Market Operations Weekly Report - Week Ended 3 August 2025

Overview

New Zealand hydro storage remains slightly below the seasonal average at 94% of mean for this time of year. Demand last week was significantly lower than the week prior with a change from colder than average to warmer than average weather.

This week's insight discusses our current consultation on how equally-priced generation offers at the same location are selected for dispatch.

Security of Supply

Energy

New Zealand hydro storage remains slightly below average for this time of year, dropping from 95% of the seasonal average to 94% over the past week. Both hydro inflows and the hydro generation share were above average last week. South Island hydro storage dropped from 90% to 88% while North Island storage increased from 134% to 140%.

Capacity

Capacity margins were relatively healthy last week with residual at all peaks exceeding 500 MW. Compared to the prior week, milder weather meant that peaks were able to be met with more residual despite lower thermal unit commitment (no Rankine units running).

The N-1-G margins in the NZGB forecast are healthy through to late September. 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 dropped significantly to 843 GWh last week from 886 GWh the week prior, with weather changing from colder than average for the time of year to warmer than average. The highest demand peak was 6,381 MW at 6:30pm on Thursday 31 July, which was 634 MW lower than the previous week's highest peak.

Weekly Prices

The average wholesale electricity spot price at Ōtāhuhu last week decreased to $126/MWh from $169/MWh the week prior. Wholesale prices peaked at $287/MWh at Ōtāhuhu at 6:00pm on Tuesday 29 July during the evening peak.

Generation Mix

Hydro generation contributed 62% of the generation mix last week, the same share as the previous week. Wind generation increased from 4% to 8% of the mix. Thermal generation decreased from 12% to 6% with lower demand and higher wind generation. The geothermal share increased from 20% to 22% with some units coming back from outages.

HVDC

HVDC flow last week was predominantly northward with overnight periods of southward flow coinciding with periods of lower North Island demand. In total, 36 GWh was sent north and 8 GWh was sent south.

Evolving market resource co-ordination: Tie-breaker provisions consultation

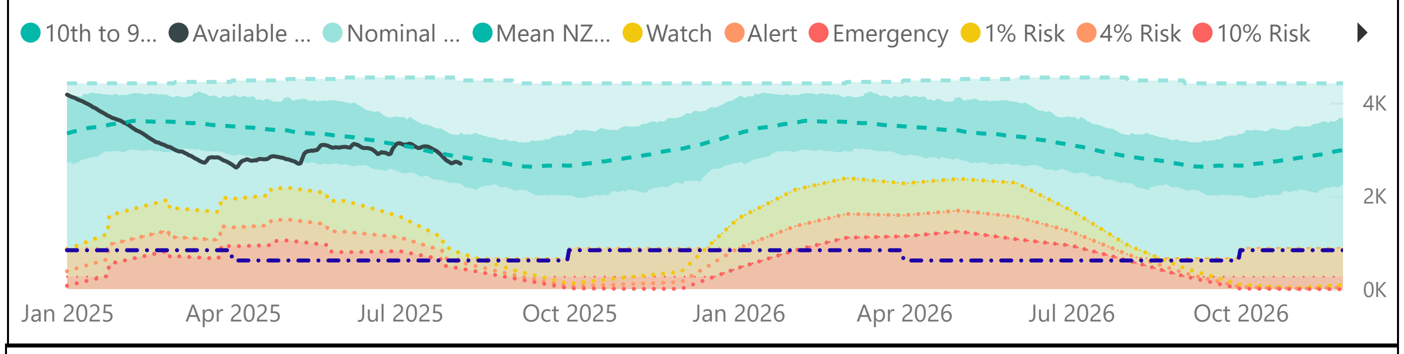
On 24 July, Transpower in its role as System Operator published a consultation asking for feedback on how tie-breaker situations should be resolved for multiple competing generator offers in the wholesale electricity market. See consultation pack here. Submissions are due by 5pm Thursday 14 August, with one week for cross-submissions closing Thursday 21 August.

New Zealand Energy Risk

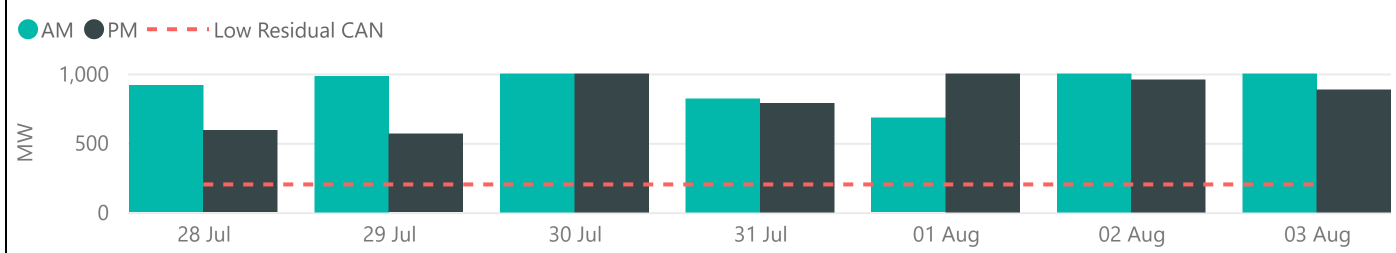
South Island Energy Risk

Normal Watch Alert Emergency

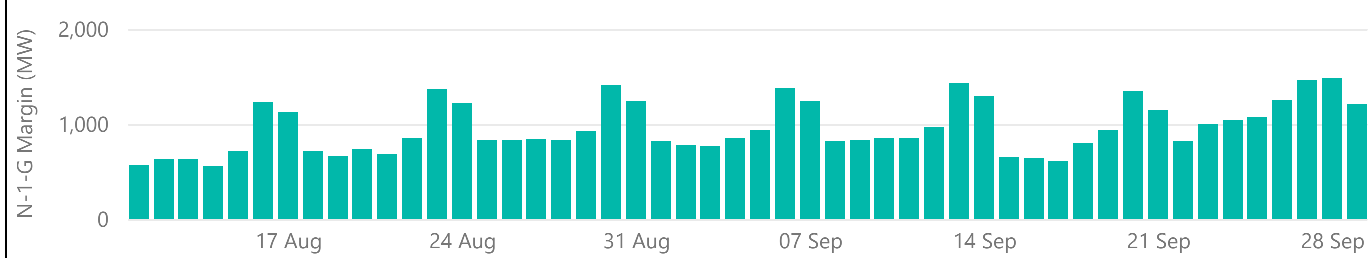
New Zealand Electricity Risk Status Curves (Available GWh)



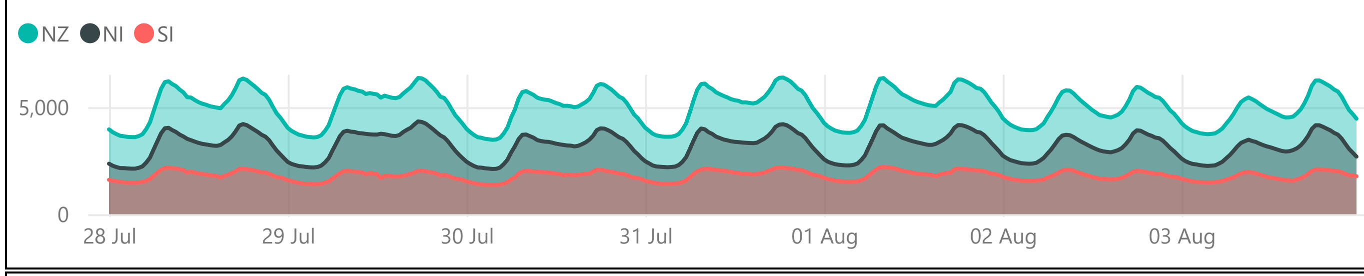
Lowest Residual Points - MW



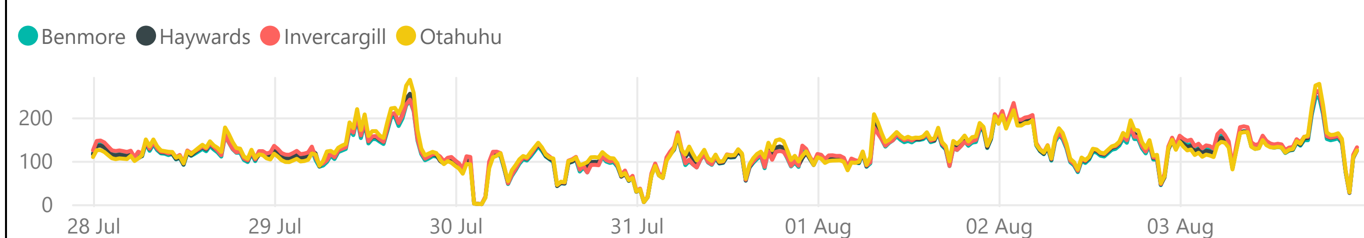
NZGB Look-Ahead (excluding next 7 days)



