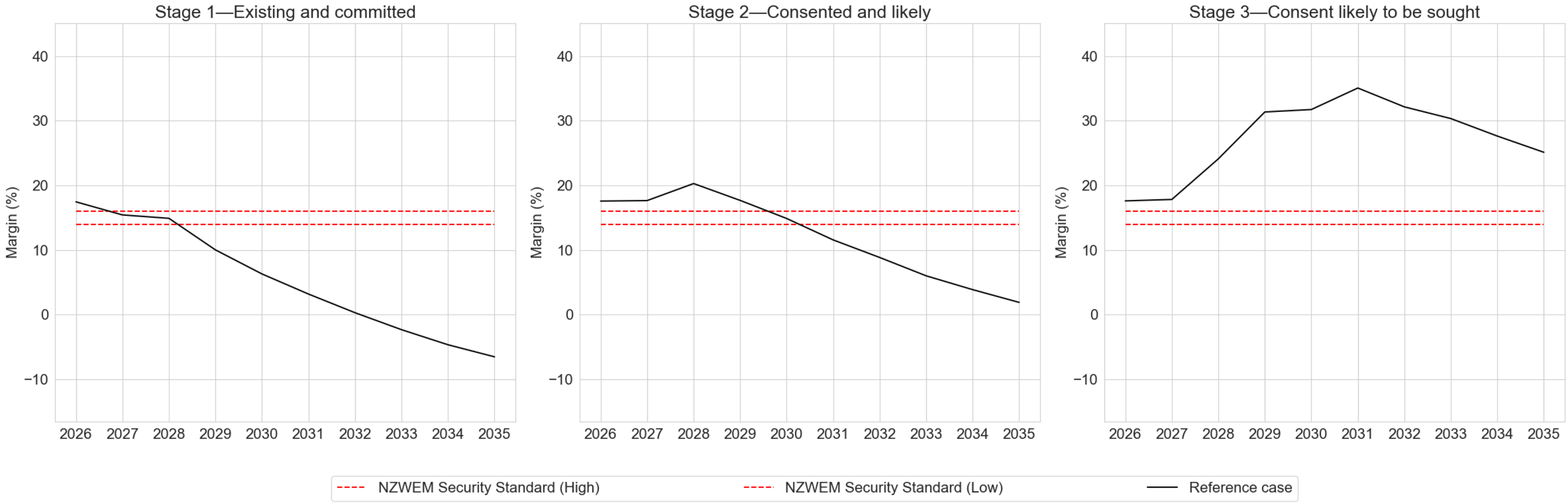
A6.1 Winter Energy Margin Results

A6.1.1 New Zealand Winter Energy Margin Reference Case Results

Figure 26 shows the NZ-WEM results for the reference case. This illustrates that:

- The NZ-WEM declines and falls below the lower security standard in 2029.
- To maintain the NZ-WEM above the lower security standard from through to 2030, in addition to existing generation, consented and likely supply projects (Stage 2) would need to be developed. However, even in Stage 2, the Reference case drops below the lower security standard in 2031.
- From 2029, there is a significant increase in the amount of unconsented generation in the pipeline (Stage 3). However, these projects have a higher degree of uncertainty in coming to market.

Figure 26: New Zealand Winter Energy Margin reference case results



A6.1.2 New Zealand Winter Energy Margin Sensitivities

In this section we present the impact the sensitivities have on the reference case and discuss whether these impacts accelerate or delay the NZ-WEM crossing the lower security standard.

Figure 27 shows the impact of each of the sensitivities when applied independently to the reference case for each of the three supply pipeline stages. The grey shaded area defines the boundary for the best and worst case of the plausible sensitivity combinations.[30] Applying each

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[30] The boundary of the grey area provides an indication of the range of the potential outcomes where different combinations of sensitivities are assumed to occur. As would be expected, combinations of sensitivities that individually reduce the WEM or WCM would pull the margins even lower if considered together (such as higher demand and delayed commissioning and low gas supply).

sensitivity independently from one another allows us to observe the magnitude of each sensitivity's impact on the NZ-WEM (relative to the reference case).

