Market Operations Weekly Report - Week Ended 22 November 2026

Overview

National hydro storage increased by 65 GWh last week, as expected in spring with snowmelt and lower load. It remained steady as a proportion of the seasonal average with a high hydro share of generation compensating for low geothermal output during Wairakei ring outages.

We draw your attention to the low N-1-G margins in the NZGB outlook for 1-3 December, discussed further below. In this week's insight we discuss the recently published System Operator Strategy.

Security of Supply

Energy

Inflows were close to average last week in both islands. South Island storage declined against the seasonal mean from 132% to 131% (despite an increase in absolute terms) with high South Island hydro generation. North Island storage increased to 107% of the seasonal mean from 103%, with Waikato hydro generation lower than average for this time of year.

Capacity

Residual generation was healthy last week. The lowest residual was 833 MW on the evening of Thursday 19 November.

The N-1-G margins in the NZGB forecast fall below 200 MW for Tuesday 1 to Thursday 3 December with multiple concurrent planned generation outages. We recommend that participants consider the flexibility of planned outages during this period and whether the start/end time of the outages can be rescheduled away from the peaks. We also recommend avoiding scheduling further outages during this period that may reduce generation margins.

Margins in the NZGB forecast are otherwise at healthy levels through to mid January. 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 increased last week to 752 GWh from 741 GWh the week prior. The highest demand peak of 5,354 MW occurred at 5:30 pm on Wednesday 18 October.

Weekly Prices

Wholesale electricity spot prices increased last week with the average Ōtāhuhu price up to $71/MWh from $46/MWh the previous week. The Ōtāhuhu price peaked at $214/MWh at 6:00 pm on Wednesday 18 November, coinciding with the week's highest load peak. High North Island reserve prices at the time limited the amount of HVDC north flow that could economically be scheduled, leading to inter-island price separation.

Inter-island energy price separation occurred through most of the week. At times this was caused by the HVDC link reaching its physical limit. At other times it was caused by high North Island reserve prices with the HVDC link setting the North Island risk. Market conditions strongly favoured northward HVDC transfer due to high South Island hydro storage and low North Island geothermal generation. Some large geothermal generators including Tauhara and Ngā Tamariki were on planned outages last week coinciding with Wairakei Ring transmission line outages (THI_WKM and THI_WRK). Constraints between Wairakei and Whakamaru bound at times early in the week as a result of these outages, leading to lower prices at and around Wairakei than in the rest of the North Island.

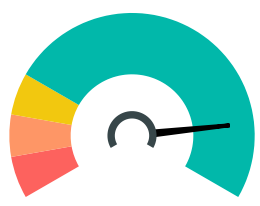
Generation Mix

Geothermal generation contributed 15% of the mix last week, much lower than its 52-week average of 24%. This was largely due to Wairakei ring transmission outages. Hydro generation compensated by generating significantly more than average at 68% of the mix. Thermal generation increased to 2.3% from 1.5% the previous week. Wind and solar remained roughly consistent with recent weeks, at 11% and 4% of the mix respectively.

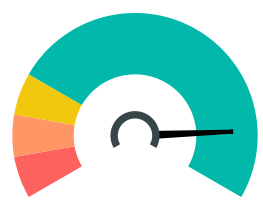
HVDC

HVDC flows last week were entirely northward, consistent with high South Island hydro storage and low North Island geothermal generation. In total 139 GWh was transferred north. This is an average 828 MW of northward flow and sets a new record for weekly northward energy transfer, beating the previous record of 136 GWh set in June 2023.

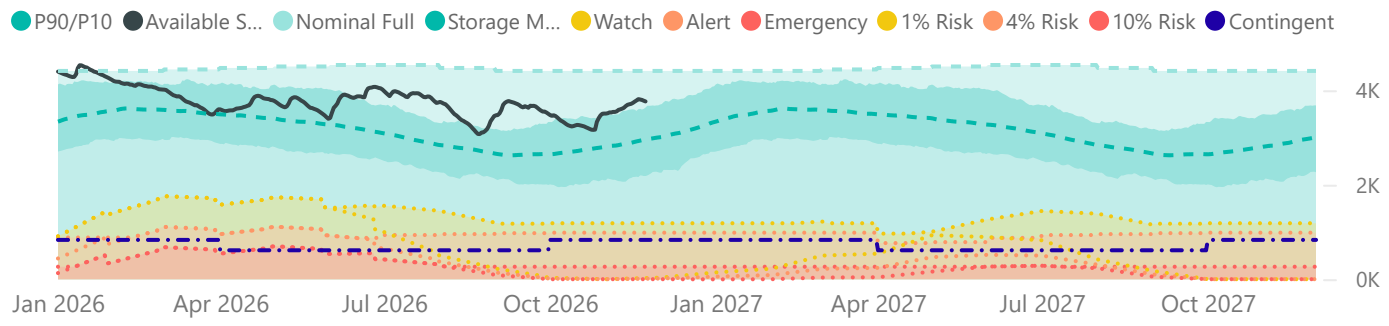
New Zealand Energy Risk



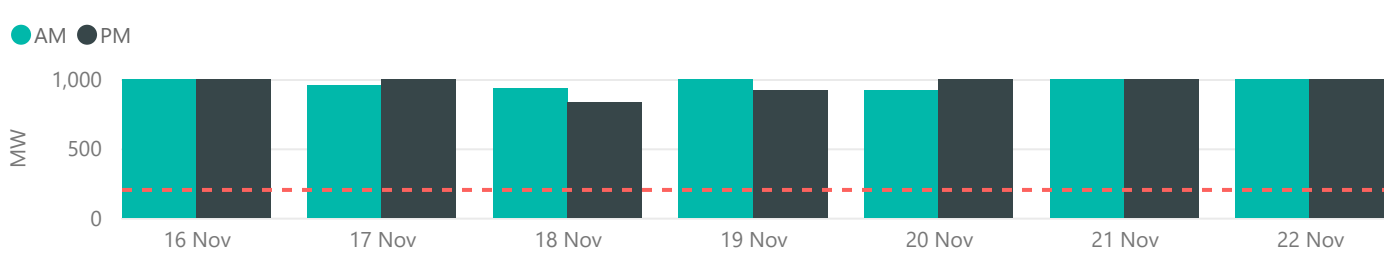
South Island Energy Risk



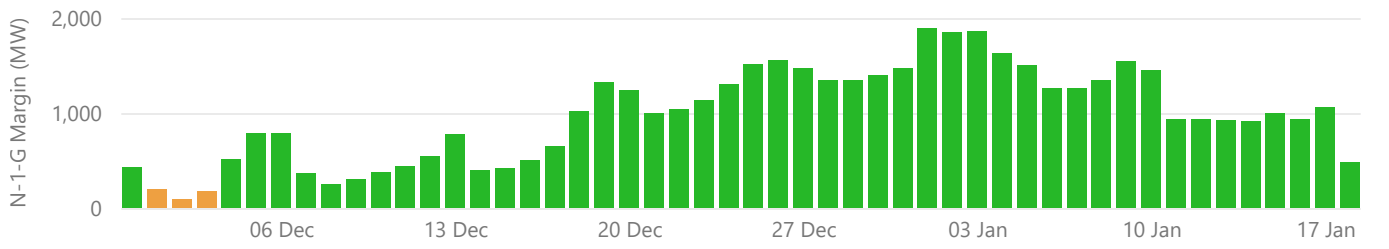
New Zealand Electricity Risk Status Curves (Available GWh)



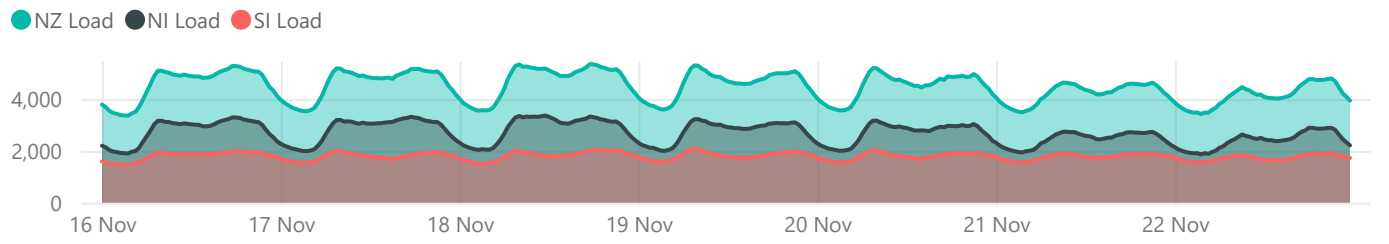
Lowest Residual Points - MW



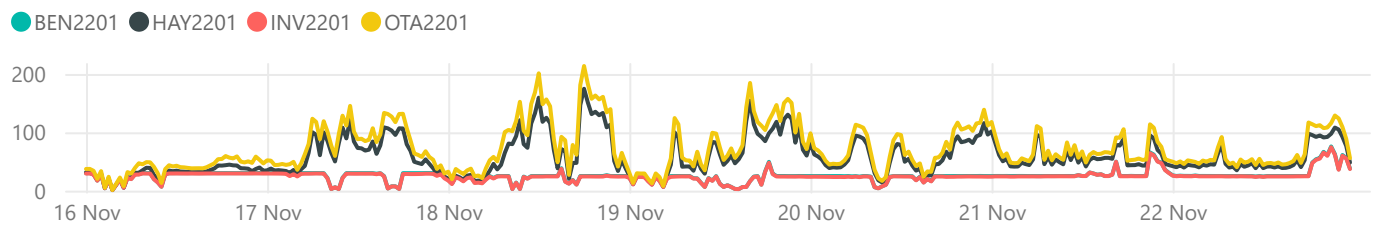
NZGB Look-Ahead (excluding next 7 days)