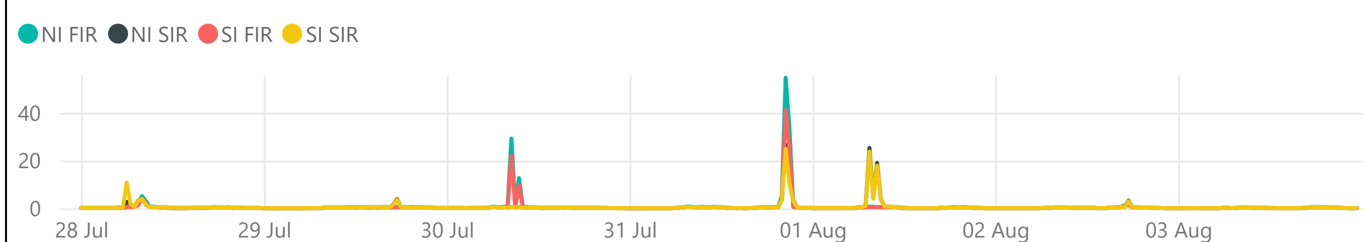
National Demand by Trading period - MW



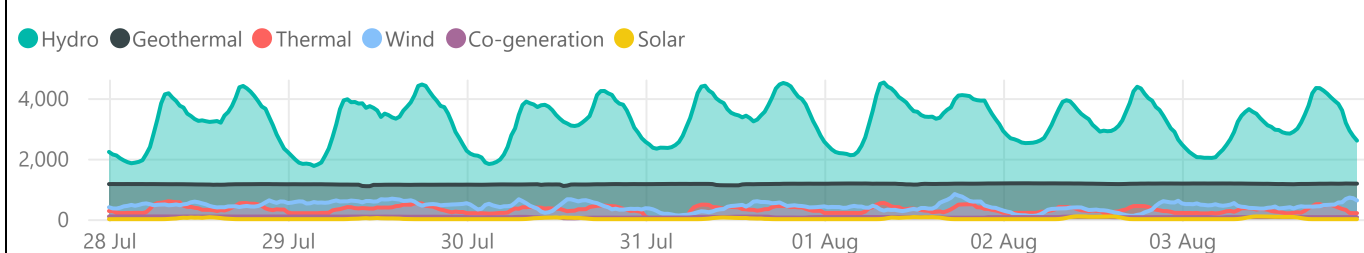
Energy Prices - $/MWh



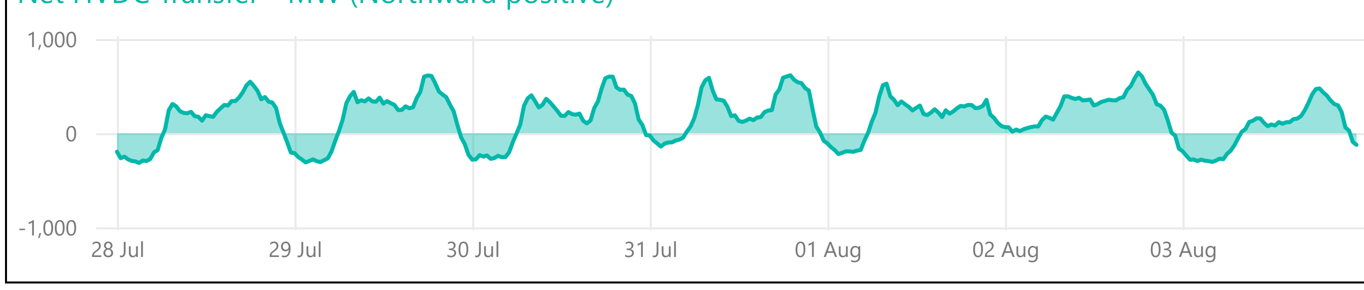
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW (Northward positive)



Weekly Insight - Tie-breaker constraint in Scheduling, Pricing and Dispatch

A tie-breaker situation arises when more equally-priced generation is offered at a single location than can be dispatched due to a network export limit. These situations are becoming increasingly common with increased investment interest in generation with a low short-run marginal cost to generate (solar, wind and geothermal). These generators are typically offered at prices of $0.01/MWh or $0/MWh (negative priced generation offers are not allowed in the New Zealand electricity market). Available very low priced generation at a location may at times exceed local transmission capacity, resulting in a situation where two or more generation offers are tied on price and a transmission constraint means they can't all be fully dispatched.

As a consequence of the increasing relevance of tie-breaker situations, generation owners and investors are increasingly seeking clarity and confidence on how tie-breakers are or will be resolved by the System Operator.

Currently, the resolution of tie-breaker situations is unprescribed and may result in the System Operator applying its discretion, close to or in real-time, to decide which generator(s) to dispatch and for what quantity. This has the potential to result in uncertain, inconsistent and unpredictable dispatch decisions that create operational challenges and undermine investor confidence. As incidences of tie-breaker situations increase in frequency this risk will be exacerbated. Consequently, we are consulting now to provide greater certainty ahead of time.

Our proposed solution

Our proposed solution introduces a tie-breaker energy constraint within the Scheduling, Pricing and Dispatch (SPD) model that allocates dispatch at a given pricing node in proportion to offered quantities. In our view this method strikes the balance between certainty, transparency and simplicity, and limits the need for System Operator discretion to be applied.

Figure 1 below shows one of many possible solutions for a hypothetical forward schedule using the current version of SPD, for two generators offering 150 MW each at the same price in a region with a 200 MW grid export limit. In these circumstances, the amount of generation cleared from each generator is not deterministic and can vary between intervals within the same schedule, and across successive schedules. The share of generation cleared from each generator in a forward schedule does not reflect how much will be cleared in real time. SPD views both solutions (fully dispatching generator 1 and curtailing generator 2, or fully dispatching generator 2 and curtailing generator 1 - or an intermediate split) as equally optimal, so the solver will stop at whichever solution it finds first.

Figure 2 below shows the only possible solution to the same forward schedule using the tiebreaker constraint. Both generators are dispatched in proportion to their offer, so in this case they are dispatched equally. This results in a more stable forward schedule.

Figure 1: one of many possible solutions for a hypothetical forward schedule without the tiebreaker constraint (status quo)

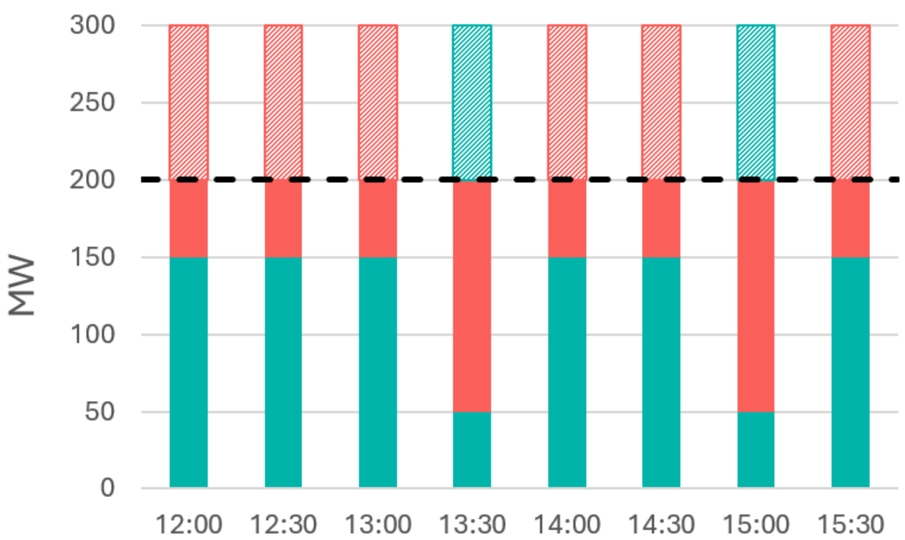
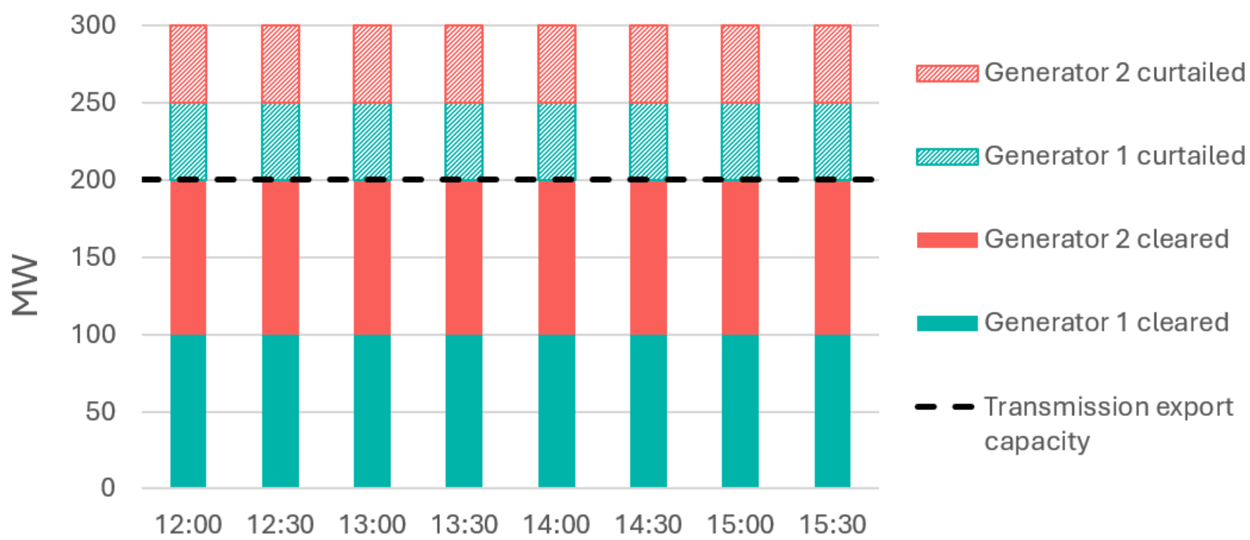


Figure 2: The one possible solution for the same forward schedule with the tiebreaker constraint



Other proposals considered

We considered other proposed methods of mitigating or solving the tie-breaker problem. Further information on these options, and our reasons for choosing our proposed solution over these options, is provided in the consultation document.

