Market Operations Weekly Report - Week Ended 26 April 2026

Overview

New Zealand hydro storage has increased from 110% to 112% of the historic mean for this time of year. This continues to be largely driven by North Island hydro storage where Taupō is at 228% of the historic mean.

This week's insight discusses a period of inter-island price separation resulting from an interesting least cost solution from the market solver (SPD).

Security of Supply

Energy

National hydro storage has increased to 112% of the seasonal mean at the end of last week. South Island hydro storage has remained the same at 104%. North Island storage increased from 208% to 228%.

Capacity

There were periods of lower than usual residual across last week during peak morning and evening periods resulting from very low wind periods. Thermal peaking units were switched on to meet national demand at these times.

The N-1-G margins in the NZGB forecast are healthy through to mid May. 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 continues to increase as we creep into the beginnings of winter. Last week demand increased from 743 GWh to 788 GWh. The highest demand peak of 6,108 MW occurred at 6:00pm on Tuesday 21 April.

Weekly Prices

The average wholesale electricity spot price at Ōtāhuhu last week was $101/MWh, increasing from $63/MWh the week prior. Wholesale prices peaked at $429/MWh at Ōtāhuhu at 7:30am on Thursday 23 April with demand increasing and a tight offer stack. This happened a few times during peak demand periods across the week.

There were several periods of price separation across the week notably on Monday and Tuesday which we discuss in this week's insight.

Generation Mix

Wind generation decreased from 14% to 7% of the mix. Hydro generation increased from 51% to 59% of the mix. Thermal generation remained at 6% of the mix despite the peak periods bringing on additional units. Geothermal decreased from 27% to 25% of the mix.

HVDC

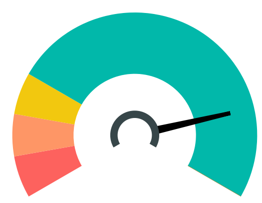
HVDC flow was mostly northward with the increased hydro generation this week to support the increased North Island demand and low wind generation. There were some periods of South Island transfer overnight when wind was moderate early in the week. In total, 77 GWh was transferred north and 14 GWh was transferred south. HVDC transfer was limited over the weekend due to a series of outages including a bi-pole outage on Sunday.

Surveys and Engagement

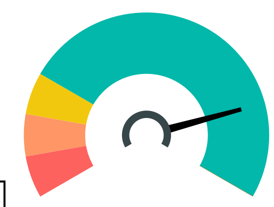
We have published our draft 2026 Security of Supply Assessment (SOSA) for consultation. Submissions close on 21 May. This provides a 10-year assessment (2026 to 2035) of the balance between supply and demand in the New Zealand electricity system.

Our Annual System Operator Participant Survey remains open to provide an opportunity for participants to set out their expectations and help us understand how we are performing the System Operator service. If you have not received the survey but would like to have your say, you can complete it here. The survey closes 30 April 2026.

New Zealand Energy Risk

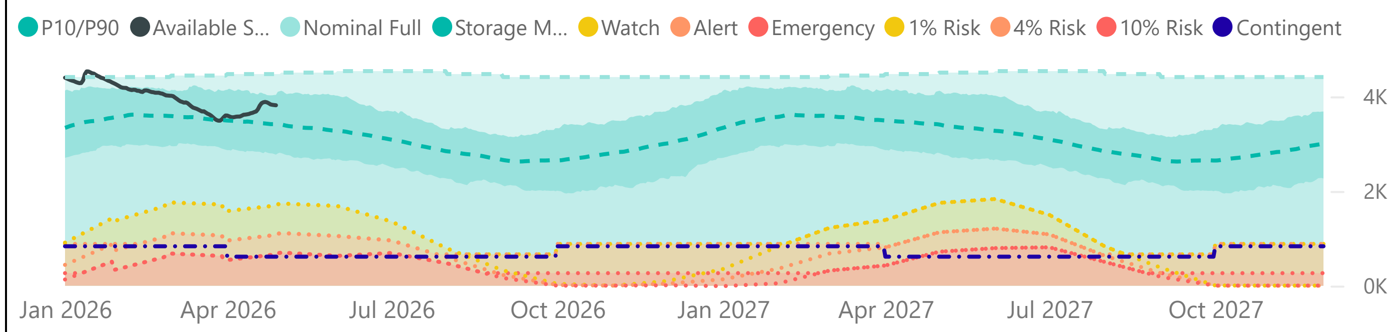


South Island Energy Risk

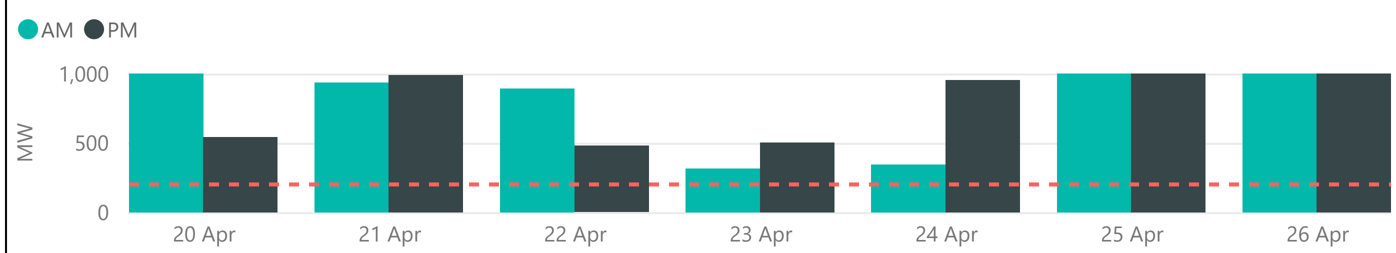


Normal Watch Alert Emergency

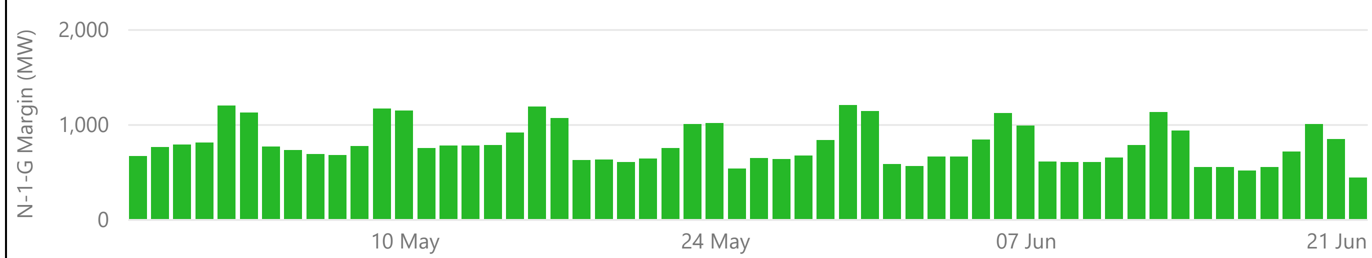
New Zealand Electricity Risk Status Curves (Available GWh)



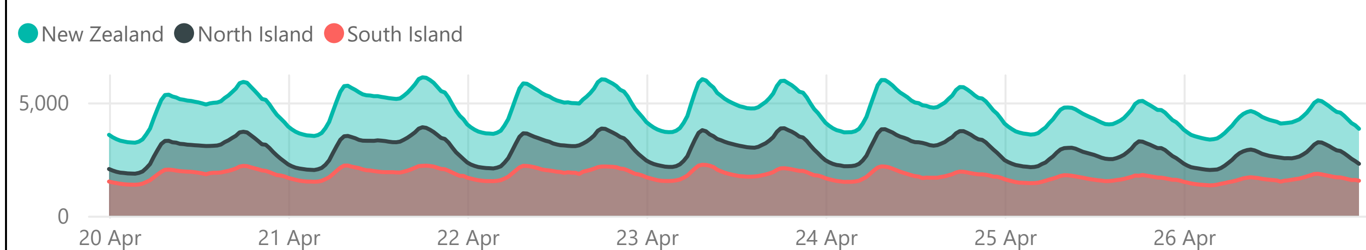
Lowest Residual Points - MW



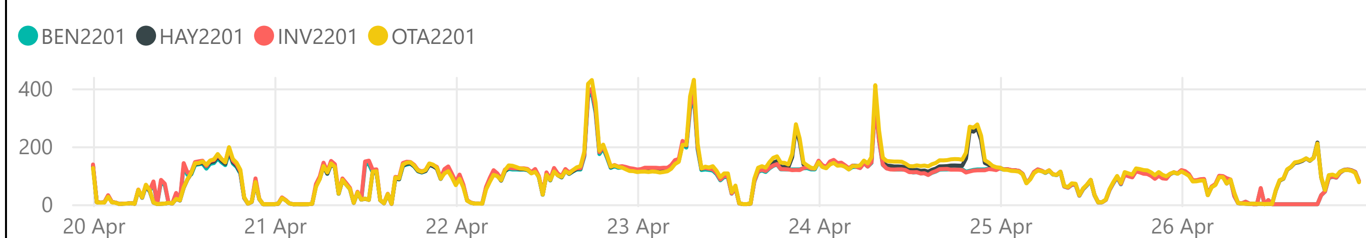
NZGB Look-Ahead (excluding next 7 days)