Figure 27: New Zealand Winter Energy margins for the reference case and all sensitivities

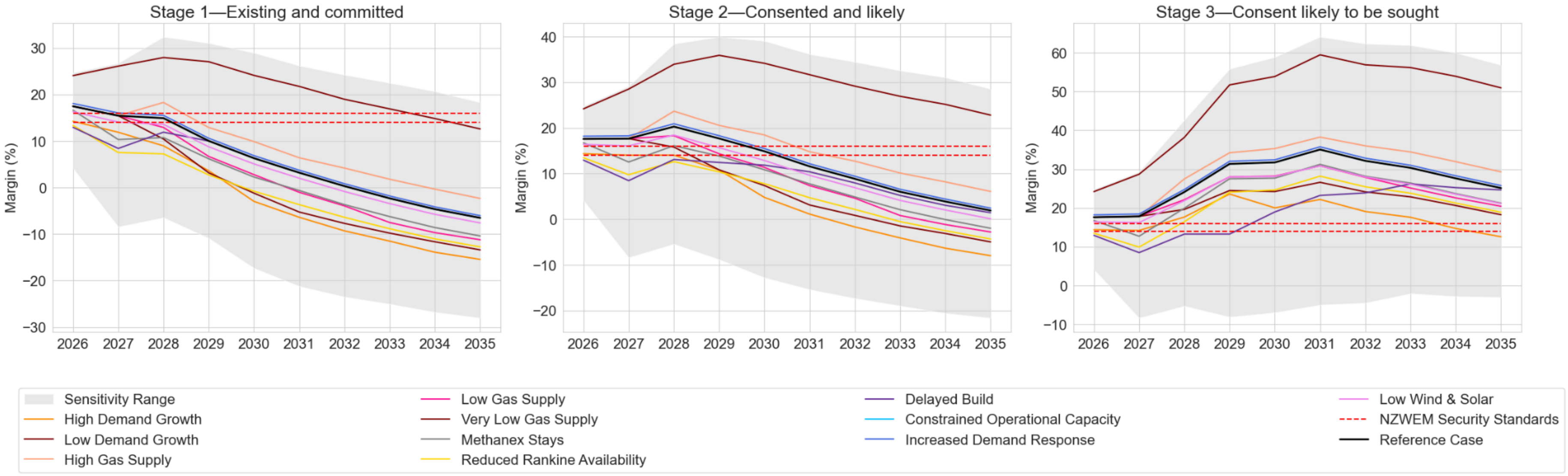


Table 8 presents the impact of each sensitivity on the reference case, showing the earliest crossing of the lower security standard for each sensitivity at each stage of the supply pipeline. The table uses a heatmap with colours ranging from red to orange to yellow for the years presented, where red cells indicate an earlier crossing of the lower security standard, and yellow cells indicate crossing the security standard in later years.

Table 8: NZ-WEM earliest crossing of the lower security standard for the reference case and sensitivities

Sensitivity	Stage 1	Stage 2	Stage 3
Reference case (NZ-WEM)	**2029**	**2031**	**>2035**
High demand growth	2027	2029	2035
Low demand growth	>2035	>2035	>2035
High gas supply	2029	2032	>2035
Low gas supply	2028	2030	>2035
Very low gas supply	2028	2029	>2035
Methanex stays	2027	2027	2027
Reduced Rankine availability	2026	2026	2026
Delayed commissioning	2026	2026	2026
Low intermittent generation	2028	2030	>2035
Increased demand response	2029	2031	>2035
HVDC upgrade	2029	2031	>2035
Constrained operational capacity	2029	2031	>2035

Most of the sensitivities cross the lower security standard in 2028 or 2029 along with the reference case. The *high demand growth* and *Methanex stays* sensitivities cross a year earlier, in 2027. *Reduced Rankine availability* and *delayed commissioning* cross this year.

Beyond 2027 the *very low gas supply*, *high demand growth*, *reduced Rankine availability* and *delayed commissioning* sensitivities have the greatest impact on reducing the NZ-WEM. The figures above indicate that, unless sufficient unconsented generation (Stage 3) is developed, the reference case and most sensitivities fall below the lower security standard by 2031. Until a large amount of currently unconsented generation is built, we will rely on thermal generation to maintain the NZ-WEM above the lower security standard.

