TRANSPOWER

Winter 2024 Outlook

31 January 2024

Contents

Glossary

Authority means the Electricity Authority Te Mana Hiko.

CCGT means a combined-cycle gas turbine, which in New Zealand is Huntly Unit 5 and TCC.

DNL means Dispatch Notification Load, which is a lower compliance version of dispatchable demand.

EDB means electricity distribution business.

EM6 is a market information portal hosted by Energy Market Services.

ERC means Electricity Risk Curves, which model the risk of a sustained energy shortage.

Huntly Unit 5 is a CCGT generating unit at the Huntly Power Station.

MDAG is the Market Development Advisory Group (to the Authority).

NIWA means the National Institute of Water and Atmospheric Research.

POCP is the Planned Outage Coordination Process portal, which participants use to supply outage information to the industry.

Rankine refers to the three steam-powered generating units at Huntly Power Station.

SFD refers to the Stratford open-cycle peaking generating units.

TCC is the Taranaki combined-cycle generating unit.

WITS is the Wholesale Information Trading System, which is a wholesale market information platform.

About this document

Purpose

This paper provides a forward-looking analysis of the energy and peak capacity issues for winter 2024. It builds on our Winter 2023 Review paper, published in October 2023, which reviewed the performance of the electricity system and market response over winter 2023.

Winter challenge

New Zealand's electricity demand is at its highest during the winter months, being:

- Peak demand, which is the highest point of electricity demand on any given day; and
- Energy demand, which is the electricity need over time (i.e. across the winter months).

Meeting peak demand on cold winter evenings or mornings requires sufficient generation capacity to be available. Meeting energy demand requires sufficient fuel (e.g. water, gas) to be available to operate generating units over time, and plant to be offered and available. New Zealand's largest source of stored energy is hydro generation. When hydro storage lakes are full our ability to meet winter energy demand is strong.

The 'dry year risk' is the impact that prolonged dry spells with insufficient inflows into our hydro lakes have on our ability to meet energy demand. Flexible demand (demand-side response) that can reduce electricity consumption in response to price, is emerging as an option to help meet the peak and energy demand challenge.

Executive summary

Peak and energy challenges for winter 2024

We expect winter 2024 will be challenging from both a peak and energy perspective, due to a combination of:

- Continued demand growth;
- Increased intermittent generation and its uncertainty during peak demand periods;
- The availability of firming generation due to planned and unplanned outages;
- Project delays (e.g. commissioning delays for Tauhara geothermal and Harapaki wind farm), placing a greater reliance on existing supply and demand-side resources; and
- Insufficient fast-start peaking capacity (thermal or battery) or dispatchable demand response.

We need more flexibility on the power system to meet these challenges. Although new resources will help meet these challenges in the longer-term, for winter 2024 existing resources must be used.

Peak challenge

Increased availability of existing generation during peak load periods (by reducing planned outages and increasing thermal unit commitment) and increased demand-response will help mitigate the peak challenge in winter 2024. The commitment of two Rankines in addition to both CCGTs and other available generation (not on outage) would provide a high likelihood of meeting the peak challenge. However, increased outages will require additional thermal generation commitment (if available) and increased demand-response. Even then we may be operating with reduced reserves during the coldest evening peaks with low intermittent generation, leaving the system vulnerable to changing conditions or sudden faults. This could lead to demand management, which could include power cuts.

Currently, hydro storage is sitting at around average levels for this time of year (January). If there are low inflows in 2024 leading to lower hydro storage over winter, there would likely be higher spot prices and increased thermal unit commitment. This would reduce the thermal commitment risk to the winter peak capacity challenge, but it will also mean the system is vulnerable to unplanned thermal outages.

Executive summary continued

Energy challenge

If hydro inflows in 2024 are low, there is an elevated energy risk in 2024 compared to 2023, due to a combination of:

- Reduced gas available for thermal generation;
- Project delays placing greater pressure on existing hydro resources; and
- Plant availability (outages) and reliability limitations (e.g. TCC limited running hours if TCC is required to run for extended periods).

The January update of the ERCs modelled the impact of the delayed commissioning of the Tauhara geothermal plant. The reduction in expected energy will need to be supplied by other generation, typically hydro, which means hydro storage is drawn down much faster throughout winter.

There is reduced gas production forecast in 2024, which reduces the gas available for thermal electricity generation. Securing additional gas (i.e. gas reallocation arrangements with the petrochemical sector), as well as running additional coal-fired generation, will help mitigate this risk. We are currently unaware of any gas reallocation arrangements for 2024. The sudden loss of major generation assets would further increase the energy risk.

Under El Niño conditions it is generally expected (but not certain) there will be above average rainfall in the major South Island hydro storage catchments during summer. A summer of high inflows would help us head into winter with a good supply of hydro storage. Current storage levels are around average for this time of year due to drier El Niño conditions.

Mitigations

While we have identified a need for short-term mitigation options to reduce capacity and energy risks in winter 2024, the options are limited to those that can be implemented in time for winter 2024 and largely relate to existing assets. We will continue to work with industry to prepare for and manage these risks. Longer-term, more flexible supply and demand-side resources are needed in the market to meet the energy and capacity challenge for a reliable and efficient electricity system that supports increased electrification and decarbonisation of the economy.

Input Assumptions

Peak and energy modelling input assumptions

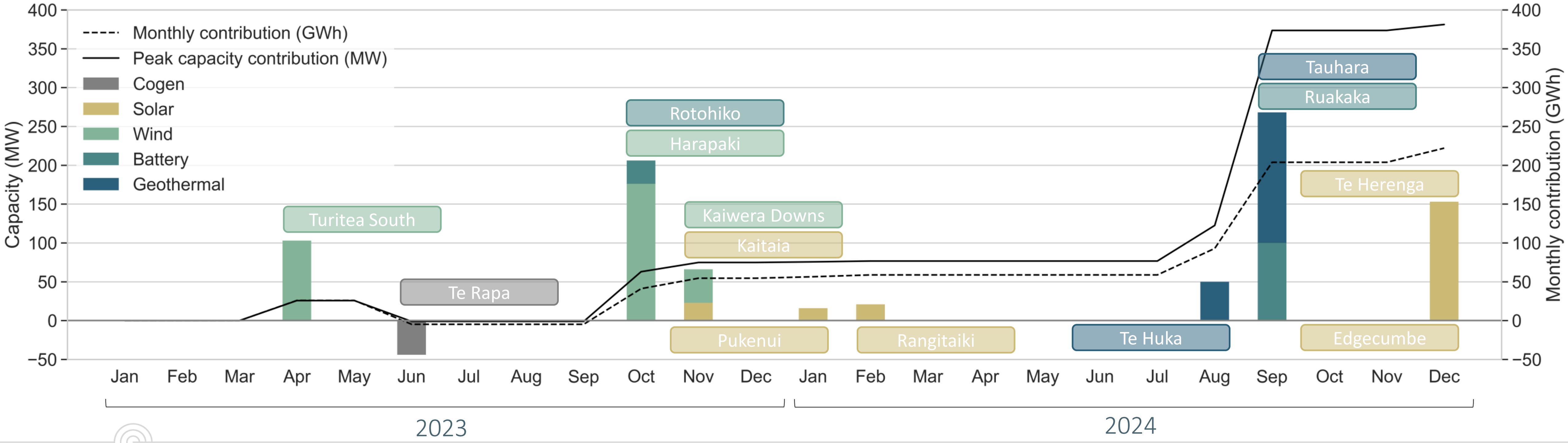
We have considered potential changes to the power system that could occur over the next 12 months that could impact the peak and energy challenge. As the peak challenge is our ability to balance supply and demand during specific high-load periods, and the energy challenge considers the supply-demand balance over a longer period, there are some differences in the modelled assumptions that are salient to each issue. A summary of these changes and how we have modelled them is provided below.

Peak	Energy
Outages: Outages entered in POCP as at January 2024 are used for both the energy and peak analysis. However, we made the following adjustments to plant availability, as POCP may not yet capture all the potential outages that could occur in 2024	
We ran sensitivities to consider the impact of additional plant on outage during peak load periods. Additional plant on outage can have a large impact on the available capacity to supply peak demand even though the energy impact of an outage could be quite small.	Outage factors were applied (percentage of operational availability), based on what we use to produce the ERCs. These factors (deratings) account for reduced energy from generating units when they are not operating, which are not entered in POCP.
Demand growth: We have been observing faster peak demand growth than energy demand growth.	
Peak demand growth has been 1.5 - 2% per annum since 2020. For 2024, we used a peak demand growth rate of 2%.	We used the medium demand growth forecast scenario that we used to model the ERCs. The average energy demand growth rate we used to model the change from 2023 to 2024 is 1.6%.
Controllable load: We consider some load response when the system is constrained for either energy or capacity.	
We included controllable load response consistent with what we observed in 2023 via difference bids when responding to Low Residual Notice scenarios. This was ~205MW (see Winter 2023 Review paper).	We included a demand reduction of ~2%, consistent with our ERC assumptions document. This accounts for demand response contracts and other loads that may reduce for extended periods if there is a period of low hydro storage and elevated spot prices.

Generation commissioning – Capacity and Energy

Utility scale wind, solar and battery assets have all been commissioned in the last year. The uncertainty and variability of intermittent generation is a challenge in meeting peak demand but is a useful provider of energy over time. In the next 12 months the Tauhara geothermal station and Ruakaka battery will be commissioned. Tauhara will assist with both energy and peak capacity while the battery will help manage peak capacity. The chart below shows the addition to both peak capacity and total energy for recent and expected generation and battery assets. It is important to note that the dates below are start commission dates, the full capacity will not be immediately available. These additions were considered in our analysis.

Under the same assumptions used in the SOSA for peak capacity contribution, capacity will increase by ~75MW by the end of 2023 and a further ~305MW by the end of 2024. Using the SOSA energy contribution factors the contribution from new generation will increase by ~55 GWh/month by the end of 2023, and a further ~167 GWh/month by end of 2024. The commissioning dates used are as at 1 January 2024.