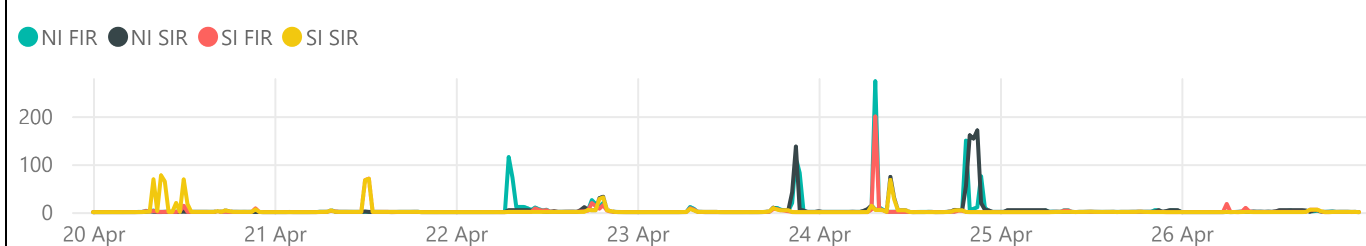
National Demand by Trading period - MW



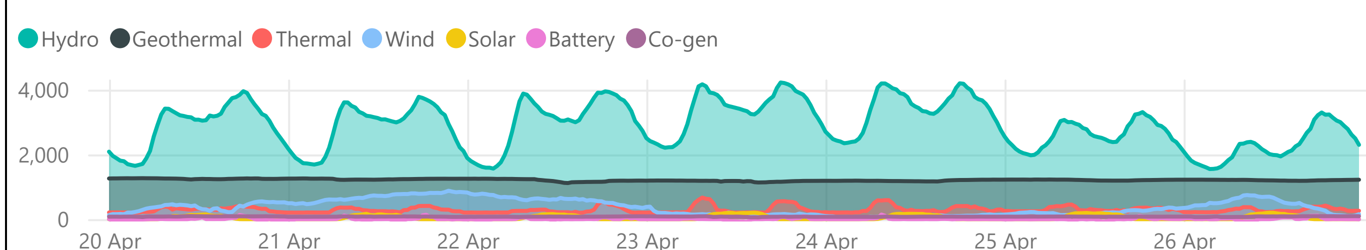
Energy Prices - $/MWh



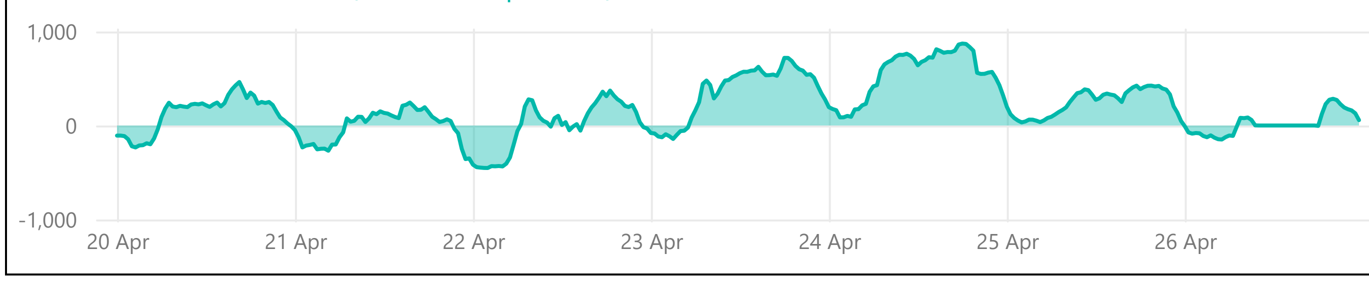
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW (Northward positive)



Weekly Insight - Reverse reserve sharing limits and price inversion

In this week's insight we look into the cause of the recent inter-island price separation that occurred on Monday 20 April. This occurrence of price separation is of particular interest due to the fact that the South Island price was higher and the direction of the HVDC transfer was in the opposite direction (northwards).

Instantaneous Reserve (IR) is the power system's backup, restoring balance if an asset trips and there is a sudden imbalance between demand and supply. The largest asset on the system at any point in time is called the 'risk setter' and determines the amount of IR required at that point in time. Covering the risk can be complicated as there is not only the reserve market to consider but also the energy offer stack in each respective island. The complexities of how SPD (Scheduling, Pricing and Dispatch) solves for the least cost solution to retain power system security can be highlighted by the price separation that occurred last Monday.

Based on the 9:15am Real-Time Dispatch (RTD) solve, SPD calculated that there was 139.8 MW of Sustained Instantaneous Reserve (SIR) from the North Island which could contribute to covering the risk in the South Island. This number was set by the reverse reserve sharing limit, which models the maximum amount by which the HVDC link could reduce northward power transfer (thereby increasing power available in the south Island) in response to a contingent event[1].

At this time, the risk setter for the South Island was Ōhau A (OHA2201 OHA0) which was generating 223.6 MW at $0.01/MWh and contributed to the final SIR required in the South Island to be 240 MW[2]. After reserve sharing, this brought the total SIR required to cover the risk to be 240 MW - 139.8 MW = 100.2 MW of SIR which needed to be covered from the South Island SIR price stack. SPD finally clears all South Island SIR up to 100.2 MW with a final marginal price of $50/MWh in the South Island.

The marginal South Island SIR price was $50.56/MWh and North Island SIR price was $0.98/MWh and the HVDC was unconstrained. One way of reducing the cost of the South Island SIR price would be to reduce the amount of SIR required to cover the South Island risk. If this can be done, SPD will be able to select a lower cost SIR tranche for a reduced marginal price. However, this does not result in an (overall) least-cost solution. Why not? There are two cases to consider:

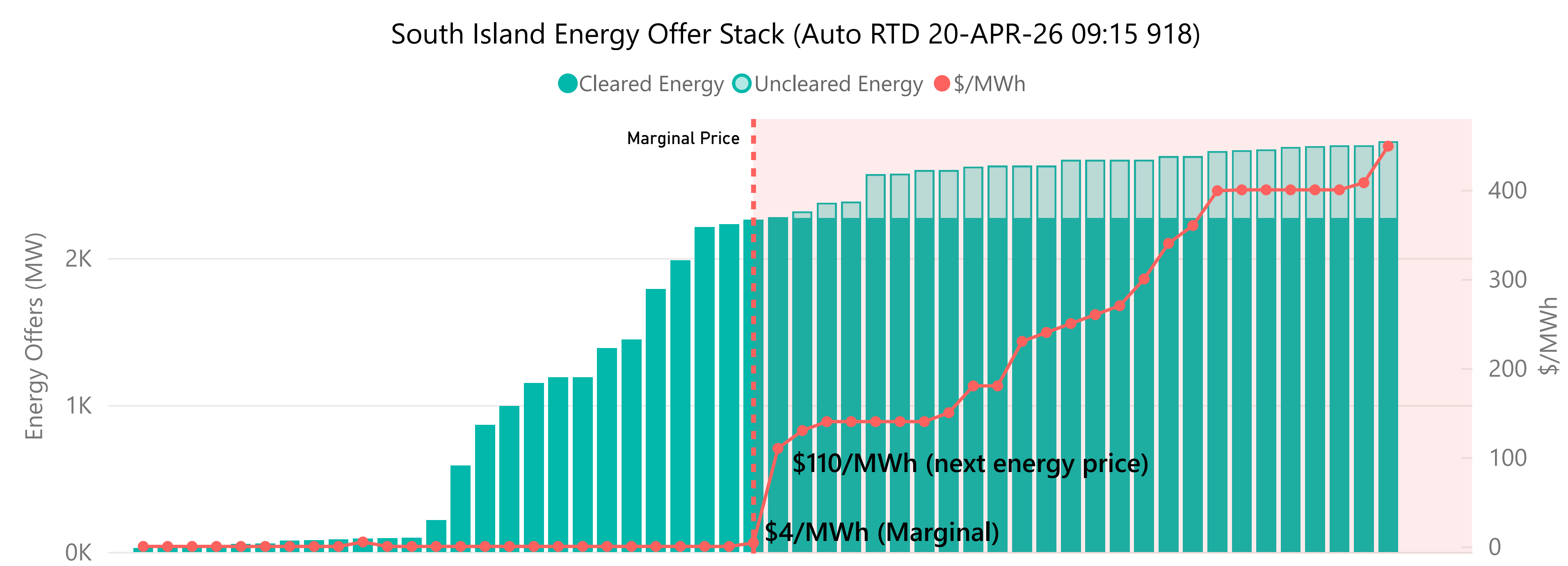
- SPD could reduce generation at OHA2201 which will reduce the South Island risk. But what this means is that there will no longer be a maximised northward transfer, which would also mean that we are reducing the opportunity for larger reverse reserve sharing.
- SPD could further increase northward HVDC transfer. To do this, additional energy must be procured from the South Island however the next offered price in the South Island was $110/MWh. The reverse reserve binding limit, and an expensive South Island energy offer stack, was the reason for why procuring more generation in the South Island was not possible for a least cost solution.