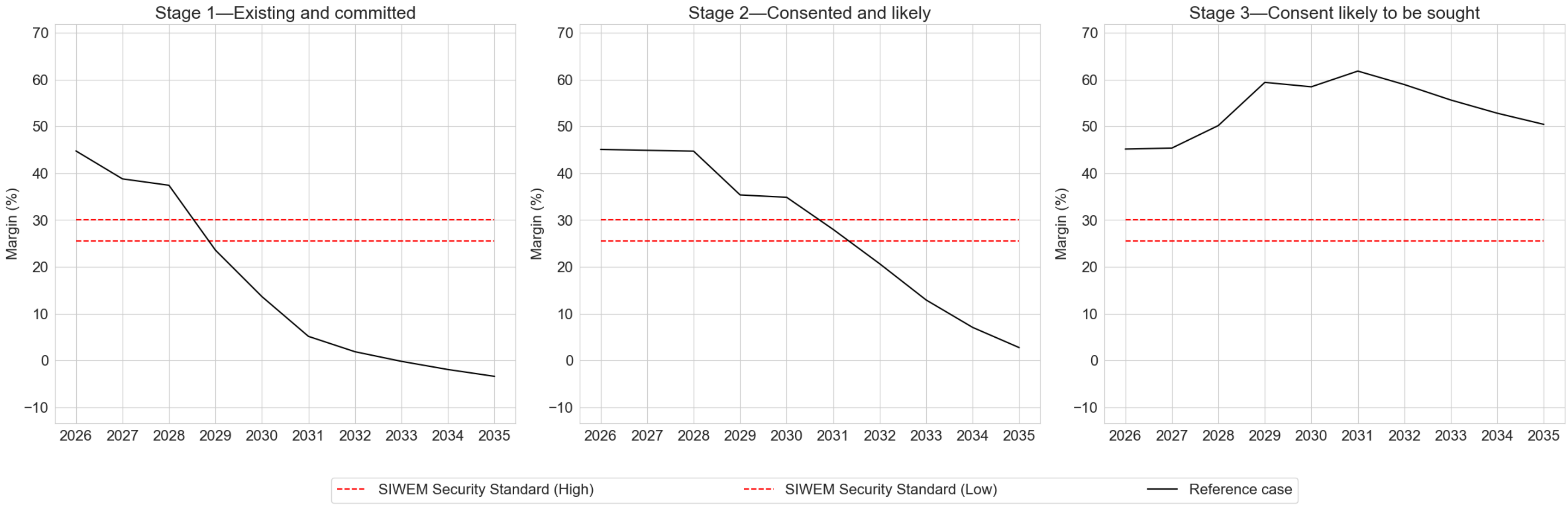
In contrast, the *low demand growth* and *high gas supply* sensitivities have the greatest impact on increasing the NZ-WEM. Under these sensitivities, if all Stage 2 generation supply is commissioned, we would maintain margins above the lower security standard until 2032, at which point the *high gas supply* sensitivity crosses the lower security standard.

A6.1.3 South Island Winter Energy Margin Reference Case Results

The SI-WEM results for the reference case are shown in Figure 28. This illustrates that:

- the SI-WEM crosses the lower security standard later than the NZ-WEM under supply pipeline Stages 1-3;
- with existing and committed generation (Stage 1) the SI-WEM declines and crosses the lower security standard in 2029; and
- for the reference case to maintain the SI-WEM above the lower security standard throughout the assessment horizon, in addition to the existing and committed generation, all the consented and some of the unconsented supply projects (Stage 3) need to be developed.

Figure 28: South Island Winter Energy Margin reference case results



A6.1.4 South Island Winter Energy Margin Sensitivities

In this section we present the impact the sensitivities have on the reference case and discuss whether these impacts accelerate or delay the SI-WEM crossing the lower security standard.

Figure 29 shows the impact of each of the sensitivities when applied independently to the reference case for each of the three supply pipeline stages. The grey shaded area defines the boundary for the best and worst case of the plausible sensitivity combinations. Applying each sensitivity independently from one another allows us to observe the magnitude of each sensitivity's impact on the SI-WEM (relative to the reference case).

Figure 29: South Island Winter Energy Margins for the reference case and all sensitivities

