Market Operations Weekly Report - Week Ended 27 July 2025

Overview

New Zealand hydro storage dropped below the historic average once again to 95% of mean for the time of year. A country-wide cold snap meant demand increased from the week prior, reaching the highest weekly demand since August 2023.

This week's insight expands on last week's, and studies the average contribution from different renewable generation types to meeting periods of peak demand.

Security of Supply

Energy

After a month-long respite from below mean storage, New Zealand hydro storage once again descended below the mean last week to 95% of historic levels for the time of year. High demand increased the use of hydro, while low inflows meant the used storage was not replenished. South Island hydro storage dropped from 95% to 90% while North Island storage decreased from 153% to 134%.

The Electricity Risk Curves (ERCs) and Simulated Storage Trajectories (SSTs) were updated and published in the July Energy Security Outlook, including a scenario testing the impact of all three Rankines remaining in 2026.

Capacity

Last week capacity margins were consistently lower than what we have seen most of this year. Five peaks dropped below 500 MW. On Monday morning residual generation dropped as low as 65 MW in real-time as New Zealanders braced themselves against the cold. Following Monday morning, despite peak demand periods being just as high or higher, residual generation remained above 300 MW due to an uptick in thermal unit commitment.

The N-1-G margins in the NZGB forecast are healthy through to late September, with moderate margins through to next weekend. 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 to 886 GWh last week from 851 GWh the week prior, this was the highest weekly demand of the year. The only other time weekly demand has been this high in the last four years was in August 2023. The highest demand peak was 7,015 MW at 8:00am on Friday 25 July, about 100 MW short of our record peak demand.

Weekly Prices

The average wholesale electricity spot price at Ōtāhuhu last week increased to $169/MWh from $95/MWh the week prior. Wholesale prices peaked at $2,431/MWh at Ōtāhuhu at 7:30am on Monday 21 July during the period of tight residual in real-time. During the highest demand peak of the week on Friday morning, prices reached $1031/MWh at Ōtāhuhu with more thermal unit commitment contributing to higher residual generation.

Generation Mix

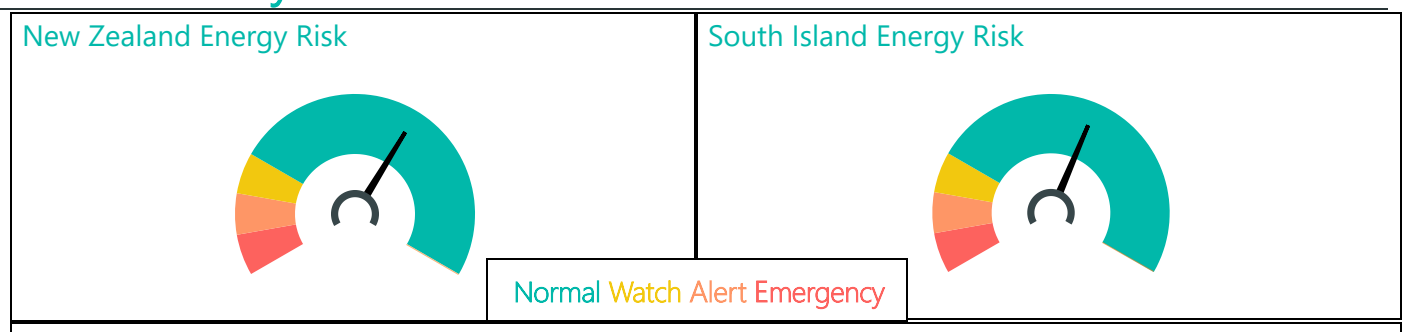
Hydro generation decreased to 62% of the mix from 64% the week prior even with hydro generation output increasing as a result of increased demand. Thermal generation increased from 6% to 12% of the mix, in line with its average contribution across the last year. Wind generation decreased from 6% to 4% of the mix and geothermal decreased from 22% to 20% with some units on outage.

