Market Operations Weekly Report - Week Ended 31 May 2026

Overview

National hydro storage remains above average, with levels at 104% of the historic mean for this time of year. North Island storage continues to be high at 163% of the historic mean, while South Island storage is at 99% of the mean.

Prior to last week we started a three-part deep dive series on the electricity sector's readiness for winter. Today's final edition looks at navigating operational risks in real-time.

Security of Supply

Energy

National hydro storage has decreased to 104% of historic mean at the end of last week from 108% the week prior. South Island storage has decreased from 103% to 99% and North Island storage decreased from 185% to 163% with lower than average inflows for both islands last week.

Capacity

Residuals were lower than usual during morning and evening peaks most of the last week. The lowest residual of 363 MW occurred during the morning of Wednesday 27 May, which coincided with the highest demand peak of the week and low wind generation.

The N-1-G margins in the NZGB forecast remain healthy, but are trending downwards into winter with tighter spots appearing; we recommend the industry watch these closely. Within seven days we monitor these more closely through the market schedules. The latest NZGB report is available on the NZGB website.

Electricity Market Commentary

Weekly Demand

Total demand was steady at 800 GWh for the week due to colder than average mornings. The highest demand peak of 6,134 MW occurred at 8:00am on Wednesday 27 May.

Weekly Prices

The average wholesale electricity spot price at Ōtāhuhu last week decreased to $98/MWh from $105/MWh the week prior. Wholesale prices peaked at $568/MWh at Ōtāhuhu at 7:30am on Wednesday 27 May, coinciding with high demand and low wind period.

Generation Mix

Wind generation remained the same at 6% of the generation mix last week, lower than its yearly average of 10%. Hydro generation was unchanged at 60% of the mix and thermal generation decreased from 8% to 6% of the generation mix. Geothermal generation increased from 22% to 25%, sitting above its annual average of 23%.

HVDC

HVDC flows last week were predominantly northward with very brief periods of southward flow overnight. Overall, 115 GWh was transferred north, while 10 GWh was transferred south during the week.

Consultations and Engagement

Draft Policy Statement

Consultation is open on our draft Policy Statement amendment proposal with submissions due by Thursday 4 June.

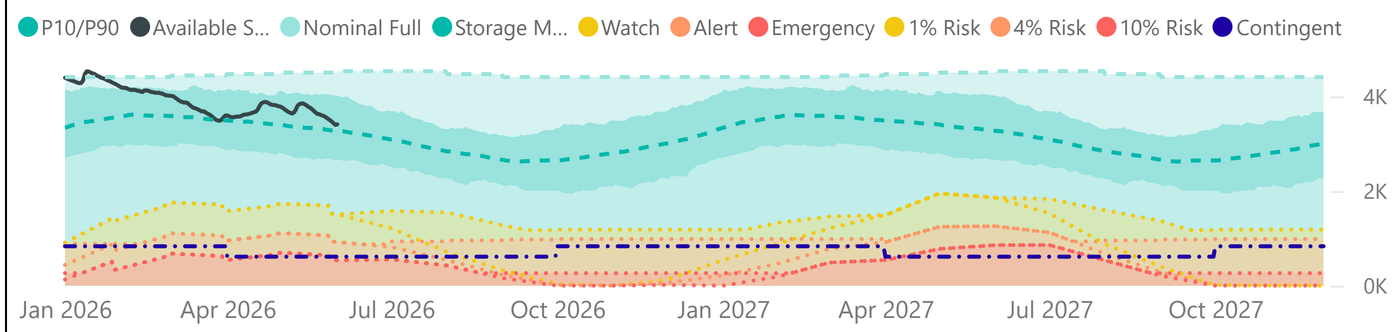
The Policy Statement describes the policies and processes the System Operator uses to meet the principal performance obligations (PPOs) in the Code for maintaining a stable and resilient power system in real-time, and to manage technical compliance and conflicts of interest.

New Zealand Energy Risk

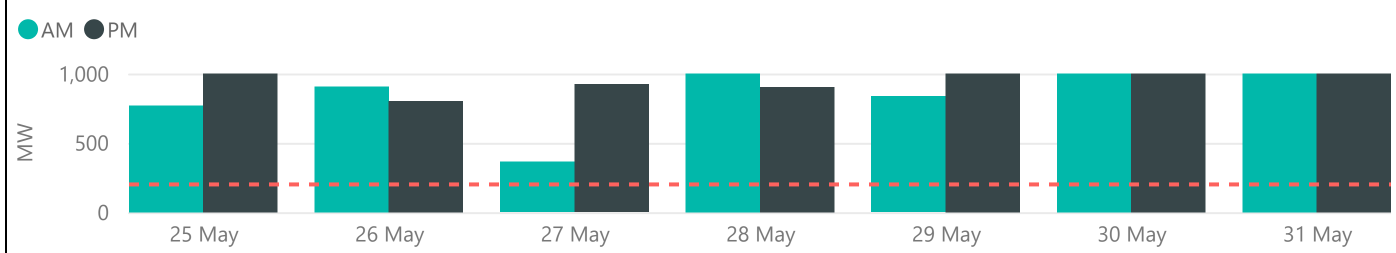
South Island Energy Risk

Normal Watch Alert Emergency

New Zealand Electricity Risk Status Curves (Available GWh)

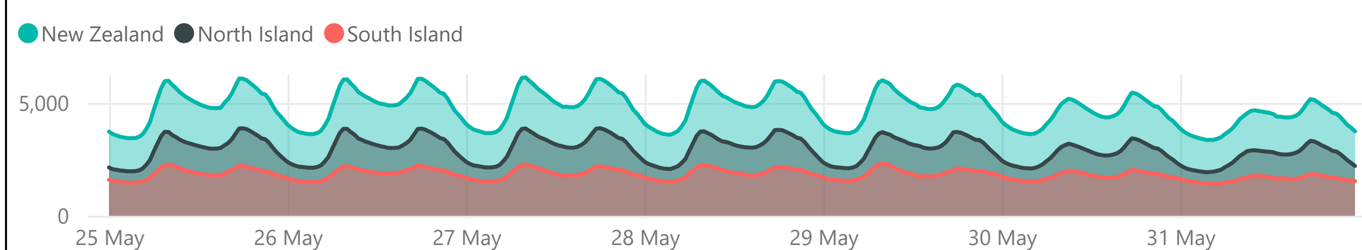


Lowest Residual Points - MW

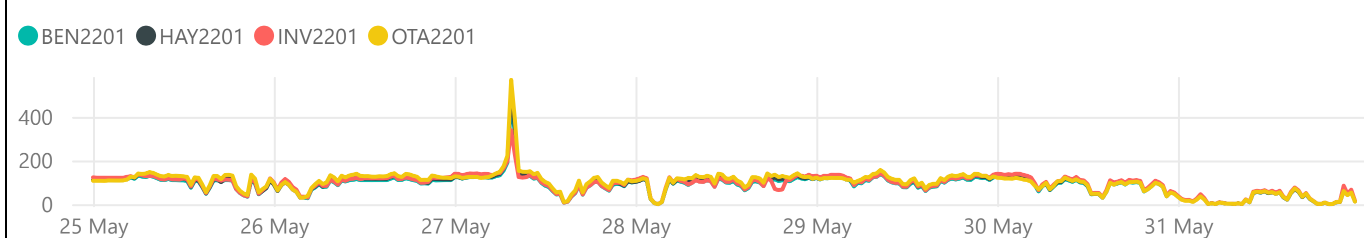


NZGB Look-Ahead (excluding next 7 days)

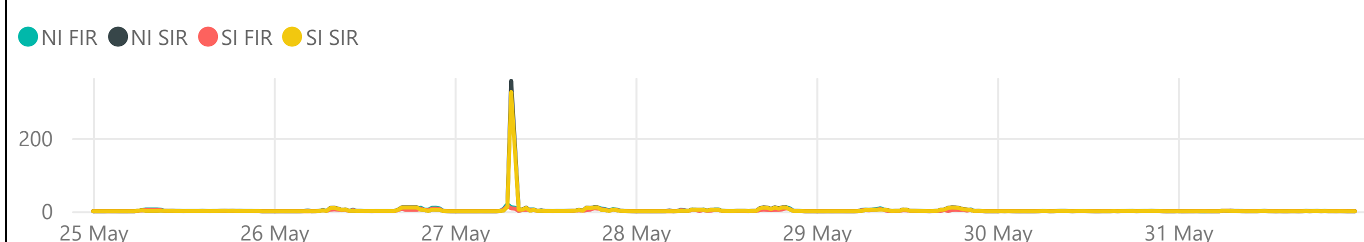
National Demand by Trading period - MW



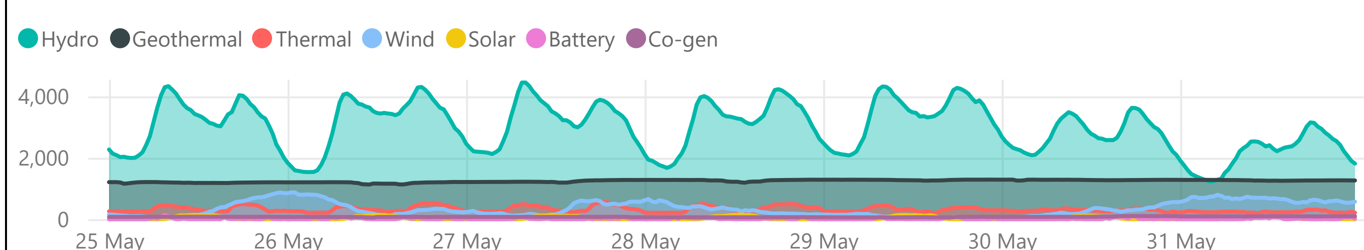
Energy Prices - $/MWh



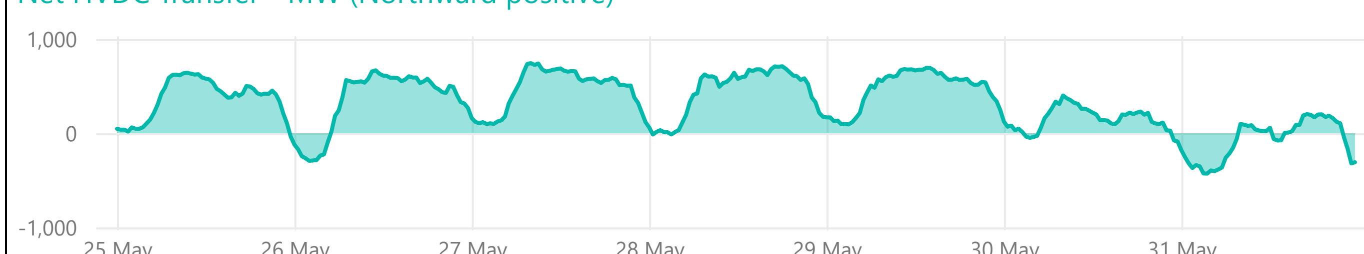
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW (Northward positive)



Weekly Insight - Winter 2026 preparedness: Navigating operational risks in real-time

Following our look at forward planning, we now examine how the System Operator manages capacity risks within a week of real-time. As timeframes compress, reliance shifts from NZGB to actual market schedules.