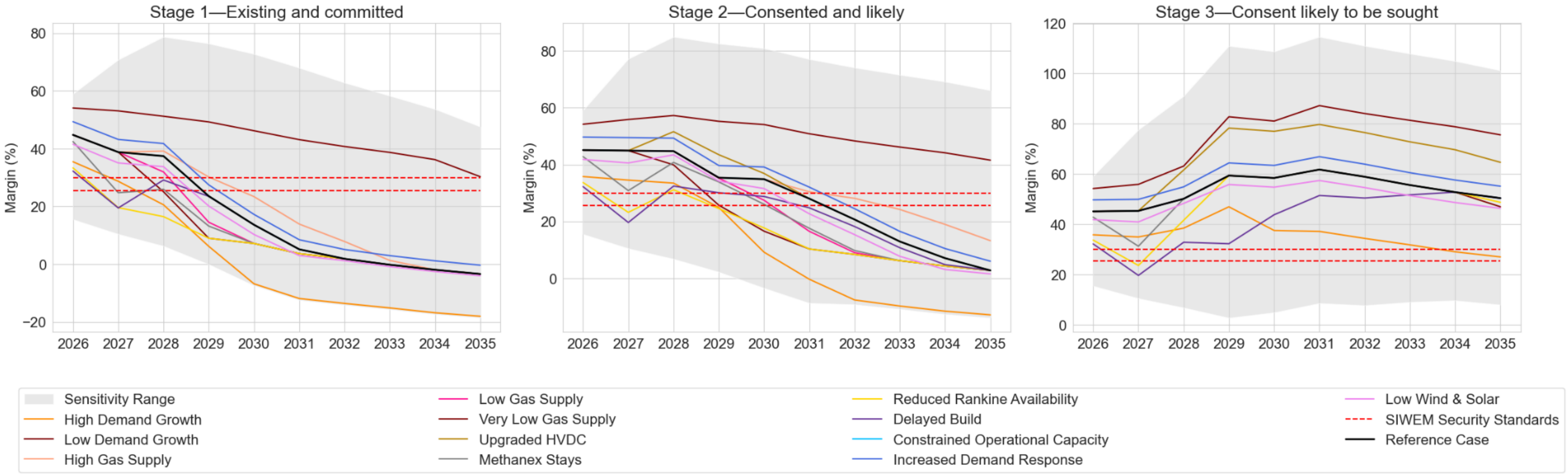


Table 9: SI-WEM earliest crossing of the lower security standard for the reference case and sensitivities

Sensitivity	Stage 1	Stage 2	Stage 3
Reference case (SI-WEM)	**2029**	**2032**	**>2035**
High demand growth	2028	2029	>2035
Low demand growth	>2035	>2035	>2035
High gas supply	2030	2033	>2035
Low gas supply	2029	2031	>2035
Very low gas supply	2028	2030	>2035
Methanex stays	2027	2031	>2035
Reduced Rankine availability	2027	2027	2027
Delayed commissioning	2027	2027	2027
Low intermittent generation	2029	2031	>2035
Increased demand response	2030	2032	>2035
Constrained operational capacity	2029	2032	>2035
HVDC upgrade	2029	2032	>2035

Reducing thermal generation capability to provide dry-year back-up has a substantial impact in accelerating this risk as shown in the *very low gas supply*, *reduced Rankine availability*, and *Methanex stays* sensitivities.

The *high demand* and *delayed commissioning* sensitivities also cause the SI-WEM to cross the lower security standard earlier than the reference case. Under *reduced Rankine availability* and *delayed commissioning* sensitivities, even if consented and unconsented generation (Stage 3) came to market, the SI-WEM would still dip below the lower security standard in 2027. This generation investment needs to be increased and accelerated to maintain the security standard beyond 2027 if these sensitivities materialised, as shown by the *delayed commissioning* sensitivity in Figure 29 crossing the lower security standard in 2027 for Stage 3 generation.

In contrast, the *low demand, high gas supply, and increased demand response* sensitivities have the greatest impact on increasing the SI-WEM. These could also be proxies for the impact of varying quantities of South Island dry-year winter demand response, greater availability of gas in the market, and/or additional South Island generation on the SI-WEM.

Increasing north-south transfer capability as in the *upgraded HVDC* sensitivity can help reduce the amount of generation needed to manage dry-year risk in the South Island if there is sufficient surplus energy in the North Island.

The impacts of the various sensitivities on the SI-WEM show the reliance on thermal back up generation to manage dry year risks, until significant new renewable generation and South Island long-duration demand response comes to market.