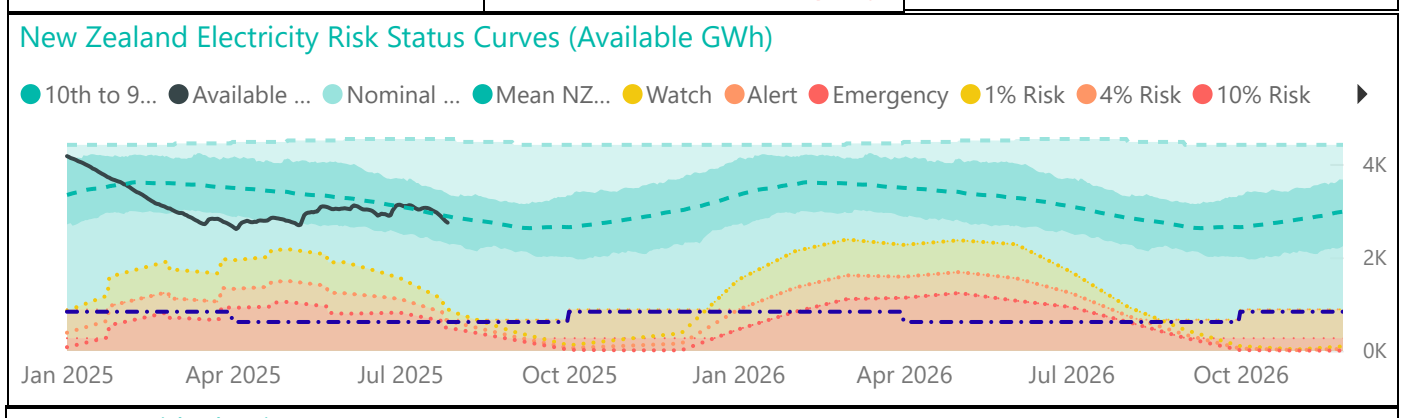
HVDC

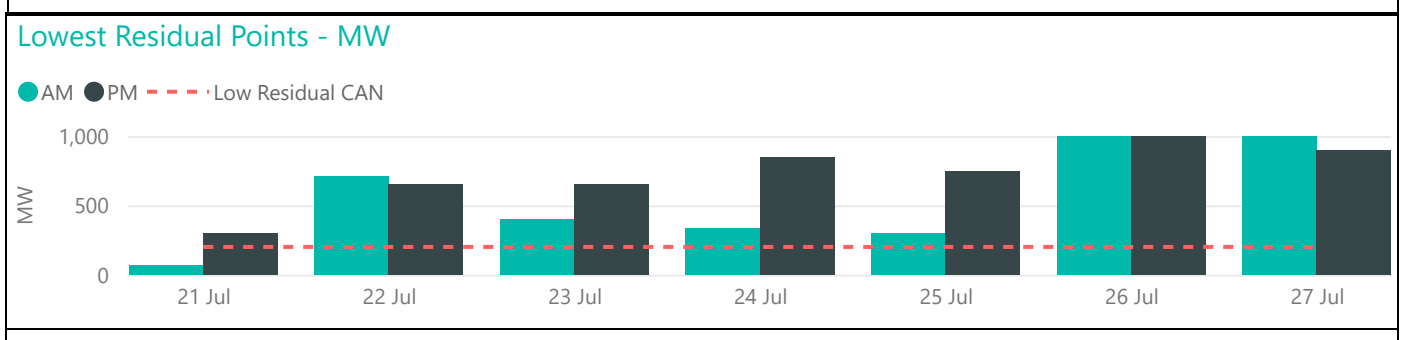
HVDC flow last week was predominantly northward with overnight periods of southward flow coinciding with periods of lower North Island demand. In total, 47 GWh was sent north and 7 GWh was sent south.

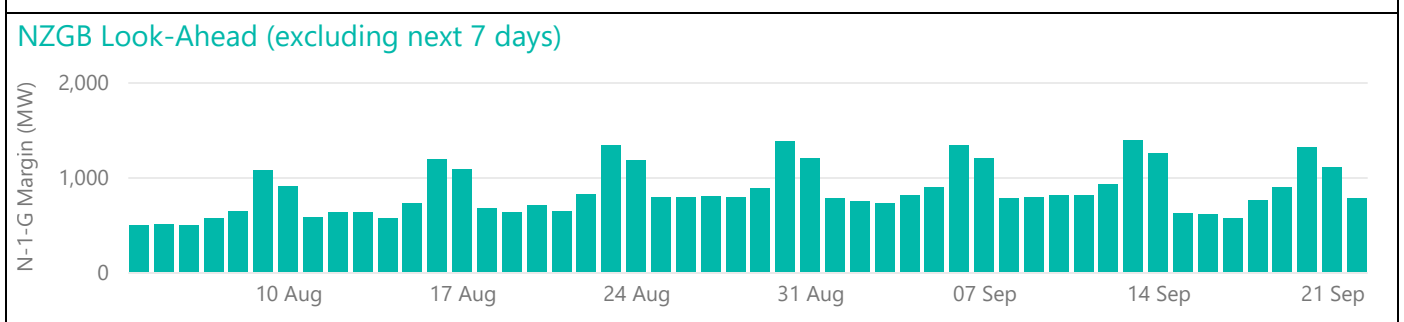
Evolving market resource co-ordination: Tie-breaker provisions consultation