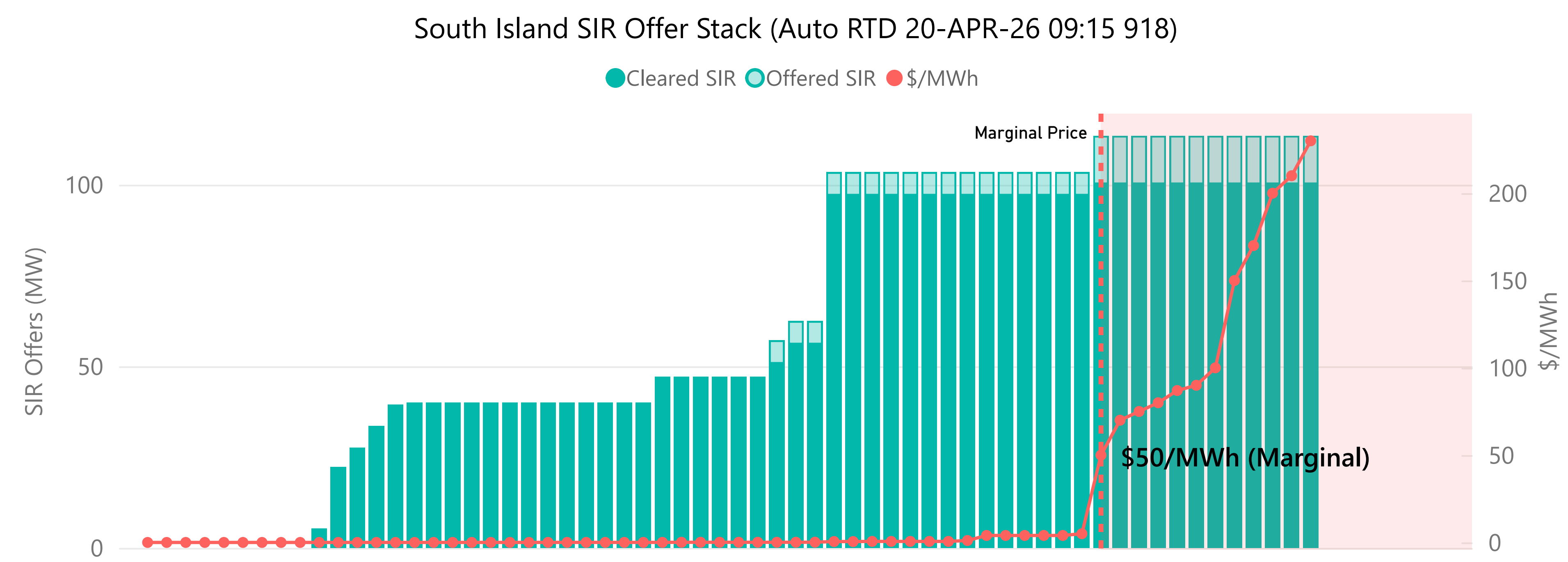
Both of these options would result in energy price separation. In this case, it was cheaper to accept SIR price separation.

In summary, there was a big generation offer gap in the South Island. There was nothing offered between $4/MWh and $110/MWh. SPD cleared all the cheaper generation available to get the HVDC high enough to share the reserve back to the South Island, however this resulted in clearing $50/MWh of SIR instead of the $110/MWh of energy. The South Island risk was unusually high at 227 MW and trying to cover this risk in the North Island would take a fair amount of generation in the North Island, and SPD determined that maximising net northward HVDC flow was the least cost solution.

[1] In this instance, the reverse reserve sharing limit was binding. To bind, reverse reserve sharing must reach the scheduled HVDC transfer – 65 MW (modulation risk). The scheduled HVDC transfer was 204.8 MW.

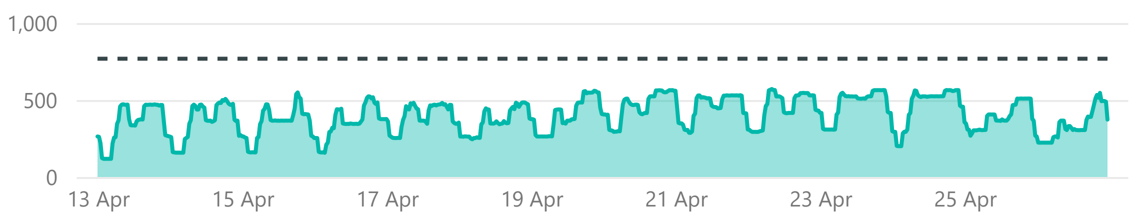
[2] An additional 11 MW is applied to cover generators that may trip following a contingent event.

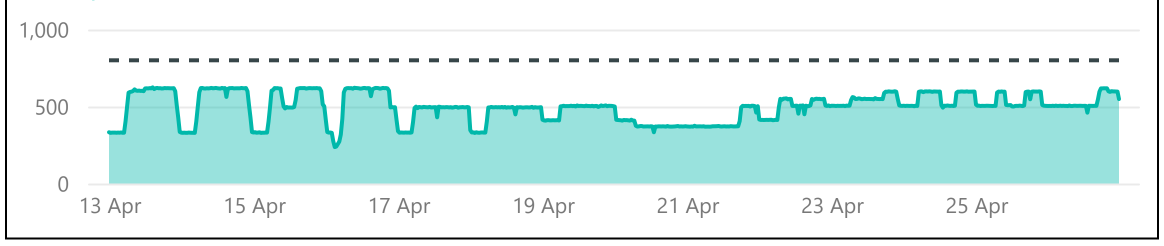


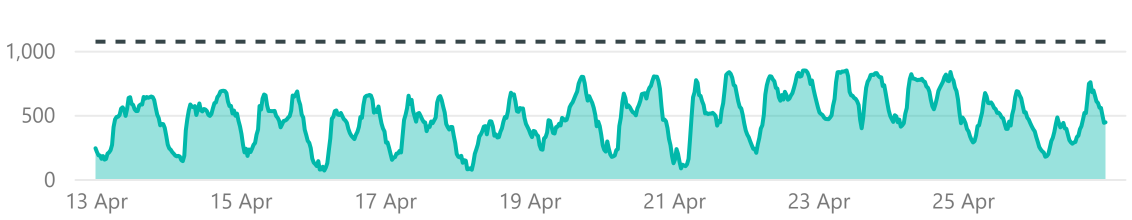


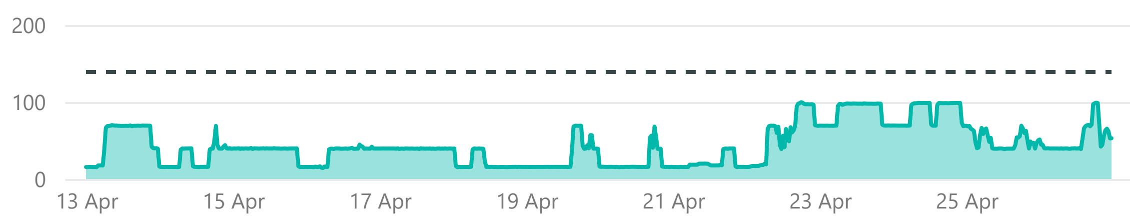
Generation Breakdown - Last Two Weeks

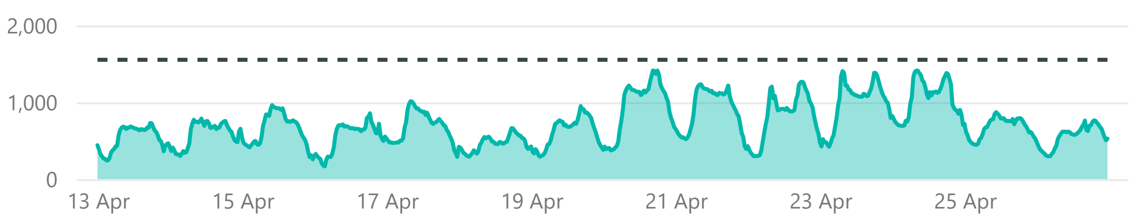
Measured in MW and displayed at trading period level for last 14 days