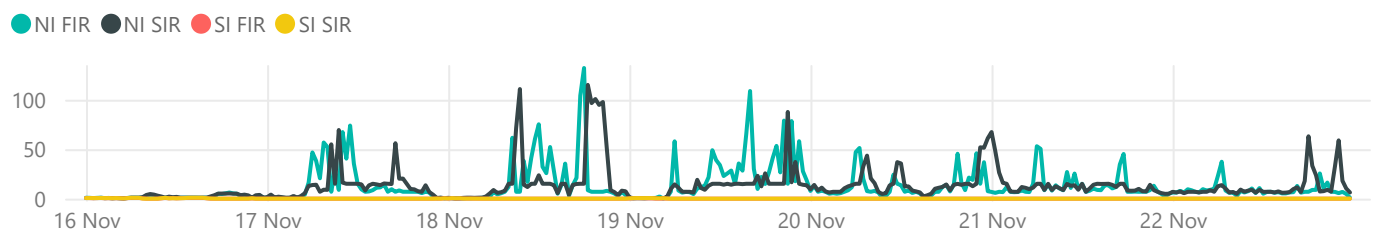
National Demand by Trading period - MW



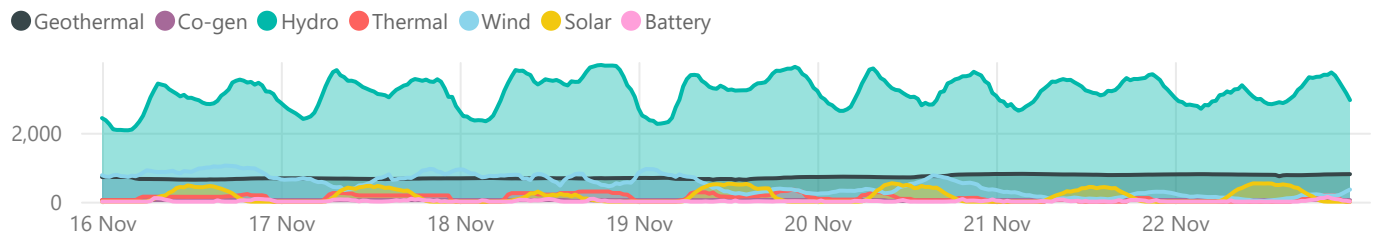
Energy Prices - $/MWh



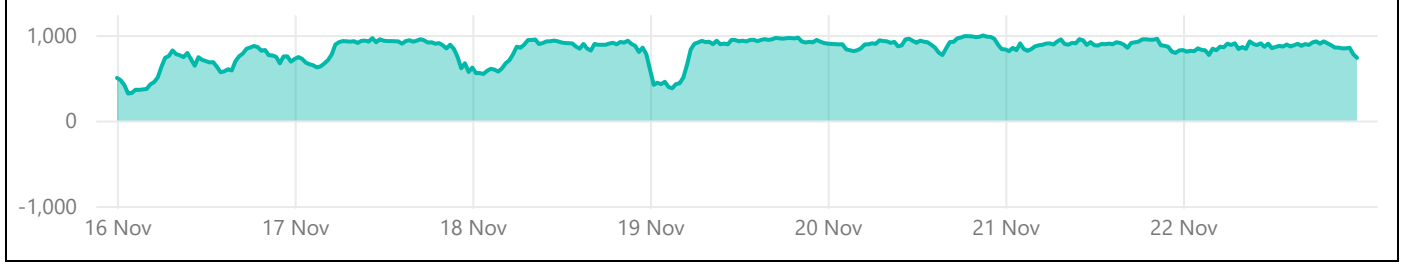
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW (Northward positive)



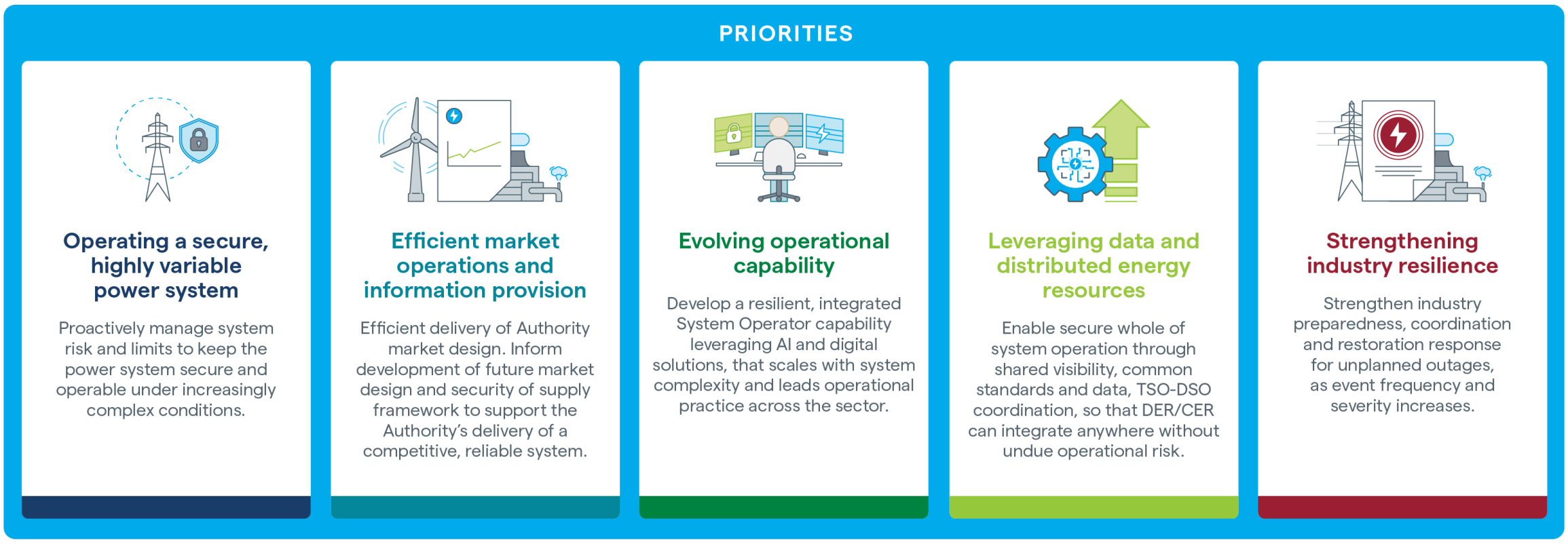
Weekly Insight - Preparing Market Operations for a more variable power system: new System Operator Strategy

This week we published the System Operator Strategy, setting out our priorities for the next three years as we prepare for significant changes to New Zealand's power system over the decade ahead.

These changes are being driven by New Zealand's growing and changing electricity needs, and the transition to a more renewable and increasingly electrified economy. The transformation of the power system will enable greater electrification and economic growth, and our role is to enable that change and continue to operate the system securely, reliably and efficiently.

Meeting this challenge will require changes across the electricity sector, not just within the System Operator. The strategy has therefore been shaped by extensive input from across the sector. Submissions, workshops and conversations with participants have challenged our thinking and helped strengthen both the priorities and the work we have identified to deliver them.

Our five strategic priorities are:
- operating a secure, highly variable power system
- efficient market operations and information provision
- evolving operational capability
- leveraging data and distributed energy resources
- strengthening industry resilience.



More variability requires new ways of operating the system

Significant growth on both the supply and demand sides is increasing the scale and complexity of market operations. More intermittent generation is connecting alongside batteries and distributed and consumer energy resources, while large new loads such as data centres and process-heat conversions can add demand in sizeable steps. These technologies and other changes to patterns of supply and demand will require more active management of the power system, and new capabilities and ways of working.

As the system becomes more complex, we will need to think differently about scheduling, dispatch and ancillary services. Clear market signals will enable participants to respond to system conditions, supporting real-time security at least cost to consumers while reducing the need for direct System Operator intervention.

A lot of the work needed to respond is already underway. Over the next three years we will make improvements while identifying and preparing for more transformational changes as the power system continues to evolve.

Unlocking the potential of new technologies while maintaining real-time security

Our Scheduling, Pricing and Dispatch (SPD) system is one example. We will identify a clear set of prioritised limitations in SPD to account for the increasing need to accommodate intermittent generation, battery energy storage systems (BESS), distributed energy resources (DER), consumer energy resources (CER), growing industrial load and maturing distribution system operator (DSO) capabilities. This will give us a foundation from which to work with the Electricity Authority to scope potential market design initiatives for their consideration and to determine future investments in market systems across a longer timeframe while maintaining real-time security.

Better forecasting and more flexible ancillary services will be required

Forecasting will become more sophisticated too, including regional P10, P50 and P90 solar, wind and demand forecasts and probabilistic scenario analysis. This will improve our ability to understand the range of possible system conditions and manage security as we move closer to real time. Longer term, the strategy anticipates exploring real-time dispatch tools where system security depends on near-real-time probabilistic forecasts.

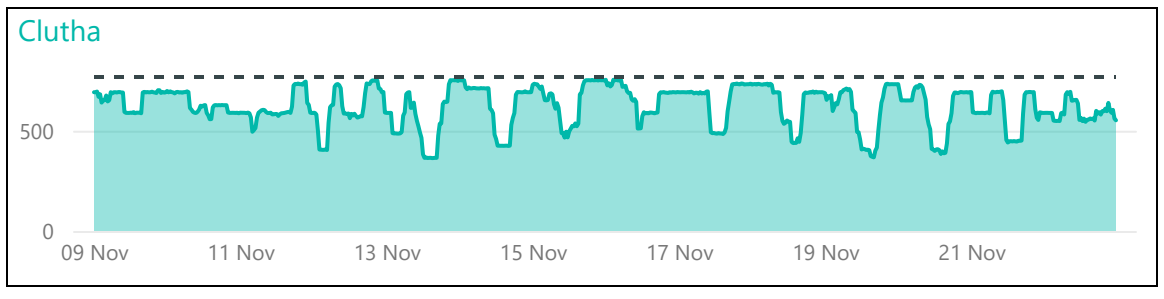
Ancillary services will evolve alongside this, including enabling greater participation from BESS and load. Future work may include new frequency-stability services and options to manage risks associated with low system strength.

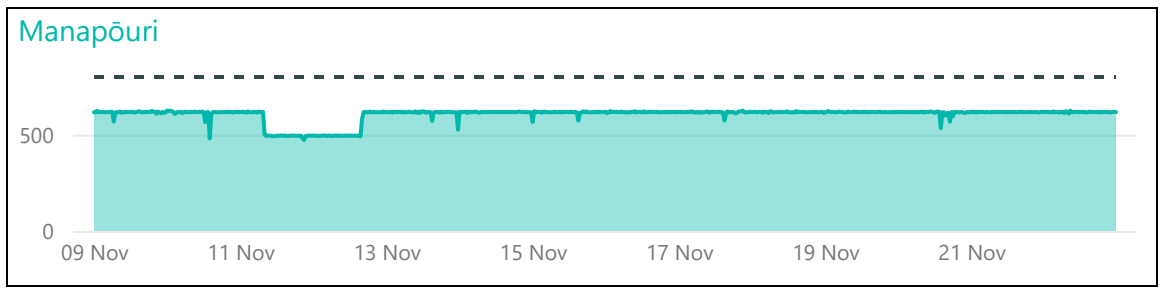
Continued collaboration with market participants and the Electricity Authority will be critical as we move from strategy into delivery and ensure our market arrangements, information and operational tools keep pace with the changing power system.