Supplying peak demand through winter 2024

Winter 2023 – Capacity summary

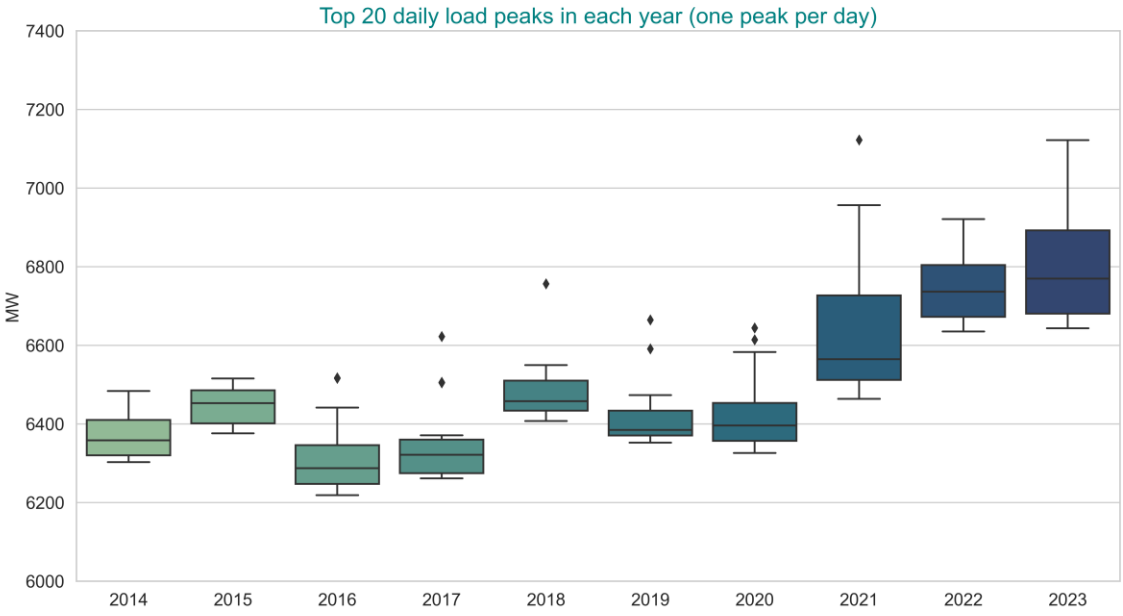
Our Winter 2023 Review paper highlighted that tight capacity margins continued in 2023, due to a combination of peak demand growth, intermittent generation growth, and the reduction in flexible resources available on the power system. Key focus points in the paper were:

- Our collaboration with the Authority and industry participants to successfully manage the winter peak capacity challenge in 2023, including through improved information, communication and event preparation.
- The growth in intermittent generation (mostly wind) means flexible resources are needed to fill the daily variation in output.
- The impact of record hydro storage levels in early winter (which reduced electricity prices) on the commercial viability of slow-start thermal units.
- The response by industry participants helped to manage eight low residual situations, four of which would have escalated to grid emergencies without the industry response. The response came from a mix of delayed or cancelled outages and the commitment of additional slow-start thermal units.
- Although there were significant unplanned outages later in winter, these were offset by strong gas and coal positions along with a weakening hydro situation, which resulted in strong thermal unit commitment, although with reduced resilience because all available generating units were operating.
- On 2nd August we had the second highest peak demand on record in New Zealand. Although demand was supplied with 300MW of residual capacity, all available assets were committed to the market, which increased our vulnerability to an unplanned outage.

Factors impacting the capacity risk in winter 2024

The conditions that contributed to the tight capacity margins over the last three years are expected to continue in 2024, including:

- Peak demand growth of 1.5 – 2% per annum since 2020.
- The uncertainty of intermittent generation output during peak demand periods.
- The availability of firm generation due to a combination of planned and unplanned outages.
- The uncertainty of slow-start thermal unit commitment based on market conditions.



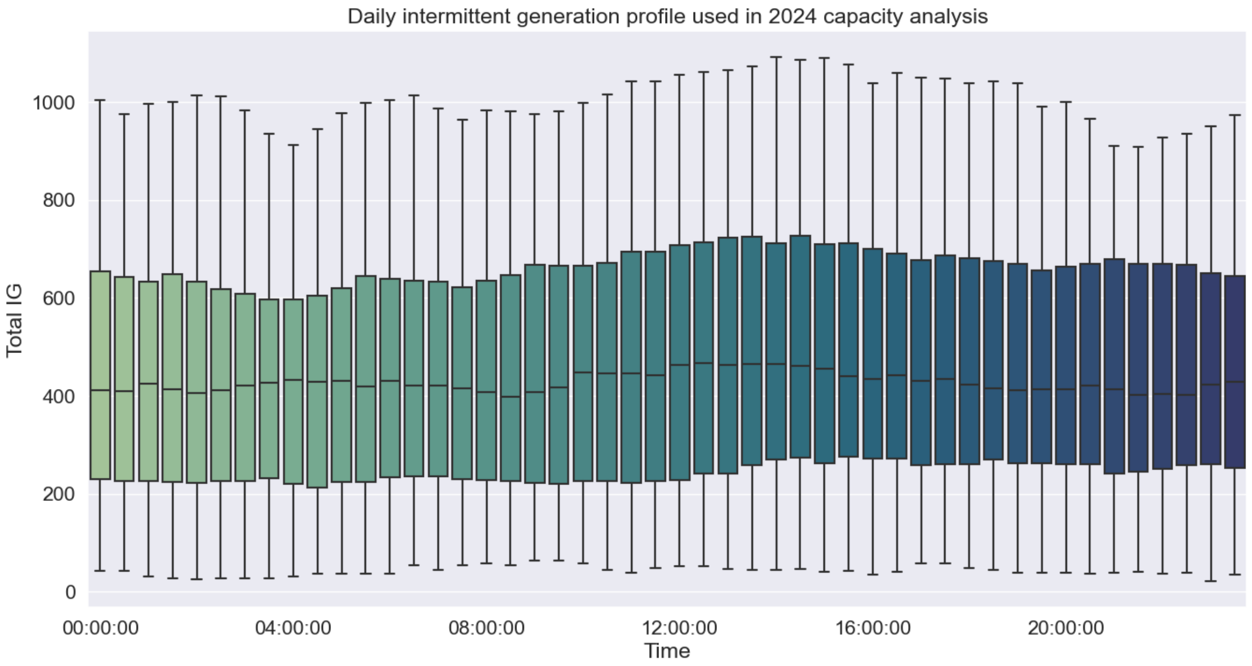
Other factors that we expect to impact winter capacity in 2024 include:

- The return of the HLY5 CCGT from an extended unplanned outage.
- The new 33MW Rotohiko battery, which will provide additional peaking capability on the system.
- Additional solar generation capacity (~60MW) expected to come online before winter 2024, although this will have less contribution to evening peak loads.
- The announced delays in the 174MW Tauhara geothermal station (delayed until after winter) and the 176MW Harapaki wind farm due to Cyclone Gabrielle.
- The continued availability of controllable load.

Understanding the size and shape of the winter peak capacity challenge

To understand the size and shape of the winter peak capacity challenge in 2024, we have simulated historical winter peak load conditions with adjustments for:

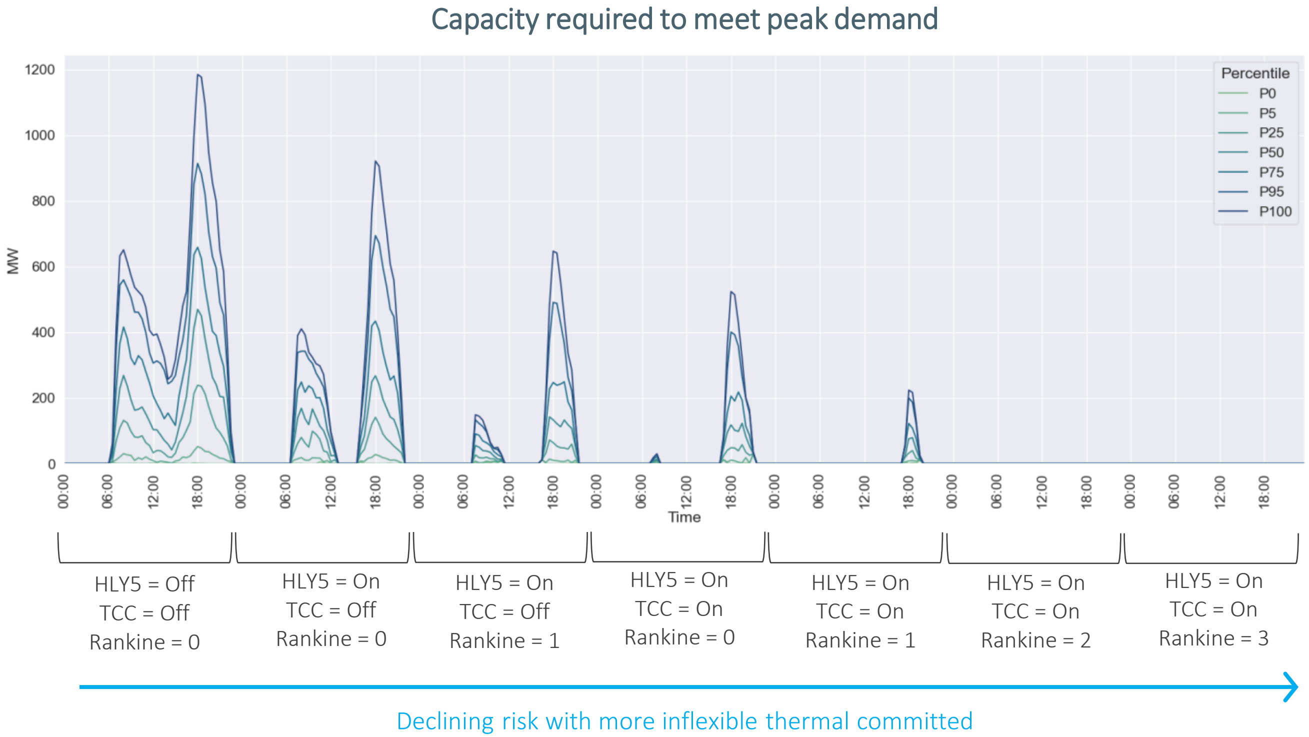
- Additional generation and BESS resources expected by winter 2024.
- The half-hour variability in intermittent generation output.
- Peak demand growth observed since 2020.
- Thermal generation commitment scenarios:
  - Huntly Unit 5: On/Off
  - TCC: On/Off
  - Rankines: 0, 1, 2, 3 units offered.
- Outages entered in POCP with a sensitivity including additional outages.
- The availability of controllable load, based on winter 2023 observations (~205MW during morning and evening peaks) with a sensitivity including additional demand response.