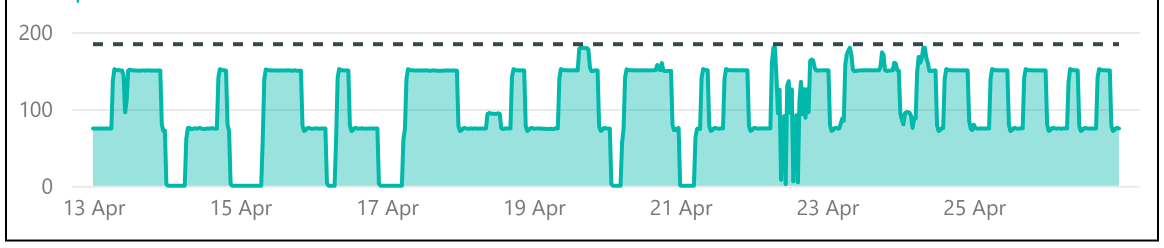
Clutha


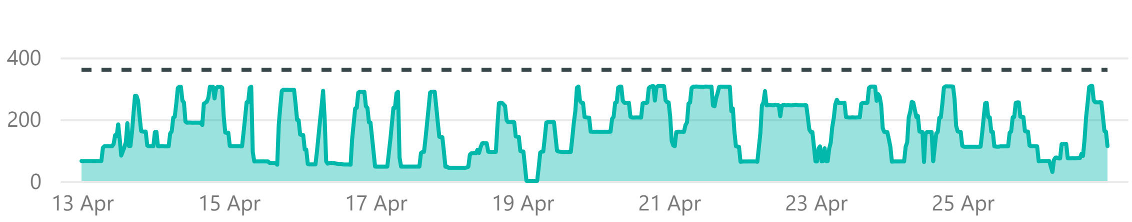
Manapouri


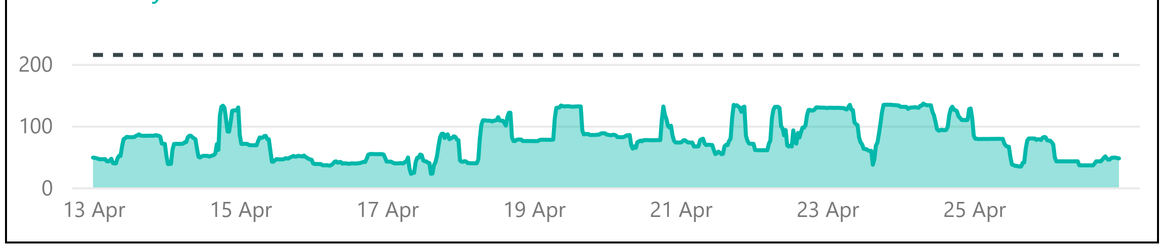
Waikato


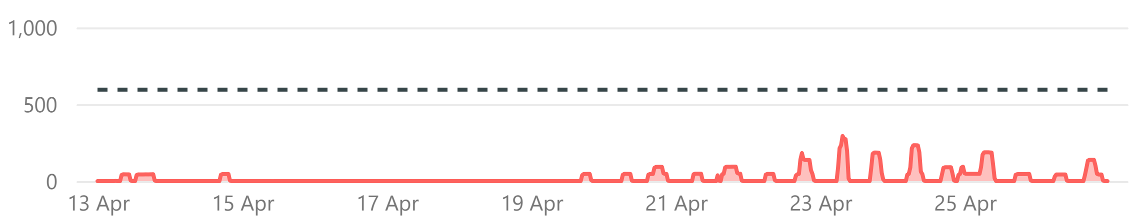
Waikaremoana


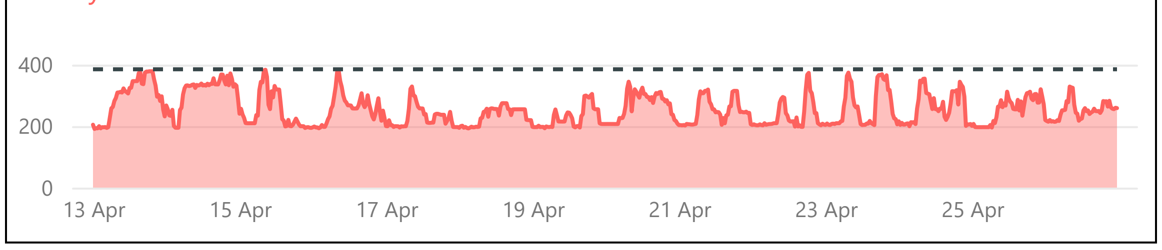
Waitaki


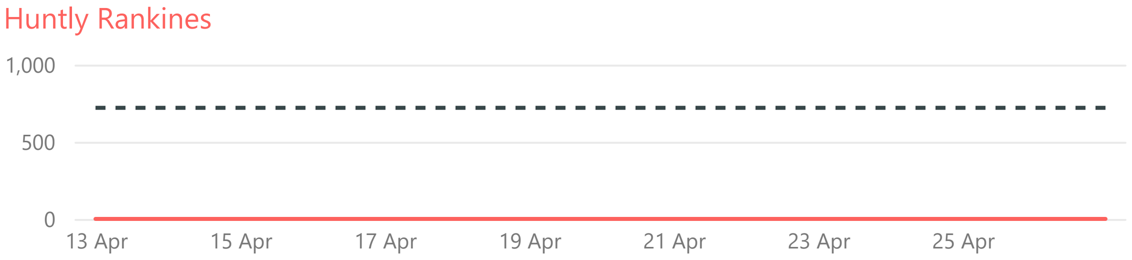
Tekapo


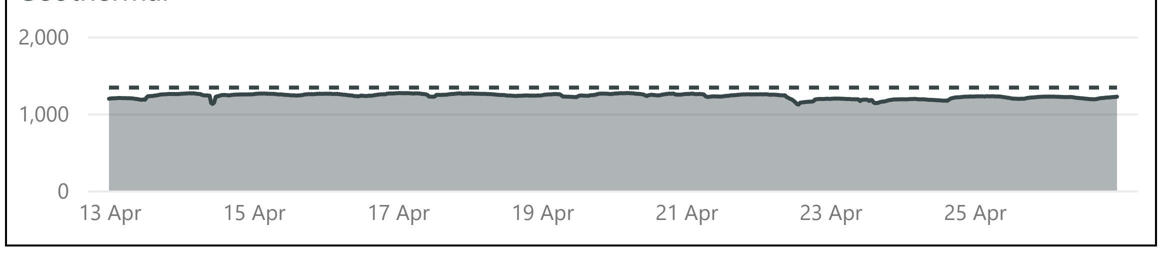
Tongariro


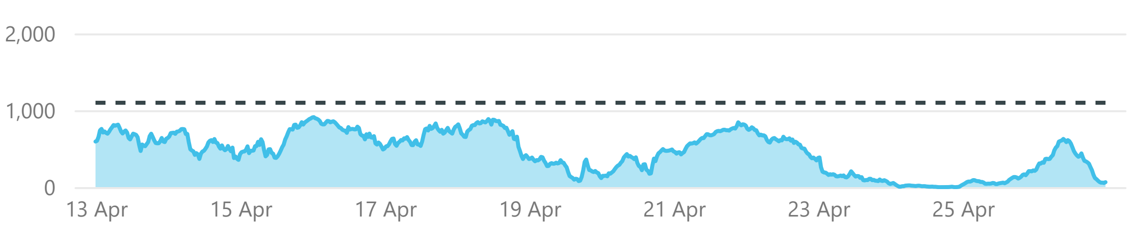
Other SI Hydro


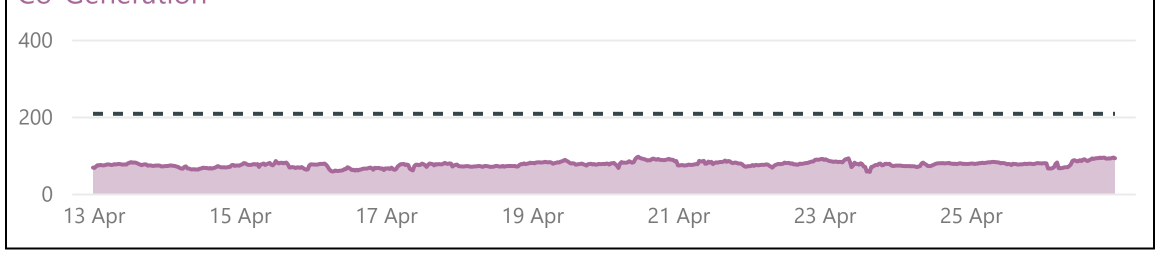
Thermal Peaking Plant


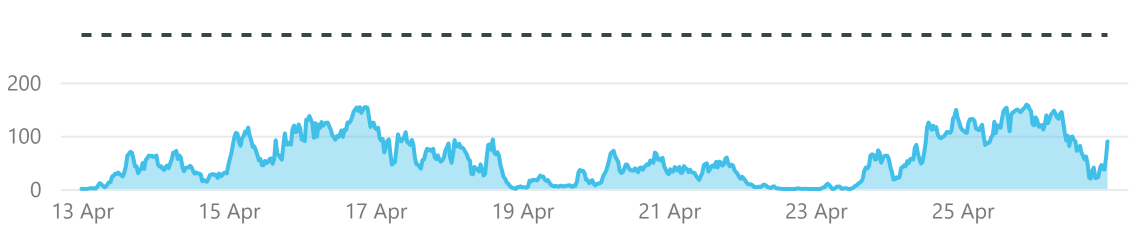
Huntly U5


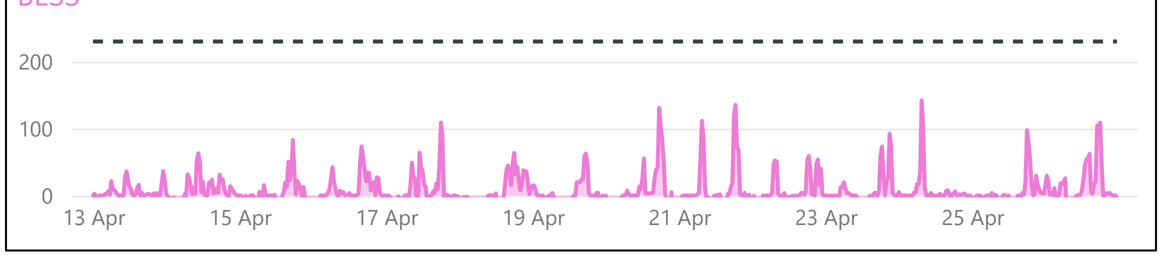
Huntly Rankines


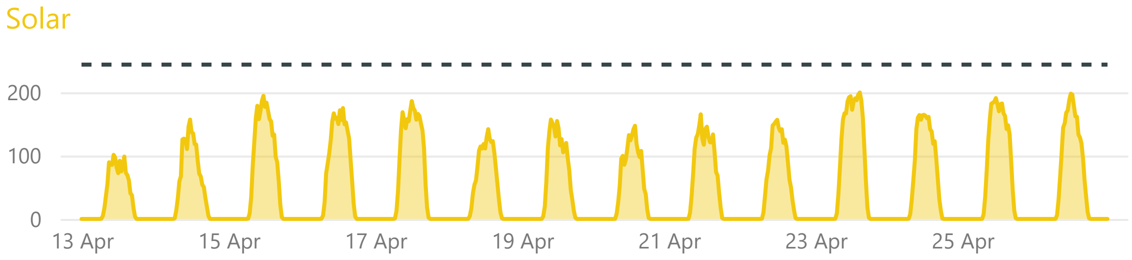
Geothermal


North Island Wind