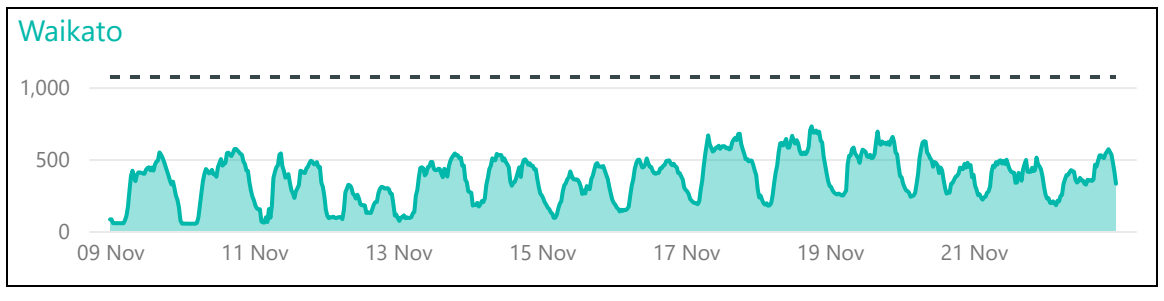
Read the strategy on our website.

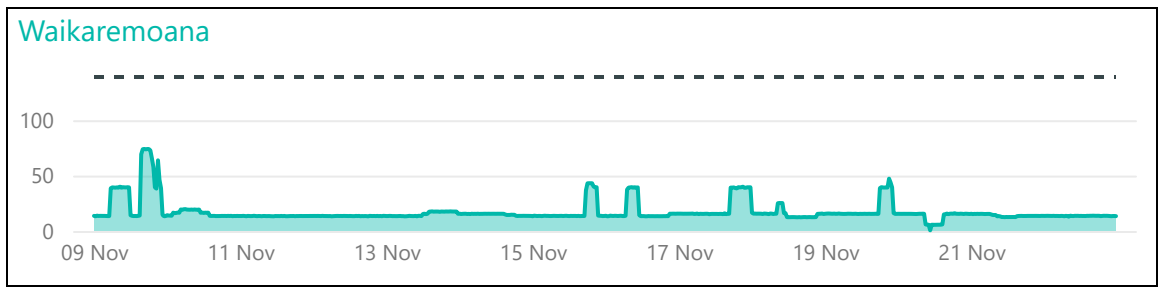
Generation Breakdown - Last Two Weeks

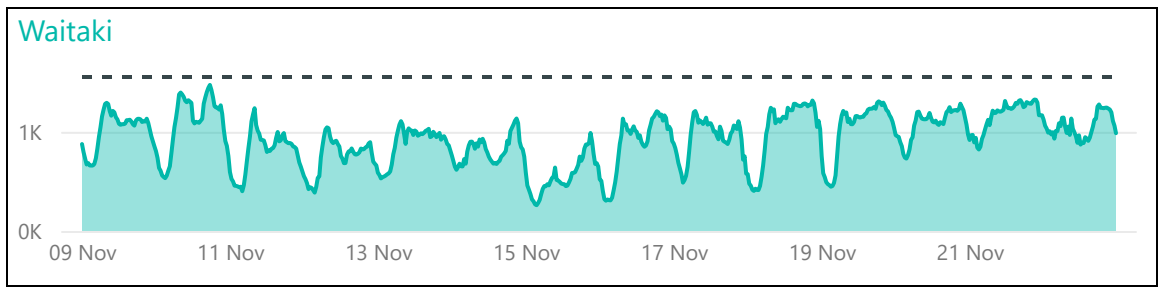
Measured in MW and displayed at trading period level for last 14 days