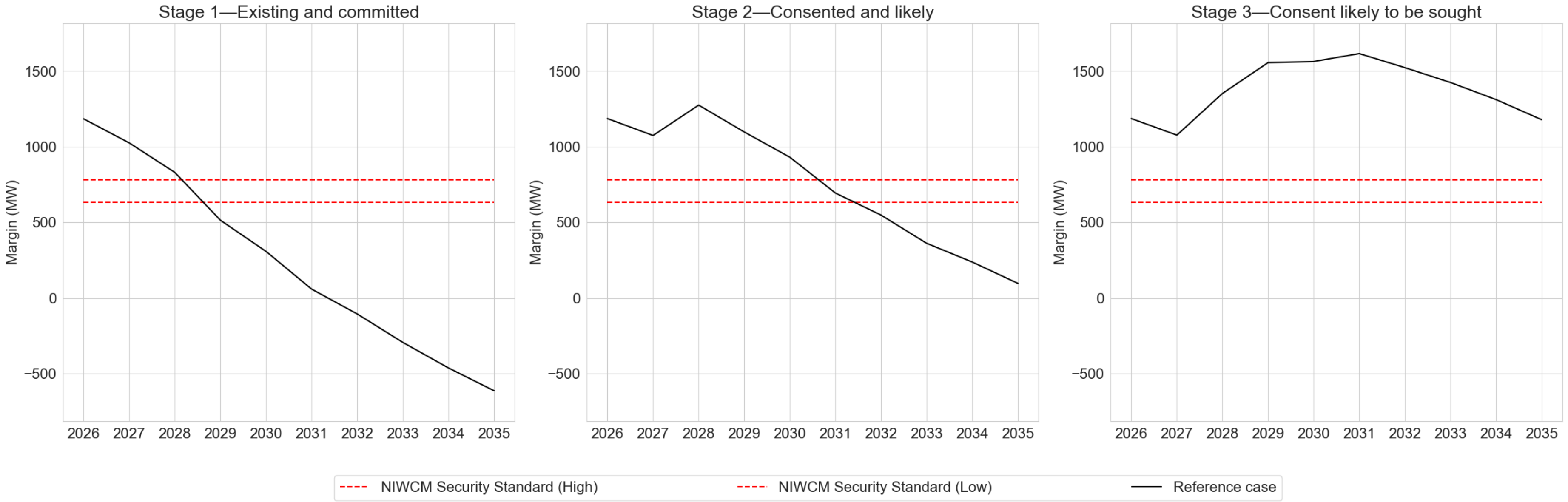
A6.2 Winter Capacity Margin Results

A6.2.1 North Island Winter Capacity Margin Reference Case Results

Figure 30 shows the NI-WCM results for the reference case. This illustrates that:

1. With existing and committed generation (Stage 1) the NI-WCM declines and crosses the lower security standard in 2029;
2. Consented and likely (Stage 2) help keep the NI-WCM above the lower security standard until 2032.
3. Additional unconsented projects (Stage 3) would be needed to maintain the NI-WCM above the lower security standard from 2032 for the remainder of the assessment horizon.

Figure 30: North Island Winter Capacity Margin reference case results



A6.2.2 North Island Winter Capacity Margin Sensitivities

In this section we present the impact the sensitivities have on the reference case and whether these accelerate or delay the NI-WCM crossing the lower security standard.

Figure 31 shows the impact of each of the sensitivities when applied independently to the reference case for each of the three supply pipeline stages. The grey shaded area defines the boundary for the best and worst case of the plausible sensitivity combinations. Applying each sensitivity independently from one another allows us to observe the magnitude of each sensitivity's impact on the NI-WCM (relative to the reference case).

Figure 31: North Island Winter Capacity Margins for the reference case and all sensitivities

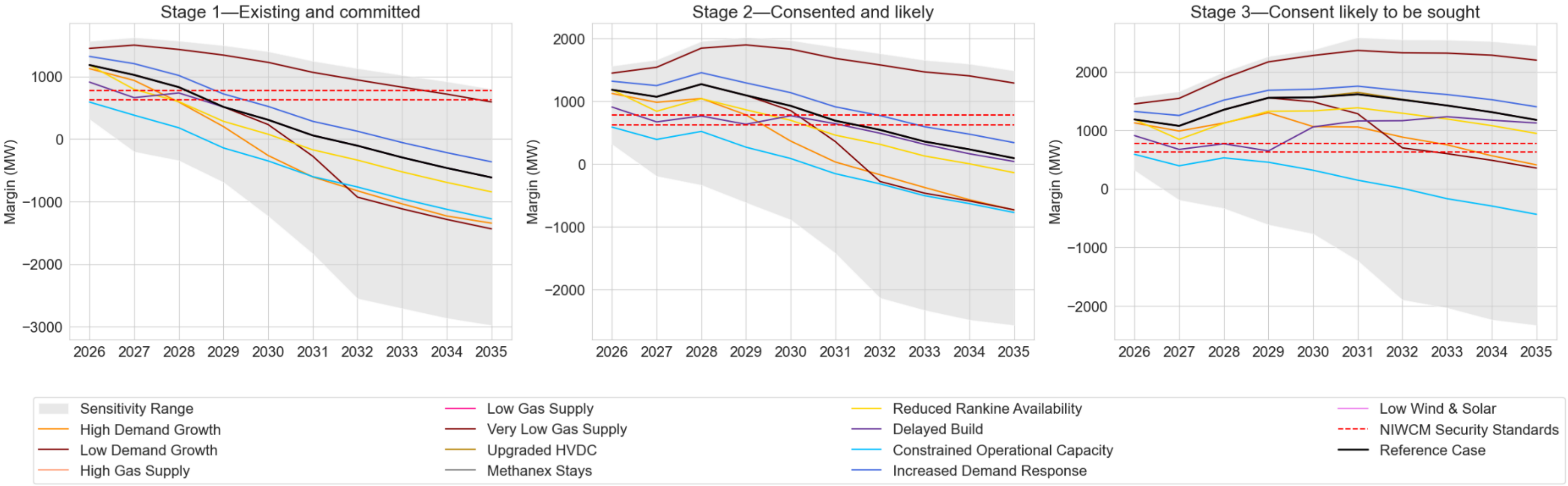


Table 10: NI-WCM earliest crossing of the lower security standard for the reference case and sensitivities