Thermal units are needed to reduce peak capacity risks

The figure shows the additional capacity required to maintain a secure dispatch for different thermal commitment scenarios. Each thermal scenario in the figure accounts for the expected investment pipeline, planned outages and the variability of intermittent generation profiles.

For winter 2024, the risk exposure to intermittent generation variability decreases with more inflexible thermal unit commitment (note the inflexibility of these units is around start-up times; once the units are committed and running they are quite flexible). For example, on cold winter days both CCGTs (HLY5 and TCC) as well as two Rankine units are required to reduce the risk of potential shortfalls due to intermittent generation variability.



As more thermal units are committed to the market, the residual capacity to maintain system security needs to be more flexible. For example, with both CCGTs committed, the "ideal" residual resource is required to:

- Operate in the morning (1 hour) and evening (3-5 hours); and
- Operate at an output of less than 10MW if intermittent generation is high and up to ~530MW if intermittent generation is low.

While more thermal unit commitment is required to help meet winter peak demand in 2024, this is due to limited flexible resources in the market. Longer-term, the role currently performed by some of the slow-start thermal units in peak load management will need to be provided by more flexible resources such as new batteries, demand response and more flexible generation (e.g. hydro or fast-start thermal peaking generation).

There is lower thermal commitment when hydrology is high

Thermal unit commitment tends to be lower when hydro storage is higher and spot prices are lower.

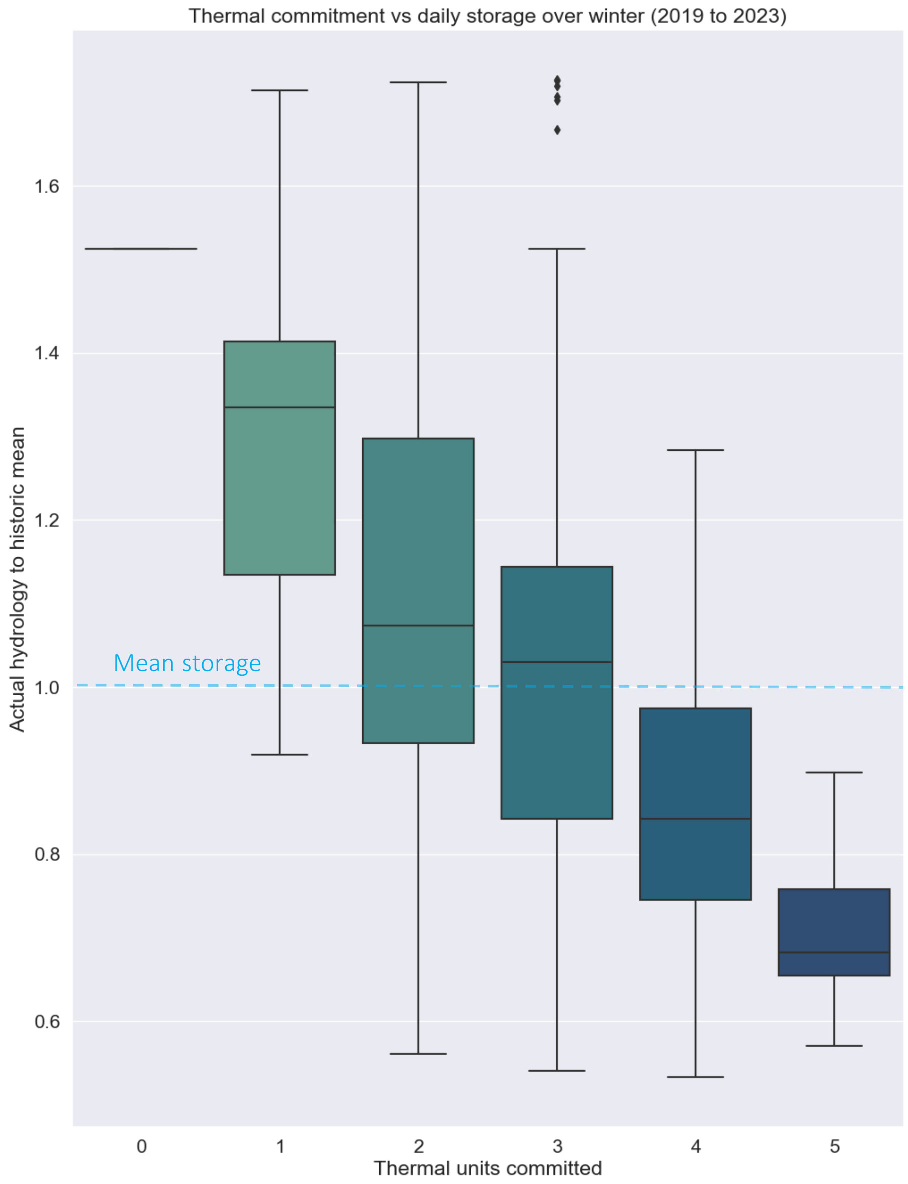
When spot prices are low, thermal generators are more likely to be uneconomic to run or marginal in the merit-order stack, resulting in decisions on whether to commit the thermal unit or not.

When hydrology is low spot prices are consistently elevated as hydro generators try to conserve water. In these conditions thermal generators are more likely to be economic and units can be committed and run (subject to plant availability and fuel supplies).

The figure shows thermal unit commitment measured against the hydro storage range (relative to mean storage) during winter over the last five years (2019-2023). When storage levels during winter are lower, it is more likely that additional inflexible thermal units will be available during peak load periods.

Currently, hydro storage is sitting at average levels for this time of year (January). If there are low inflows in 2024 leading to lower hydro storage over winter, there would likely be higher spot prices and increased thermal unit commitment. Paradoxically, this would reduce the thermal commitment risk to the winter peak capacity challenge.

However, last year significant outages meant that we faced several near-record peaks with no further generation units available if demand had been higher (i.e. all available units were committed and running).



Increased outages in winter will be challenging

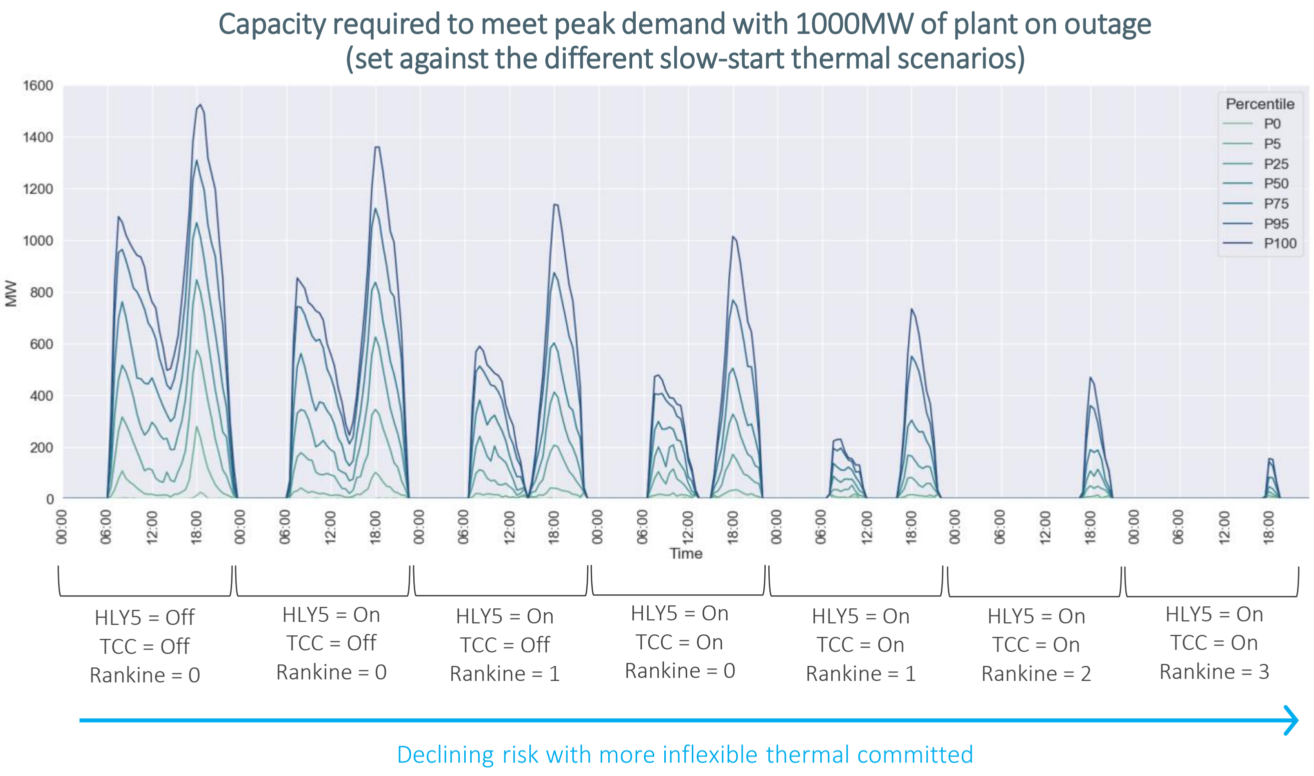
We highlighted in our Winter 2023 Review paper a reduction in the number of planned outages during peak load periods in winter 2023. This increased available capacity to meet peak load periods and reduce the supply risk.