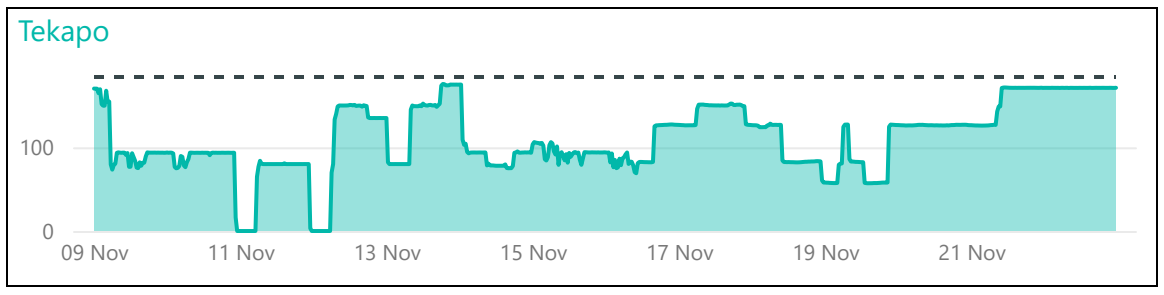


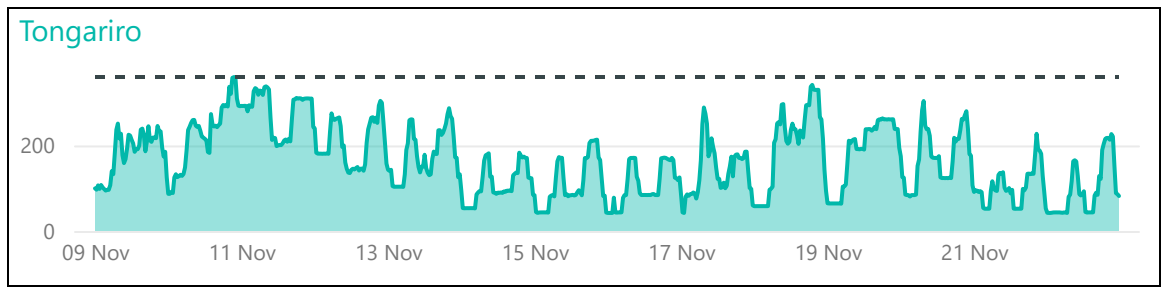


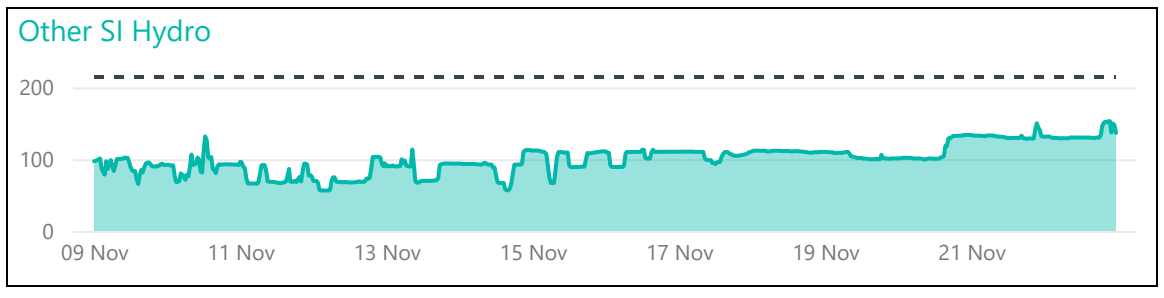


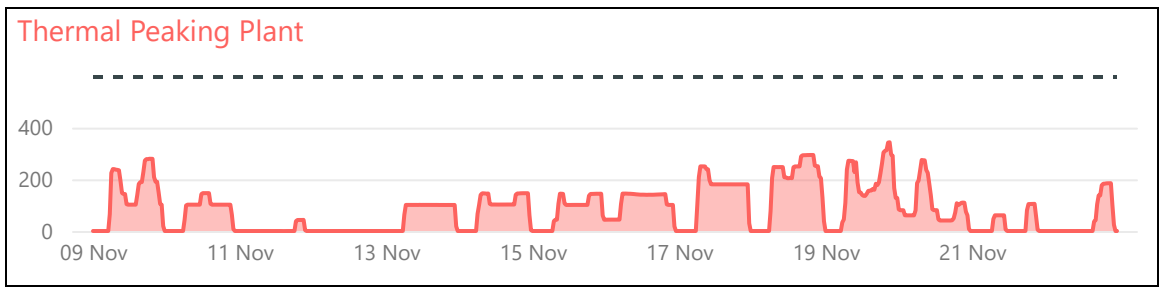


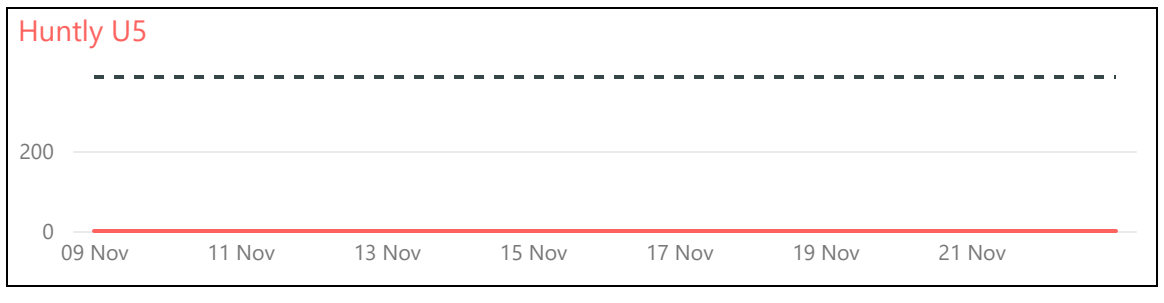


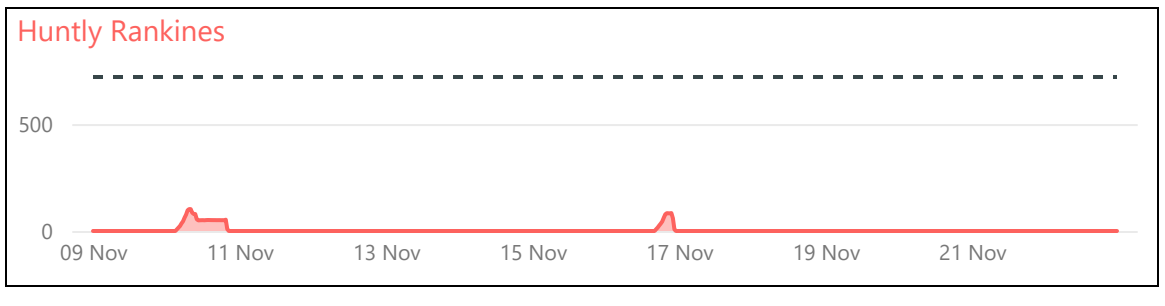


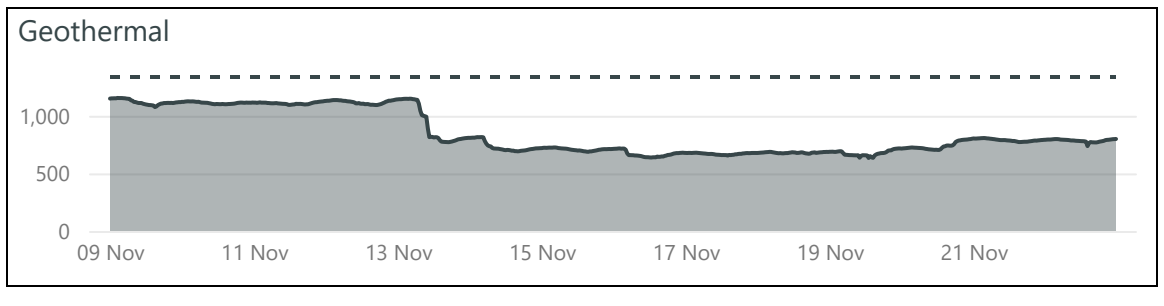


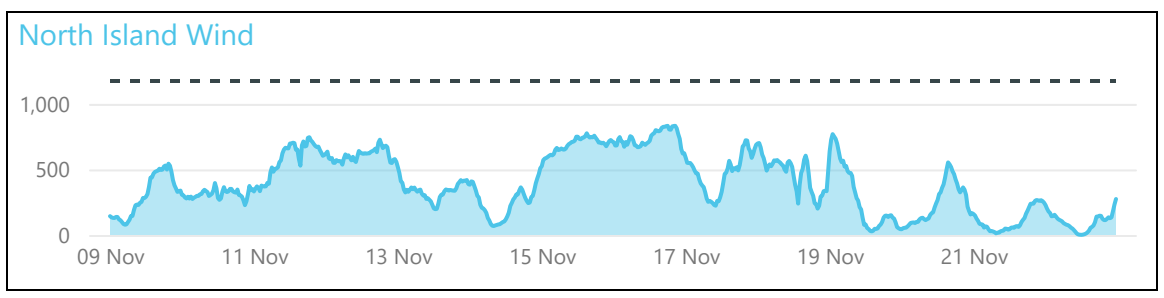


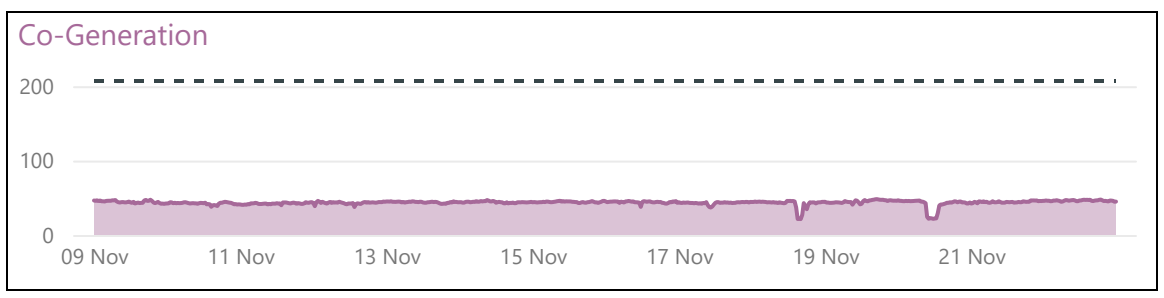


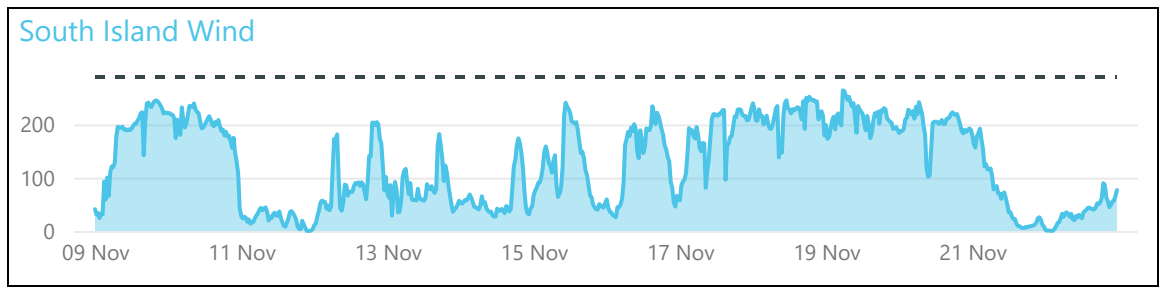


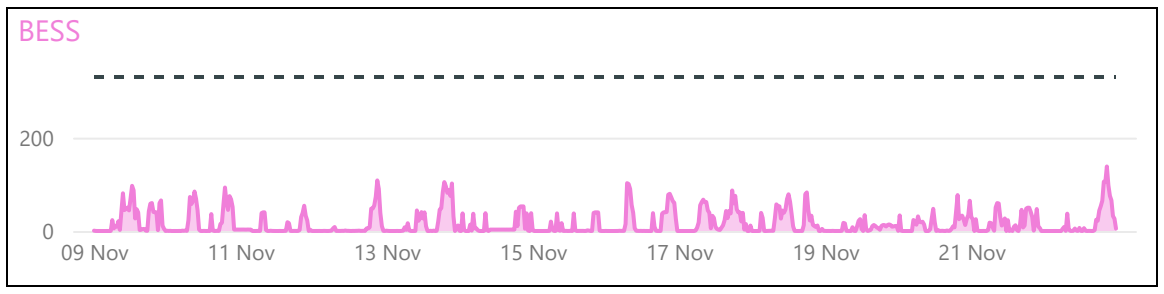


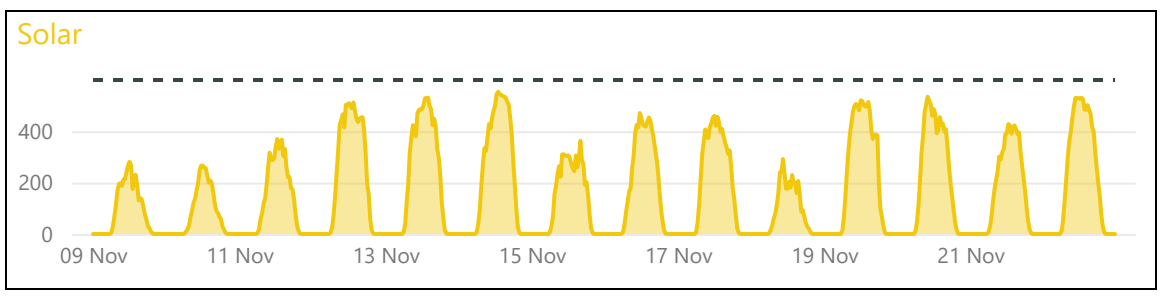






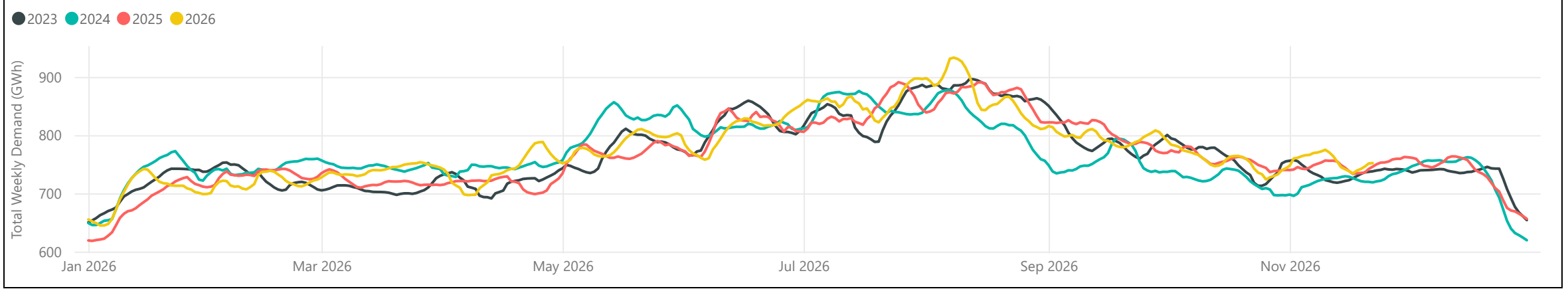




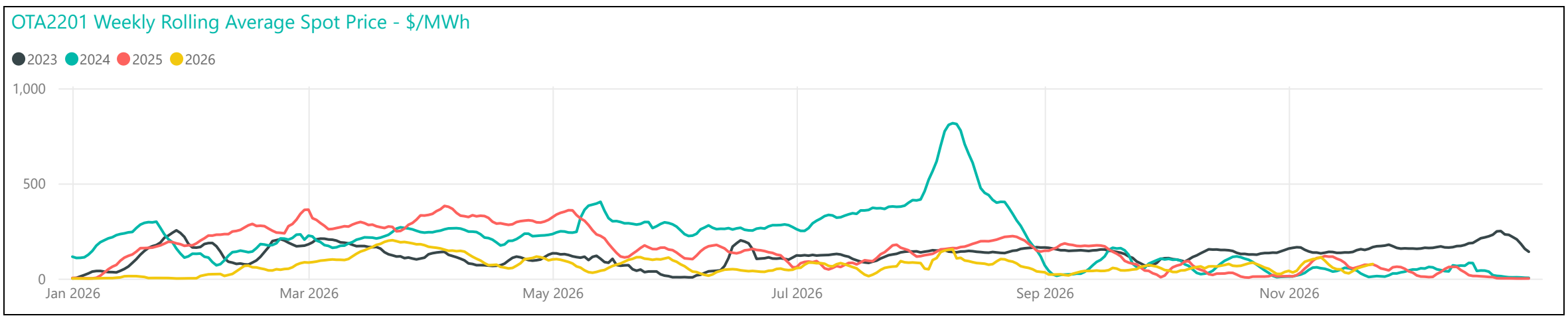


Weekly Profiles

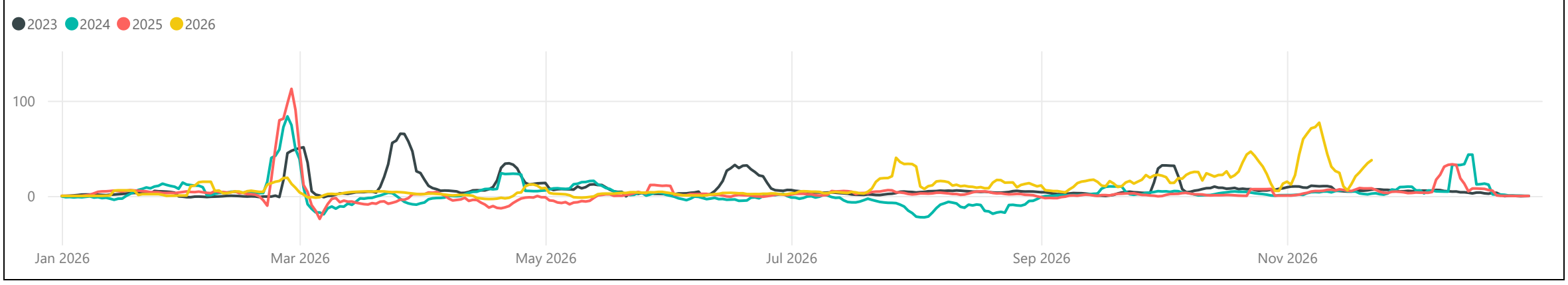
National Weekly Demand - GWh - 7 Day Rolling