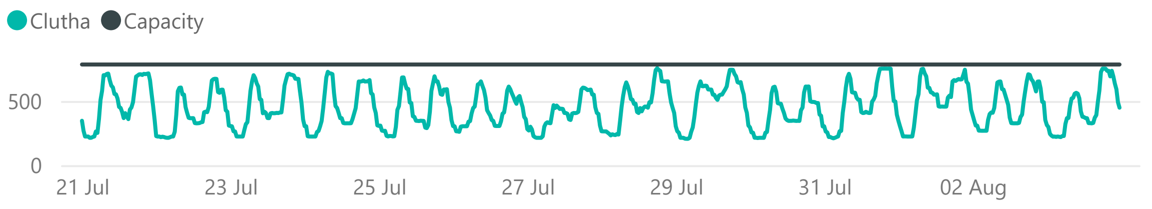
Options considered were:

- Equal MW allocation, regardless of offer quantity
- Prioritising generation by type, e.g. geothermal over intermittent
- Prioritising earlier-submitted offers
- Considering local distribution constraints
- Refinement of the Must-Run Dispatch Auction (MRDA)

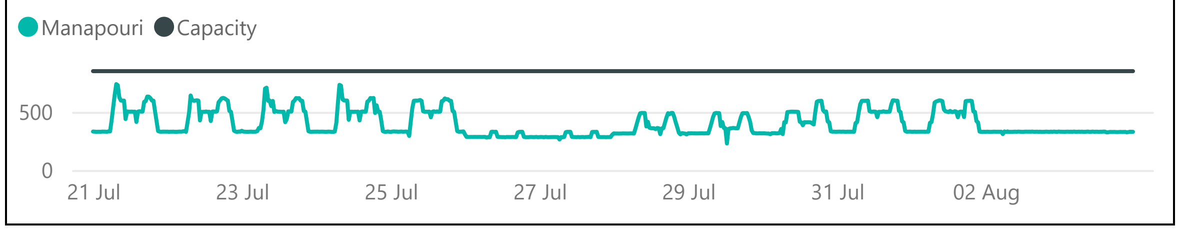
Generation Breakdown - Last Two Weeks

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

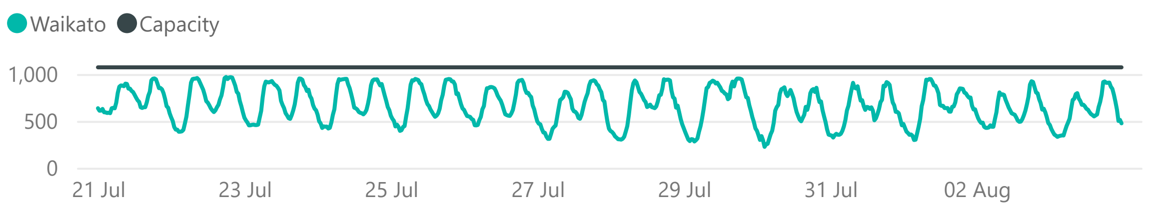
Clutha



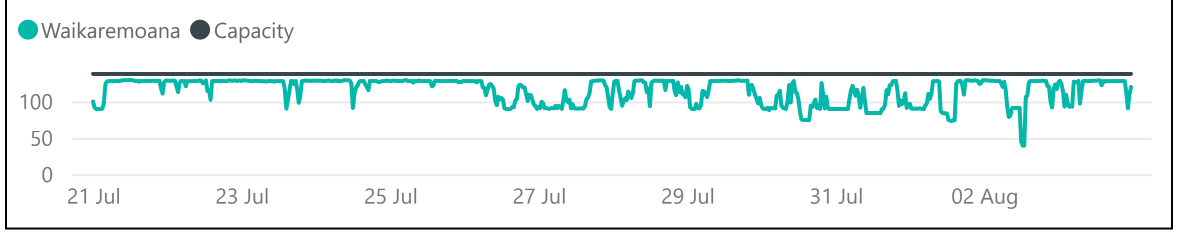
Manapouri



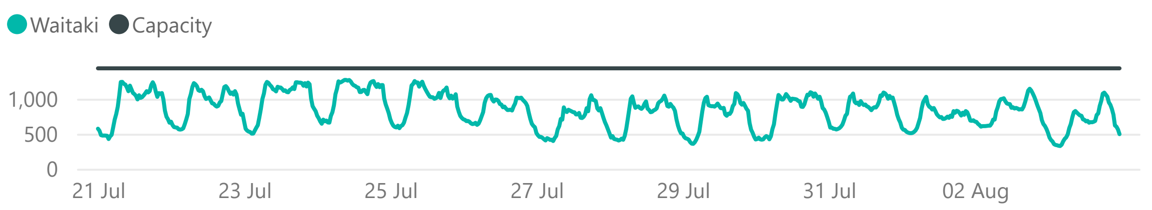
Waikato



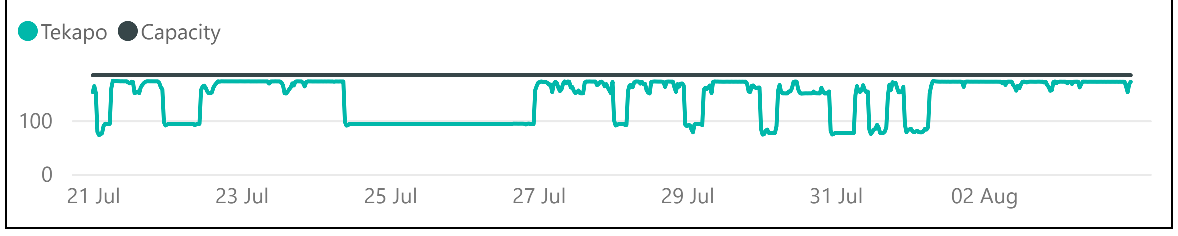
Waikaremoana



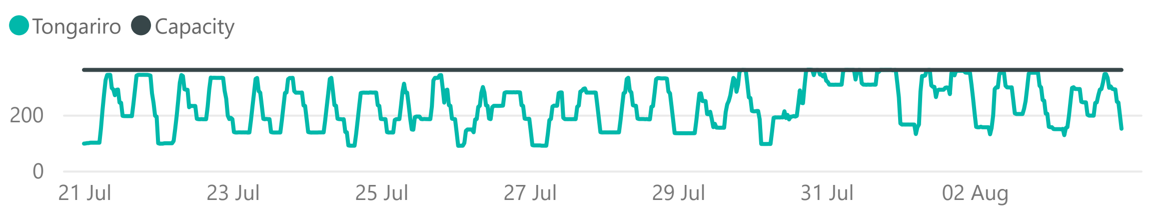
Waitaki



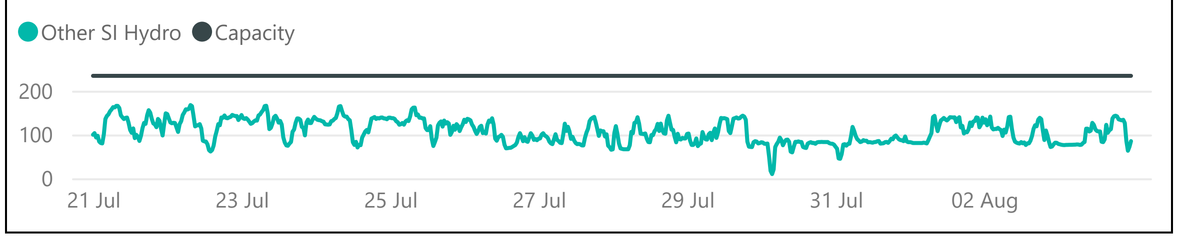