Co-Generation


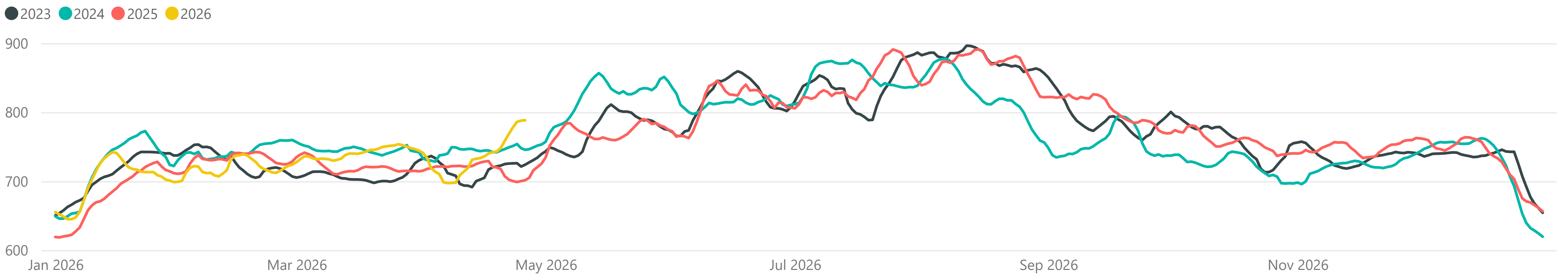
South Island Wind


BESS


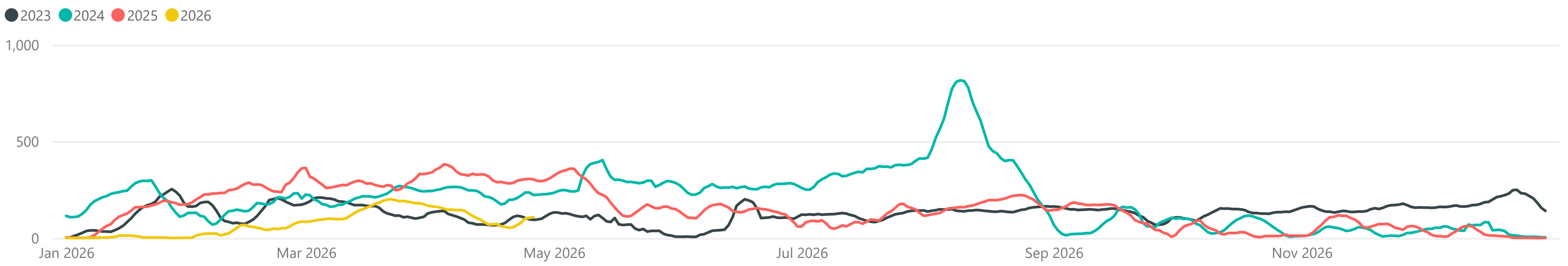
Solar


Weekly Profiles

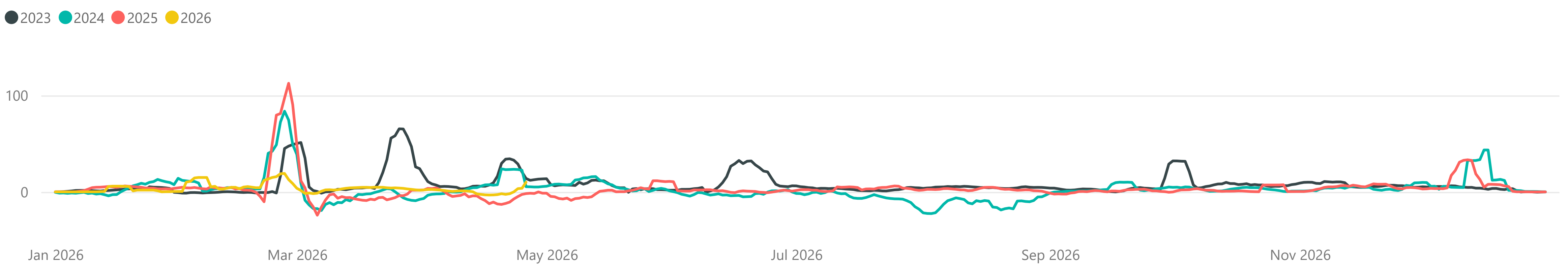
National Weekly Demand - GWh - 7 Day Rolling



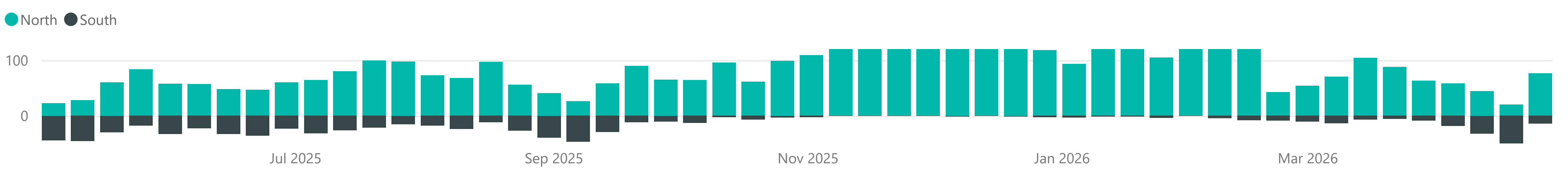
OTA2201 Weekly Rolling Average Spot Price - $/MWh



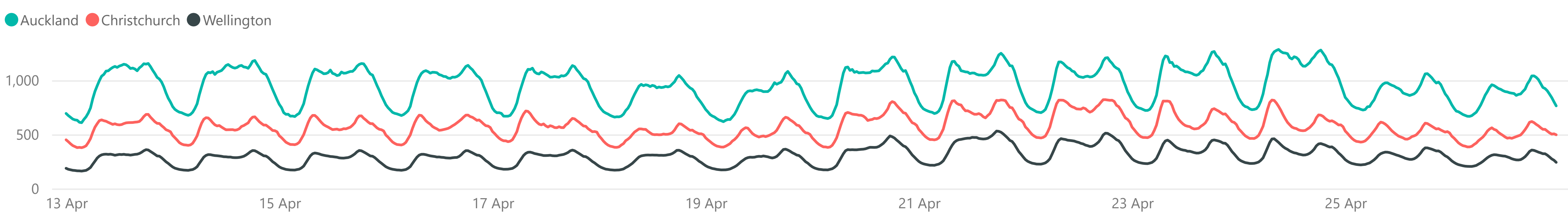
Weekly Rolling Price Separation (HAY2201 - BEN2201) - $/MWh



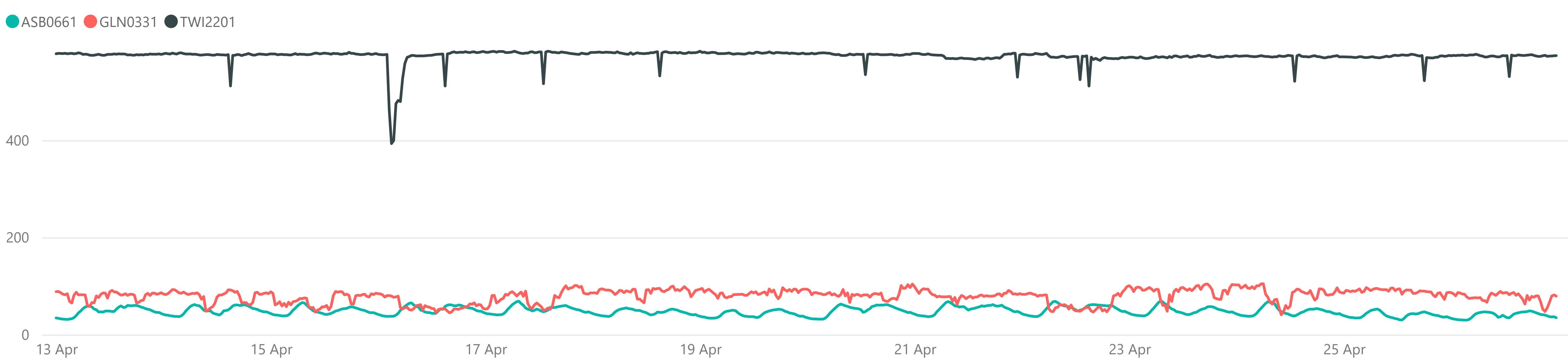
HVDC Transfer - Weekly GWh



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



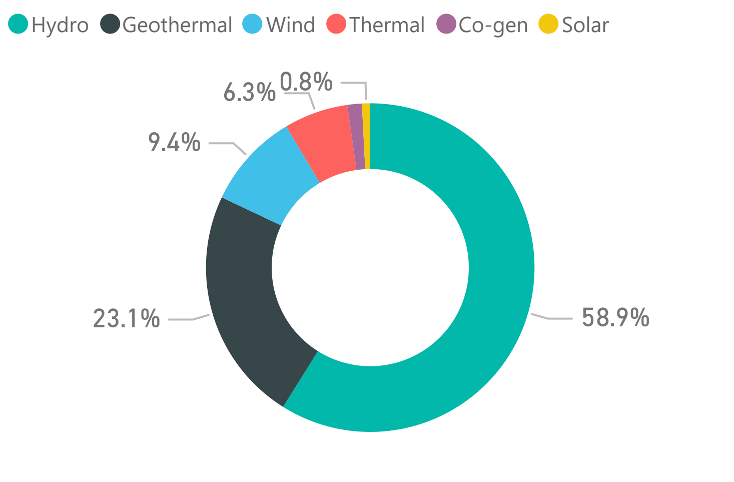
Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*