We expect the same trend in winter 2024. At the time of this analysis, ~500MW of non-intermittent generation planned outages was entered into POCP for winter 2024. These were included in our capacity assessment on the previous slide.

If more outages are required during peak load periods (planned or unplanned) there will be an increased risk to meeting winter peak demand.

The figure shows the capacity required to meet peak demand if ~1000MW of generation is on outage during winter peaks, set against the different slow-start thermal scenarios.

Under this condition, additional thermal commitment would be needed to be robust to intermittent generation variability (i.e. a third Rankine unit). Even then we may be operating with reduced reserves during the coldest evening peaks with low intermittent generation.

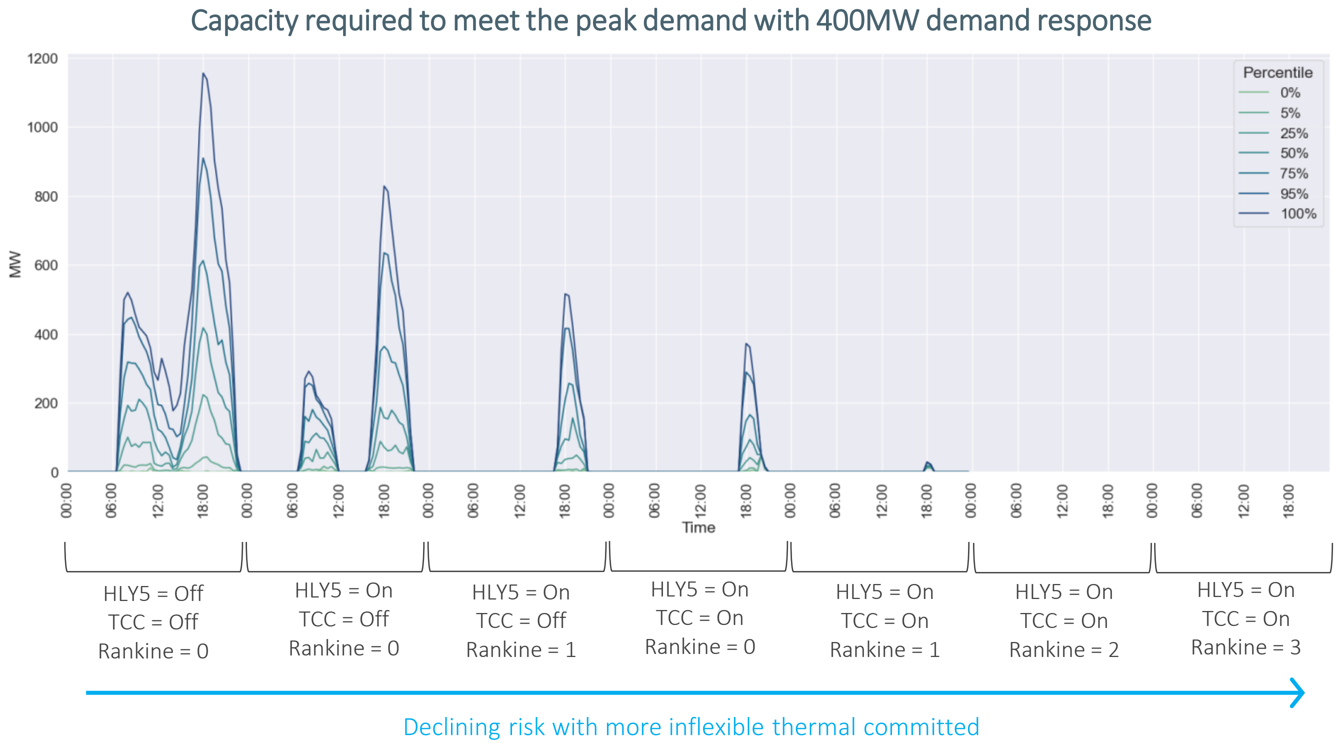


Demand-response will help, but little confirmed uptake

Over winter 2023, ~205MW of controllable load was bid into the market by EDBs via difference bids. An additional 20-30MW was bid in by SolarZero as part of an Ara Ake-funded trial using the Dispatch Notified Load (DNL) market product.

In our base analysis, we have assumed the continued availability of ~205MW of controllable load demand response. To understand the potential impact if additional demand response was made available in winter 2024, we tested a scenario where 400MW of demand response was bid in (including the ~205MW of existing controllable load).

The figure indicates that with 400MW of demand response bid into the market and using our base outages assumption, there is less need to commit a second Rankine unit if both CCGTs are committed and operating during peak load periods. *The additional demand response we tested (195MW in addition to the 205MW controllable load) is illustrative only. While no new demand response participation has been approved, two load control providers have expressed interest in DNL participation. But we would need a significant uptake of demand response or increased controllable load to reduce our reliance on thermal generation.*



The benefit of demand response that is bid into the market (i.e. as dispatchable demand or DNL) is that it is visible to the market and can be optimised with other supply-side resources for more efficient outcomes, which may reduce the need to run additional thermal generation.

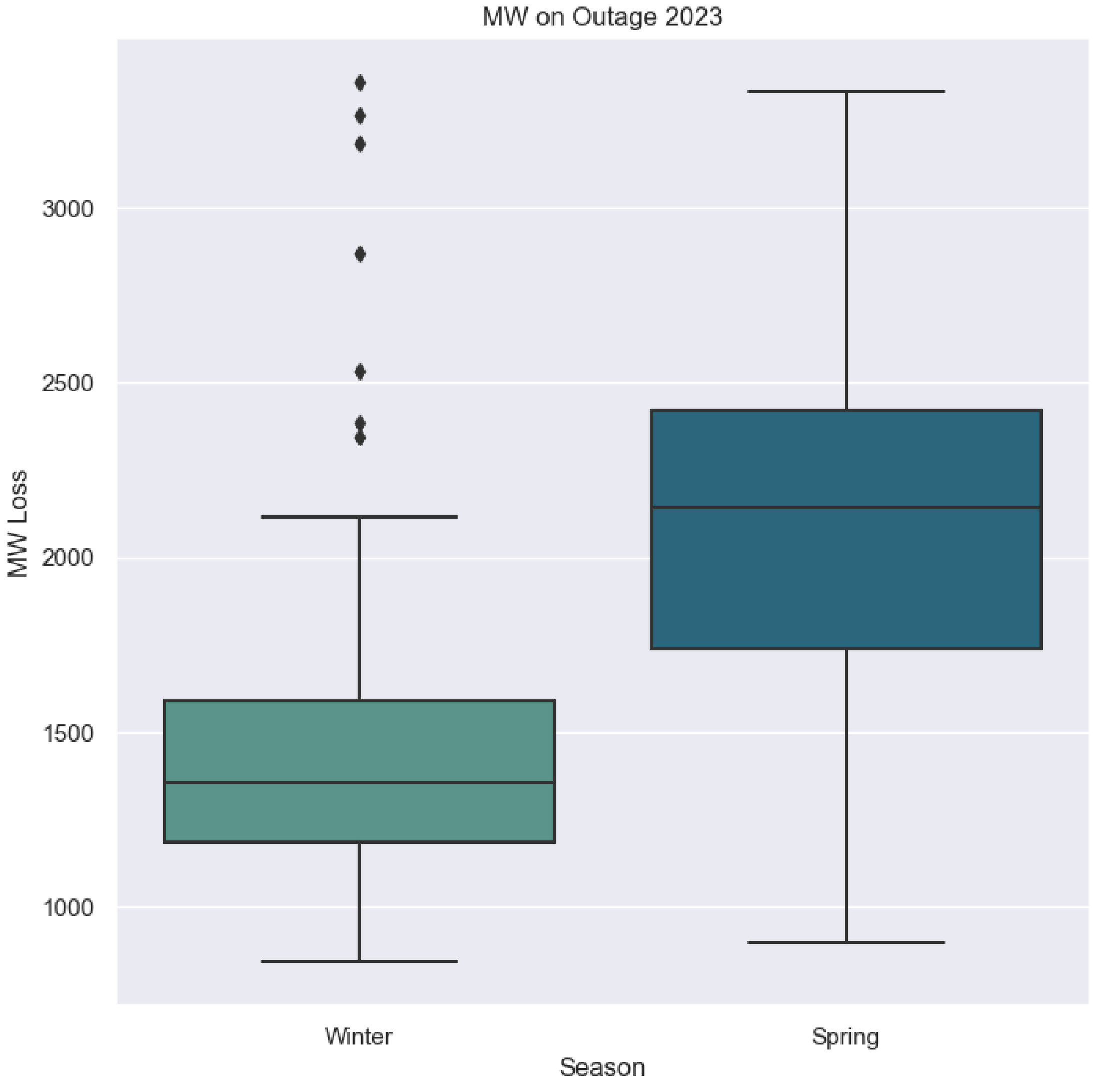
Managing shoulder period capacity margins

Outages are necessary to ensure the long-term reliability of assets. Although asset owners have some flexibility around when to take outages, they cannot be deferred indefinitely. Ideally, outages would be taken during low load periods, but too many outages (planned and unplanned) during low load periods can present new capacity risks.

November loads are normally much lower than winter peak loads. However, in November 2023 we issued two Low Residual Notices due to a combination of asset outages (planned and unplanned) and low wind conditions. Responses from market participants helped to manage these situations. See our market summary here for more details.

This is a useful reminder that tight capacity situations are not restricted to winter peak load conditions, especially with more intermittent generation on the system and the variability in its output, combined with asset outages (planned and unplanned).

The availability of flexible market resources that can respond to these situations (at short notice) is important and will also help asset owners schedule outages, which are critical for the long-term reliability of the system.