Tekapo



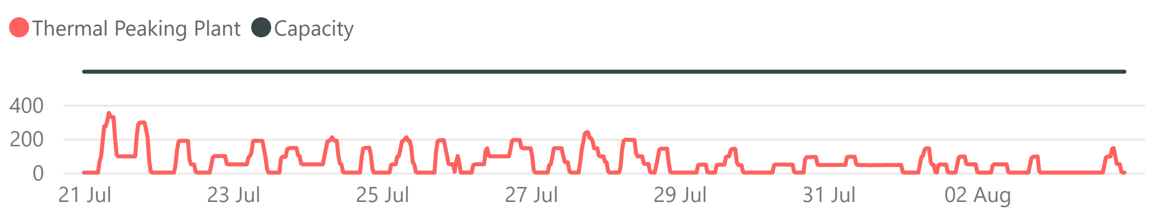
Tongariro



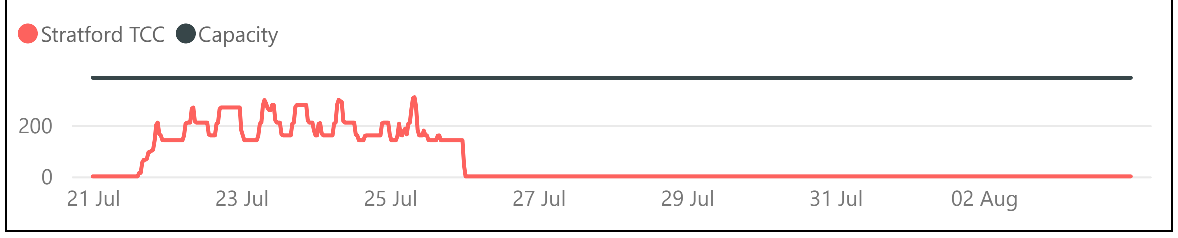
Other SI Hydro



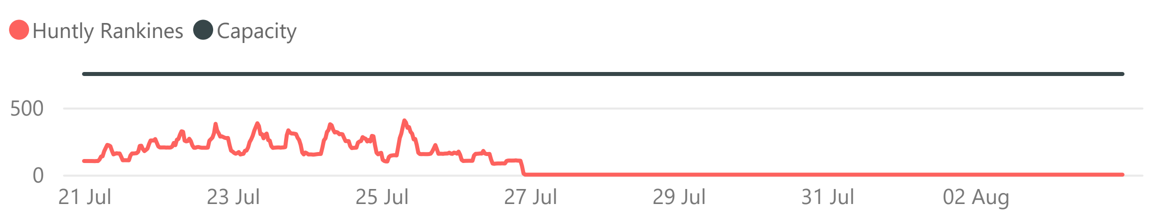
Thermal Peaking Plant



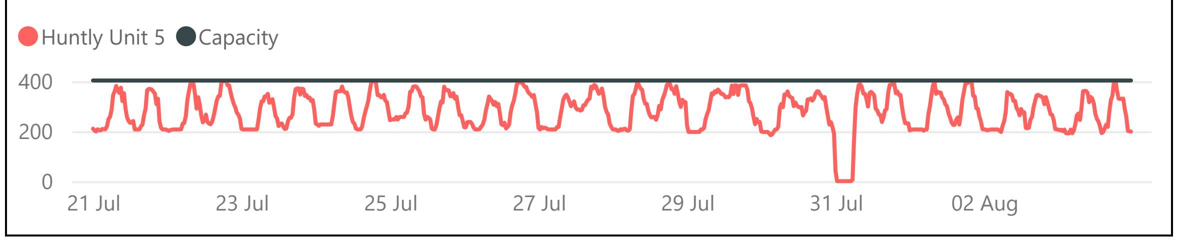
Stratford TCC



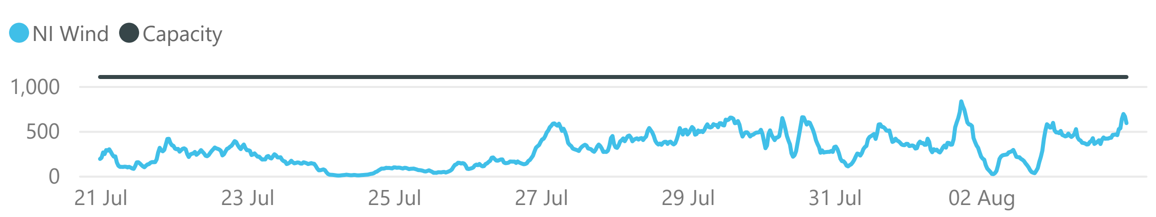
Huntly Rankines



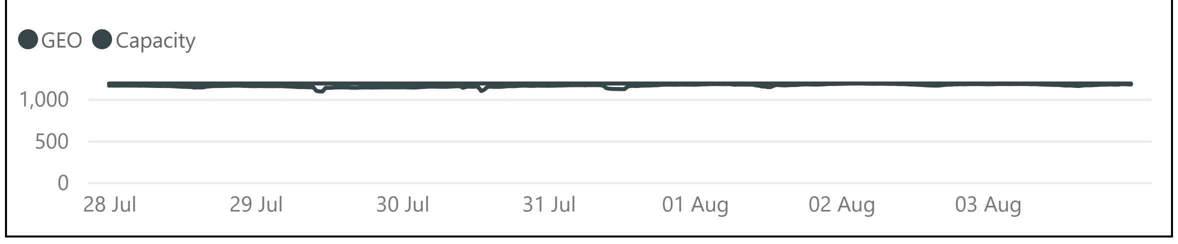
Huntly U5



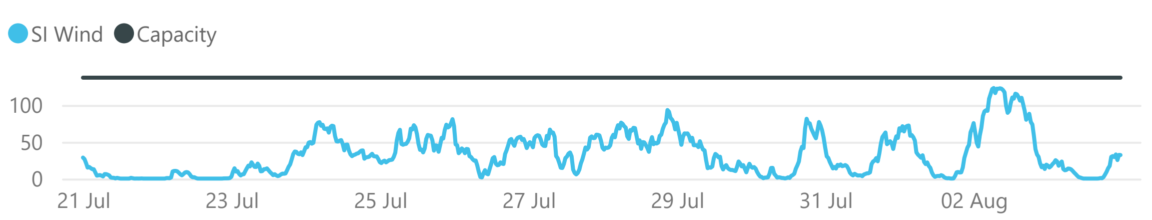
North Island Wind



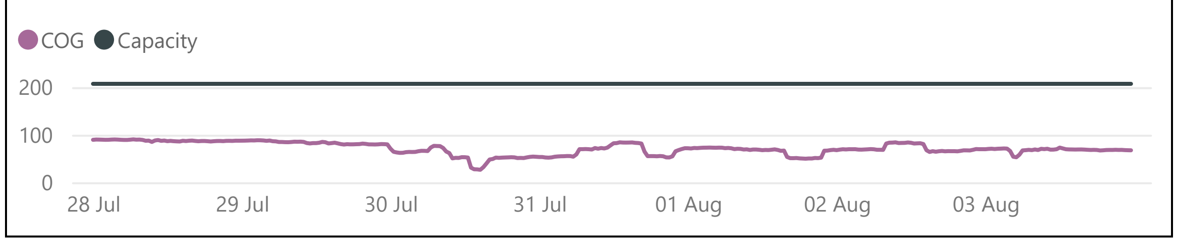
Geothermal



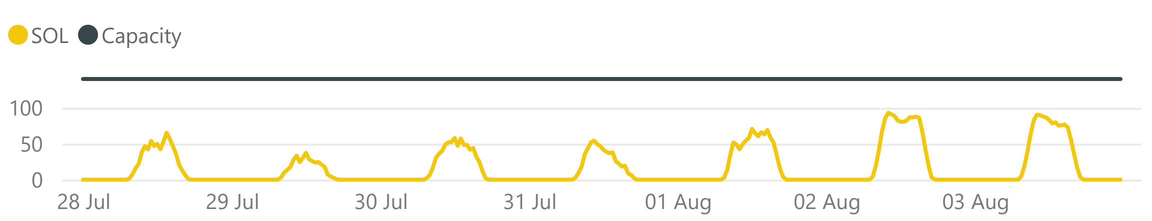
South Island Wind



Co-Generation

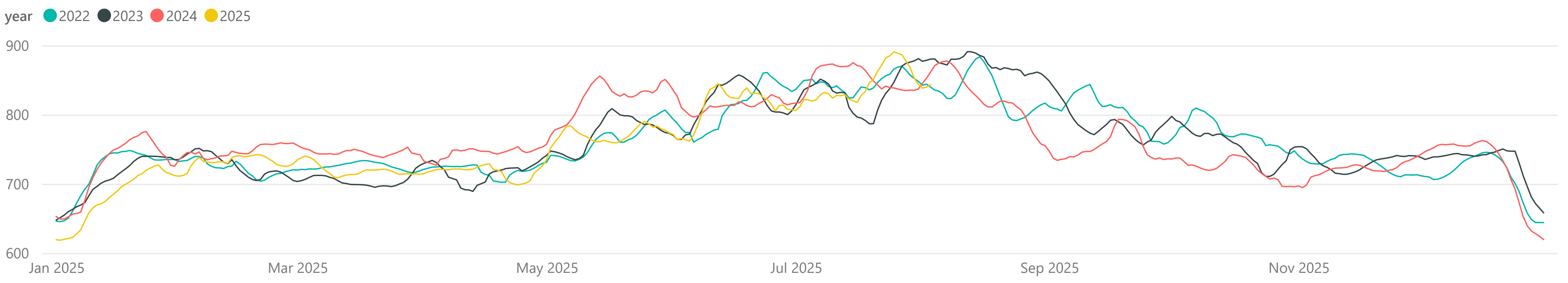


Solar

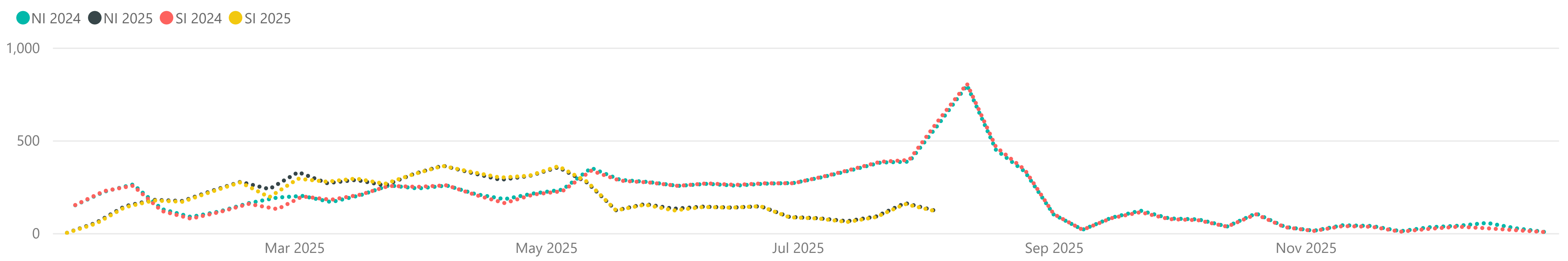


Weekly Profiles

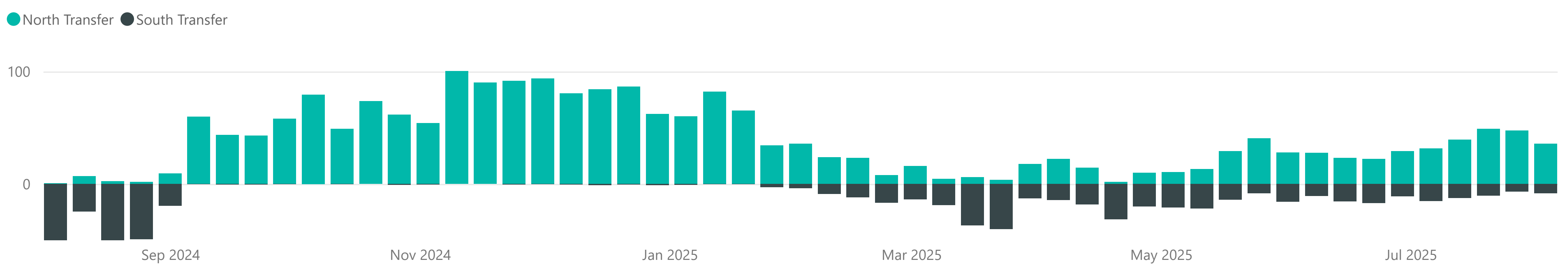
National Weekly Demand - GWh - 7 Day Rolling