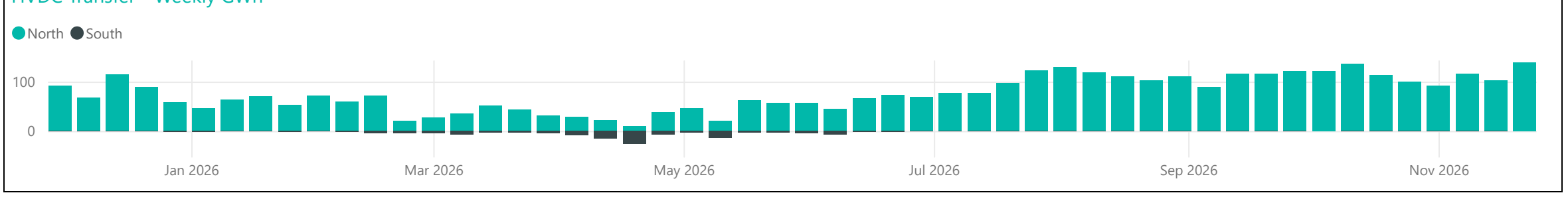
OTA2201 Weekly Rolling Average Spot Price - $/MWh



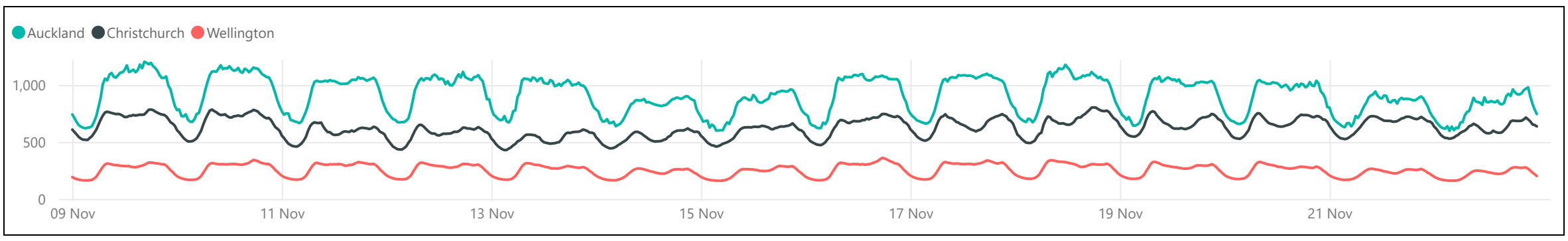
Weekly Rolling Price Separation (HAY2201 - BEN2201) - $/MWh



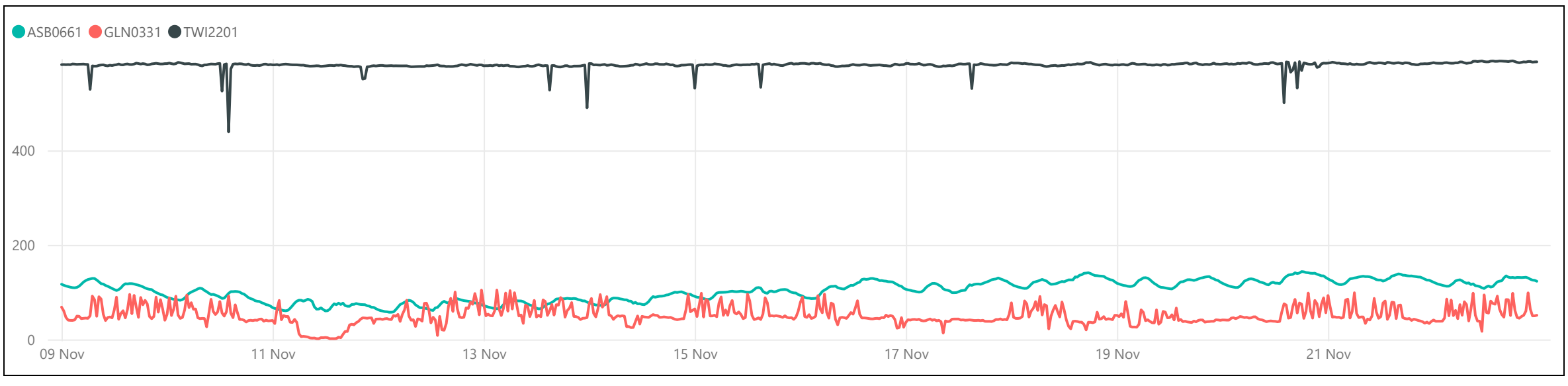
HVDC Transfer - Weekly GWh



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



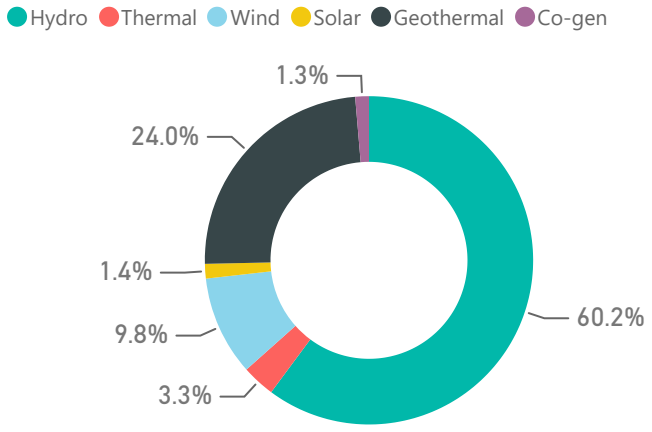
Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*



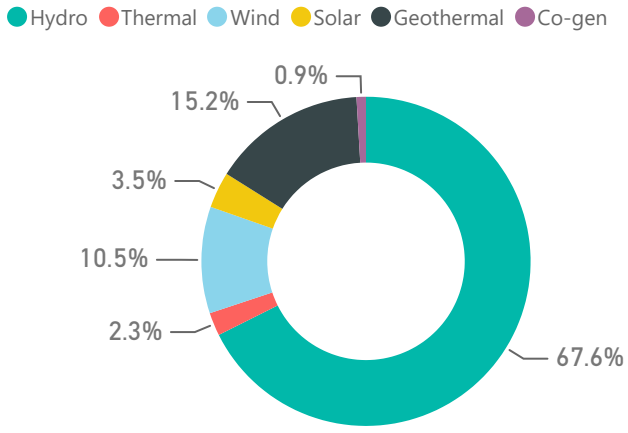
TRANSPOWER

Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



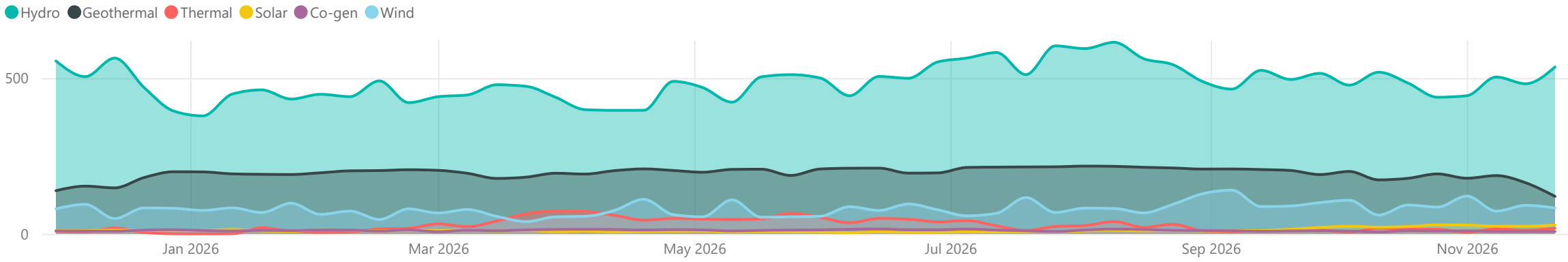
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
97%	19,380	23.7

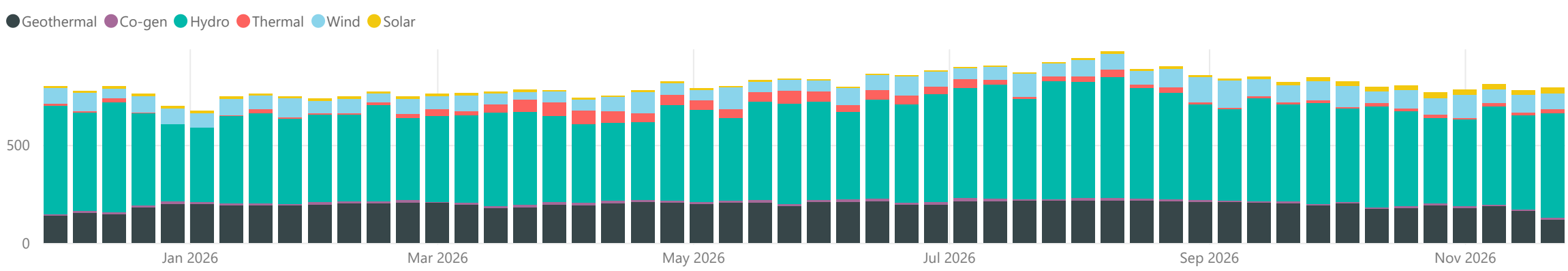
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
95%	34,335	41.9