Project delays are a risk

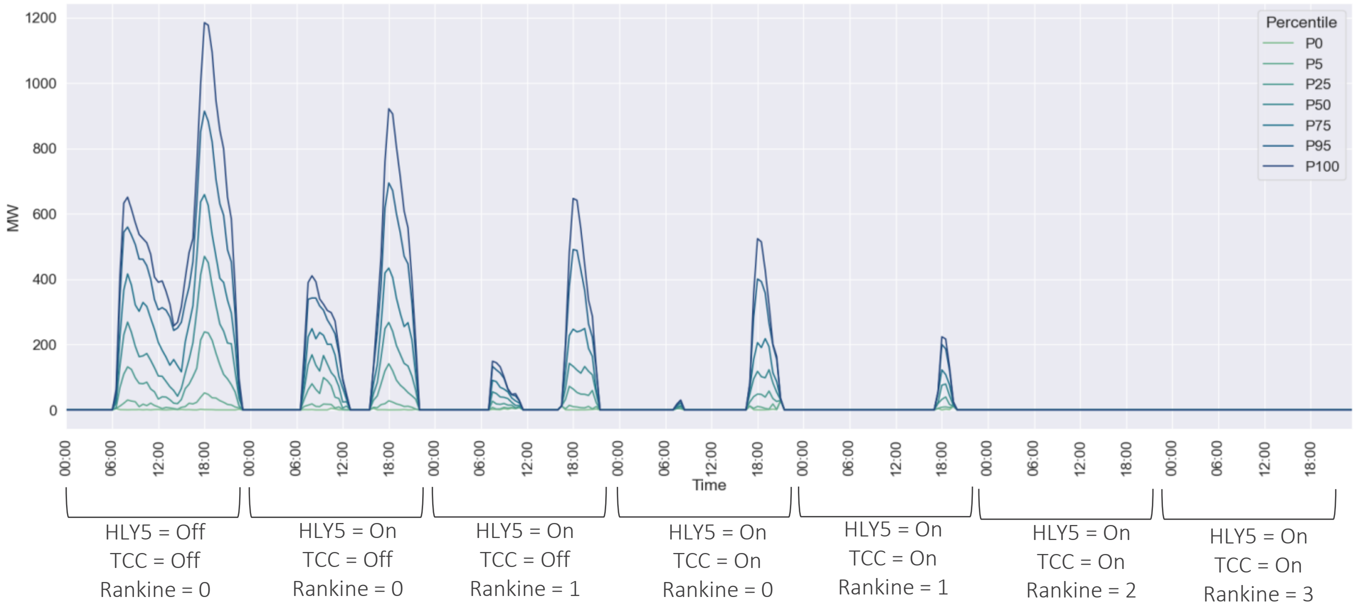
The availability of generating units can be impacted by planned and unplanned outages as well as commitment decisions. Having sufficient resources that can be scheduled when some units are not available reduces system capacity risks. This was seen in 2023 with the unplanned outage of the HLY5 CCGT and the SFD22 peaker resulted in increased Rankine commitment and reduced planned outages over peak load periods.

Given the large number of planned projects to meet demand growth, project delays is another form of plant availability risk. Building and commissioning generation plant is a complex process and project delays are not uncommon. Recent project delays include the Harapaki wind farm delay, due to Cyclone Gabrielle, and the Tauhara geothermal delay due to a range of issues.

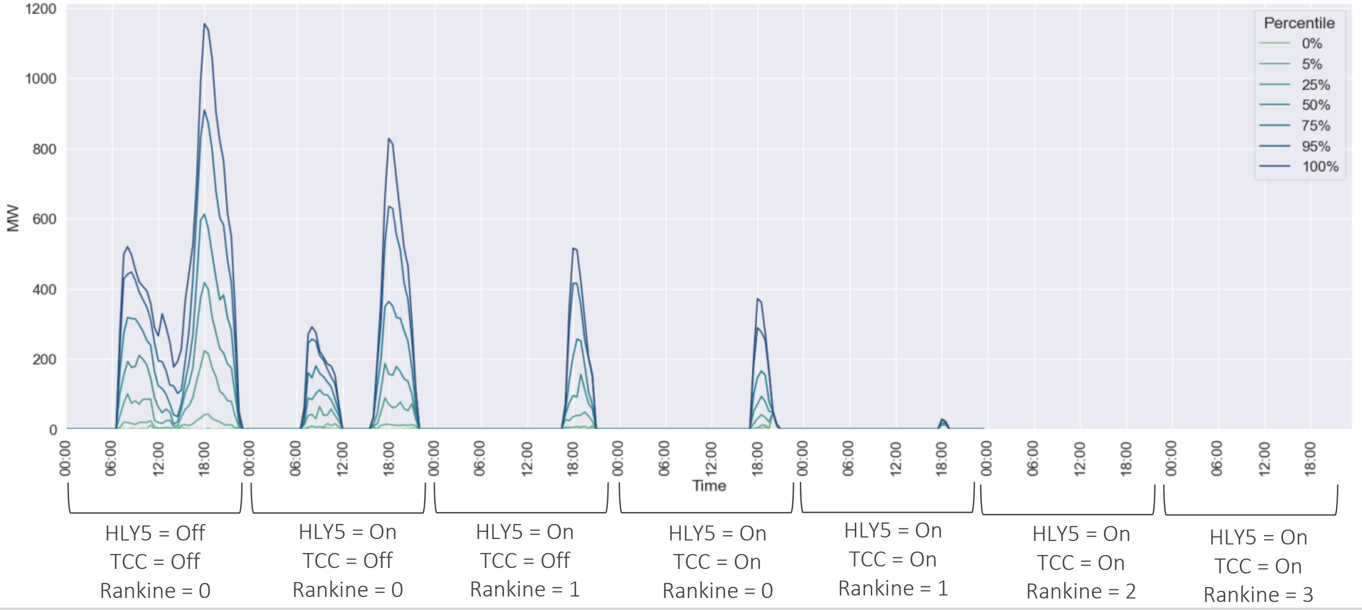
The availability of sufficient existing generation and demand-side resources to meet demand will be important to manage the delay risks as more generation projects are planned.

The figure shows the impact of the delays in the Tauhara geothermal plant and Harapaki wind farm on peak capacity requirements. This indicates these delays increase the need for the second Rankine commitment to meet the winter capacity requirements. The analysis assumes the same base case demand response (see slide 17).

Capacity required to meet the system peak requirements with project delays



Capacity required to meet the system peak requirements without project delays



Supplying energy demand through 2024

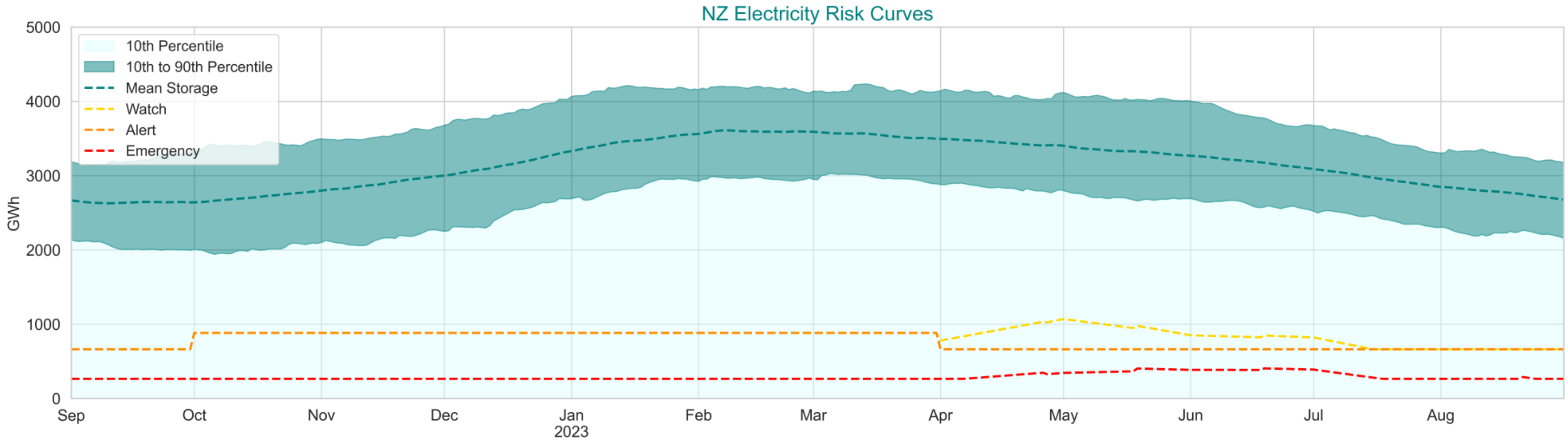
Winter 2023: Energy demand supplied with no plausible risk all winter

Above average hydro storage persisted through 2023 until late August. This resulted in periods of hydro spill and set a new June storage record. This was driven by a strong 12 months of inflows.

The electricity risk curves (ERCs) model the power system's ability to reduce its reliance on hydro storage. In 2023, we modelled the risk (of an energy shortfall over time) as low, indicating our reliance on hydro storage to maintain energy security was low.

Increased gas production, high levels of stored gas and coal stockpile, meant there was plenty of thermal fuel available in the event of a security of supply emergency. The largest contributing factor to high levels of gas availability was a 3-month planned outage from Methanex during winter. Methanex is the largest user of gas in New Zealand.

Due to the high levels of hydro storage and low ERCs the risk of a dry winter never became a concern during 2023, even after accounting for the unplanned outages at Huntly Unit 5, Manapouri and Kawerau geothermal.