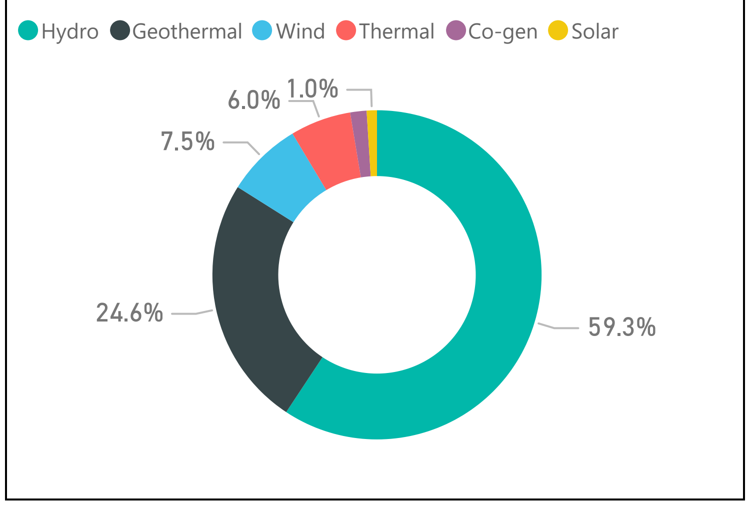
TRANSPOWER

Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



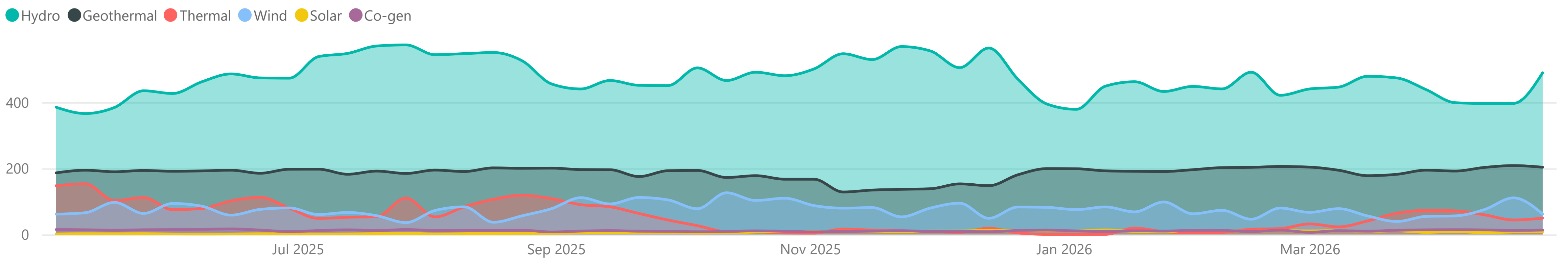
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
92%	42,602	52.0

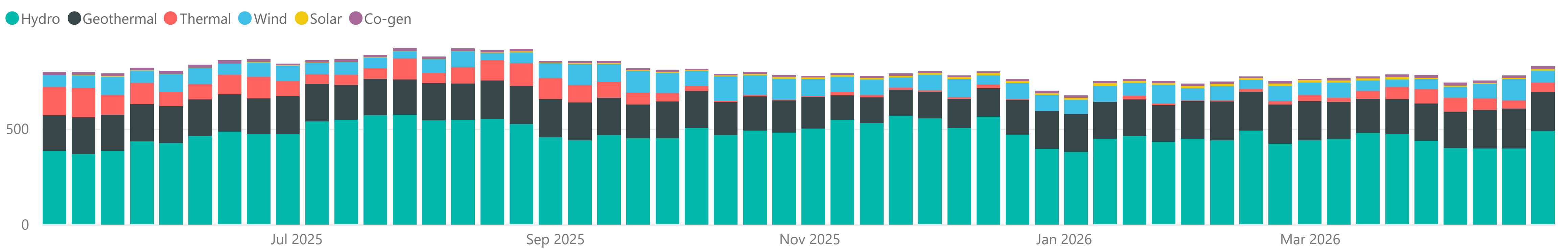
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
92%	46,689	57.0