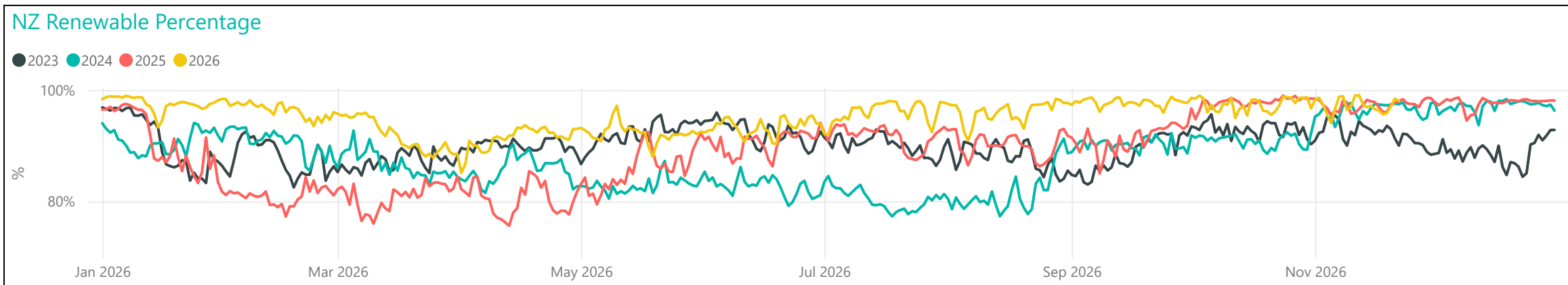
Weekly Generation Mix - GWh



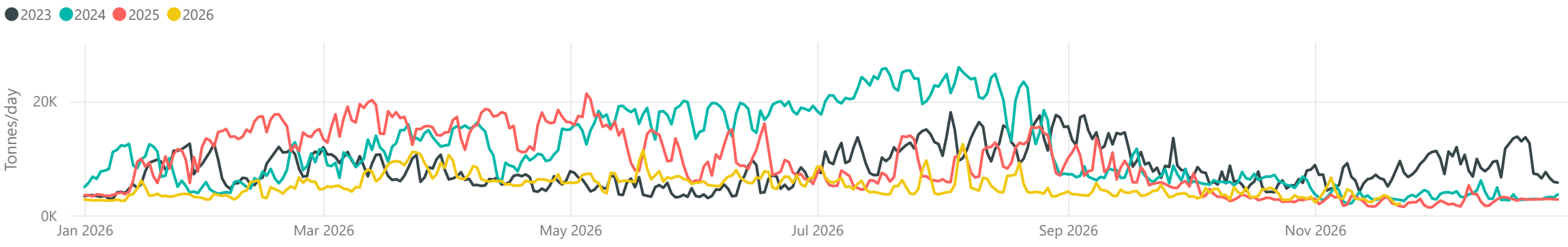
Weekly Generation Mix - GWh



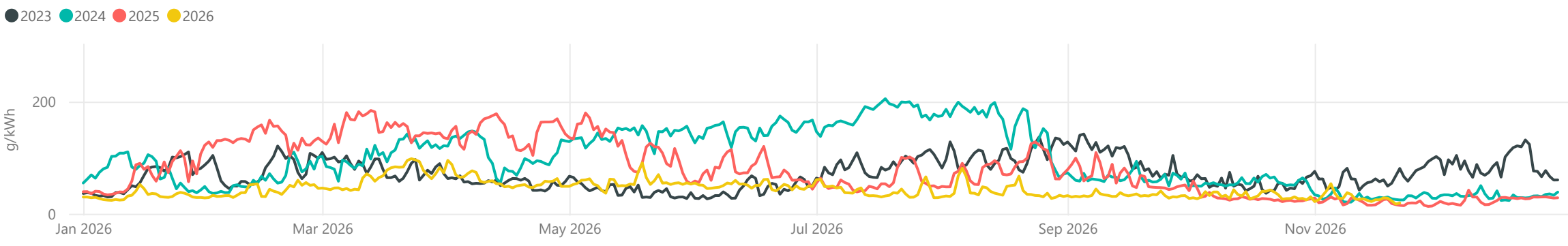
NZ Renewable Percentage



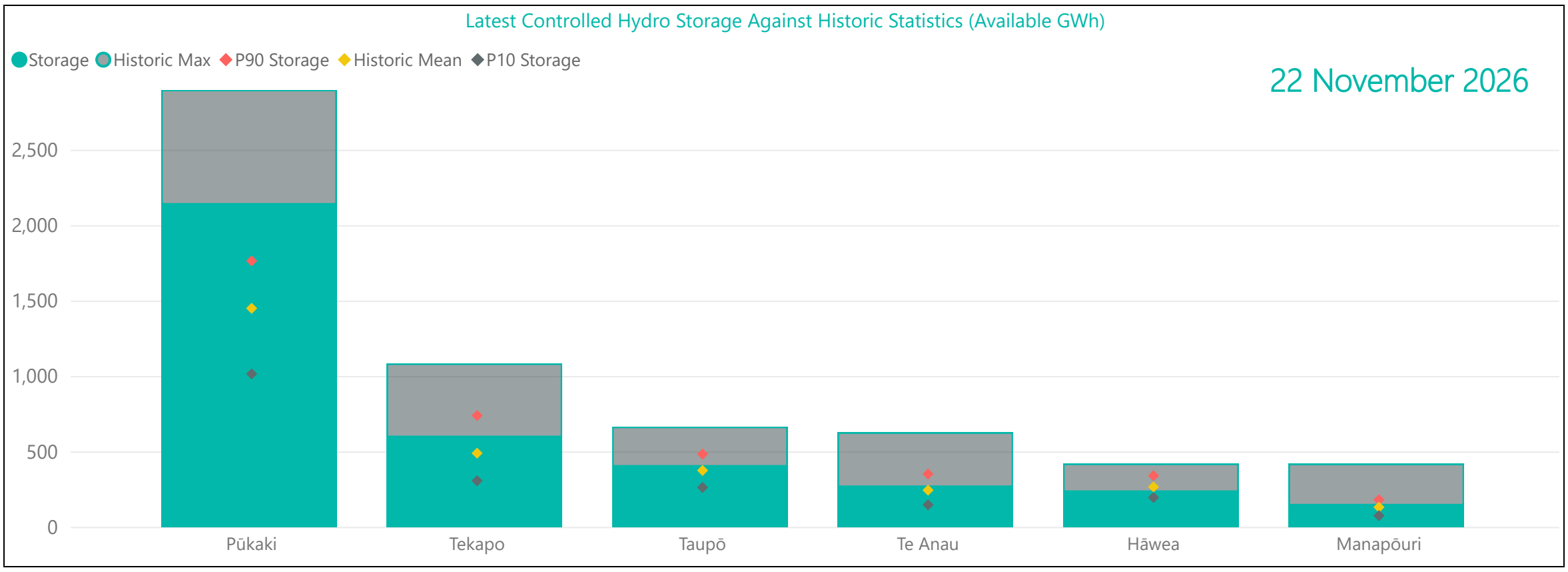
CO2 Tonnes/Day

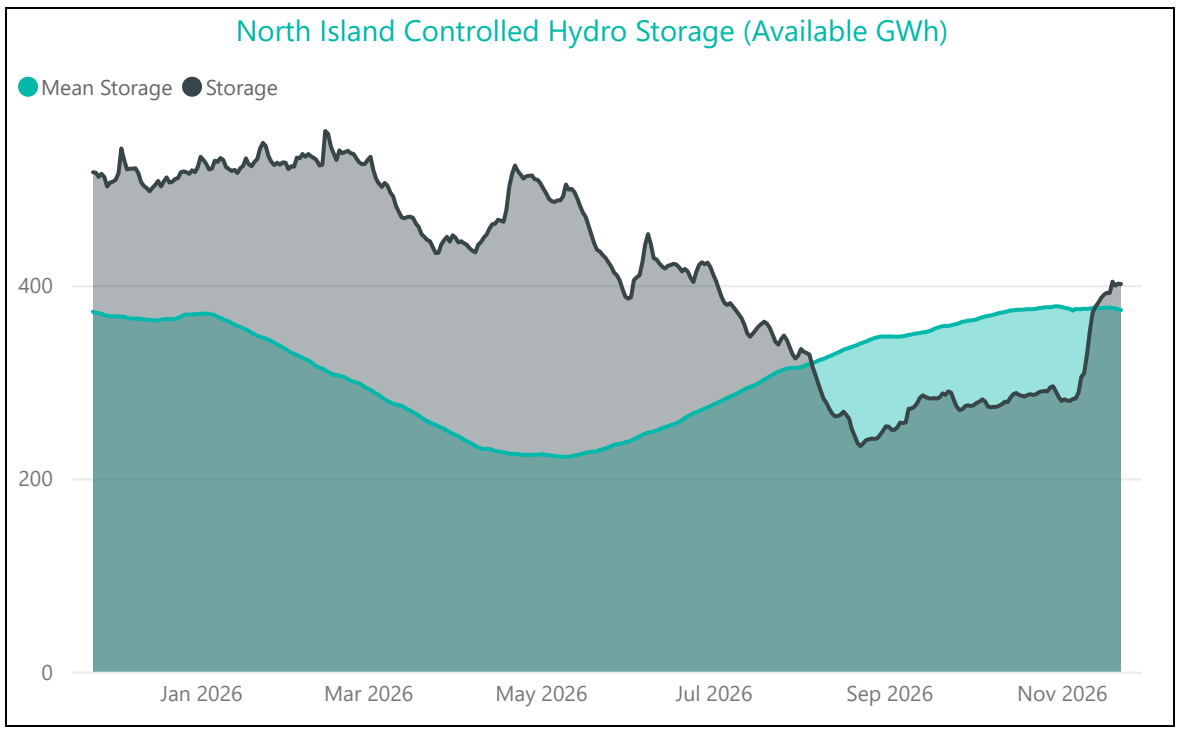


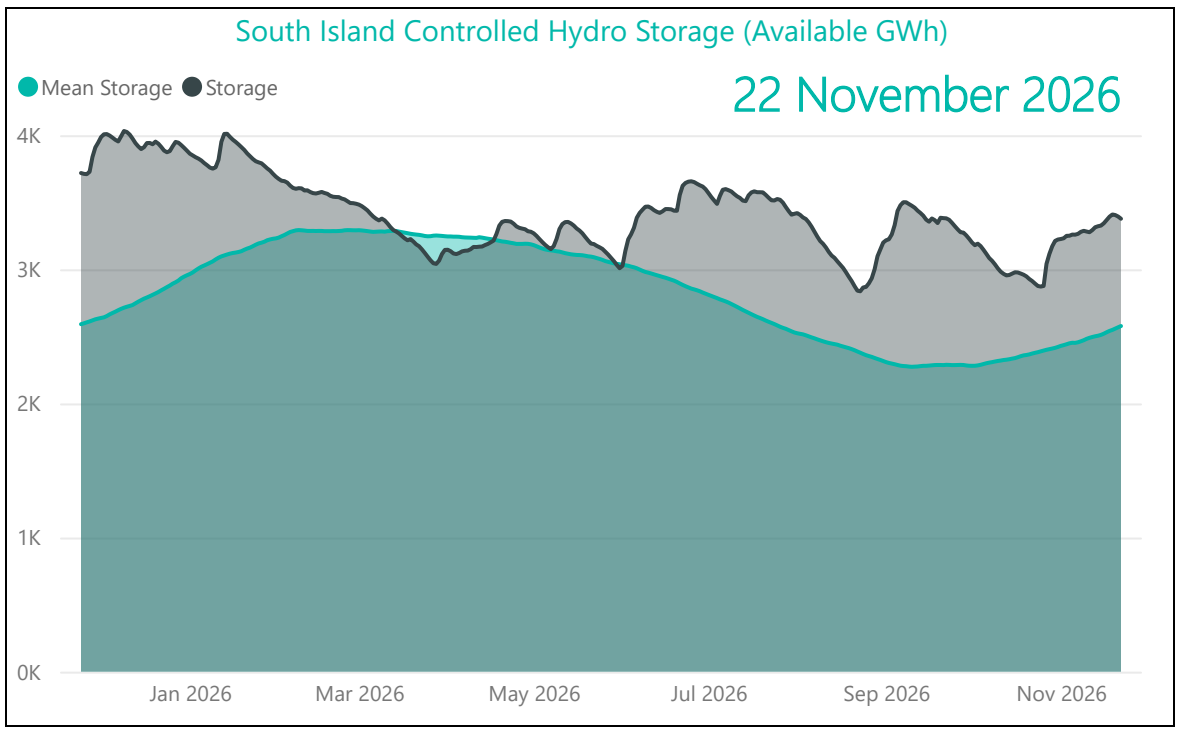