Market Schedules

From seven days out, the Week-Ahead Dispatch Schedule (WDS) provides the first operational view of unit commitments and expected wind output. This extended horizon gives the industry early visibility to shift planned outages or prepare slow-start thermal units before conditions tighten.

At 36 hours ahead of real-time, this transitions to the Non-Response Schedule (NRS) Long, which runs every two hours, refining intermittent generation and demand forecasts as weather models gain accuracy. As the operating window narrows, the NRS Short solves every 30 minutes covering 4 hours ahead. This frequency provides a highly granular view so participants can dynamically adjust their offers and avoid potential shortfalls. There is a Price-Responsive Schedule (PRS) counterpart to these schedules as well, which additionally incorporates price component of the active purchaser bids. Running in parallel, the PRSL and PRSS provide indicative pricing to signal market conditions, allowing demand-side participants to voluntarily reduce load in response to high prices before physical scarcity occurs.

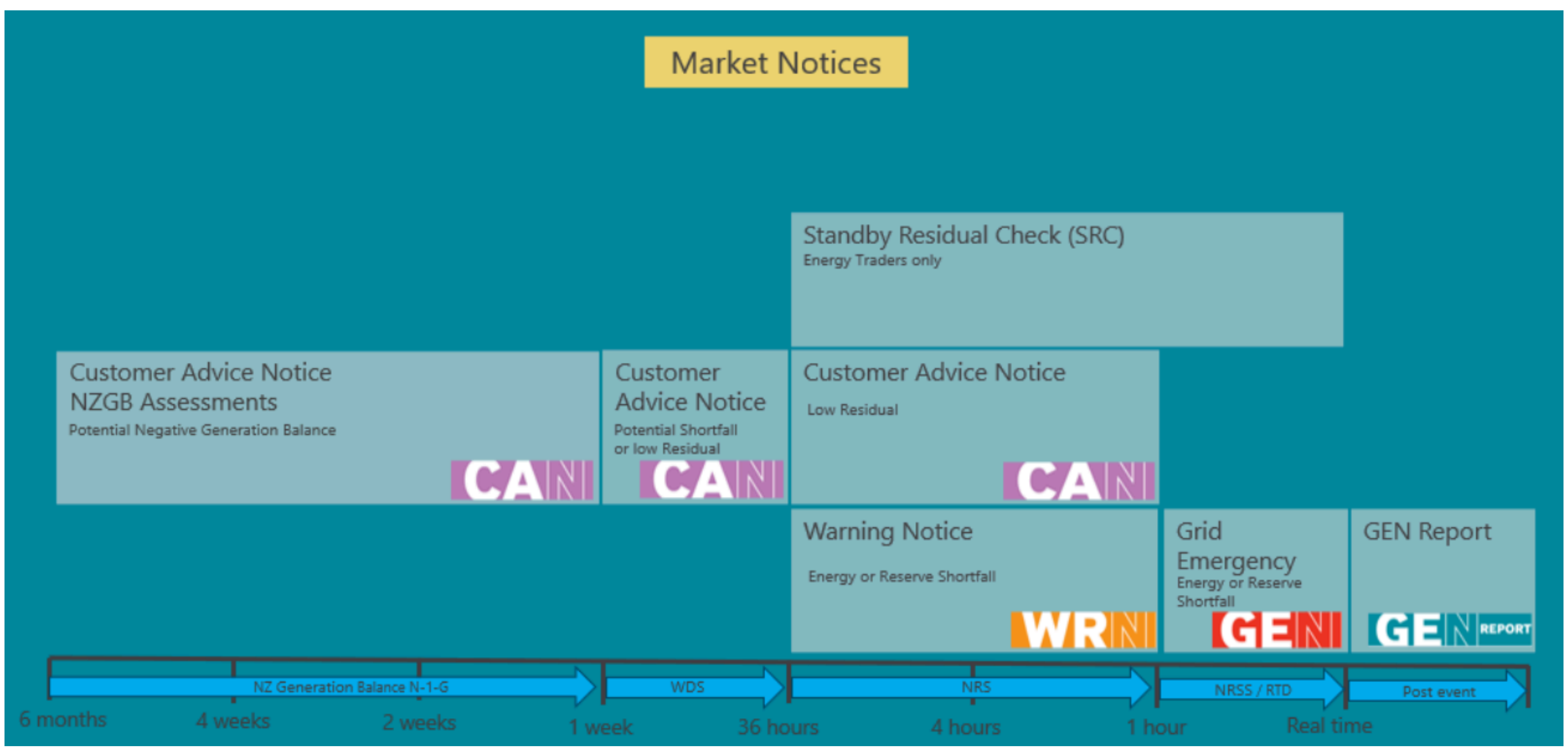
At one hour ahead of real-time for grid-connected generators, or 30 minutes for embedded and dispatch notification participants, gate closure locks in participant offers. This restriction fixes the generation stack, preventing late offer changes under normal conditions to ensure the System Operator can securely dispatch the physical grid. Intermittent Generation is the exception, utilising persistence offers that update in real-time. Finally, the Real-Time Dispatch (RTD) schedule drives actual system operations. Solving every five minutes, the RTD immediately dispatches physical assets to match exact real-time load and sets the final market spot prices.

Throughout this sequence, the System Operator continuously evaluates these schedules to calculate residual capacity: the generation remaining after meeting demand, losses, reserves, and frequency keeping requirements. While sufficient capacity exists in aggregate, robustness depends entirely on operational delivery. High stored energy does not reduce peak capacity risk if unit availability and outages are binding. Under these conditions, the system relies on active coordination rather than passive adequacy. Residual capacity acts as the primary operational trigger metric, with a key escalation threshold at 200 MW, below which the system is considered tight.

Market Notices

As conditions tighten, the System Operator follows a defined escalation pathway based on residual capacity margins. The figure below shows the timeline of market notices. The first operational trigger is a Customer Advice Notice (CAN), typically issued when residual capacity drops below 200 MW. However, this is not a purely automated trigger; the System Operator applies prudent judgement to assess whether a genuine low residual situation exists. This includes evaluating intermittent generation forecast accuracy, incoming weather, and the makeup of the remaining residual generation (including additional generating capacity in the South Island available to be transferred on the HVDC), specifically noting if it relies heavily on slow-start thermal units. The CAN serves as an early signal, prompting participants to verify their physical availability and ensure offer accuracy.

If the low residual escalated to a shortfall that persists or worsens closer to real-time, a Warning Notice (WRN) is issued between 36 hours and one hour before real-time. This explicitly requests participants to re-offer available generation, shift discretionary load, or commit standby units. To manage the tightening situation ahead of actual scarcity, the System Operator may also dispatch out-of-merit generation. Finally, if the system reaches imminent physical scarcity within one hour of real-time, a Grid Emergency Notice (GEN) is declared. Under a GEN, the System Operator transitions from requesting market responses to actively instructing the participants, gaining the authority to mandate load shedding to securely balance the grid. In practice, mandated demand management typically starts by working with local lines companies to switch off controllable load, such as hot water heaters. In extreme circumstances, the System Operator manages instructed load-shedding (power cuts) as a last resort. The System Operator is currently working with industry to co-design an emergency reserve ancillary scheme (ERAS) to establish an additional demand response capability as a 'penultimate resort' ahead of instructed load-shedding. The ERAS is expected to be operational ahead of Winter 2027.



Participant response

System outcomes during stress periods depend not only on the physical capacity available, but on the timeliness and effectiveness of participant responses to system signals. Risk is therefore conditional rather than deterministic. While peak demand drives these events, the increasing variability of intermittent generation and planned outages play a major role in shaping actual capacity outcomes.

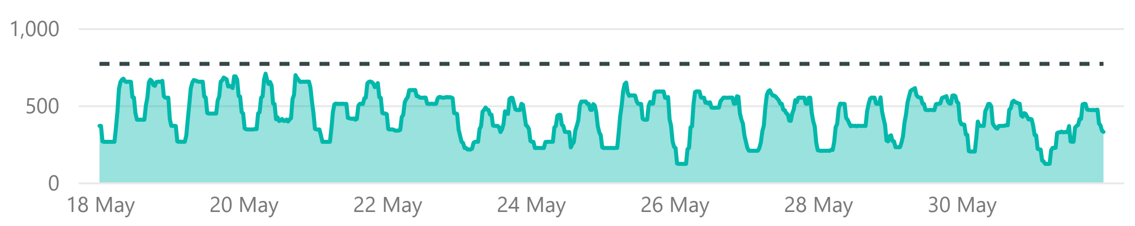
To maintain balance, system management relies on proactive signalling and progressive escalation. This underscores the critical role of market participants. Generation availability, offer accuracy, responsiveness to notices, and readiness to manage load are the primary determinants of system performance.