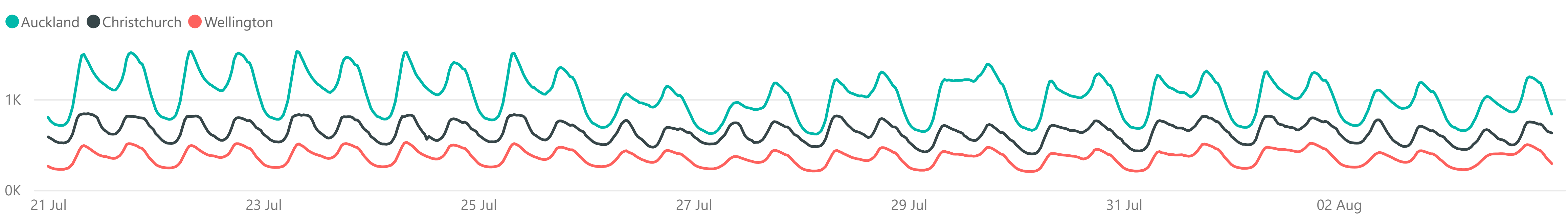
Weekly Spot Price - $/MWh



HVDC Transfer - Weekly GWh

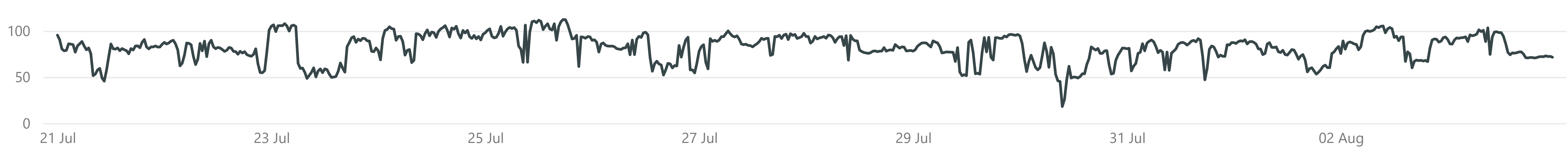


Conforming Load Profiles - Last Two Weeks *Measured in MW shown by region*

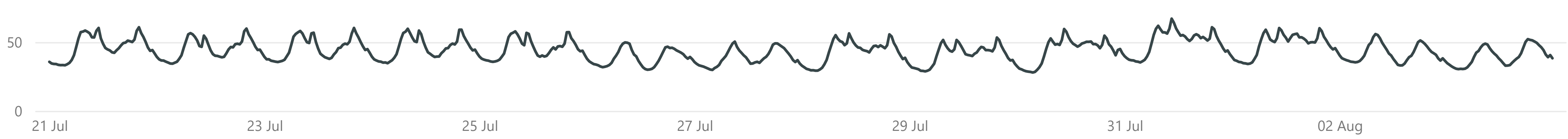


Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*

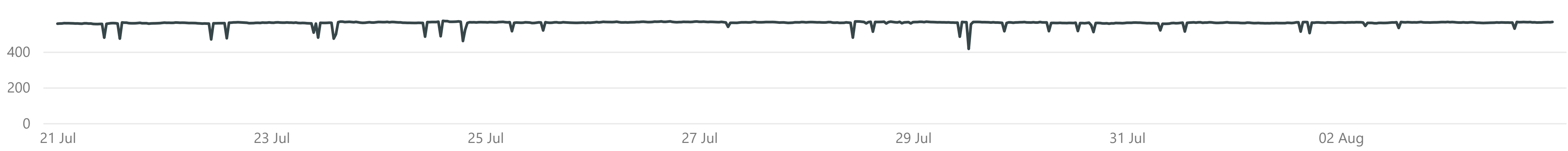
GLN0331



ASB0661

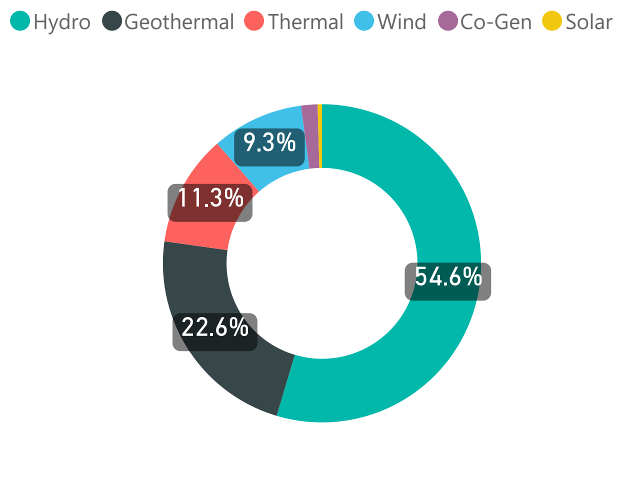


TWI2201

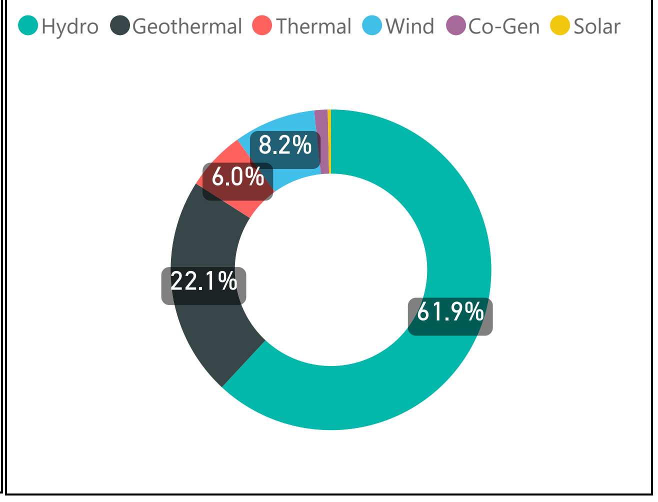


Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



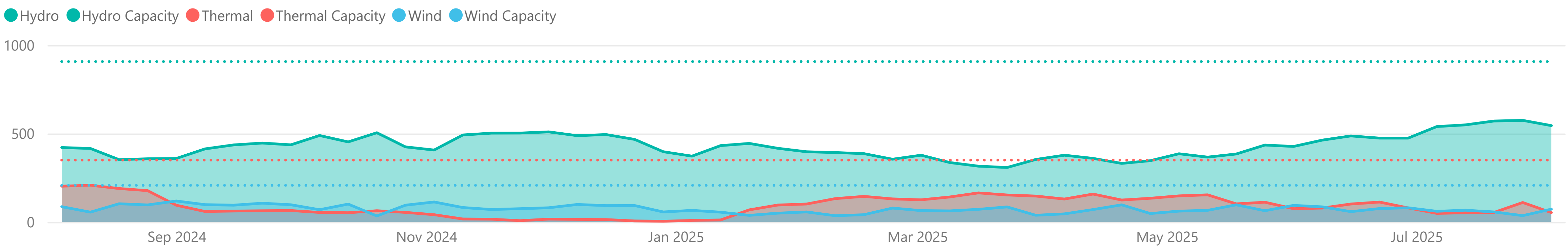
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
93%	43,307	49.2

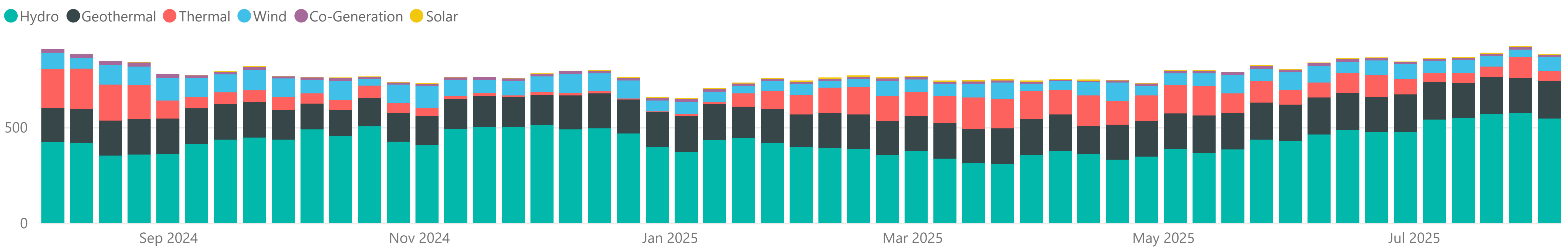
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
87%	71,070	89.9