Average CO2 g/kWh

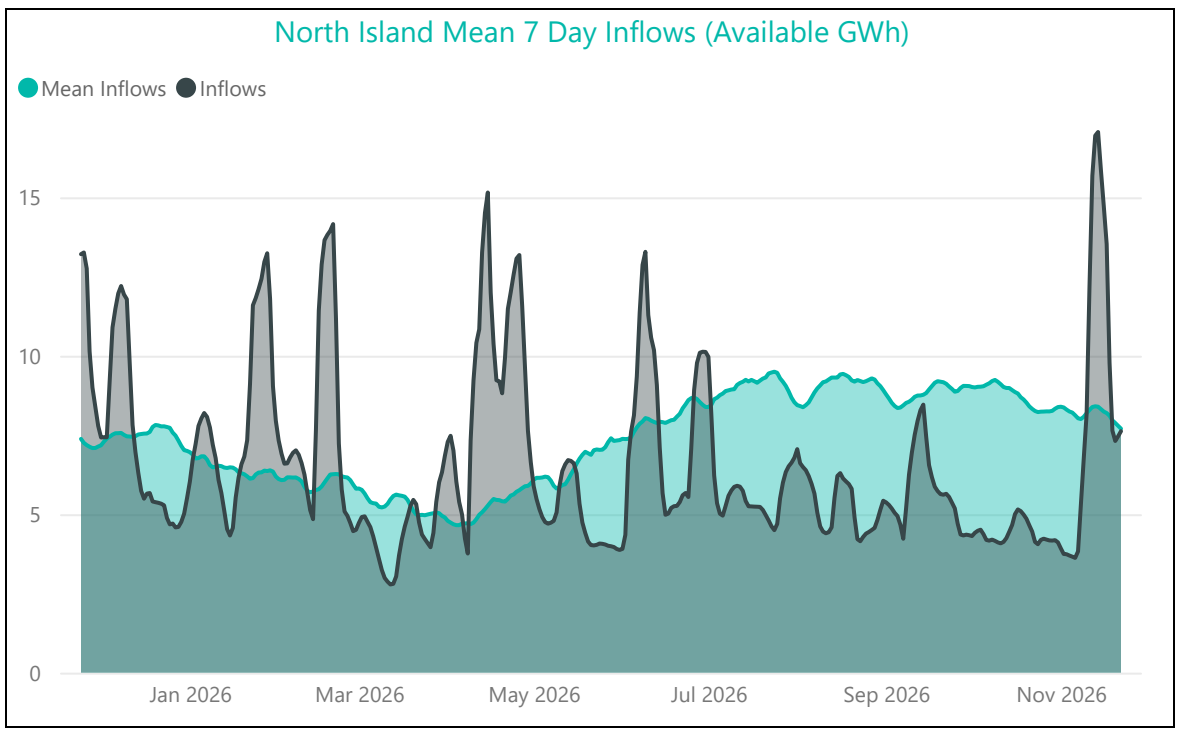


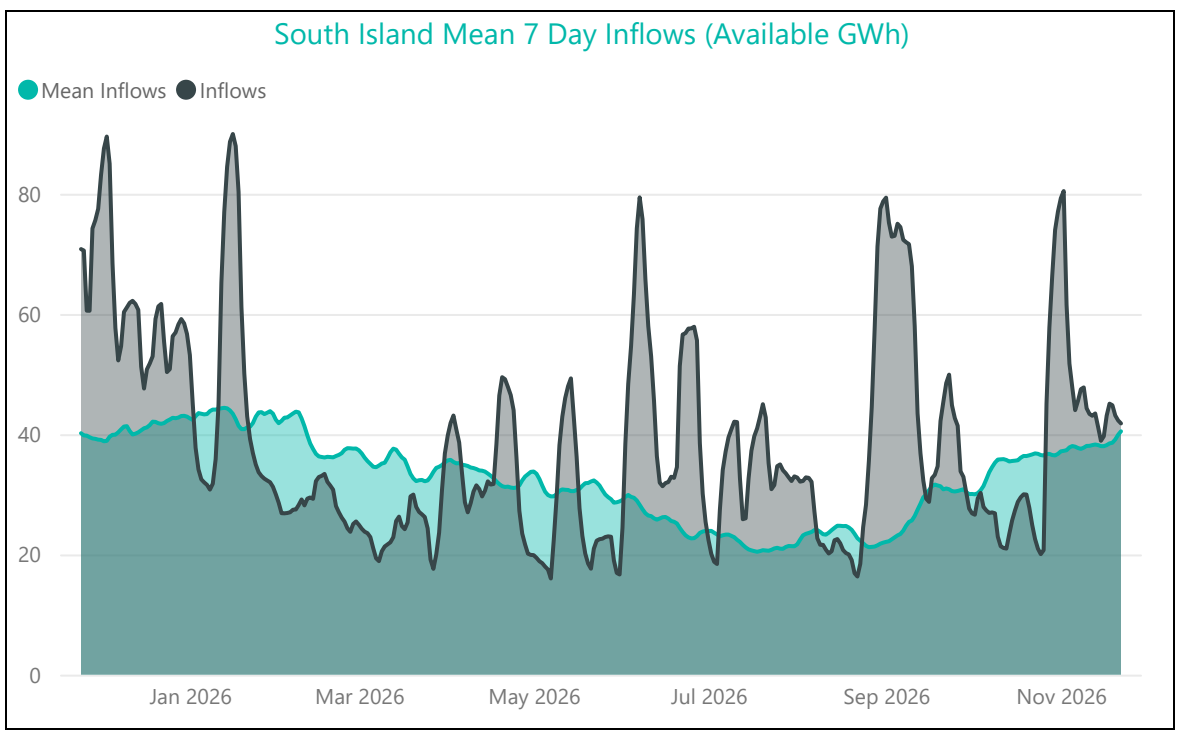
Hydro Storage











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

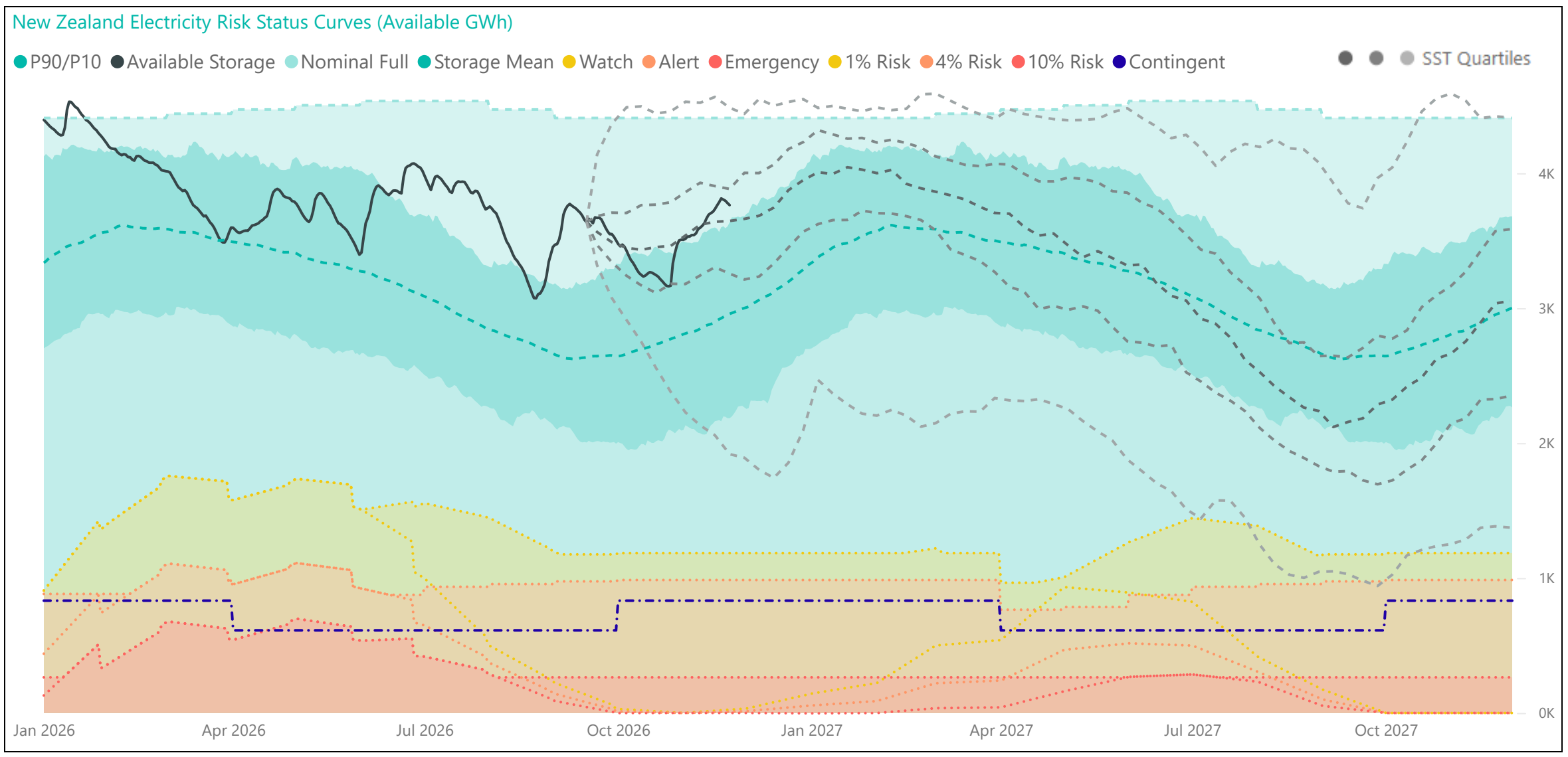
For any inquiries related to security of supply contact market.operations@transpower.co.nz