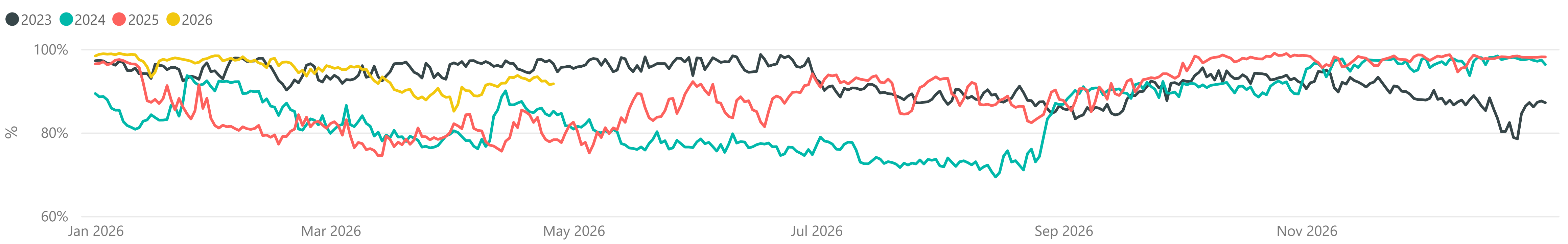
Weekly Generation Mix - GWh



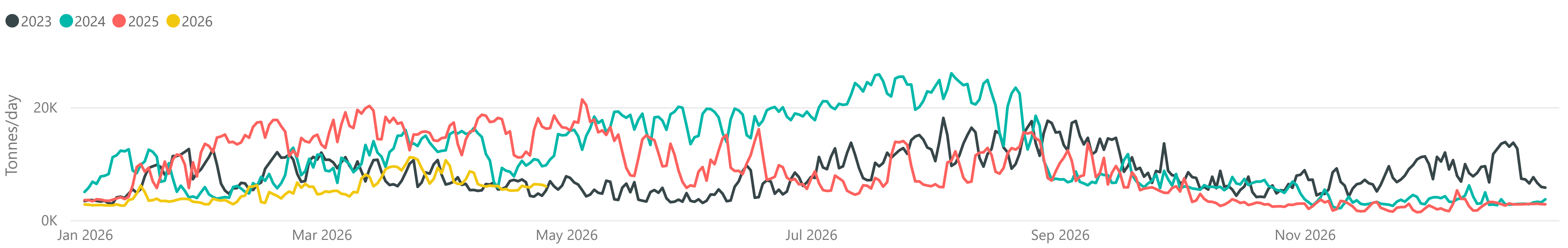
Weekly Generation Mix - GWh



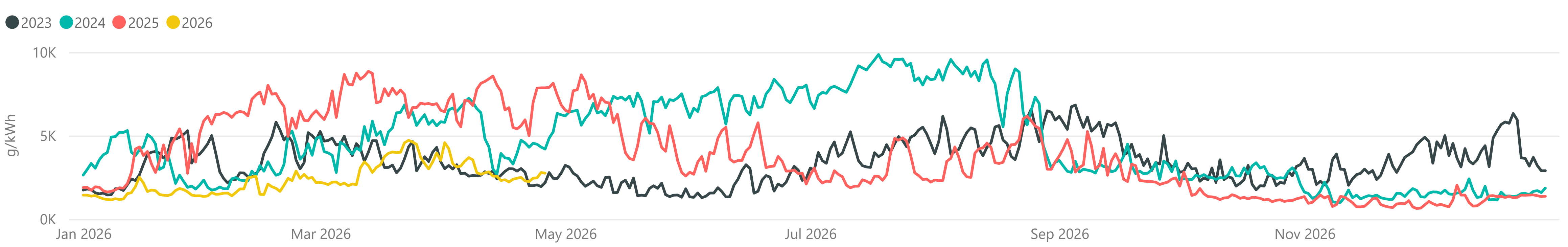
NZ Renewable Percentage



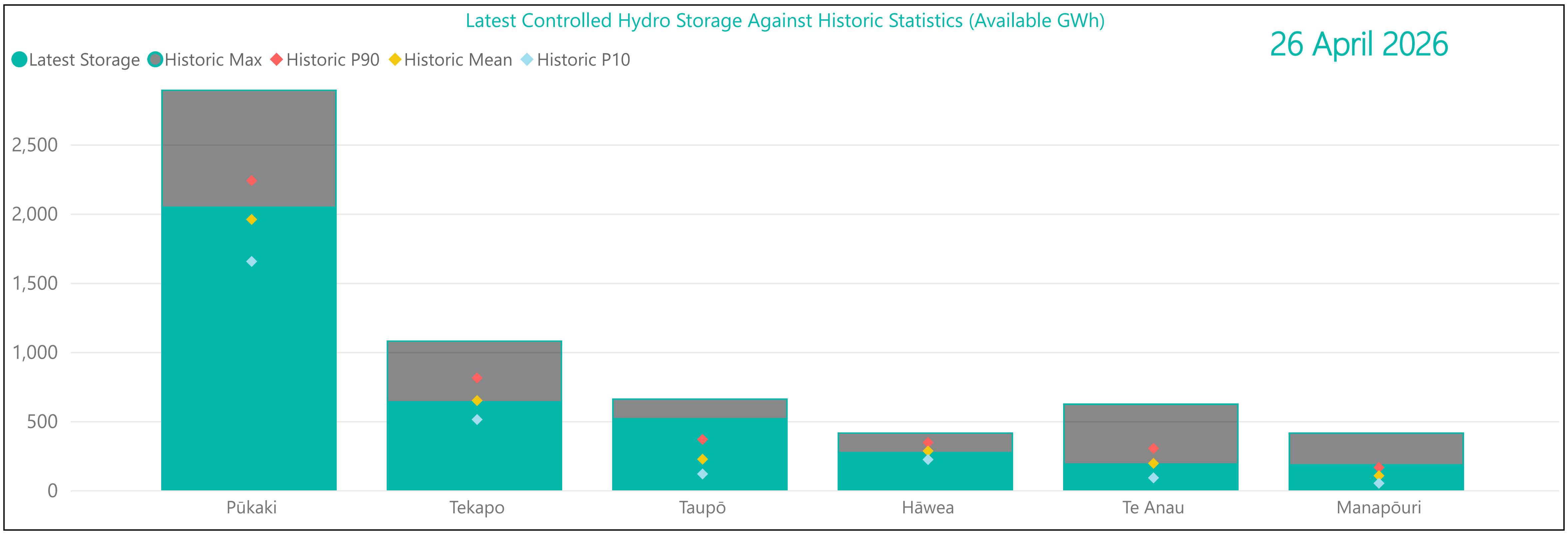
CO2 Tonnes/Day

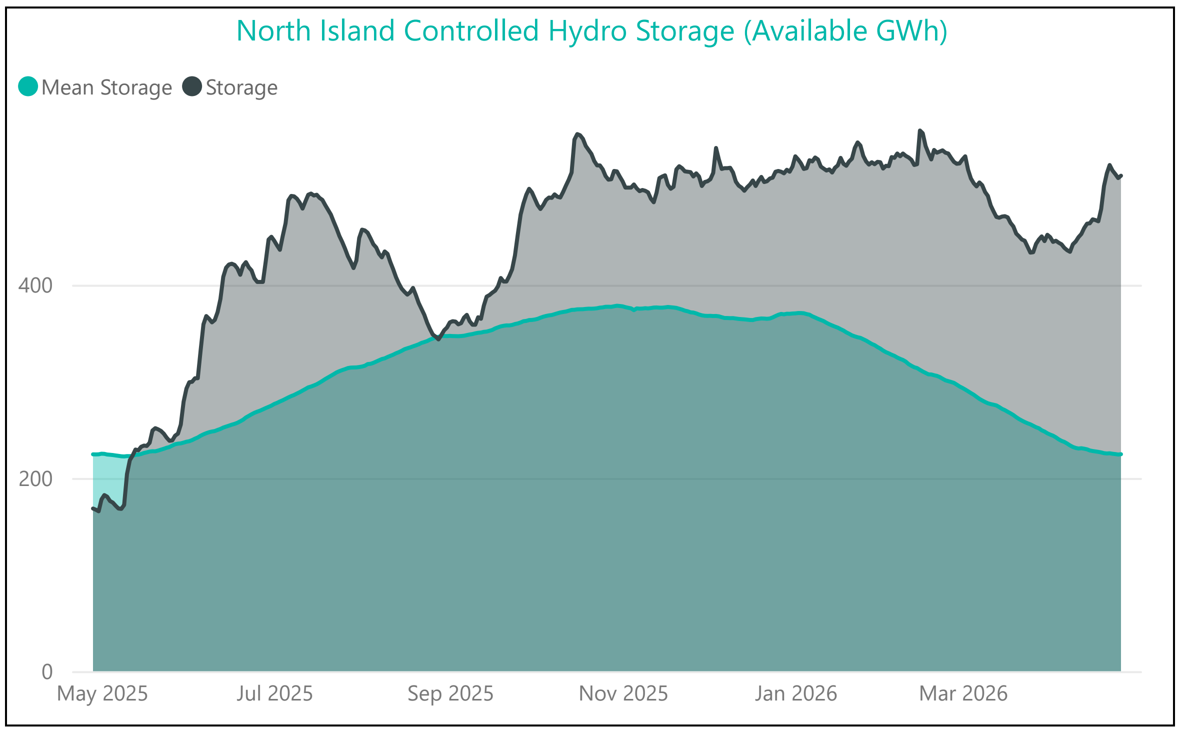


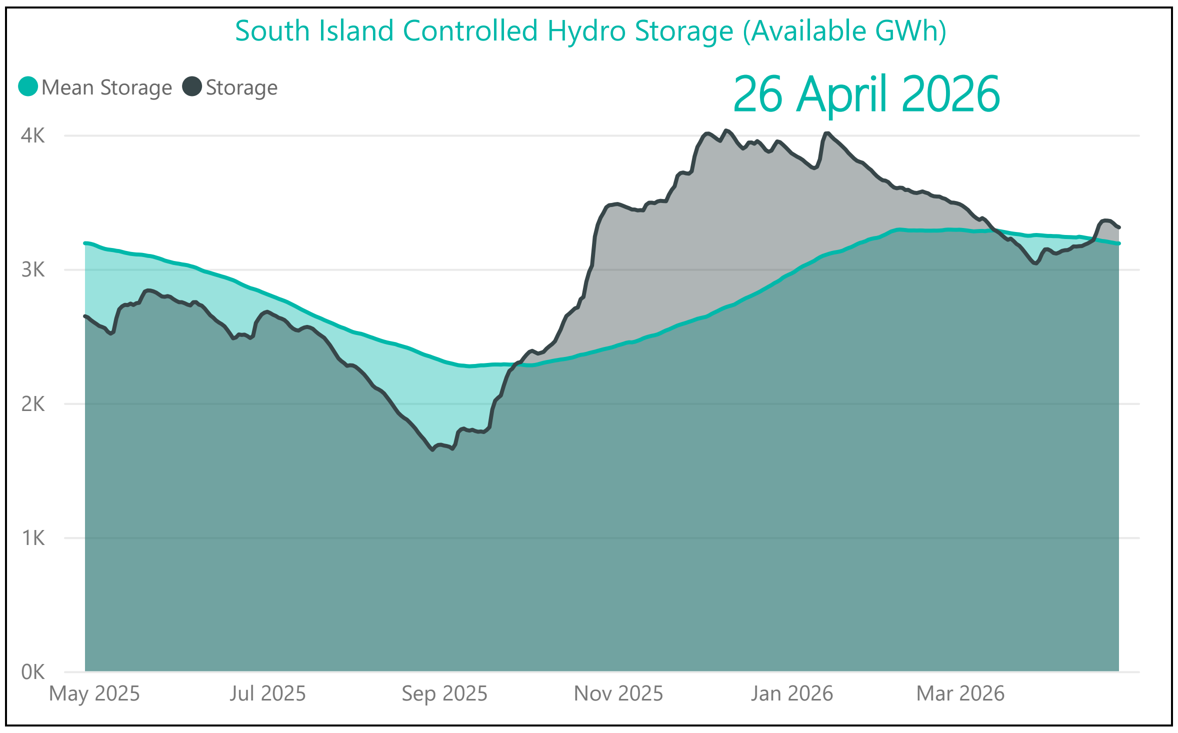
CO2 g/kWh

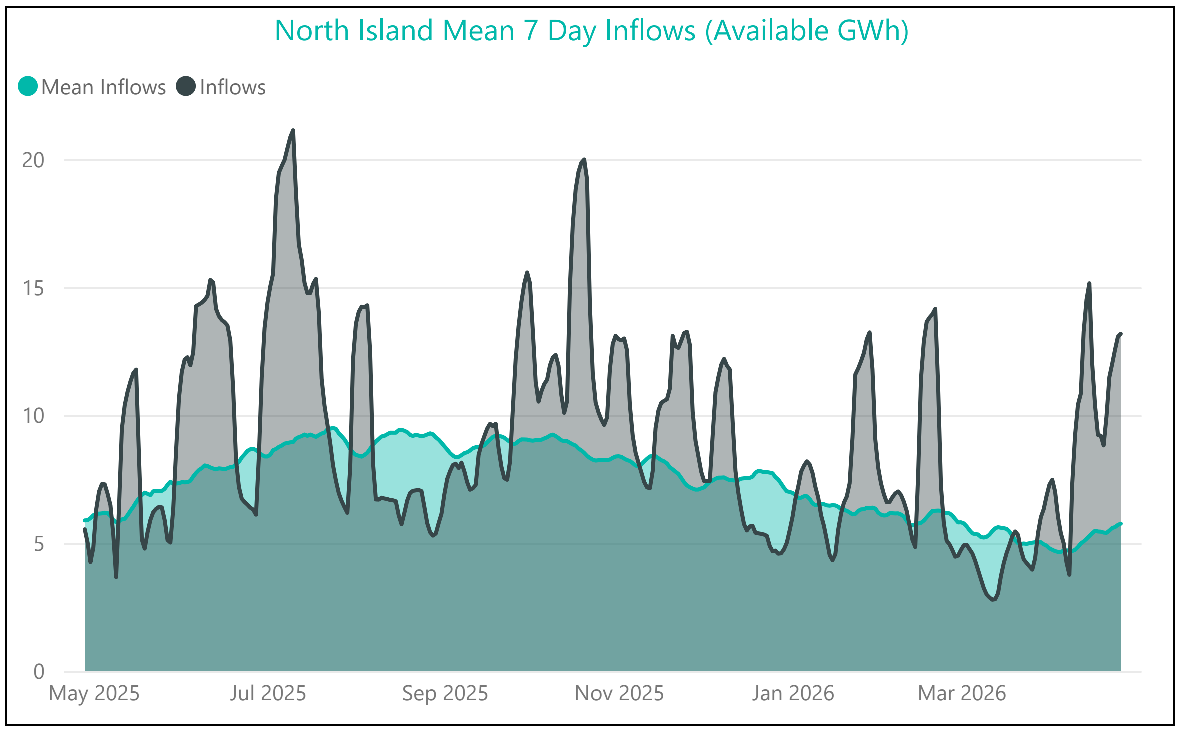