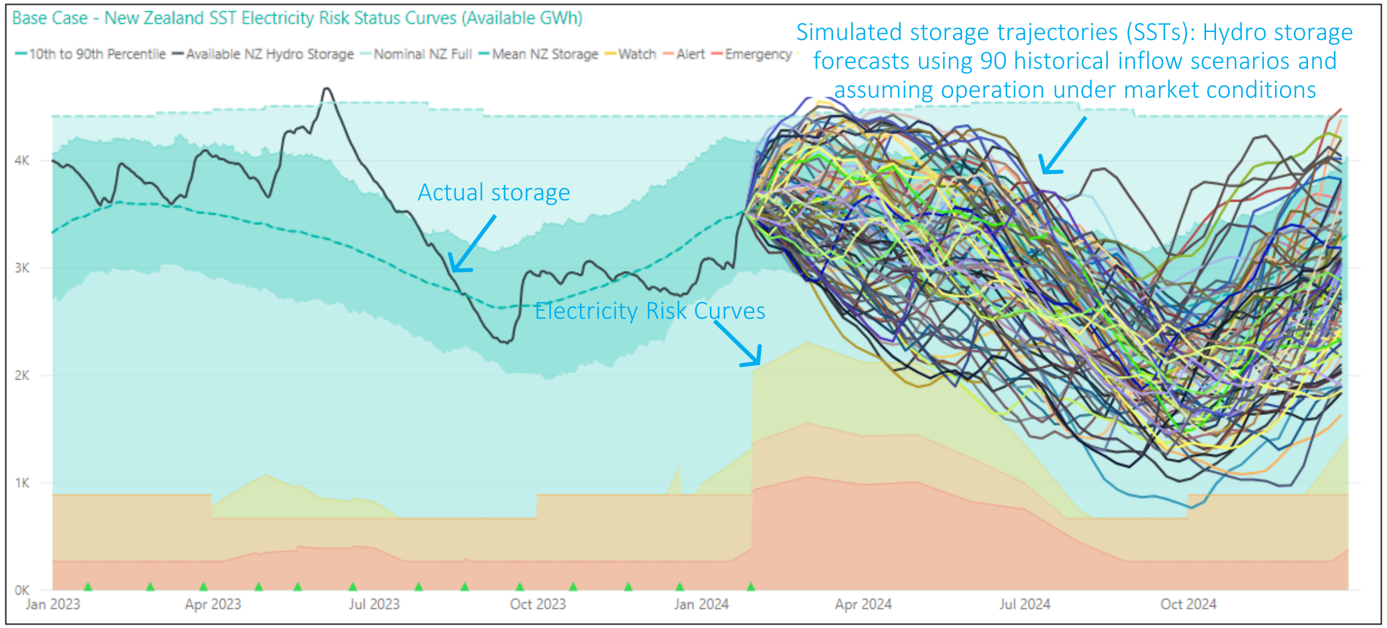


Winter 2024: Higher risk of energy shortfall

The ERCs for 2024 show a much higher risk of an energy shortfall than for 2023. This is shown in the figure by the increase in the Watch, Alert and Emergency curves in 2024 compared to 2023. The Watch curve is based on the 1% ERC which represents a 1% chance of running out of hydro storage over the next 12 months if hydro storage reduces to that level.

The primary reasons for the increase in the 2024 ERCs is the reduced availability of existing thermal generation in 2024 and limited new generation coming to market to meet the forecast demand growth in 2024. The combination of reduced non-hydro generation and increased demand means we are more reliant on hydro generation to meet the forecast 2024 energy demand, which increases the risk of running out of hydro storage under low hydro inflow conditions.

Electricity Risk Curves and SSTs produced in November 2023



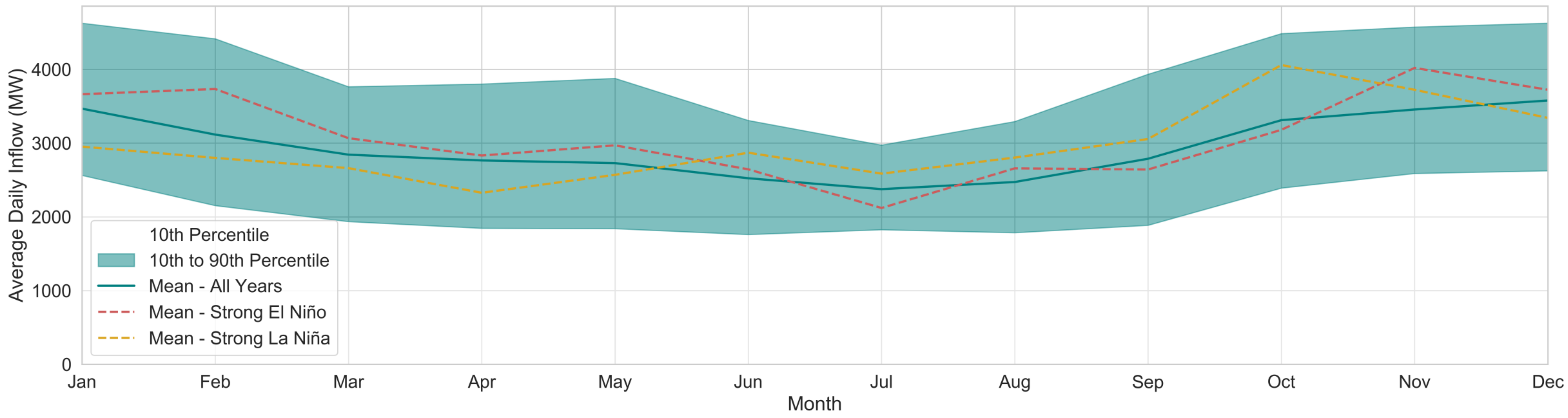
One of the primary reasons for reduced thermal availability in 2024 is the reduced gas production forecast, which reduces the gas available for thermal electricity generation. Other factors include the limited availability of some thermal generation due to outages, constraints and reliability risks (e.g. TCC limited running hours if TCC is required to run for extended periods). Additionally, there is limited new generation being added to the system in the next 12 months. This is exacerbated by the delay in the 174MW Tauhara geothermal generating station, which has been delayed from Q1 2024 to Q3 2024. This delay in firm baseload energy increases the reliance on hydro generation in 2024 to meet the forecast increase in energy demand.

What impact will El Niño have?

El Niño weather conditions started during spring, interrupting the La Niña conditions that had persisted for three years. NIWA has forecast ~100% chance that El Niño persists through March with more variable rainfall patterns than experienced during strong El Niños in the past.

Under El Niño conditions it is generally expected (but not certain) there will be above average rainfall in the major South Island hydro storage catchments during summer. Elsewhere, normal or below average rainfall is expected, possibly increasing irrigation load.

A summer of high inflows into the South Island hydro storage catchments will help us head into winter with a good supply of hydro storage. Although the forecast does not yet extend through winter, high hydro storage at the start of winter provides more resilience during winter when hydro catchment precipitation mostly falls as snow, ending up in the lakes when the snow melts. While these are typical El Niño conditions, these conditions are not guaranteed to occur in 2024 and as at 31 January we have experienced drier El Niño conditions with increased inflows in January resulting in current storage sitting at around average for this time of year.

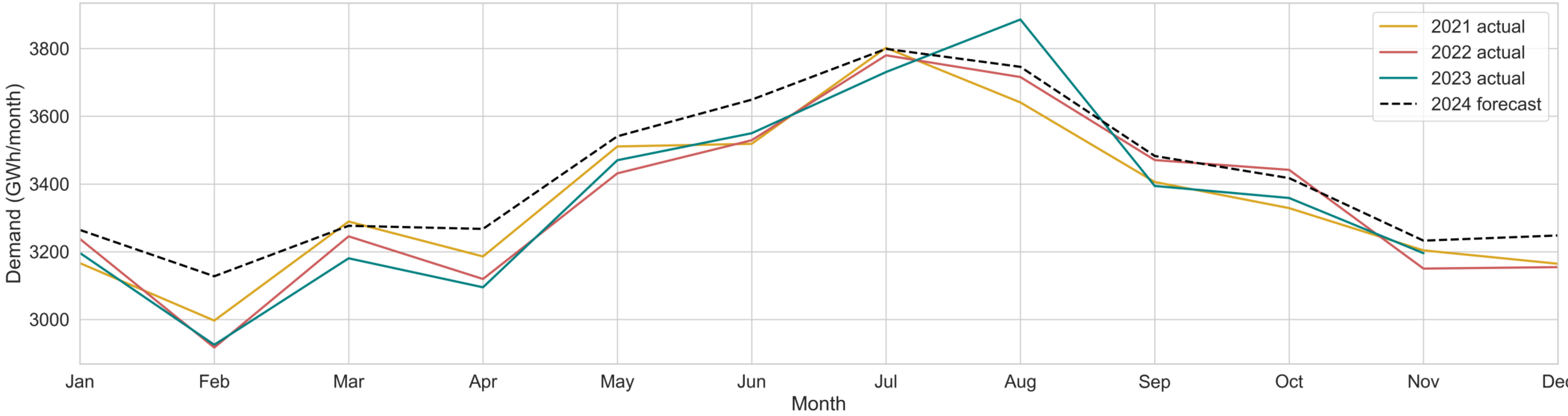


Energy demand continues to grow

Energy demand growth is expected to continue in 2024, largely driven by growth in ICP connections. There are a range of factors that can impact the actual demand growth relative to the forecast. These factors include:

- A cooler winter in 2024 could result in a larger increase in energy demand. The last three winters have been the warmest on record, which has reduced energy demand. An example of the impact of cooler temperatures was observed in August 2023 where the average monthly temperature was below previous monthly averages resulting in a spike in monthly demand.
- El Niño typically brings average or below average rainfall to most of the country, which could drive higher demand over summer due to increased irrigation. Historically this has resulted in ~5% increase in national demand.

Each of these factors or changes could result in increased ERCs due to more generation being required to meet the shift in demand.