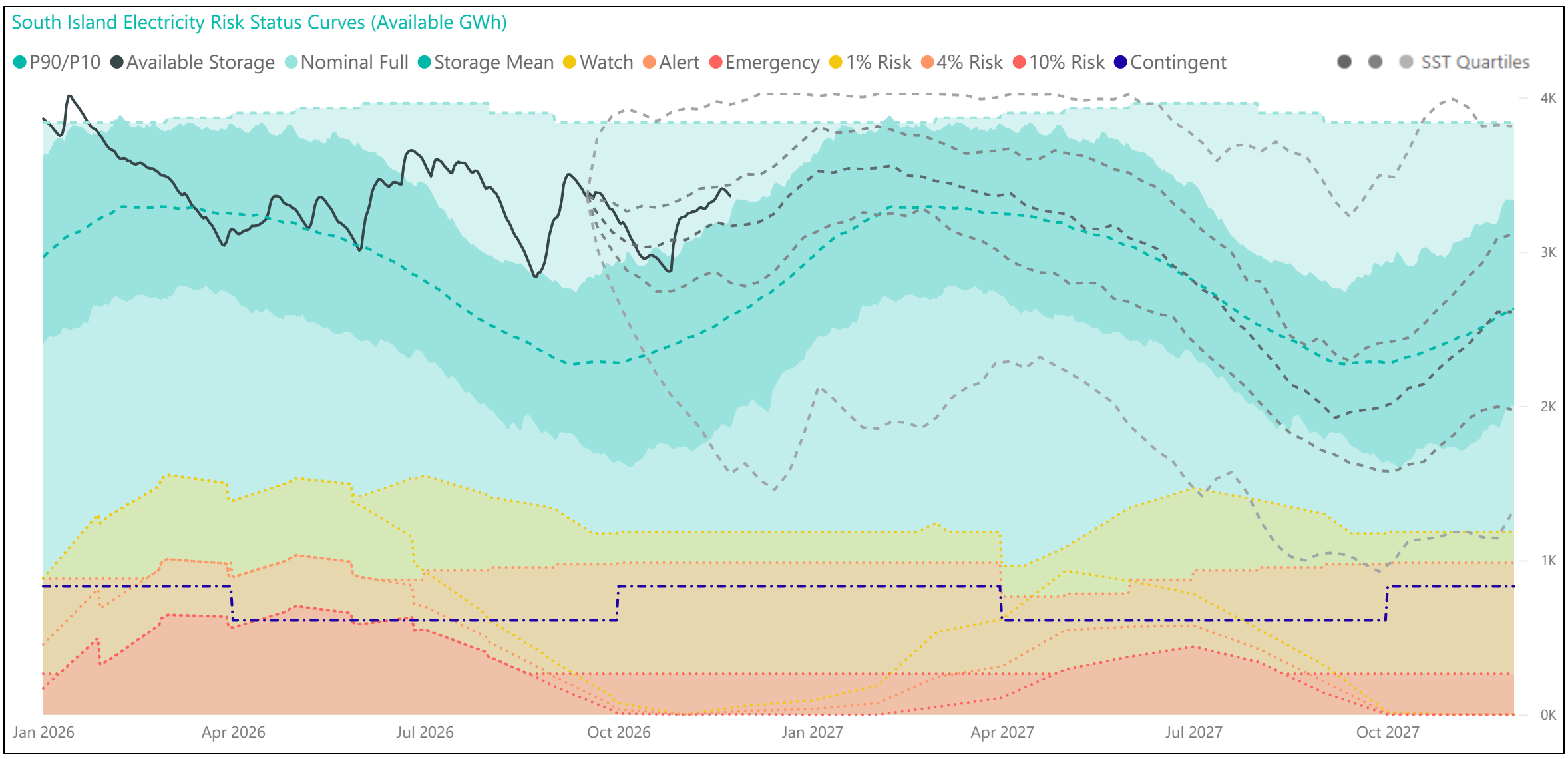
Hydro data used in this report is sourced from *NZX Hydro*.

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





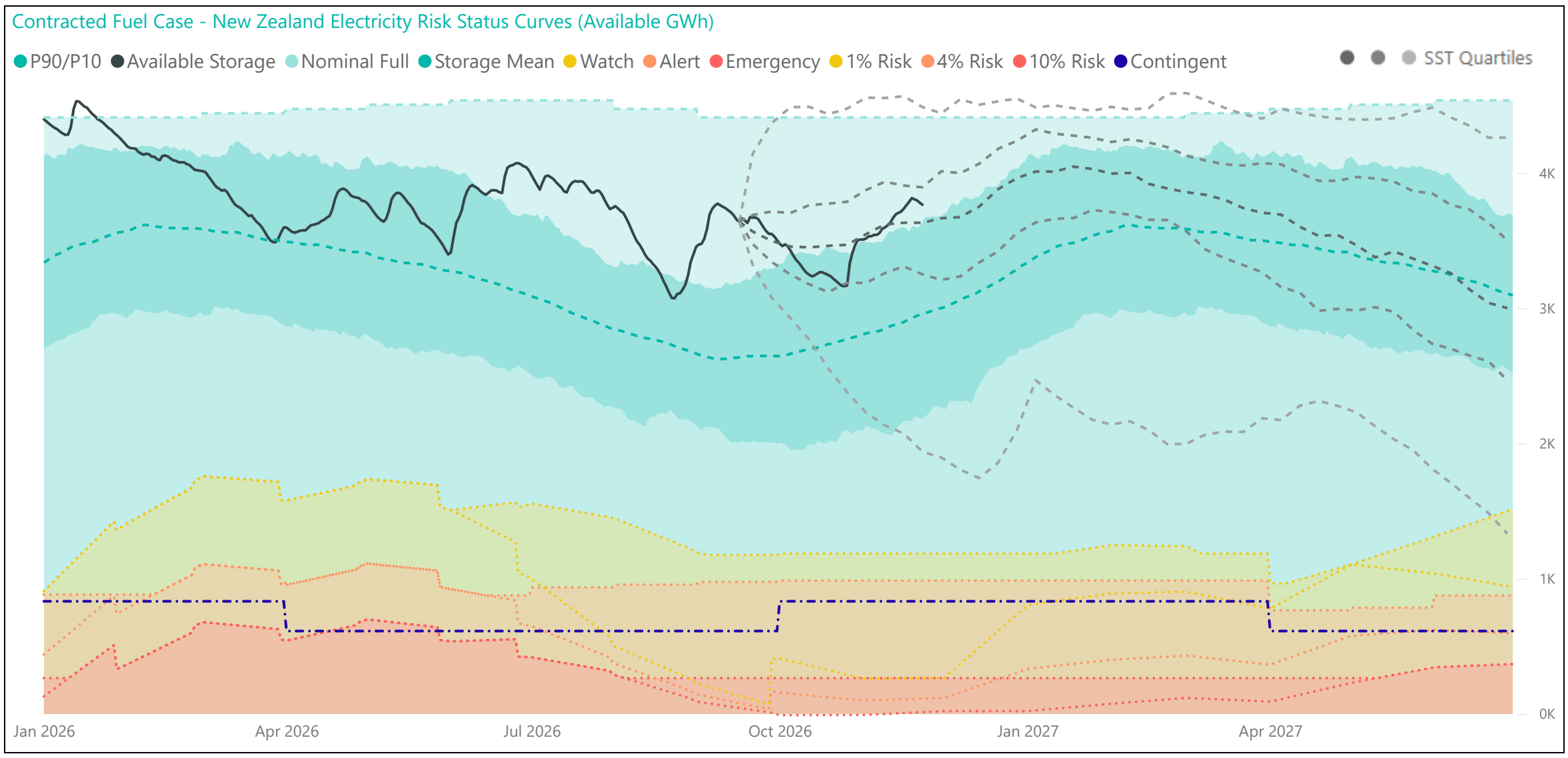
Electricity Risk Curve Explanation:

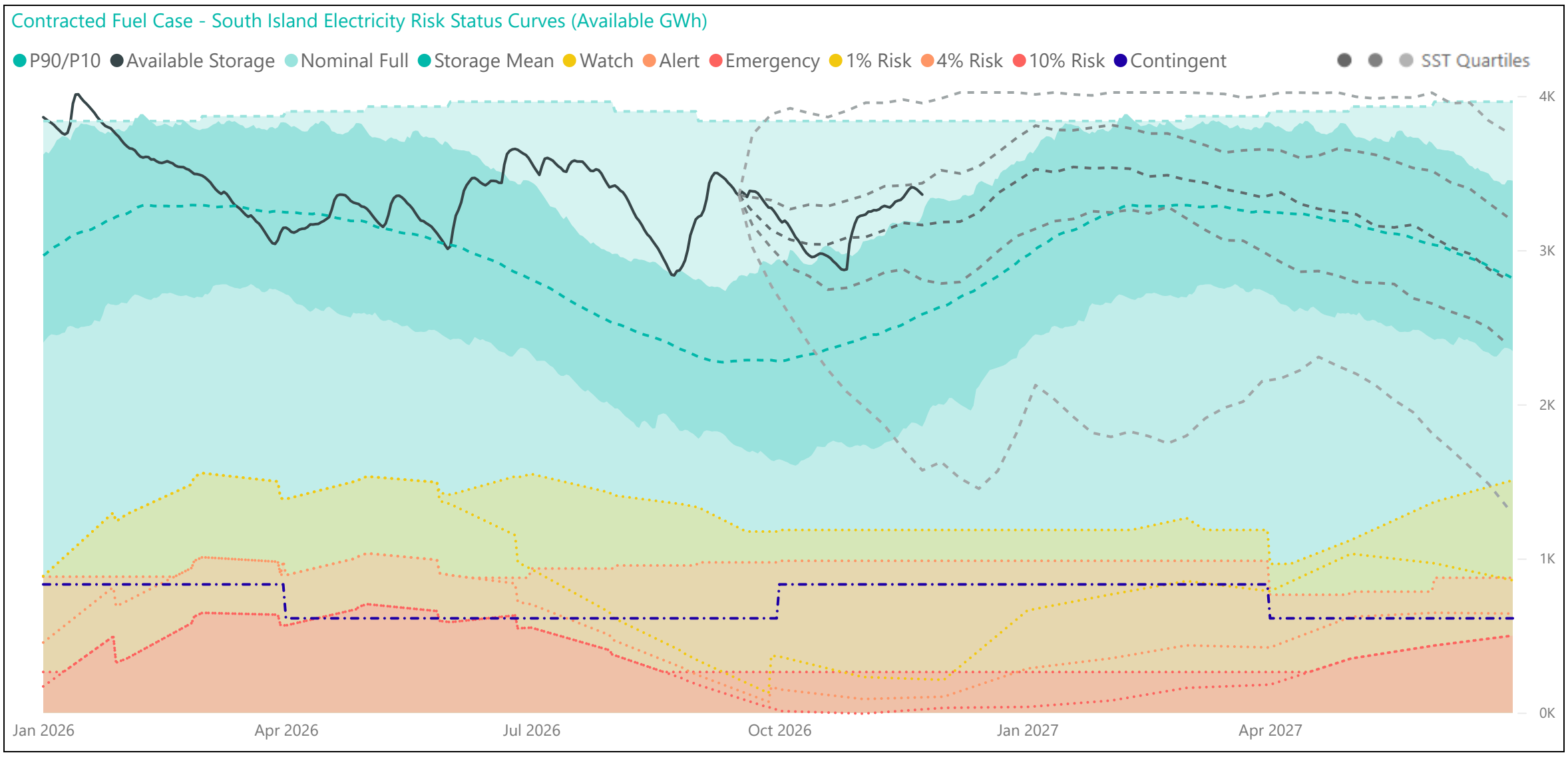
Watch Curve - The maximum of the one percent risk curve or the Alert curve plus the greater of the Watch adder or the worst-case simulated storage drop
Alert Curve - The maximum of the four percent risk curve and the floor and buffer
Emergency Curve - The maximum of the 10 percent risk curve and the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





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

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).