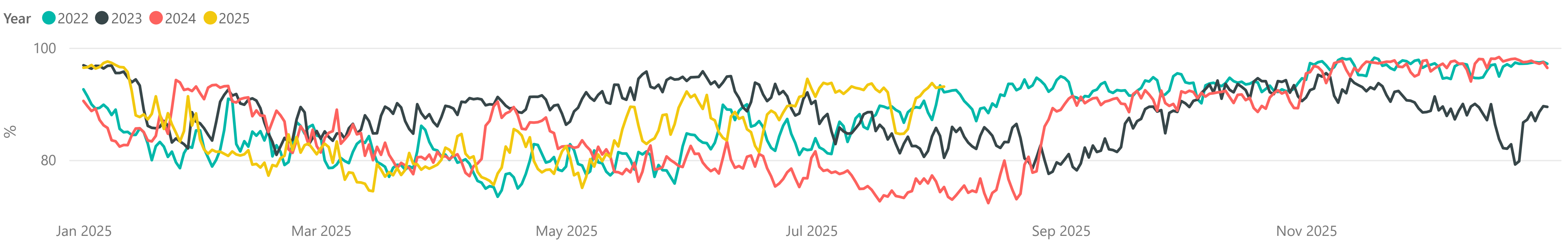
Weekly Generation Mix vs Capacity - GWh



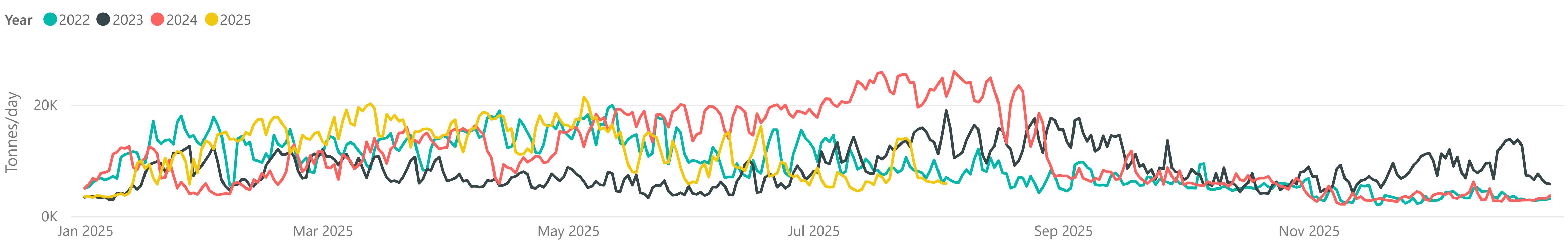
Weekly Generation Mix - GWh



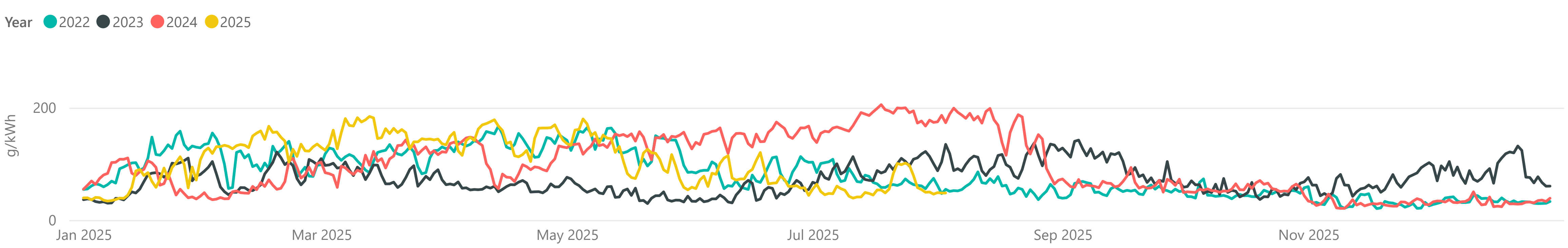
NZ Renewable Percentage



CO2 Tonnes/Day

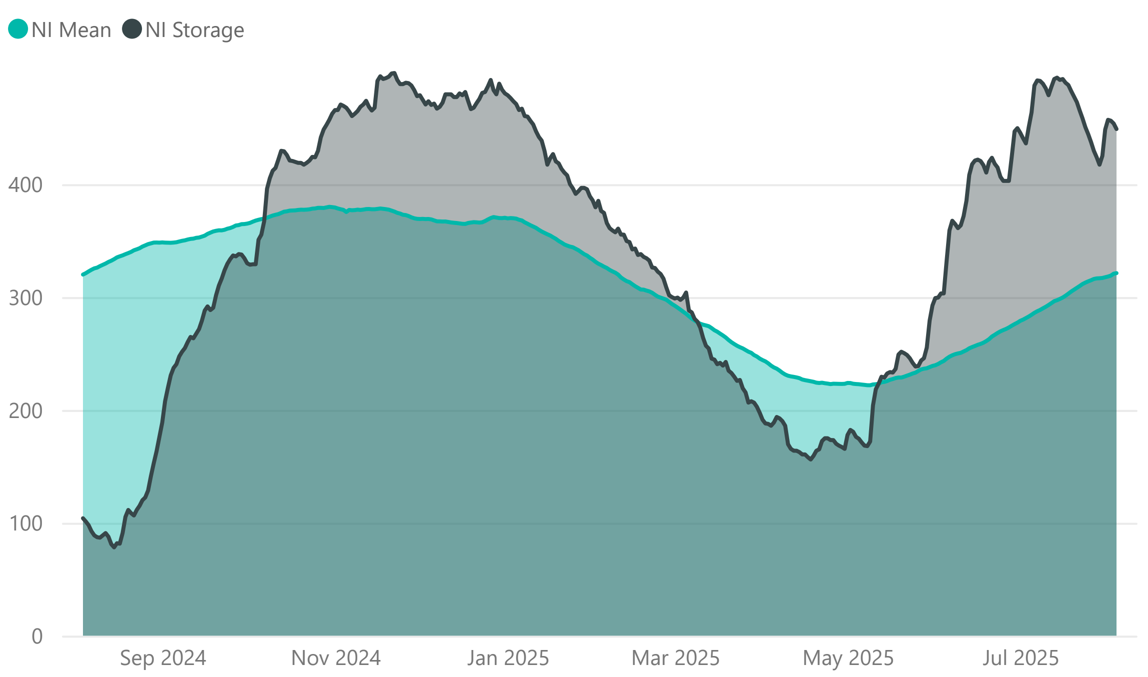


CO2 g/kWh



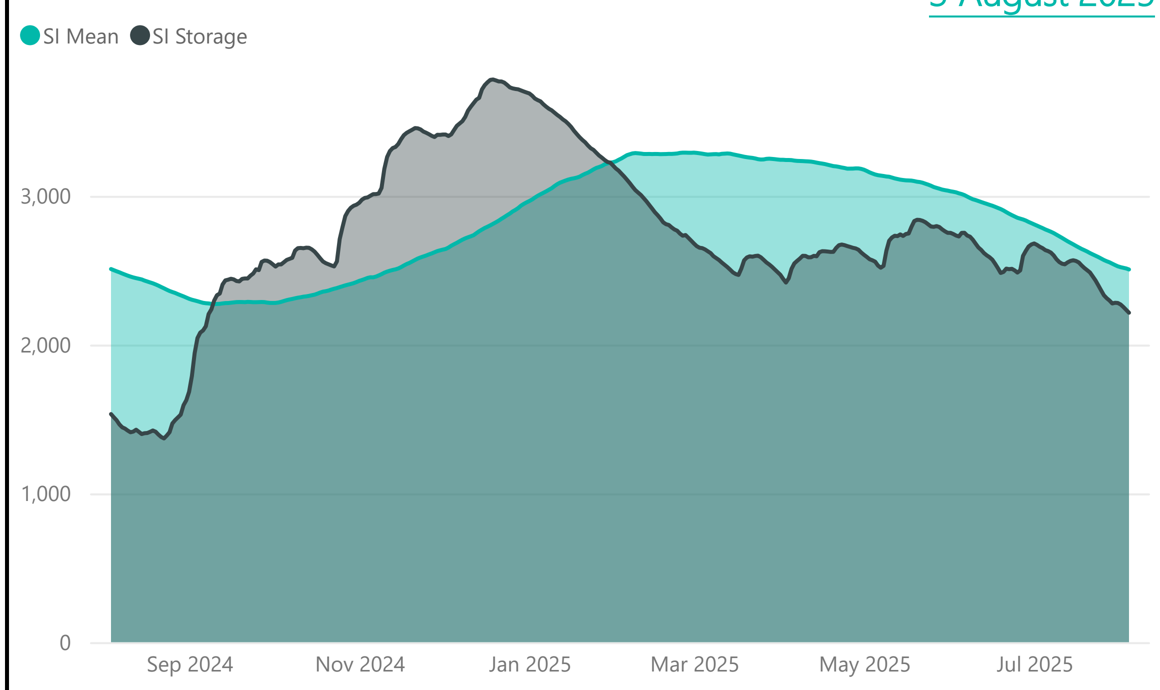
Hydro Storage

North Island Hydro Storage (Available GWh)