Sensitivity	Stage 1	Stage 2	Stage 3
Reference case (NI-WCM)	**2029**	**2032**	**>2035**
High demand growth	2028	2030	2034
Low demand growth	2035	>2035	>2035
High gas supply	2029	2032	>2035
Low gas supply	2029	2032	>2035
Very low gas supply	2029	2031	2033
Methanex stays	2029	2032	>2035

Reduced Rankine availability	2028	2031	>2035
Delayed commissioning	2029	2032	>2035
Low intermittent generation	2029	2032	>2035
Increased demand response	2030	2033	>2035
Constrained operational capacity	2026	2026	2026
HVDC upgrade	2029	2032	>2035

The *constrained operational capacity* sensitivity highlights the importance of adequate thermal commitment at times of low intermittent generation to manage capacity risks in our system with increasing intermittency if there is insufficient investment in flexible resources. This impact reduces under Stage 3 where more unconsented battery investment is signalled.

The *very low gas supply* and *reduced Rankine availability* sensitivities substantially impact on pulling the NI-WCM down below the security standards. Gas peakers can provide peaking capacity while operating at a low overall capacity factor, so reallocation of some gas to power generation from other sectors could allow the gas peaking fleet to provide up to 430 MW of NI-WCM supply even in a scenario where gas supplies are low. This explains why the results only start to show significant impact of the *very low gas supply* sensitivity from 2031 onwards.

In contrast, the *low demand growth* and *increased demand response* sensitivities have the greatest impact on improving the NI-WCM, by reducing demand over peak periods and increasing thermal unit availability during peaks respectively. Development of projects beyond stage 2 is still required to maintain the NI-WCM above the lower security standard for the duration of the assessment horizon in the *increased demand response* sensitivity, and beyond stage 1 in the *low demand growth* sensitivity.

A6.3 Comparison with the 2025 Security of Supply Assessment

Figure 32 shows the NZ-WEM reference case results cross the lower security standard three years later than in the 2025 SOSA, when considering only the existing and committed supply projects (Stage 1). This is primarily due to an increase in gas reallocation from the industrial sector to electricity generation relative to the level modelled in the 2025 SOSA, as well as lower overall demand.

When considering the consented supply projects (Stage 2), we can see that for most of the assessment horizon the NZ-WEM reference case is higher than in the 2025 SOSA. This is again due to a lower demand forecast and an increase in gas supply and consented supply projects from 2028 onwards.

When considering the unconsented but consent likely to be sought supply projects pipeline (Stage 3), the NZ-WEM reference case is higher than in the 2025 SOSA until the end of the assessment horizon. This is the result of an increase in consent-expected projects compared to last year's consented but potentially less likely to proceed pipeline, after the redefinition of pipeline stages in SOSA 2026, in addition to the drop in the demand forecast.

Figure 32: New Zealand Winter Energy Margin reference case comparison, 2026 and 2025