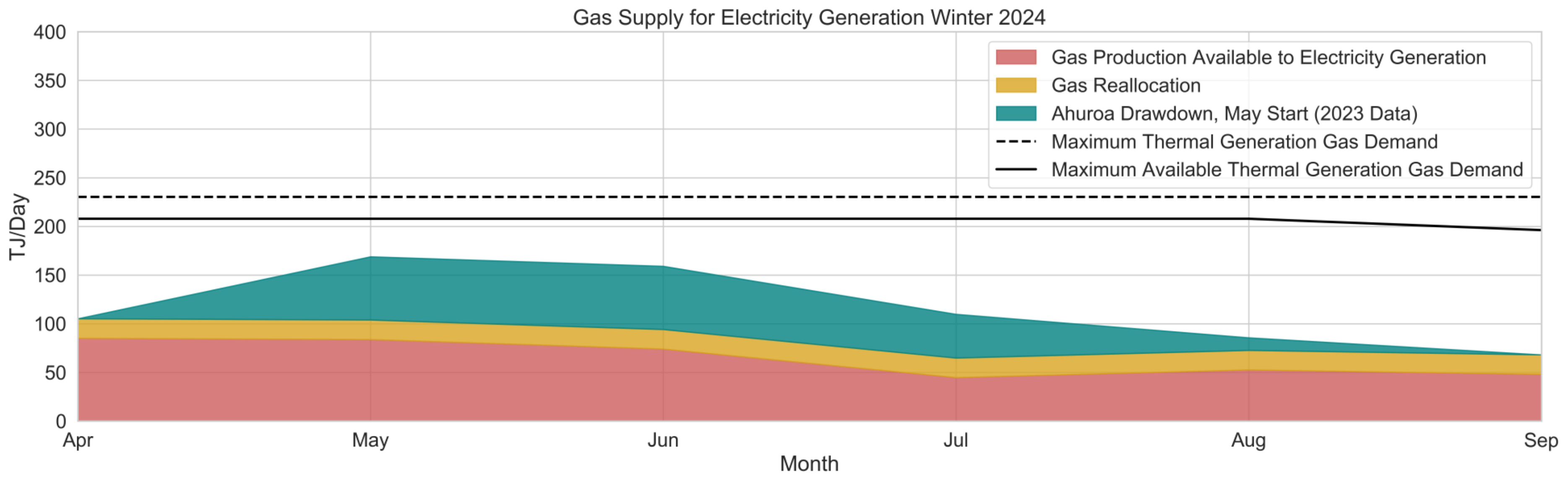


Reduced thermal generation forecast

Thermal generation is forecast to be more constrained in winter 2024 than winter 2023, due to:

- Gas production is forecast to reduce in winter 2024 compared to winter 2023.
- No formal gas reallocation agreements. In 2023, the Methanex shutdown released additional gas for electricity generation, but we are unaware of any arrangements for 2024. We do assume a baseline of 20 TJ/day gas demand reallocation from the petrochemical sector to electricity generation in a security of supply emergency. To give some indication, 20 TJ/day is equivalent to supplying a SFD peaker for 90% of the time.
- Thermal unit availability: One SFD peaker modelled on outage[1] for the whole of 2024 and TCC has limited running hours (if TCC is required to run for extended periods).

On average across winter 2024, gas supplied to thermal generation is constrained by gas availability, based on current forecasts and knowledge of unit availability. The coal stockpile is sufficient to run a single Rankine unit at full capacity for approximately 12 months, or all three Rankine units over winter.



1. The SFD peaker availability was updated in POCP prior to the publication of this paper to be available from 1 May 2024, however we have retained this scenario in our model to demonstrate the impact of an outage of similar capacity.

Project delays and unplanned outages increase the energy risk

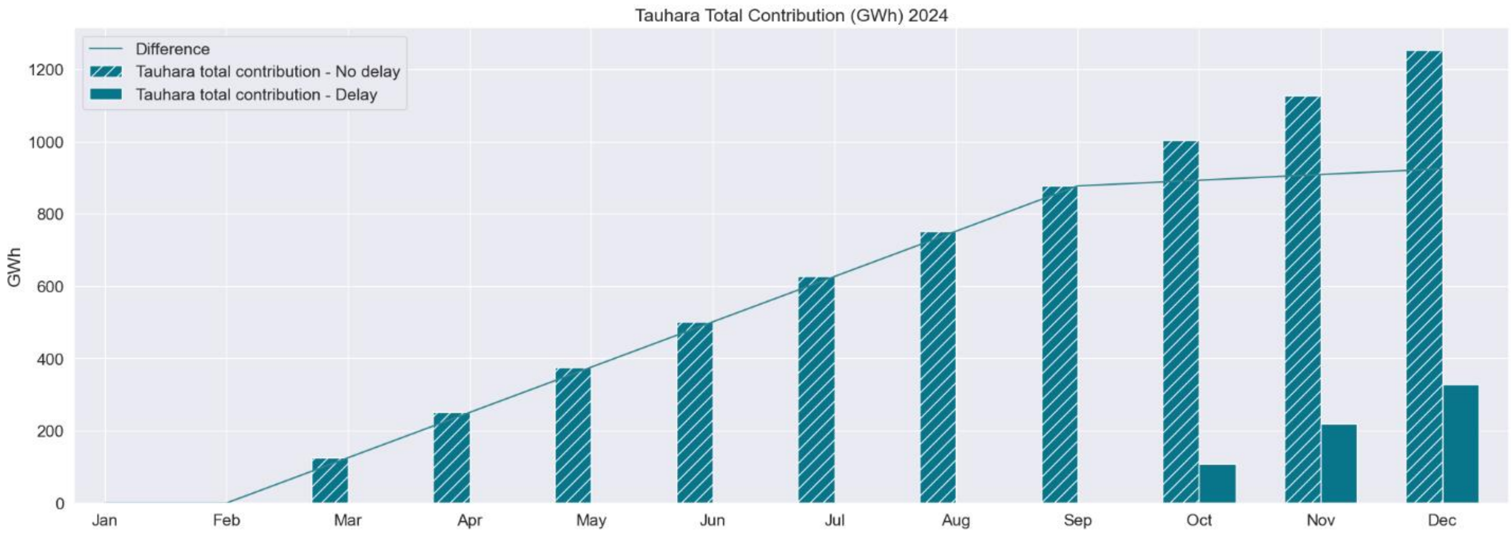
The ability to maintain security of supply is increasingly dependent on new generation entering the market and the continued availability of existing generation. ~167 GWh/month of new electricity generation is expected to be commissioned in 2024.

Expected new generation assets are included in the calculation of the ERCs and delays in their commissioning can have large impacts on the energy risk.

The Tauhara geothermal plant was supposed to commission in March 2024 and was supposed to contribute [~1250 GWh] to the power system in 2024[2]. In November 2023, Contact announced a delay in the Tauhara commissioning date to Quarter 4 of 2024. This delay will reduce its 2024 contribution to [330 GWh], which will be delivered in Quarter 4, when the winter capacity risk has largely ended.

The lost expected energy [of ~920GWh] will need to be supplied by other generation, mostly hydro, which means hydro storage is drawn down much faster throughout winter. The January update of the ERCs modelled the impact of the Tauhara delay.

Note unplanned outages of major generation assets would have a similar impact on the energy risk. Planned outages are modelled in the ERCs, but unplanned outages are difficult to account for and any that arise would put upward pressure on the ERCs.



2. Assuming Tauhara operated at full capacity from commissioning.

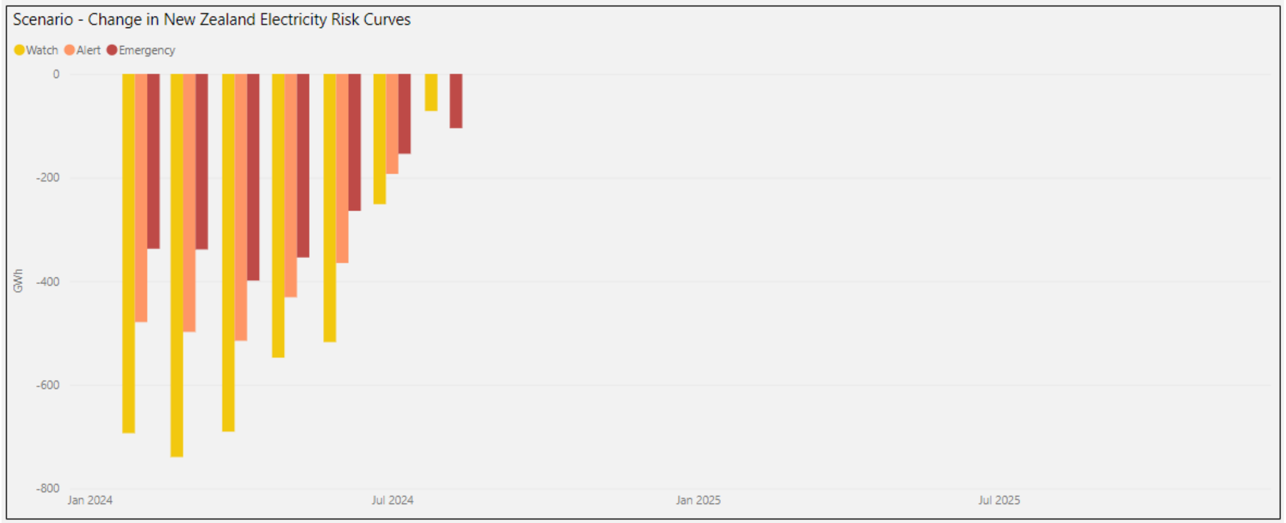
Gas reallocation would lower the energy risk in 2024