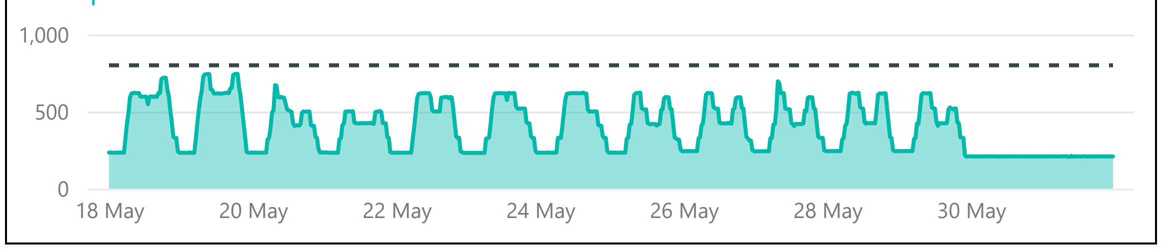
Winter 2026 outlook

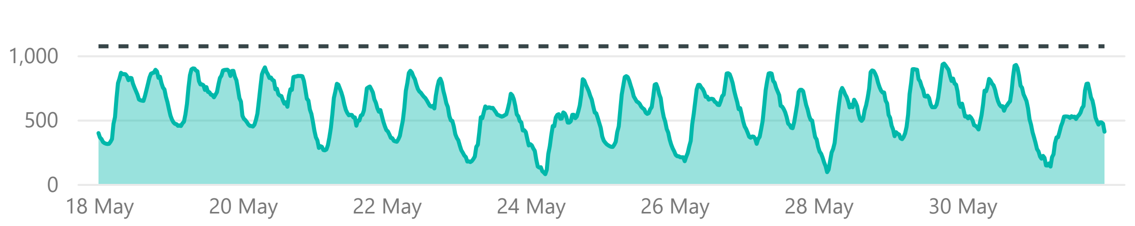
Overall, winter 2026 is expected to be manageable under normal conditions, but tight peak periods remain a credible risk. The key risk is not simply the availability of capacity, but the ability of the system to operationally deliver that capacity under stress conditions. Navigating these mid-winter peaks requires a market that responds efficiently to operational signals ensuring slow-start thermal assets are committed in advance, outage management is dynamic, and demand response is available, providing security when tight situations emerge.

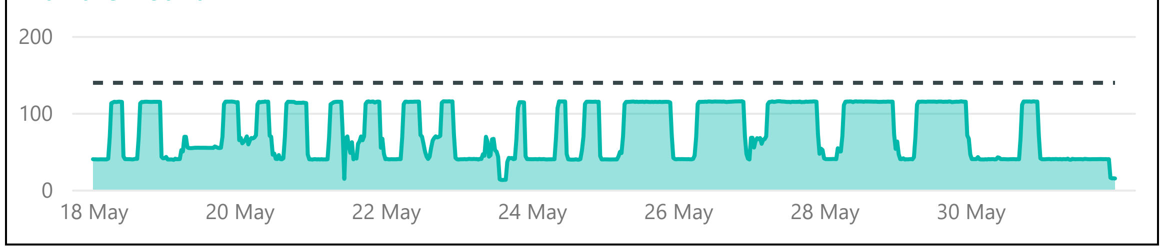
Generation Breakdown - Last Two Weeks

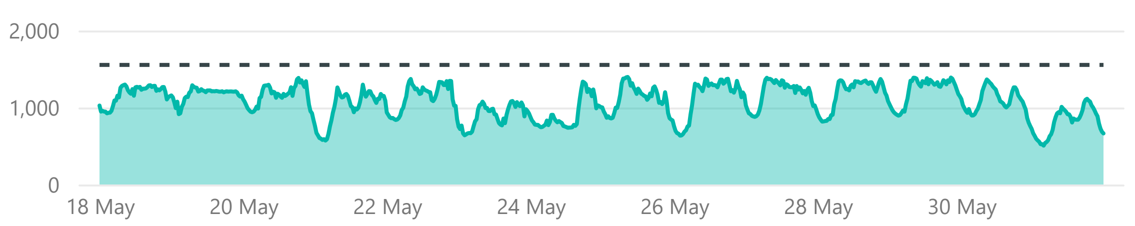
Measured in MW and displayed at trading period level for last 14 days