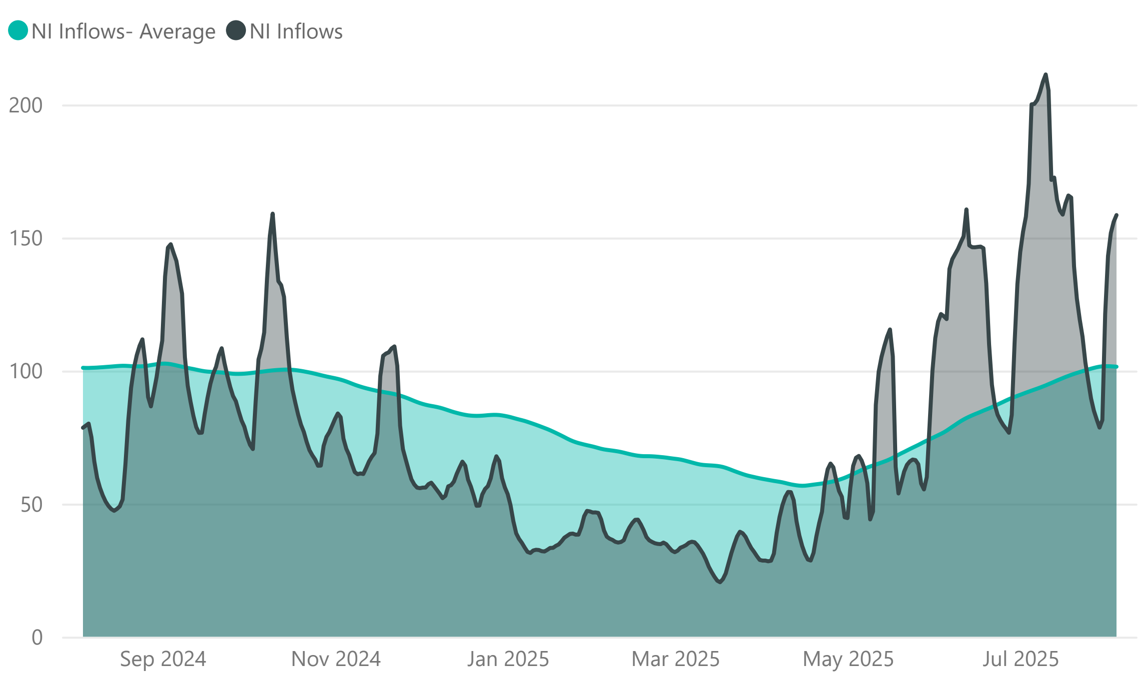


South Island Hydro Storage (Available GWh)

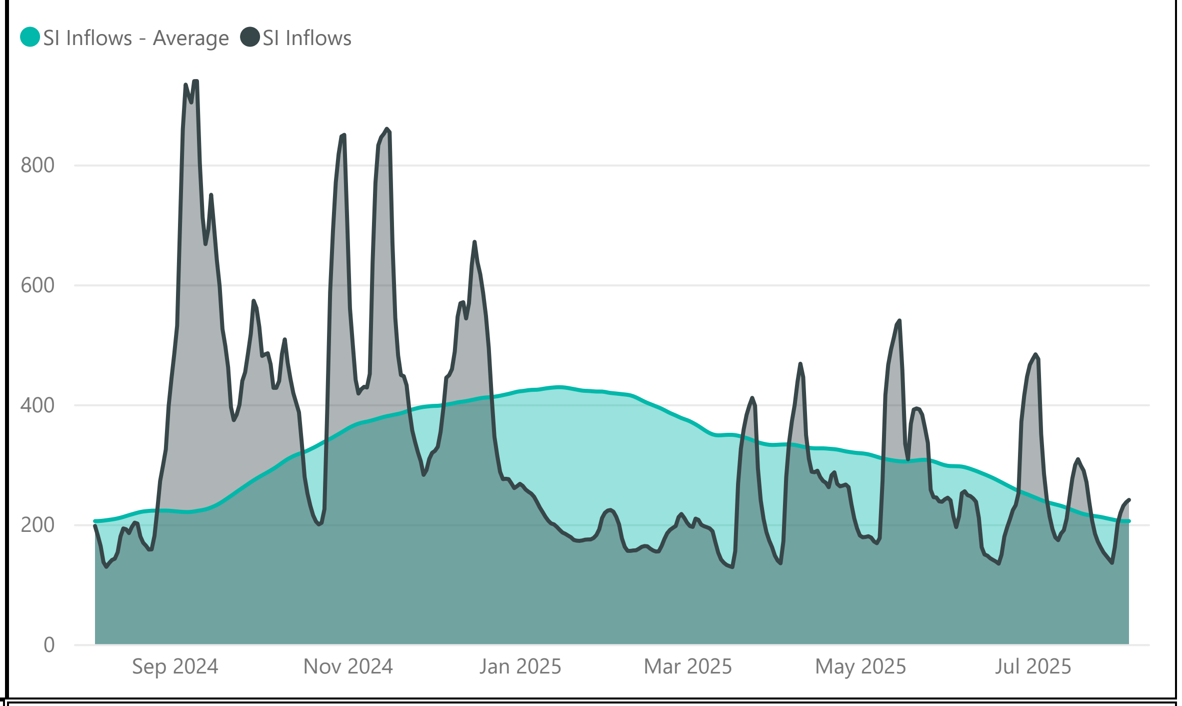
3 August 2025



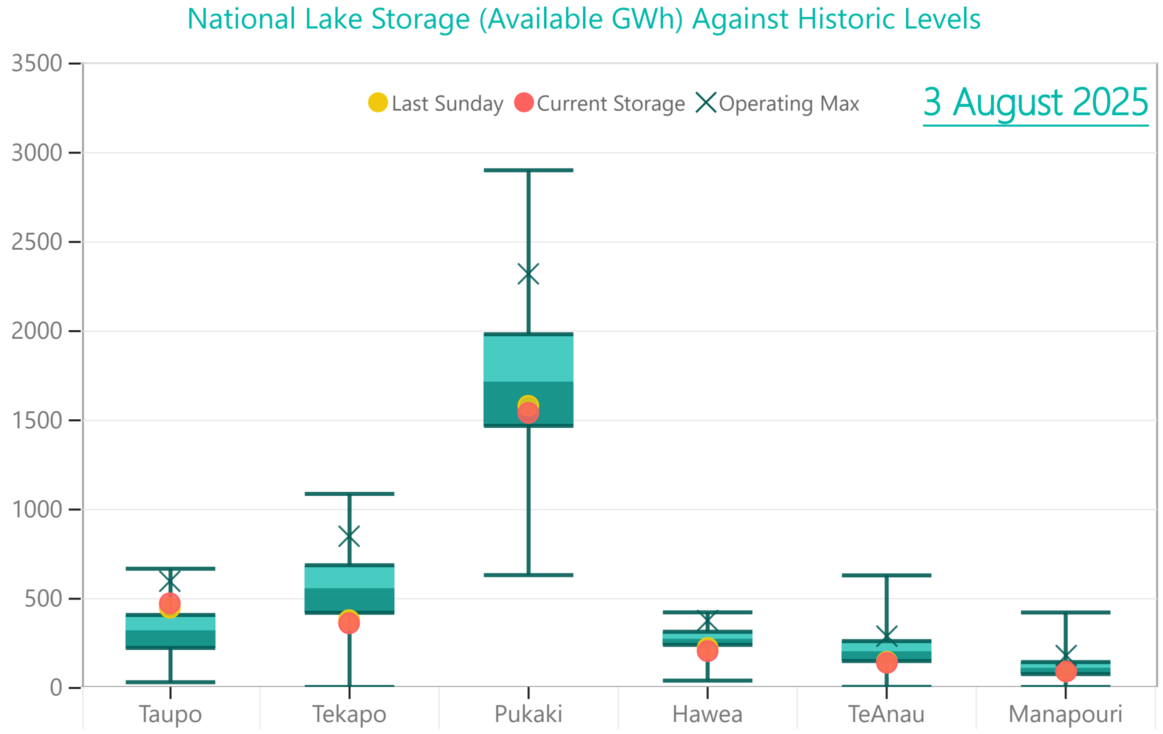
North Island Mean 7 Day Inflows (Available GWh)