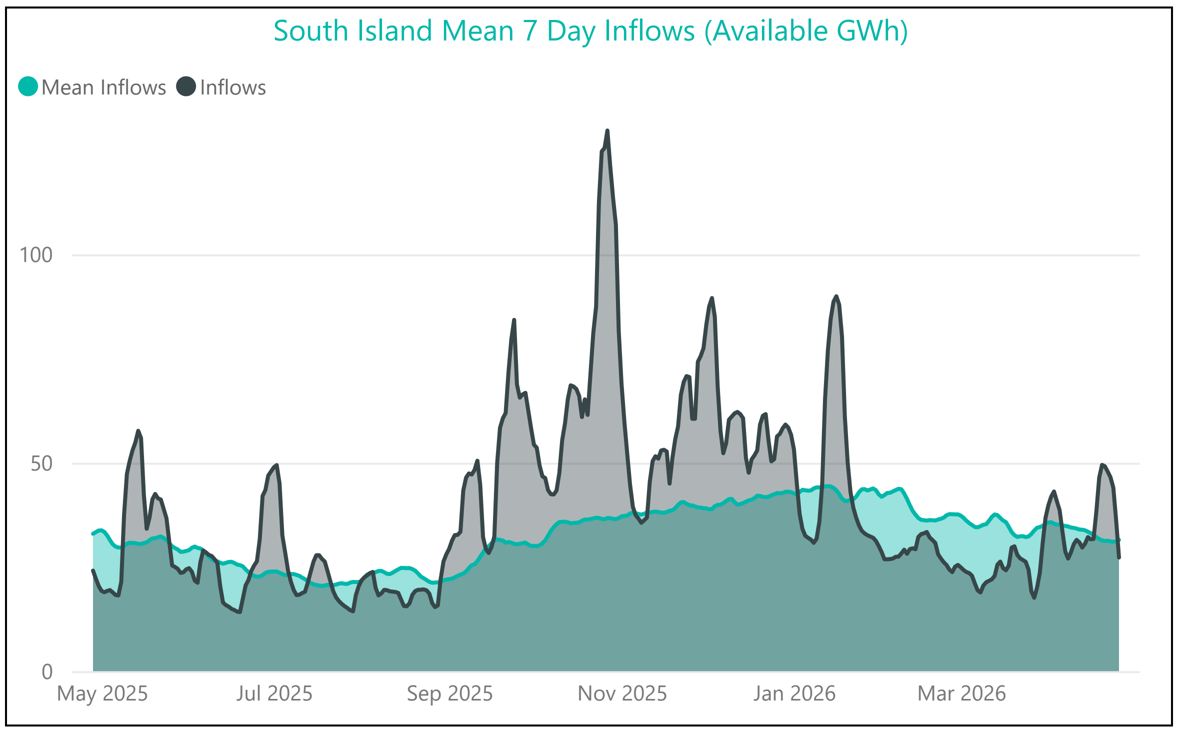
Hydro Storage











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

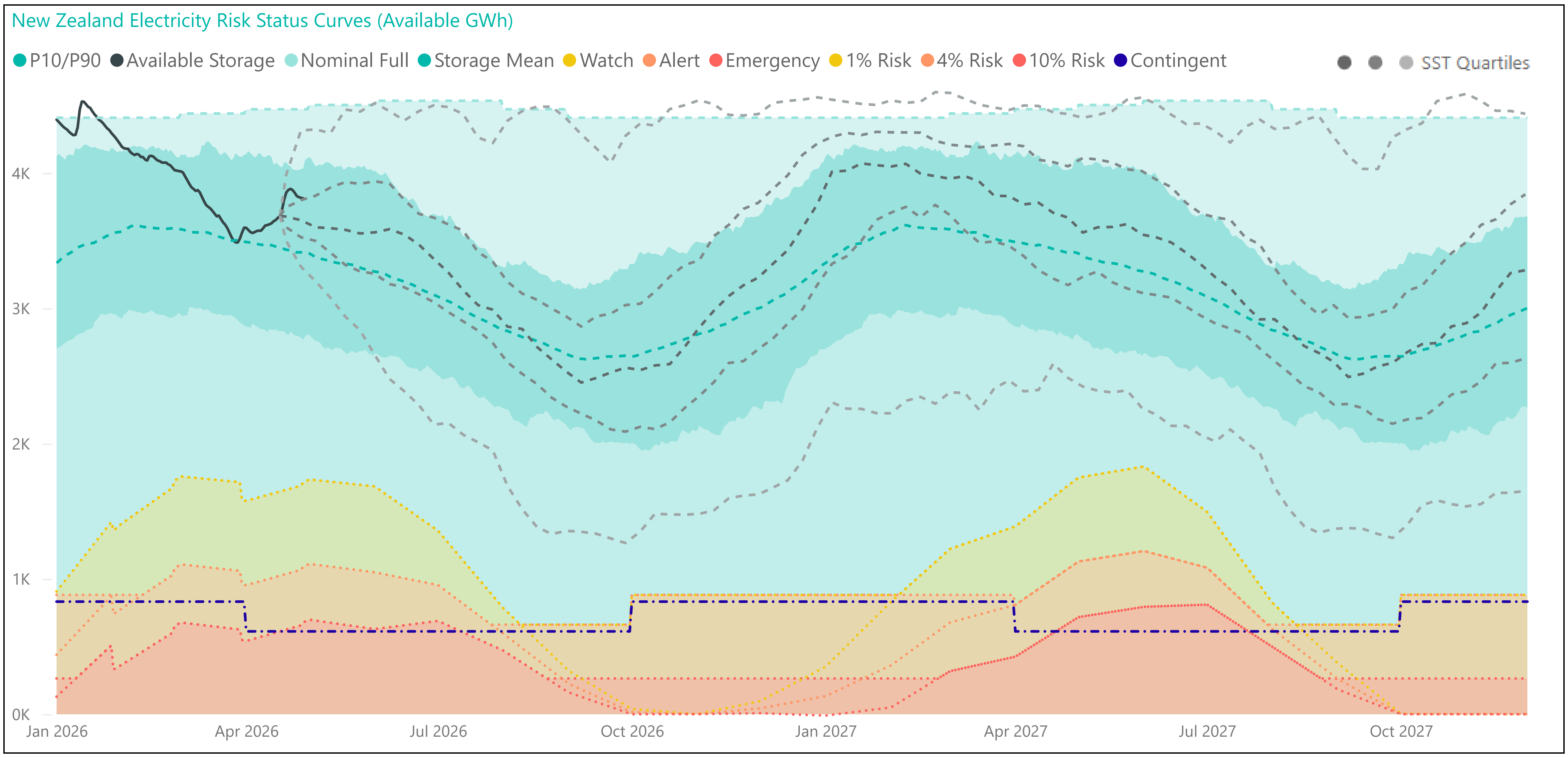
For any inquiries related to security of supply contact market.operations@transpower.co.nz

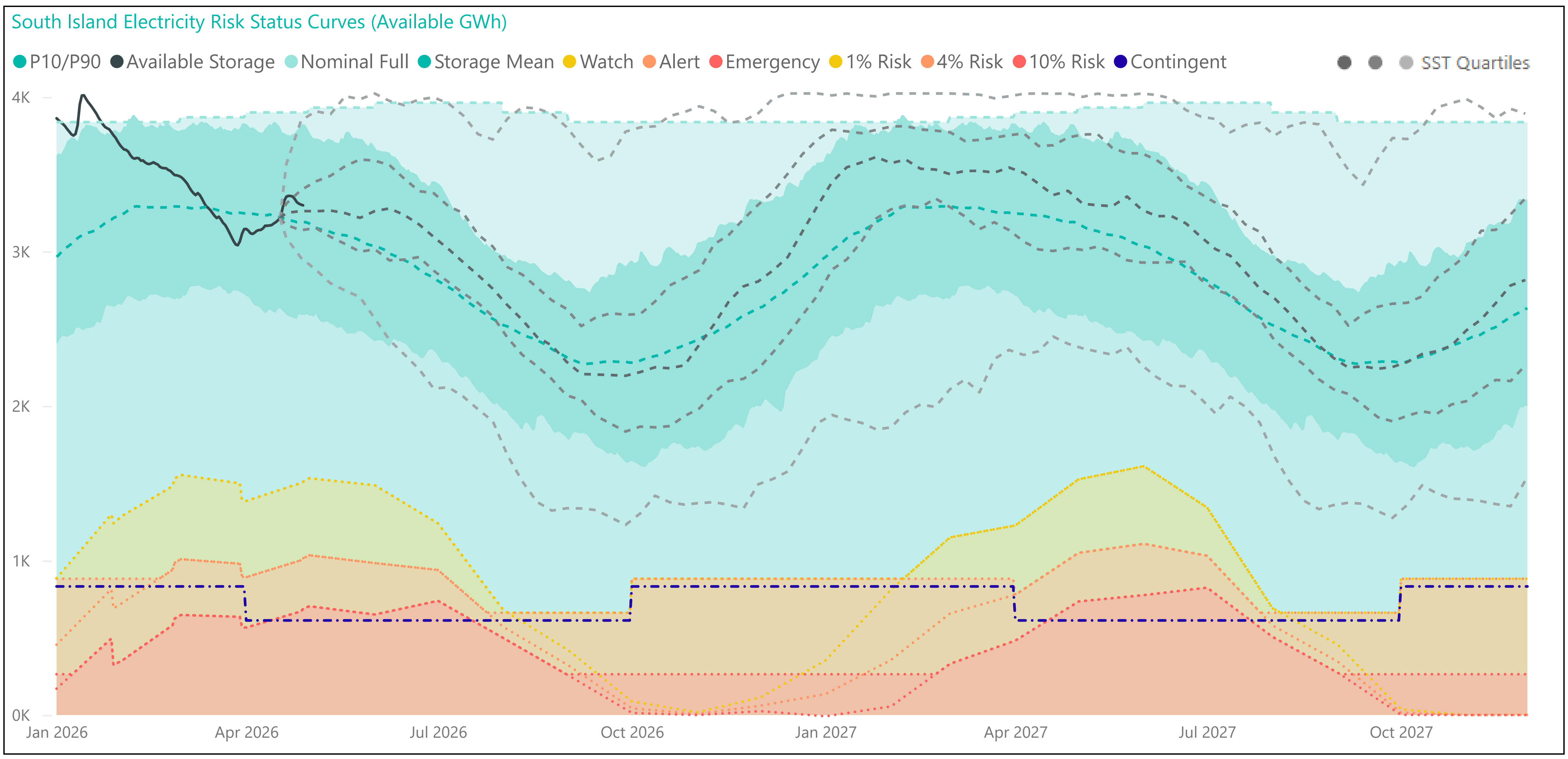
Hydro data used in this report is sourced from *NZX Hydro*.

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).