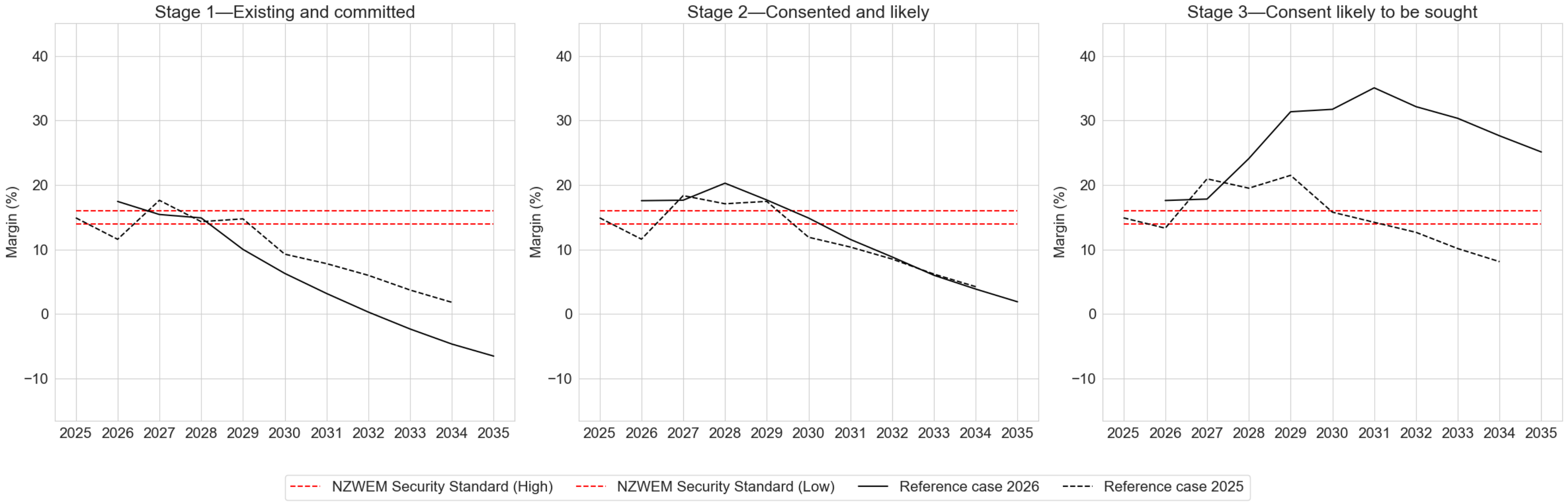


Figure 33 shows the SI-WEM reference case results cross the lower security standard three years later than in the 2025 SOSA, when considering only the existing and committed supply projects (Stage 1). This is primarily due to a decrease in the SI-WEM demand forecast and an increase to the existing and committed South Island supply pipeline, with the ability for the North Island supply to support the South Island constrained by the north-to-south transfer capability.

This shift remains consistent across stage 2, with the 2026 SOSA resulting in the SI-WEM crossing the lower security standard slightly later. Consent likely to be sought generation projects (Stage 3) have seen a significant increase in this year's SOSA, lifting the SI-WEM above the lower security standard out to the end of the assessment horizon.

Figure 33: South Island Winter Energy Margin reference case comparison 2026 and 2025

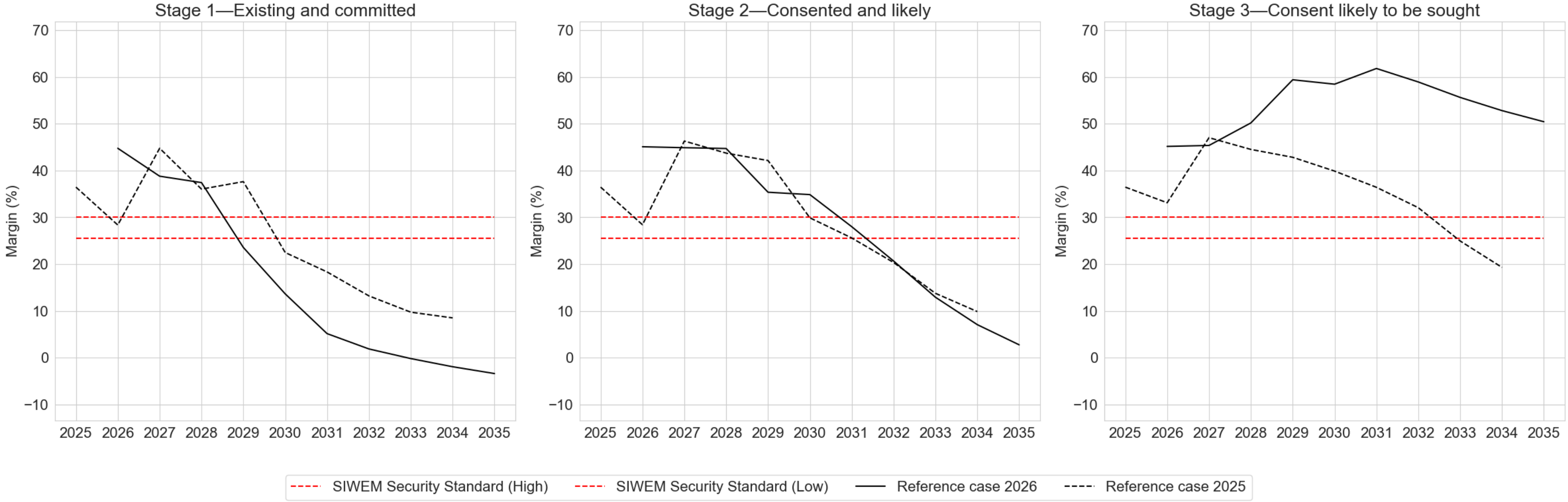
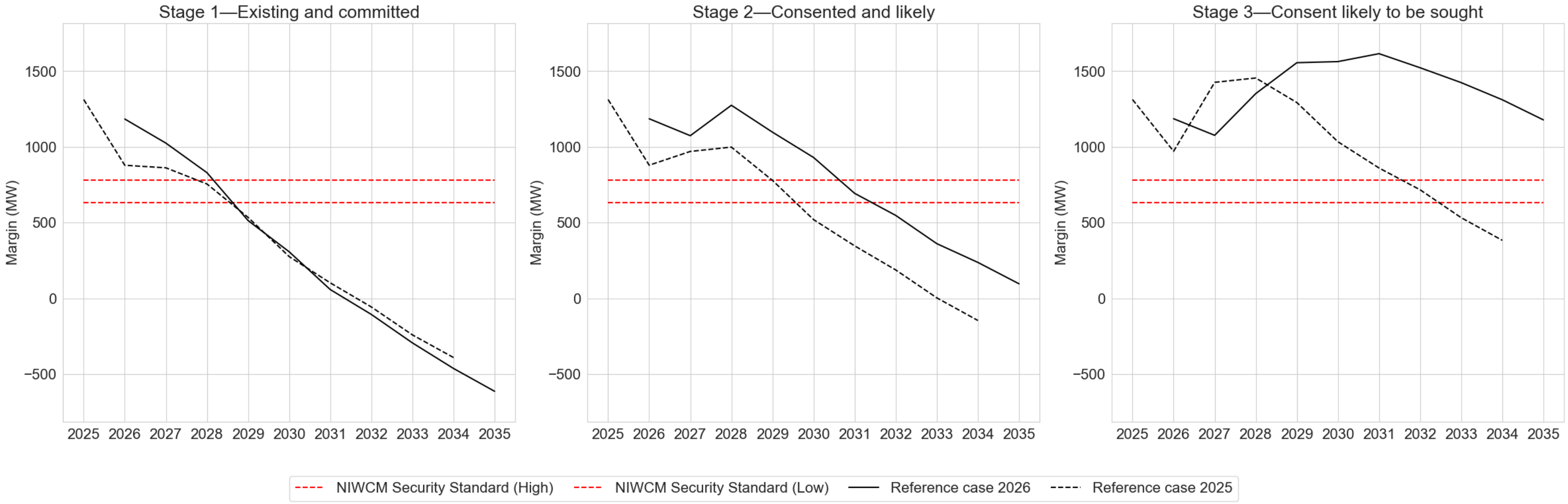