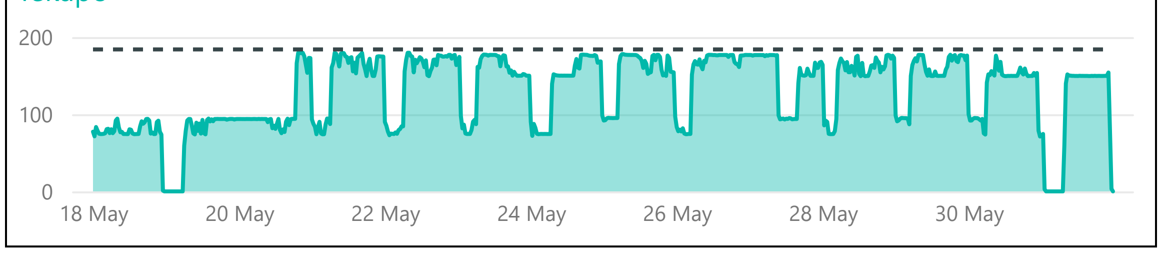
Clutha


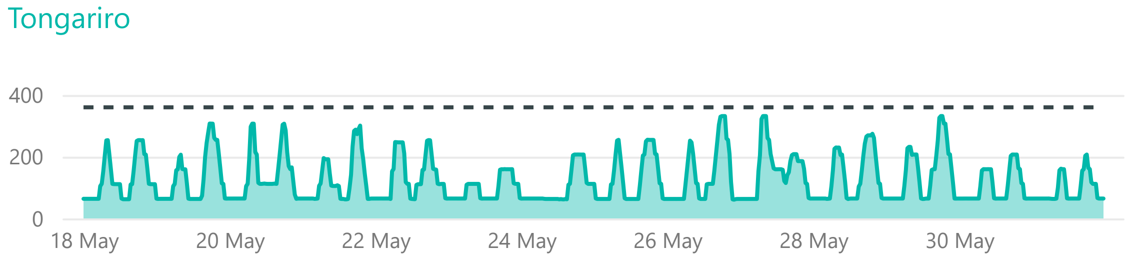
Manapouri


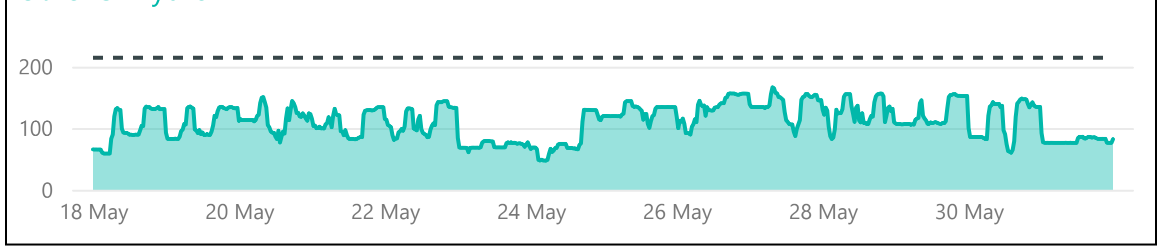
Waikato


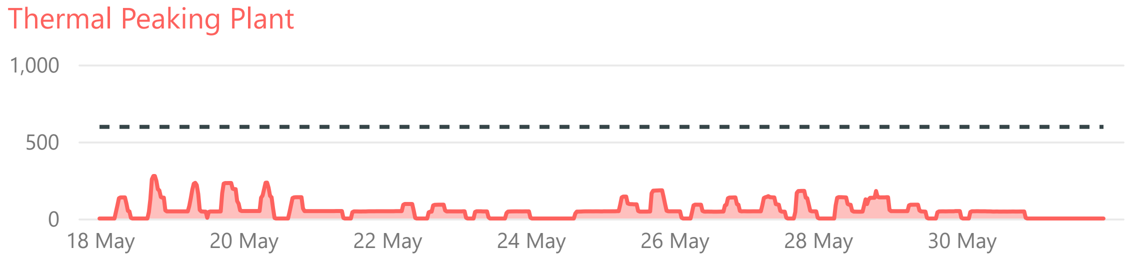
Waikaremoana


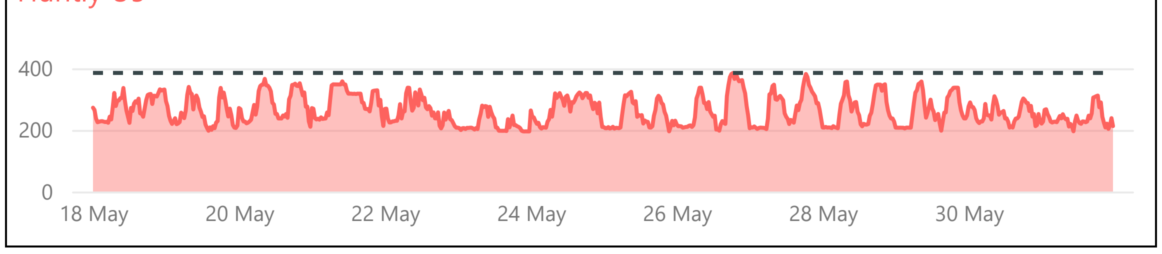
Waitaki


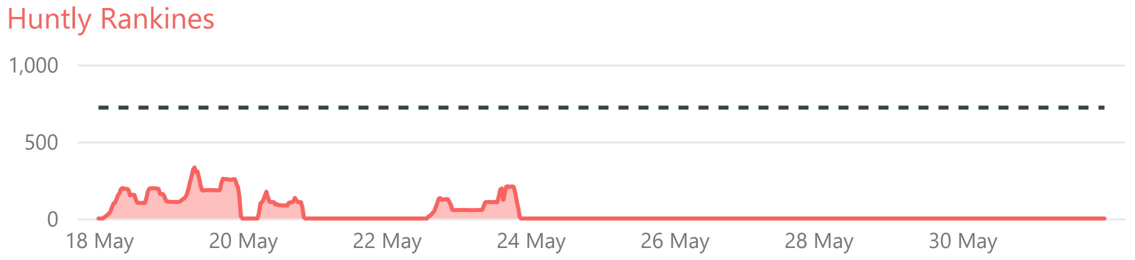
Tekapo


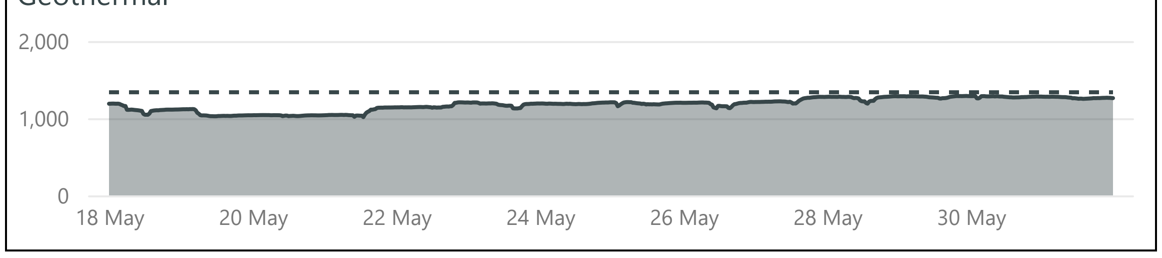
Tongariro


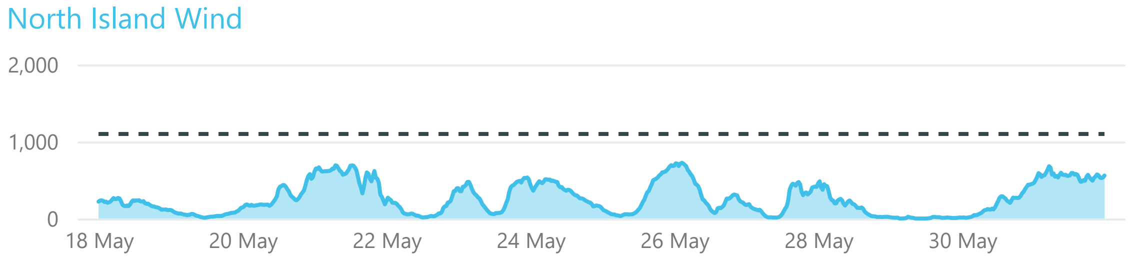
Other SI Hydro


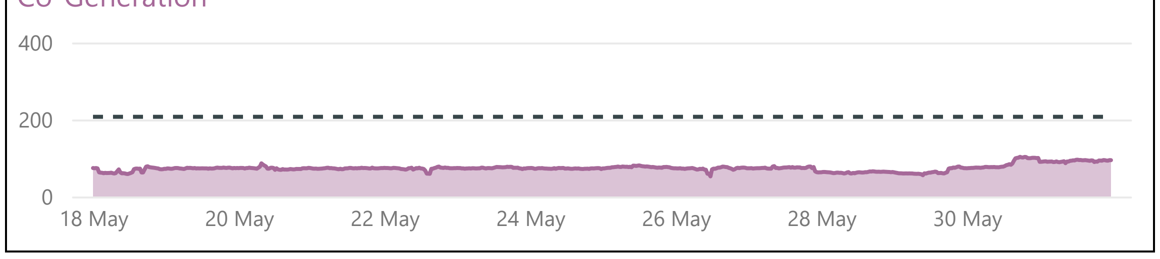
Thermal Peaking Plant


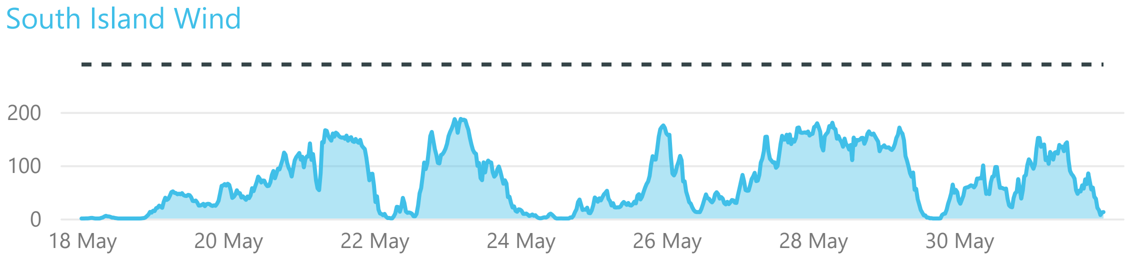
Huntly U5


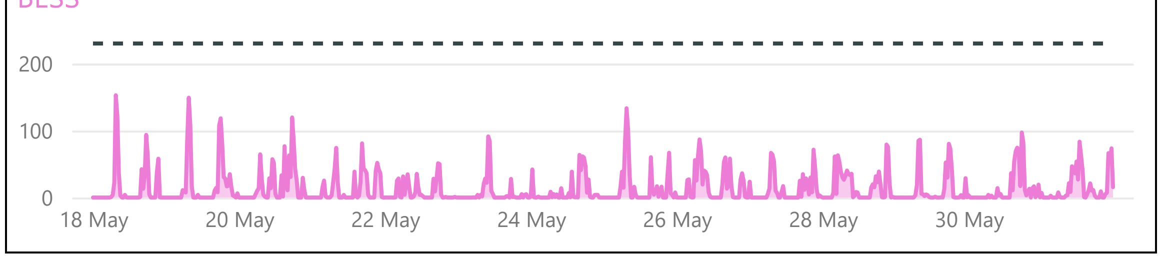
Huntly Rankines


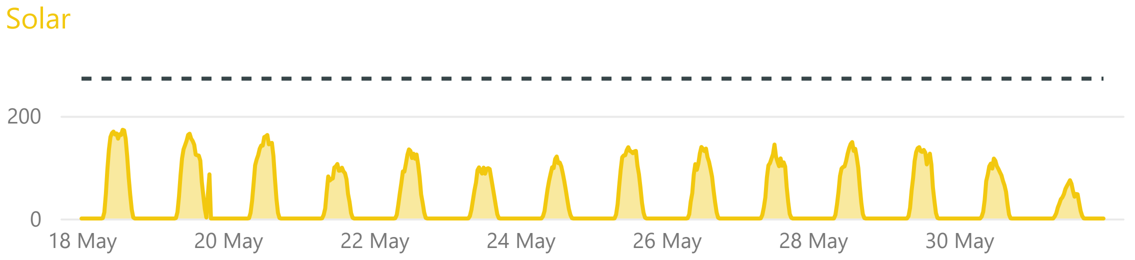
Geothermal


North Island Wind


Co-Generation


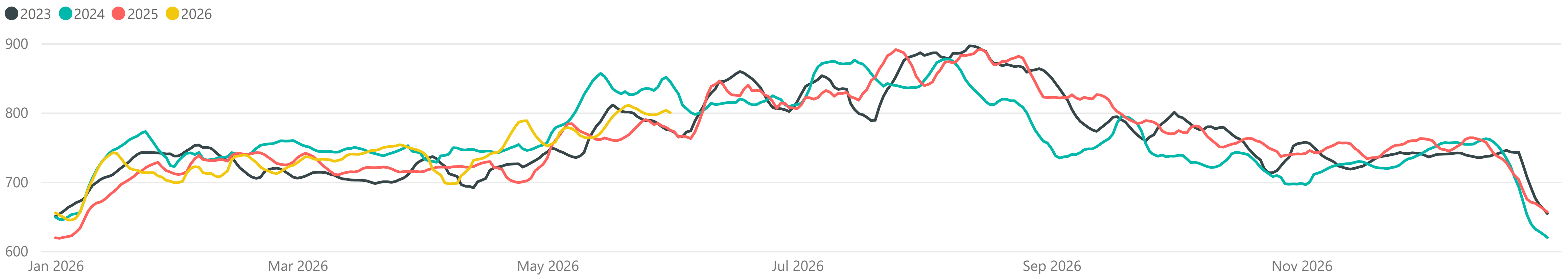
South Island Wind


BESS


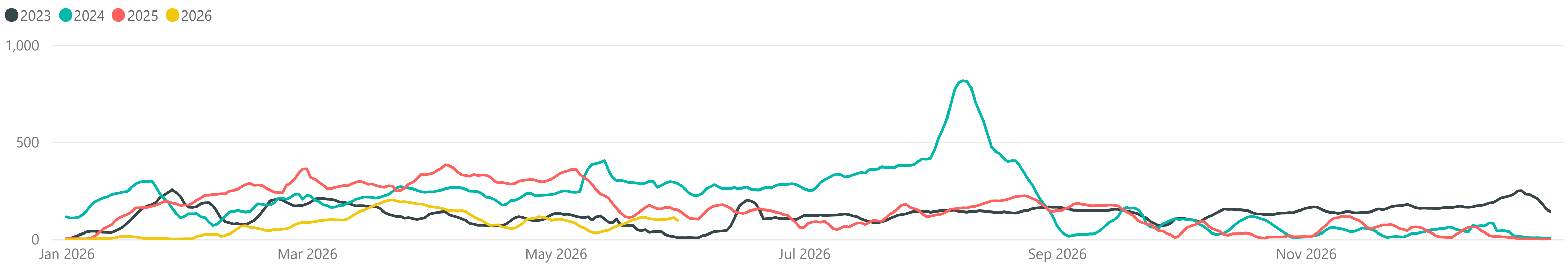
Solar


Weekly Profiles

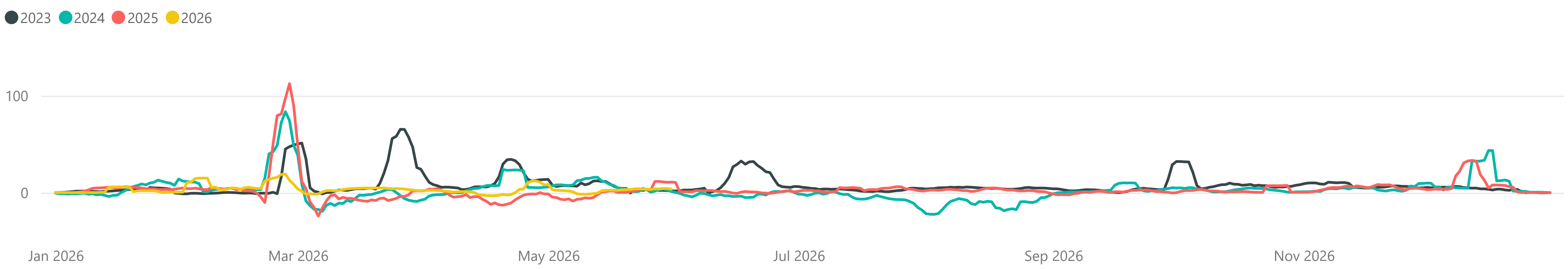
National Weekly Demand - GWh - 7 Day Rolling