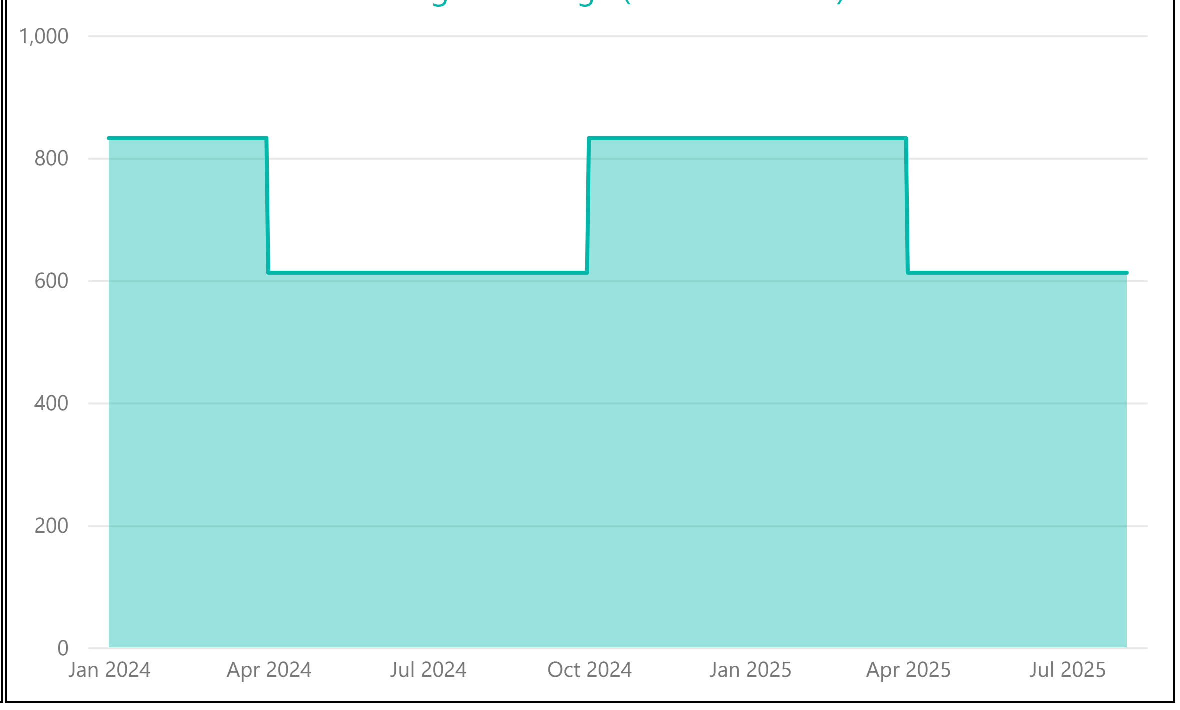
South Island Mean 7 Day Inflows (Available GWh)



National Lake Storage (Available GWh) Against Historic Levels



Contingent Storage (Reserved 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

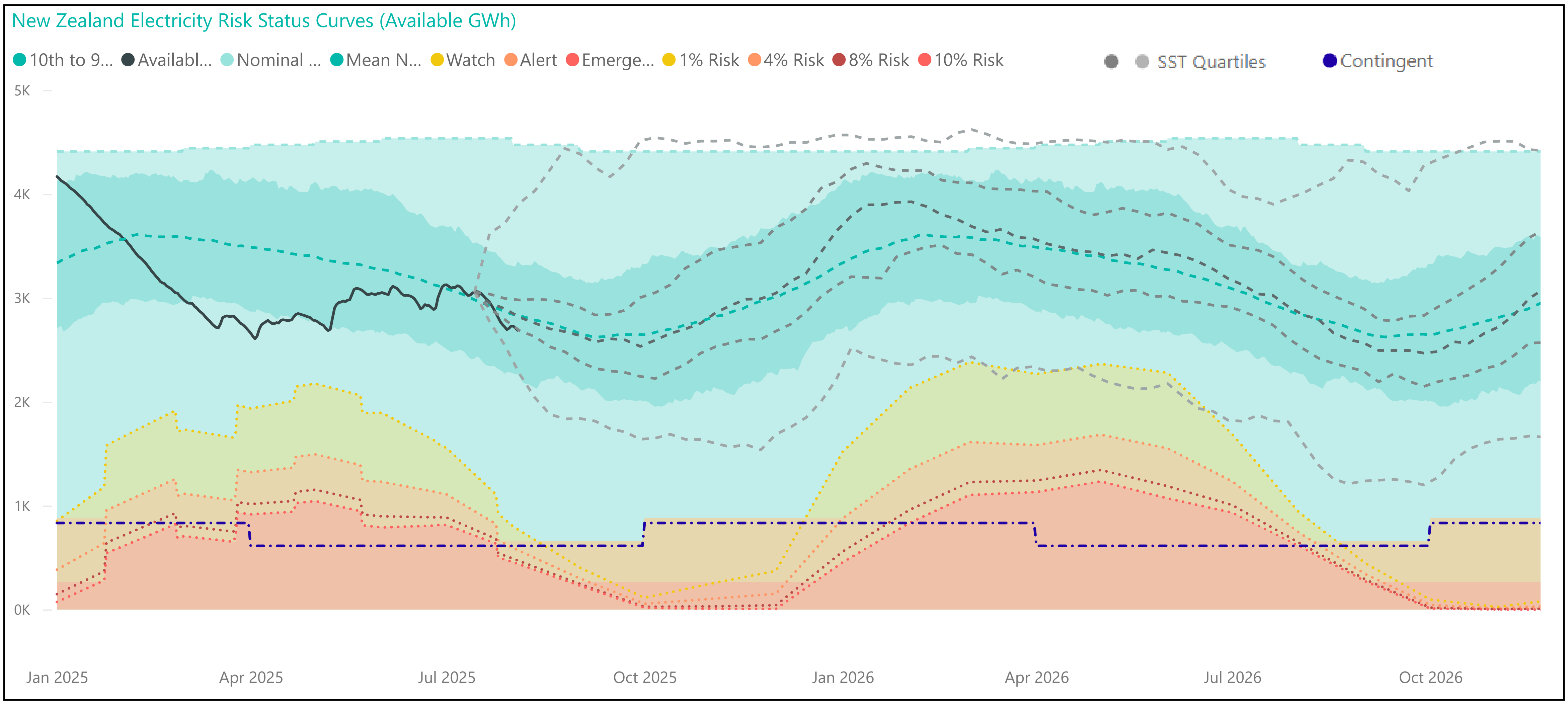
For any inquiries related to security of supply contact market.operations@transpower.co.nz

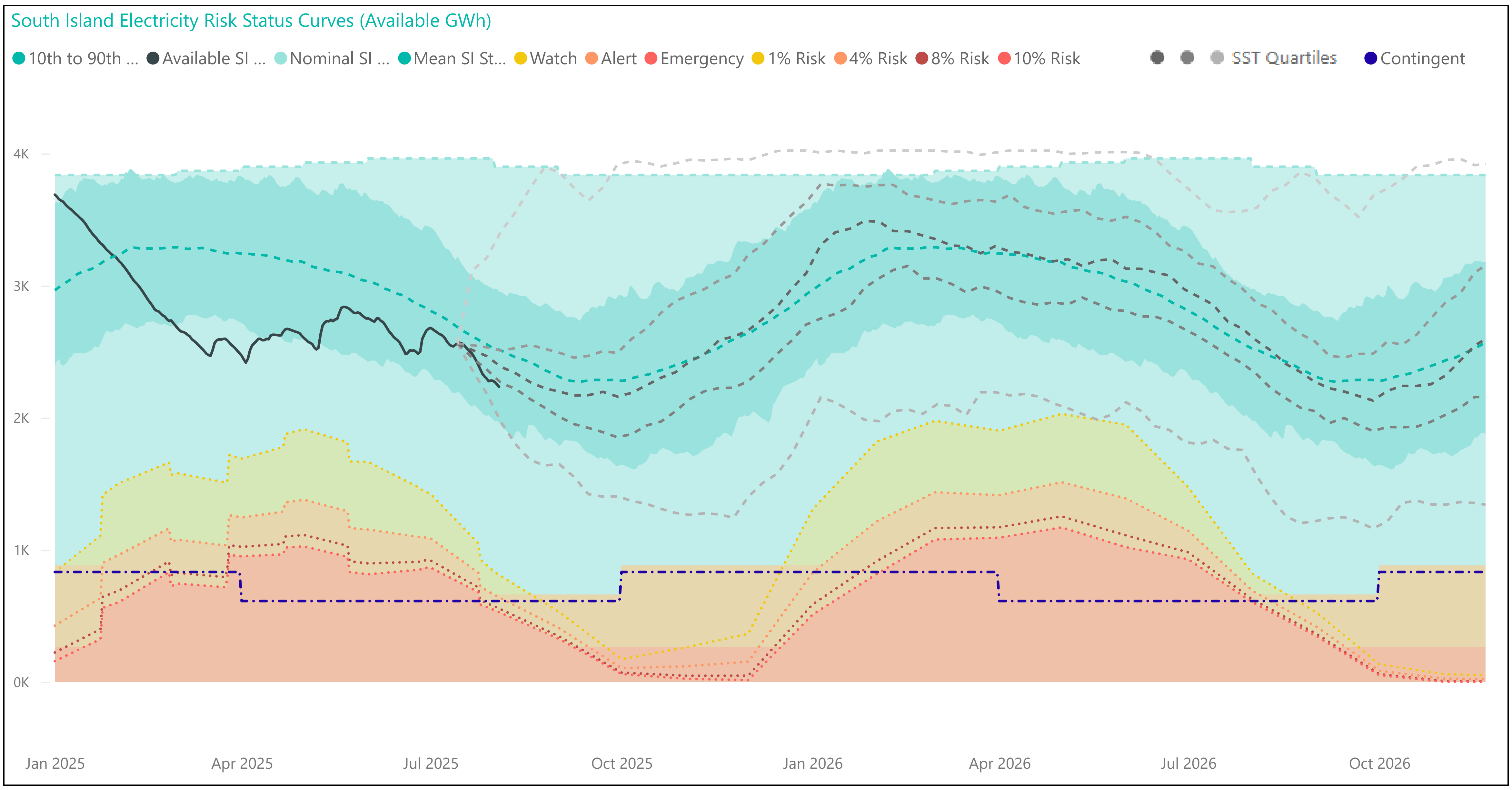
Hydro data used in this report is sourced from *NZX Hydro*.

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





Electricity Risk Curve Explanation:

Watch Curve - The maximum of the one percent risk curve and the floor and buffer
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. The buffer is 50 GWh.

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).