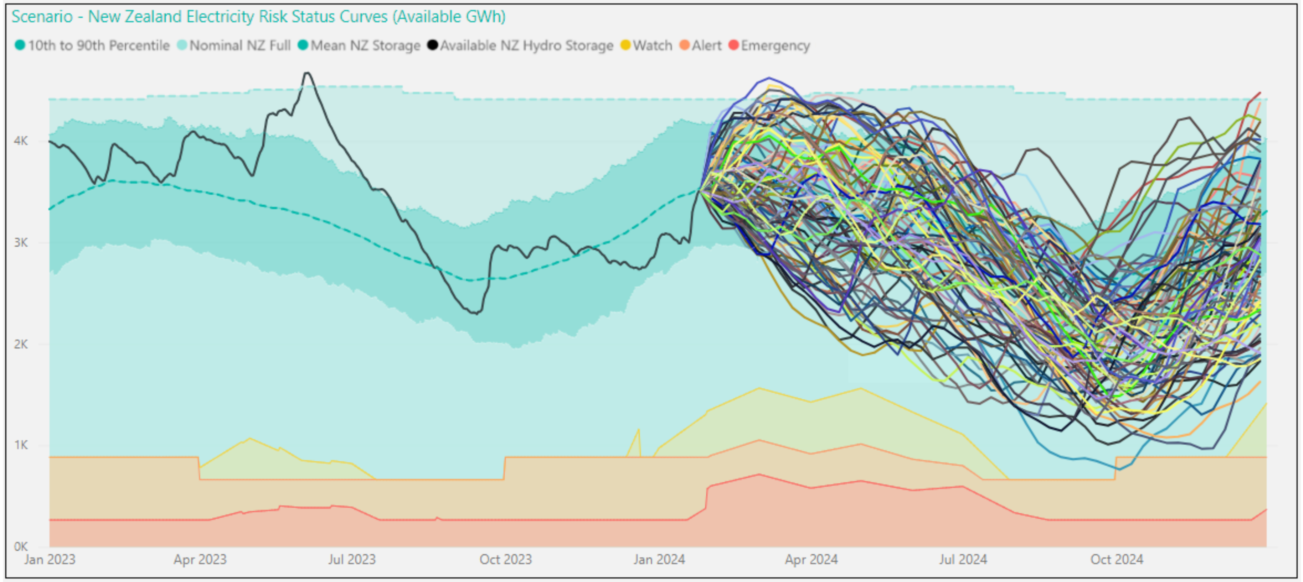
The constraints we highlighted on thermal generation in 2024 are largely due to the amount of gas supply available for electricity generation. We ran a sensitivity to investigate the impact of 100 TJ/day gas reallocation from the petrochemical sector for electricity generation over June - August 2024. We are unaware of any such arrangements for 2024, but similar arrangements have occurred before, including in winter 2023.

An additional ~80TJ/day of gas supply available (on top of the ~20 TJ/day baseline) for electricity generation over winter 2024, reduced the national Watch curve by up to 740 GWh in summer, and up to 500 GWh in autumn and winter.

This sensitivity highlights the importance of flexibility in fuel supply, which can provide seasonal flexibility in generation to reduce energy risks over extended periods. While this sensitivity explores a supply-side option, large demand-response for extended periods, where possible, would also help reduce dry-year risks.

The bar chart at the top shows the impact the gas reallocation scenario has on each electricity risk curve (i.e. a material decrease in the risk). The chart below shows the updated electricity risk curves under the gas reallocation scenario.





How can we mitigate the challenge?

Short-term mitigation options are limited

We have identified a need for short-term mitigation options to reduce capacity and energy risks in winter 2024. However, short-term mitigation options are limited to those that can be implemented in time for winter 2024 and largely relate to the use of existing assets and processes.

Industry actions can help reduce the risk

Increased thermal commitment: The increased commitment of inflexible thermal generation mitigates the risks of intermittent generation variability. However, with more thermals committed, the "ideal" resource to fill the remaining capacity shortfall would be flexible (e.g. battery, fast-start peaker, demand response). Without these flexible resources in the short-term, additional thermal commitment could be used to reduce the risk.

Increased demand response: Some demand response capability can come to market faster than supply-side options, which makes it a viable short-term option. When demand response resources are bid into the market (ideally as dispatchable demand or DNL), they can be optimised with other supply-side resources for more efficient outcomes. Demand response that is not bid into the market is uncertain and can lead to the scheduling of unnecessary thermal generation or involuntary load curtailment (when demand response would have been a better outcome). However, there is currently limited demand response uptake in the market.

Outage flexibility: Shifting and having flexibility to shift planned outages out of winter peak load periods. This would reduce the capacity risk and the exposure to unplanned outages.

Thermal fuel availability: Contracting for sufficient thermal fuel ahead of need. In the short-term increased thermal fuel options are limited. Gas reallocation agreements have been observed in the past, but we are currently unaware of any arrangements in 2024.

Accurate, up-to-date information: Accurate information that is frequently updated helps co-ordinate resources and improve preparation for tight periods. Examples include: (a) forecasts of expected generation capability (via energy and reserve offers) up to 7 days into the future; (b) accurate forecasts of demand (load bids) up to 7 days into the future; and (c) up-to-date outage information in POCP.

Improved information and preparation

Improving information to the market

The Authority has decided to retain three of the four initiatives implemented for winter 2023, which improved information available to the market. We are coordinating with the Authority to retain these options for 2024 and beyond:

- Residuals via WITS – showing residual generation available to meet demand.
- Sensitivity schedules via WITS – providing a range of forecast price outcomes based on different demand scenarios.
- Wind forecast generation via EM6 - showing the range of wind generation we can expect to see against a central forecast.

The Authority is currently consulting on the retention of the fourth initiative, namely controllable load availability via WITS – showing how much controllable load is available should an event happen and demand management be necessary.

Improving communications, industry awareness and co-ordination

A well-managed event requires good industry co-ordination and advanced warning where possible. In 2023 we focused on improving event management through industry workshops and a practice exercise prior to winter. For winter 2024, we will coordinate with the Authority to refamiliarize industry stakeholders on the protocols for managing tight capacity situations and to run a shortfall simulation exercise. Such exercises are important to improve event communication, awareness and co-ordination.

We are also updating the System Operator Rolling Outage Plan (SOROP). While the conditions when the SOROP would apply are more extreme than what is being assessed in this paper, updating the SOROP will help reduce uncertainty and improve co-ordination of rolling outages under more extreme conditions.

Longer-term mitigations

New generation and demand-side resources, as well as fit-for-purpose market settings, will be needed to meet the peak capacity and energy challenges in the longer term.

Timely new investment needed to meet the energy and capacity challenge

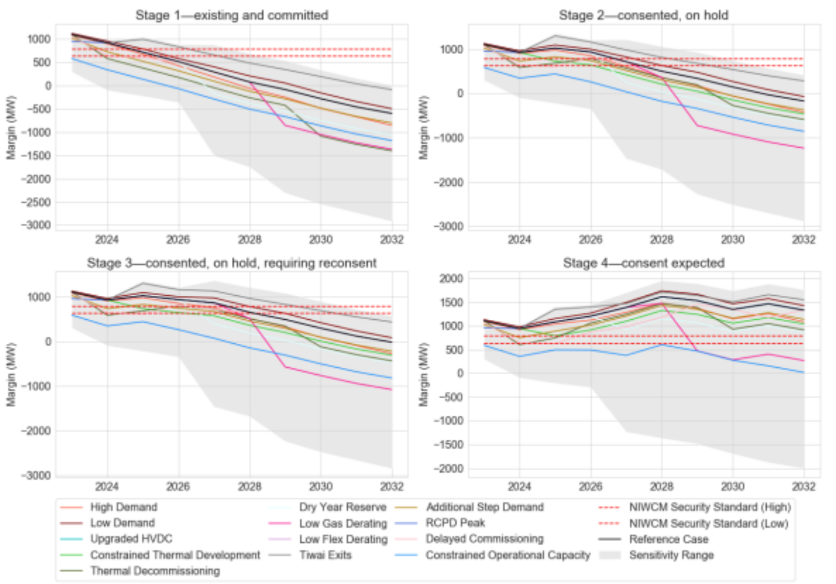
In the coming years, the majority of new generation projects are expected to be wind and solar with increasing quantities of grid-scale batteries. Our most recent annual Security of Supply Assessment (SOSA) shows there are sufficient potential generation resources in the pipeline to increase the energy and capacity margins above the security standards provided these resources come to market in time.

The uncertainty and variability of intermittent generation is a challenge in meeting peak demand, but it is a useful provider of energy over time (i.e. a more useful contributor to the energy challenge than the peak challenge). Whereas batteries are more useful in meeting the peak challenge. Increased demand-response and peaking generation will also be important in meeting the energy and peak challenges.

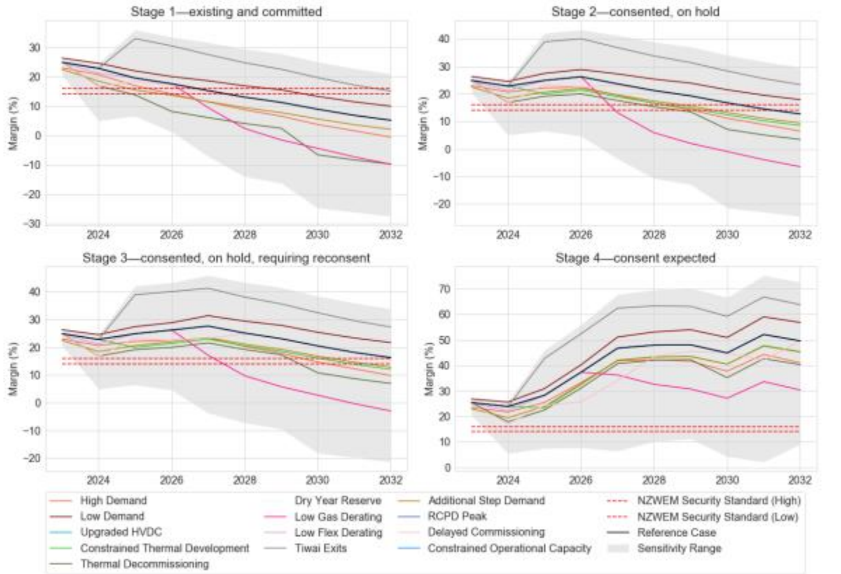
Market settings need to evolve to reduce uncertainty and increase incentives for flexibility

Longer-term, more flexible supply and demand-side resources are needed in the market to meet the energy and capacity challenge and support increased electrification and decarbonisation of the economy. There must be sufficient market incentives to incentivise timely investment in flexible resources. In our role as System Operator we cannot build new plant or batteries or change market settings; we rely on other market participants to develop these options. While we are supporting multiple workstreams and projects across the industry, alignment between these workstreams is imperative to ensure market settings evolve in a coordinated manner to incentivise appropriate investment in the right place at the right time.

2023 SOSA capacity margin results



2023 SOSA energy margin results



Thank you

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