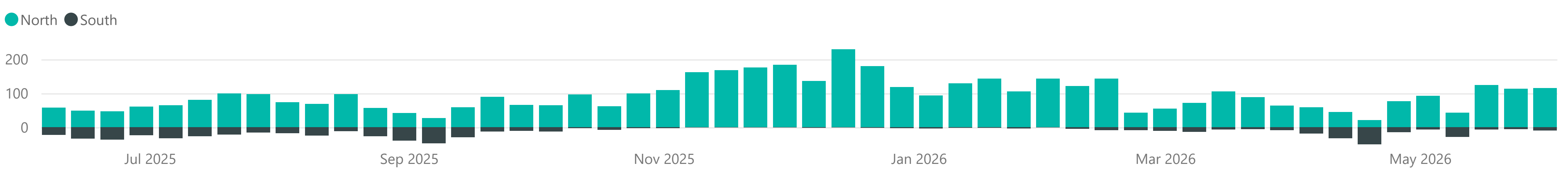
OTA2201 Weekly Rolling Average Spot Price - $/MWh



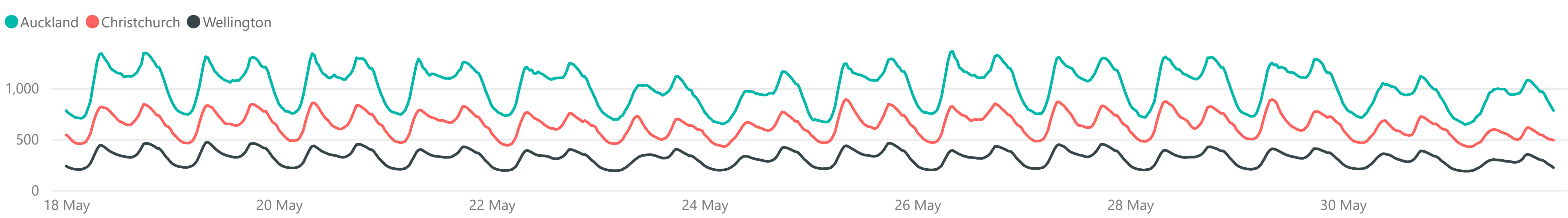
Weekly Rolling Price Separation (HAY2201 - BEN2201) - $/MWh



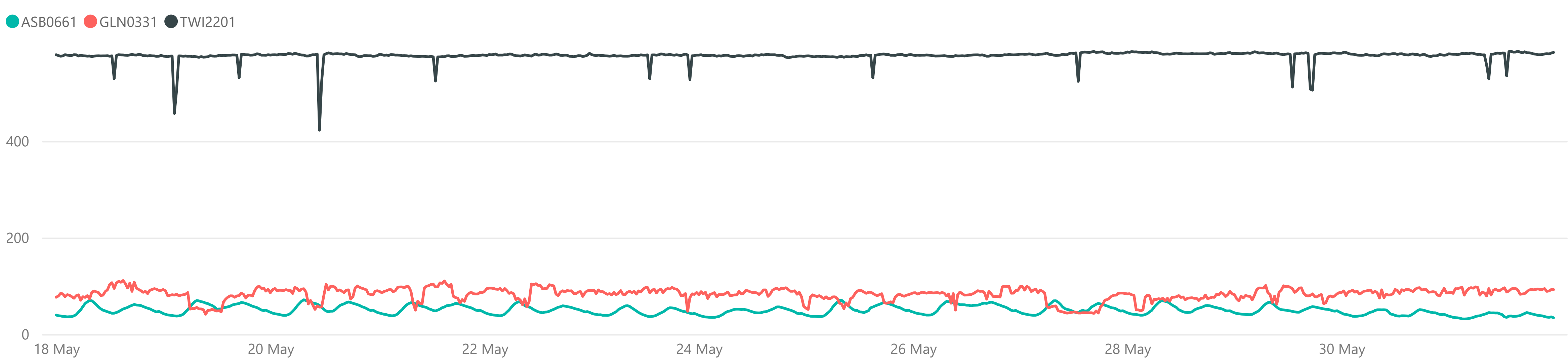
HVDC Transfer - Weekly GWh



Conforming Load Profiles - Last Two Weeks *Measured in MW shown by region*

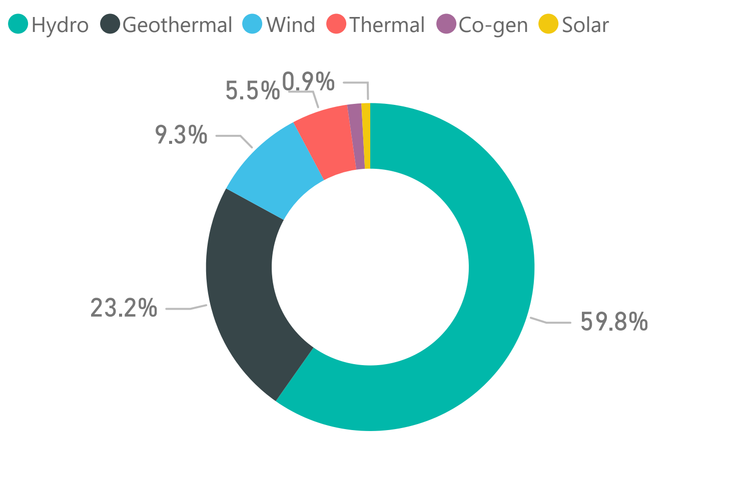


Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*

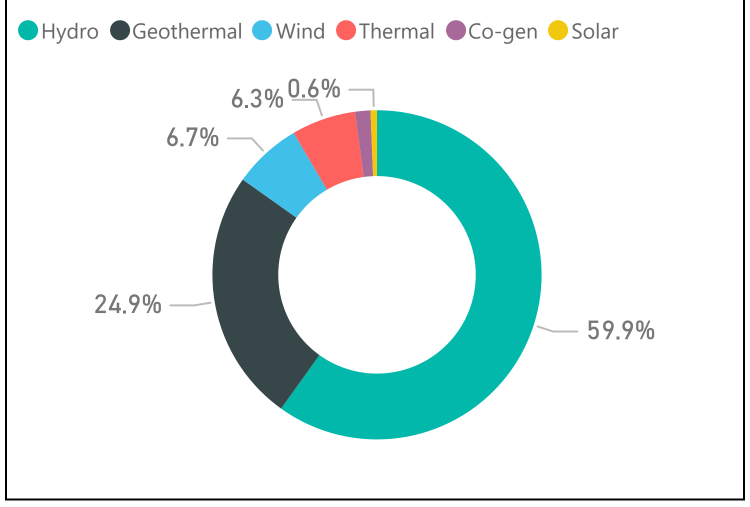


Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



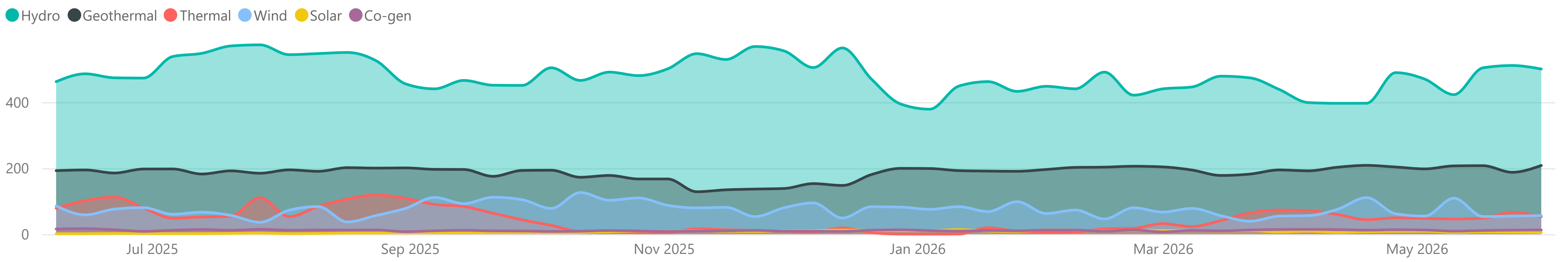
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
92%	44,937	54.0

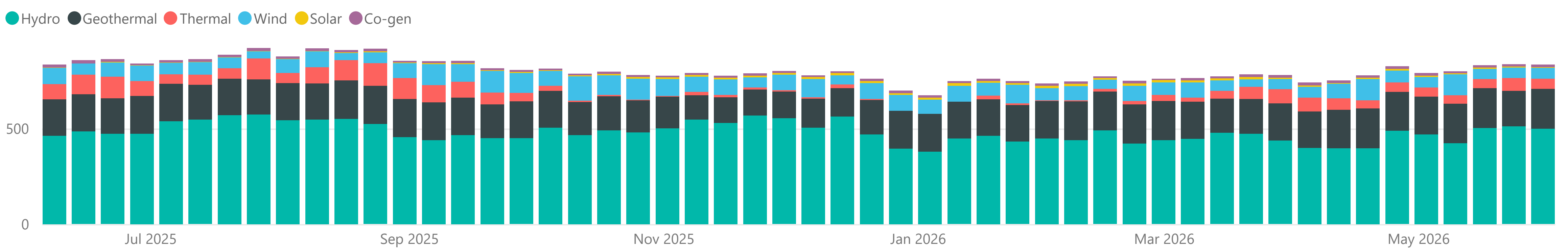
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
93%	41,914	50.8