Figure 34 shows that the NI-WCM reference case results cross the lower security standard in the same year as in the 2025 SOSA when considering only the existing and committed supply projects (Stage 1). The NI-WCM in stage 2 is uniformly shifted roughly two years later when compared with the 2025 SOSA for the same pipeline. Initially, the NI-WCM for the 2025 SOSA declines in 2027 and falls below the 2025 SOSA's NI-WCM in stage 3 due to a decrease in the number of committed new supply projects, but it surpasses the 2025 SOSA's NI-WCM from 2029 onwards as the number of new projects increases which contribute significantly to capacity margins, such as batteries.

Figure 34: North Island Winter Capacity Margin reference case comparison, 2026 and 2025



Appendix 7: Security of Supply Reporting

The SOSA forms part of New Zealand's electricity security of supply framework. The System Operator performs other functions related to security of supply, as 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 horizon as part of the monthly Energy Security Outlook; short-term monitoring and information provision, such as the weekly reporting of hydro storage levels relative to the Electricity Risk Curves; and implementation of emergency measures where necessary.

The SOSA analysis assesses the supply pipeline against the three security standards based on information provided by market participants, and does not analyse or consider other aspects of future investment such as:

- the availability of transmission and distribution network capacity;
- the deliverability of planned new-build generation; or
- the commercial viability or market incentives required for resources to be developed.

More detailed security of supply forecasts that highlight shorter term timeframes and operational risk include the Energy Security Outlook, New Zealand Generation Balance, System Security Forecast, various Market insights, and the Weekly Market Report. Table 11 provides a breakdown of the purpose of each report.

Table 11: Summary of System Operator security of supply reporting

Report	Term	Energy	Capacity	Frequency	Voltage	Stability
Weekly Market Report	1 week	Yes	Yes	No	No	No
Monthly Energy Security Outlook	2 years	Yes	No	No	No	No

Quarterly Security Outlook	6 months	Yes	Yes	No	No	No
Annual Security of Supply Assessment	10 years	Yes	Yes	No	No	No
Biennial System Security Forecast	3 years	Yes	Yes	Yes	Yes	Yes

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