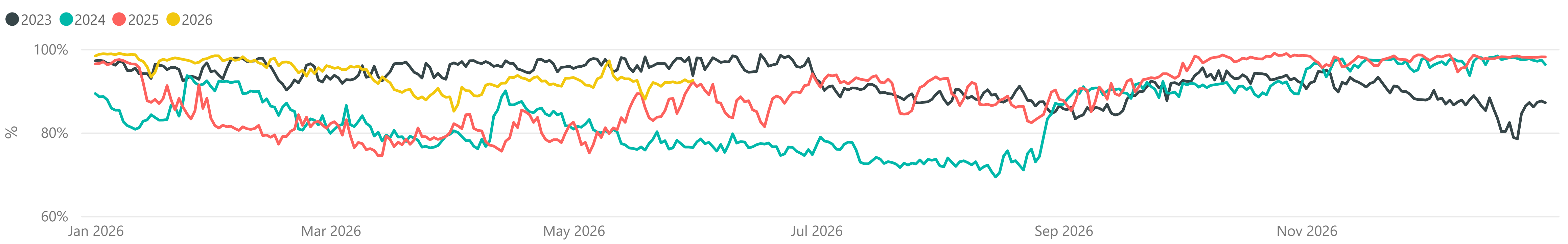
Weekly Generation Mix - GWh



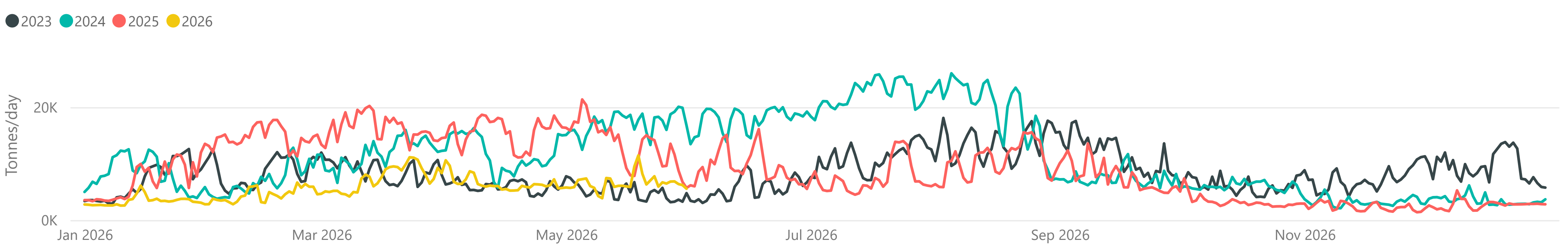
Weekly Generation Mix - GWh



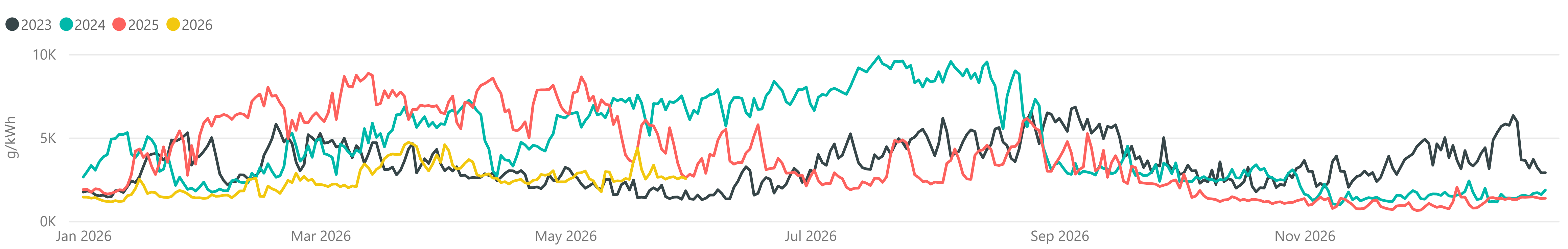
NZ Renewable Percentage



CO2 Tonnes/Day



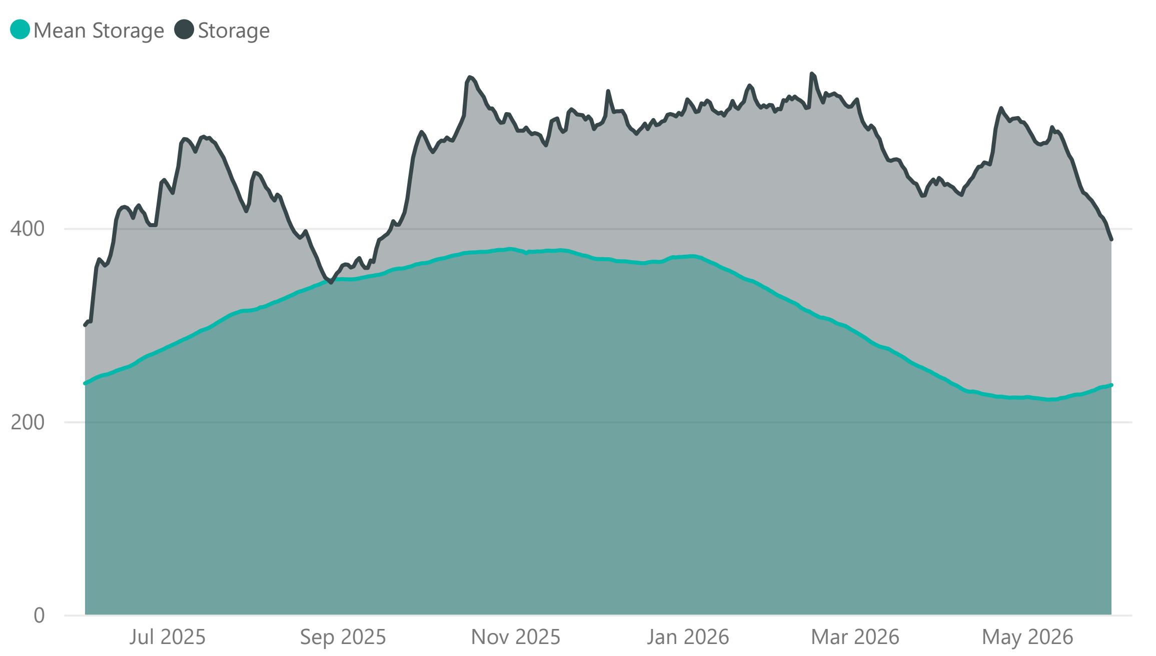
CO2 g/kWh



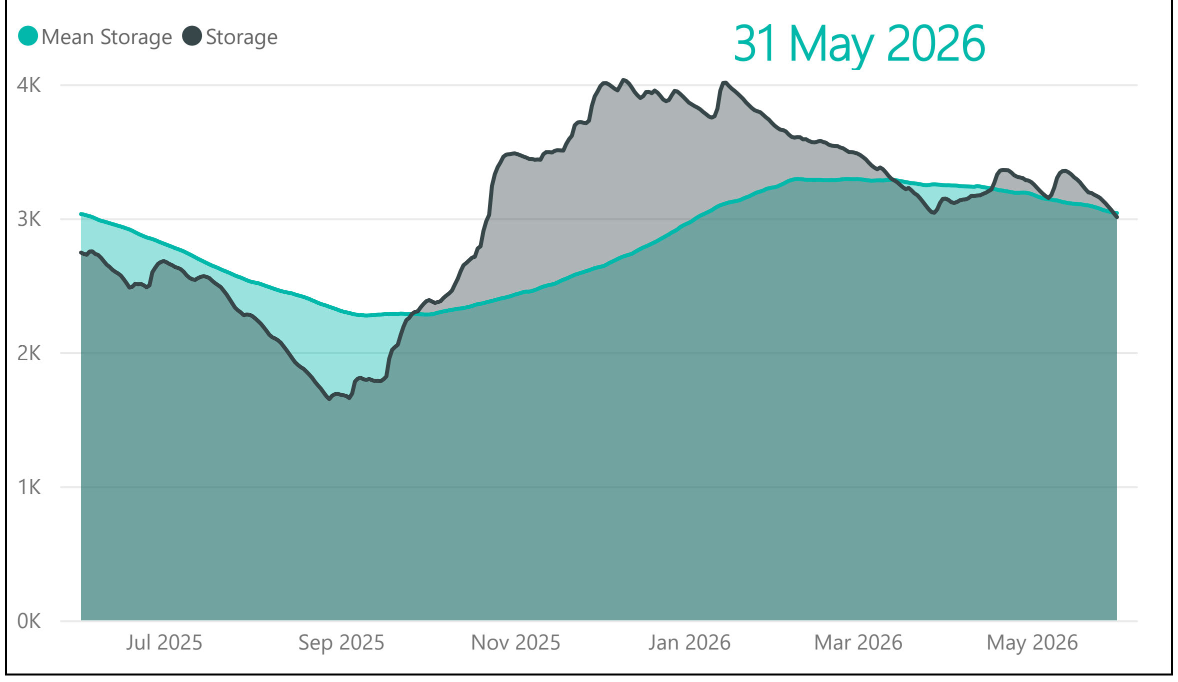
Hydro Storage

Latest Controlled Hydro Storage Against Historic Statistics (Available GWh)

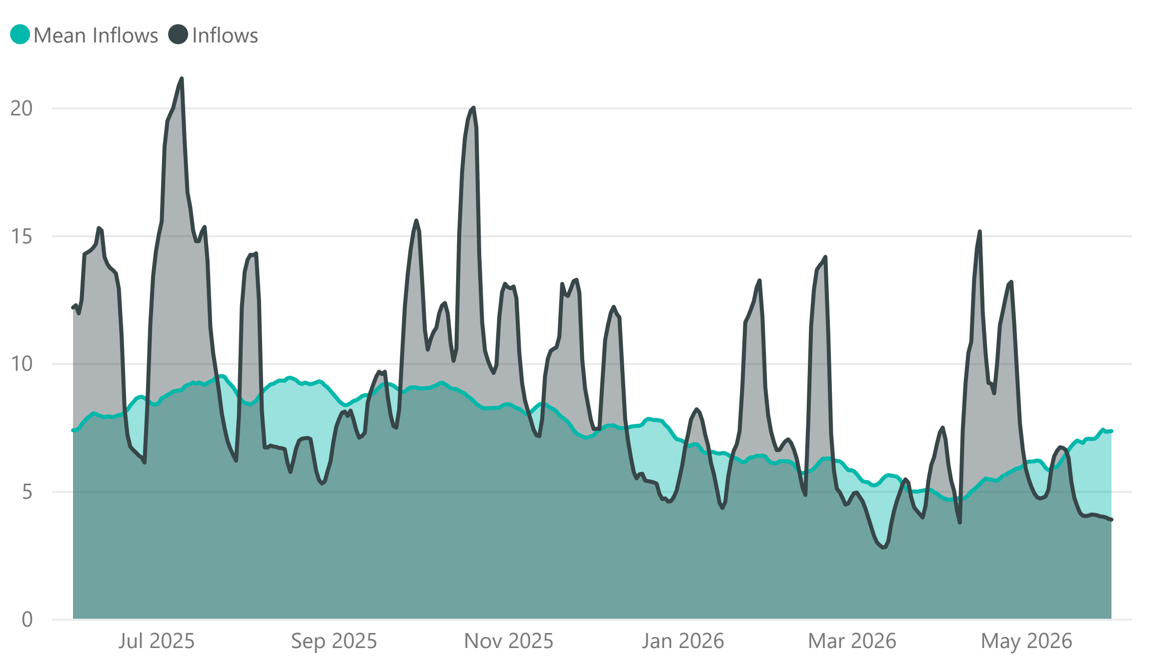
North Island Controlled Hydro Storage (Available GWh)



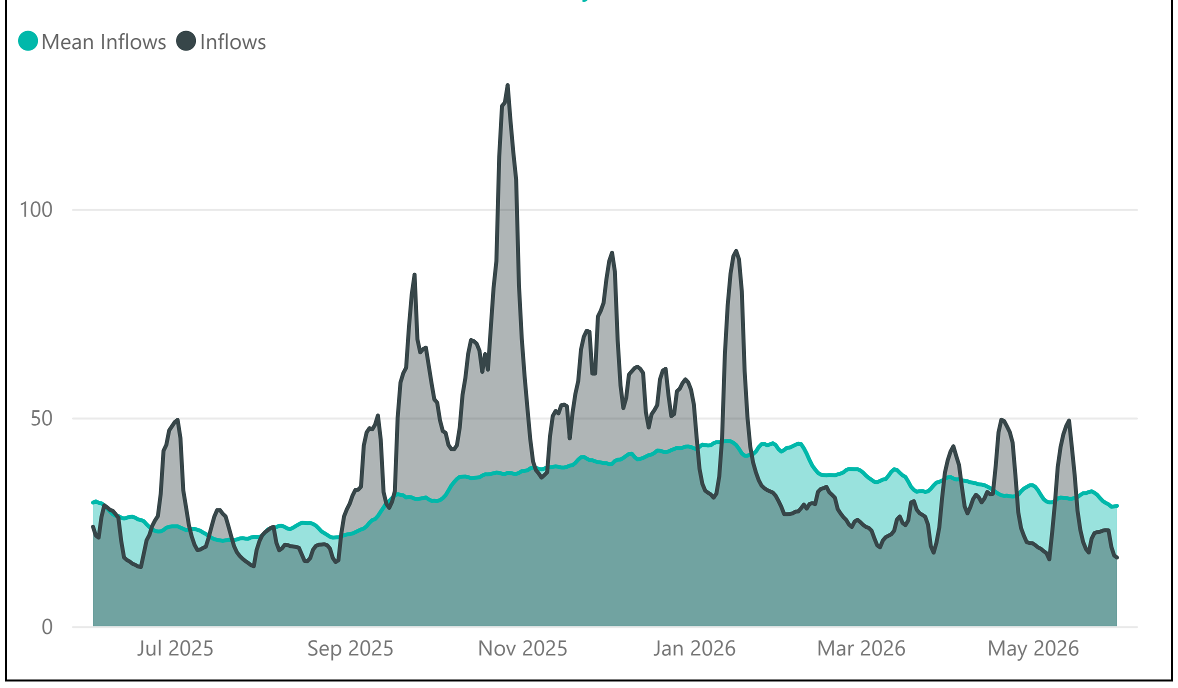
South Island Controlled Hydro Storage (Available GWh)



North Island Mean 7 Day Inflows (Available GWh)



South Island Mean 7 Day Inflows (Available GWh)



For further information on security of supply and Transpower's responsibilities as the System Operator, refer to our webpage here: https://www.transpower.co.nz/system-operator/security-supply

For any inquiries related to security of supply contact market.operations@transpower.co.nz

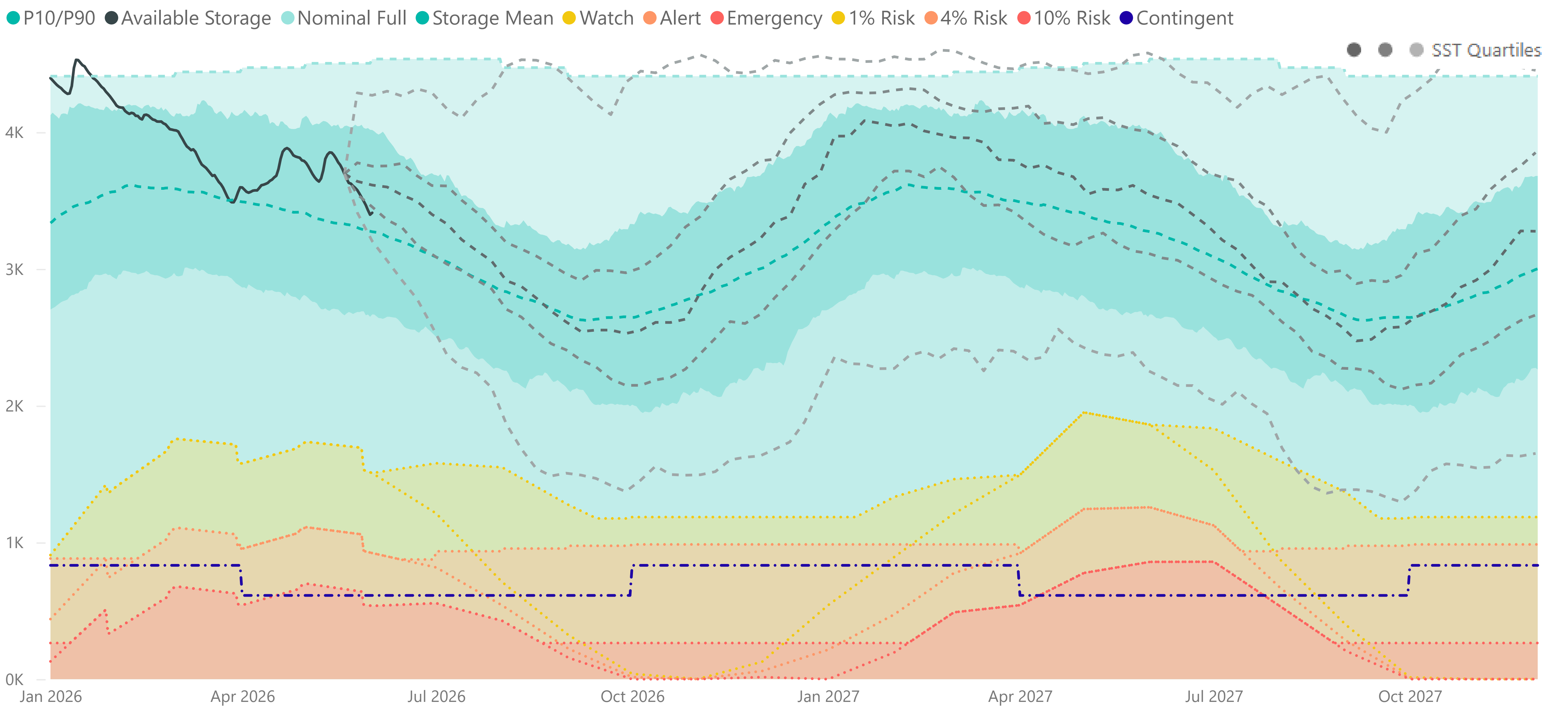
Hydro data used in this report is sourced from *NZX Hydro*.

Electricity risk curves have been developed for the purposes of reflecting the risk of extended energy shortages in a straightforward way, using a standardised set of assumptions.

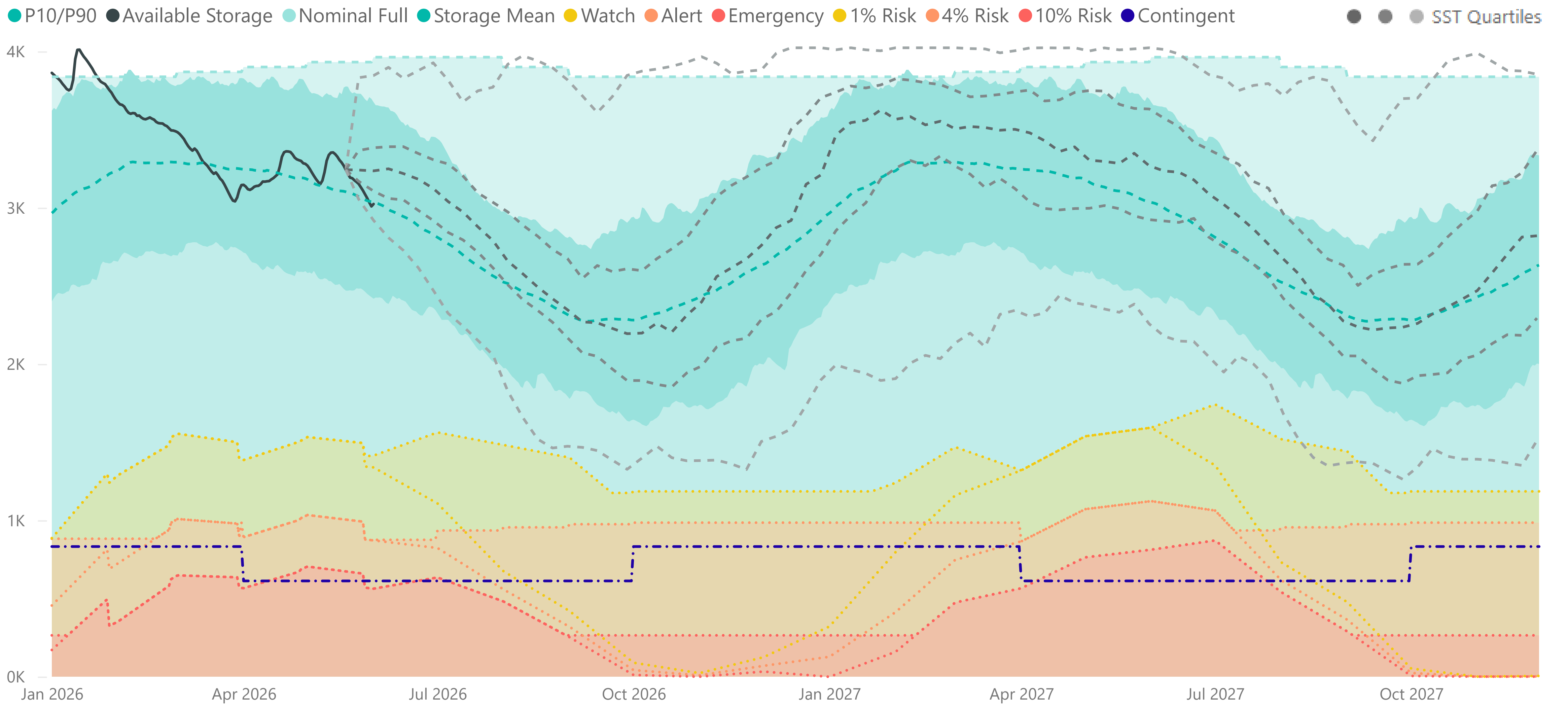
Further information on the methodology of modelling electricity risk curves may be found here: https://www.transpower.co.nz/system-operator/security-supply/hydro-risk-curves-explanation

Electricity Risk Curves

New Zealand Electricity Risk Status Curves (Available GWh)



South Island Electricity Risk Status Curves (Available GWh)



Electricity Risk Curve Explanation:

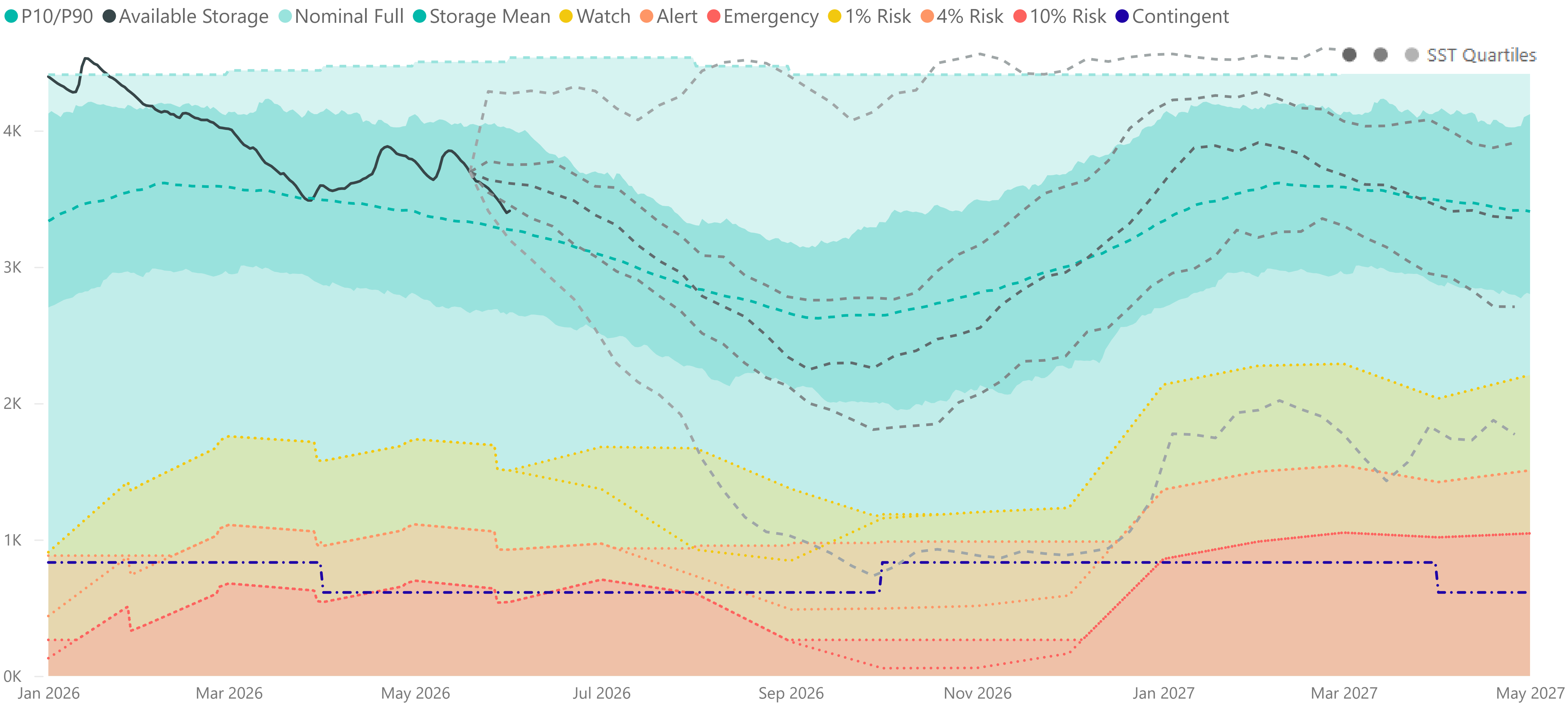
Watch Curve - The maximum of the one percent risk curve or the Alert curve plus the greater of the Watch adder or the worst-case simulated storage drop
Alert Curve - The maximum of the four percent risk curve and the floor and buffer
Emergency Curve - The maximum of the 10 percent risk curve and the floor and buffer
Official Conservation Campaign Start - The Emergency Curve
Official Conservation Campaign Stop - The maximum of the eight percent risk curve and the floor and buffer

Note: The floor is equal to the amount of contingent hydro storage that is linked to the specific electricity risk curve, plus the amount of contingent hydro storage linked to electricity risk curves representing higher levels of risk of future shortage, if any, and the buffer as specified in the SOSFIP.

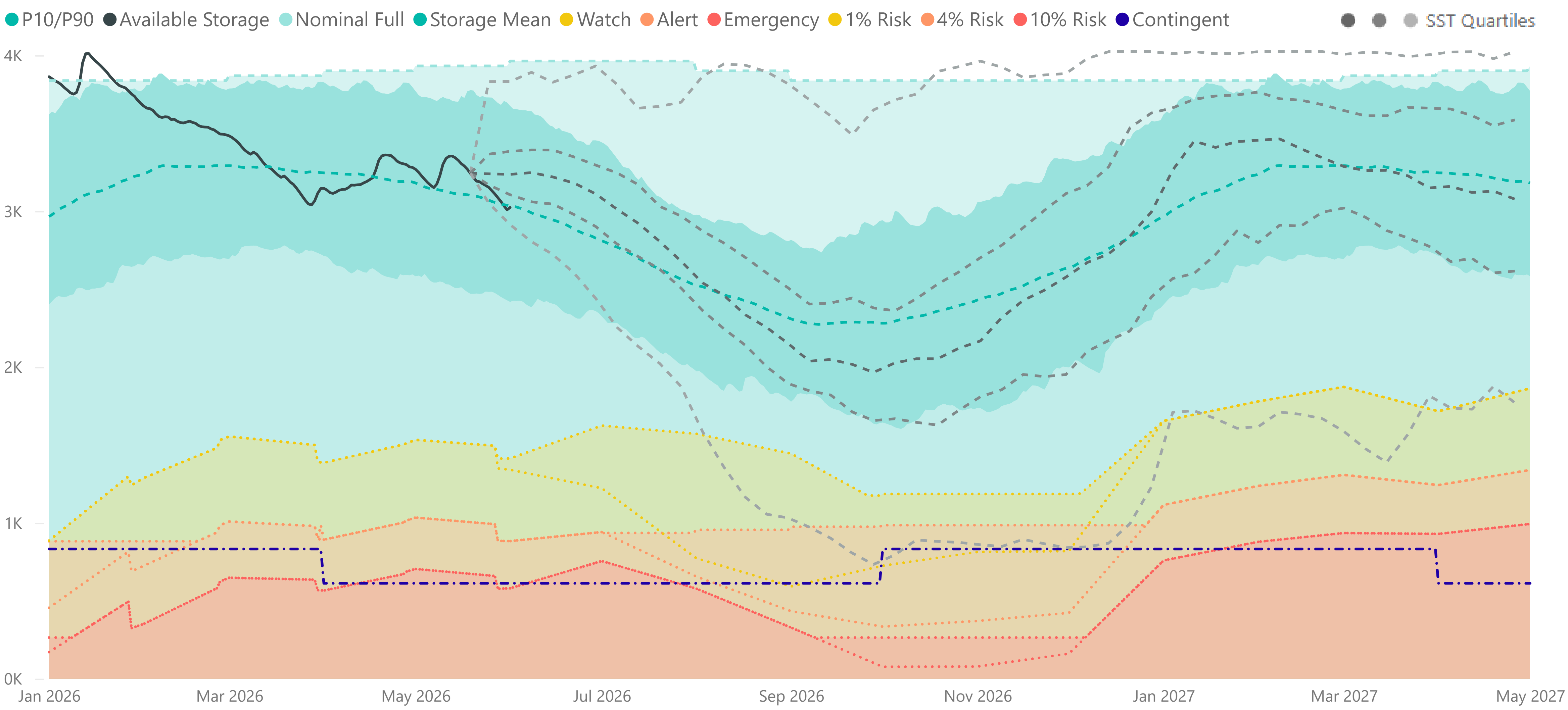
The dashed grey lines represent the minimum, lower quartile, median, upper quartile and the maximum range of the simulated storage trajectories (SSTs). These will be updated with each Electricity Risk Curve update (monthly).

Electricity Risk Curves - Contracted Fuel Case

Contracted Fuel Case - New Zealand Electricity Risk Status Curves (Available GWh)



Contracted Fuel Case - South Island Electricity Risk Status Curves (Available GWh)



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