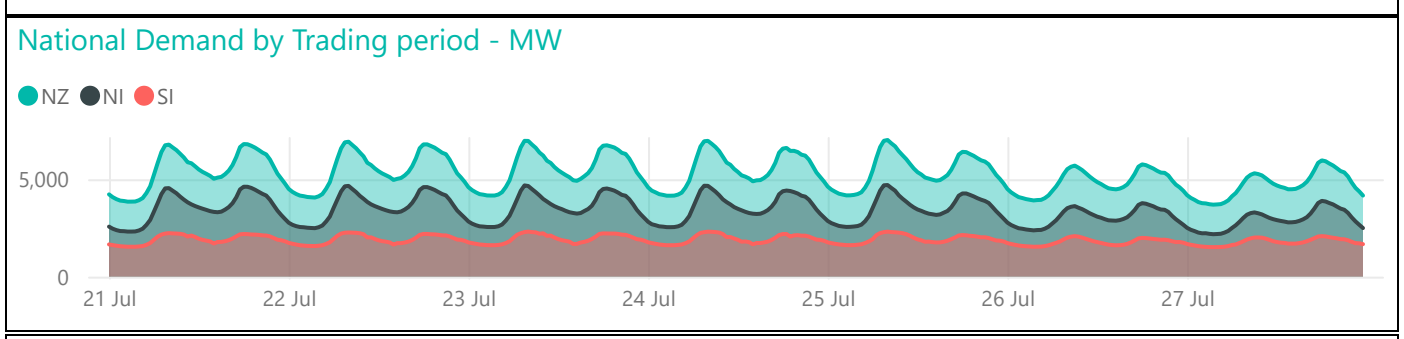
Last week Transpower, in its role as System Operator, published a consultation asking for feedback on how tie-breaker situations should be resolved for multiple competing generator offers in the wholesale electricity market. See consultation pack here. Submissions are due by 5pm Thursday 14 August, with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

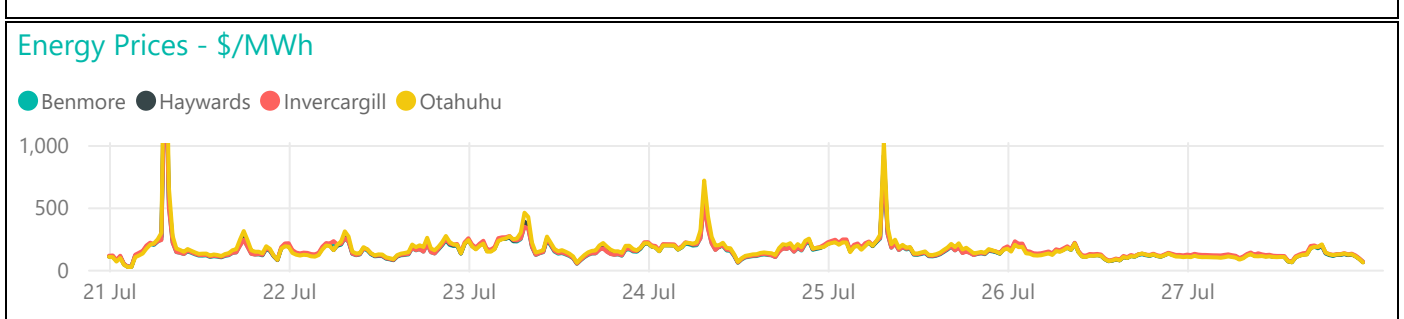


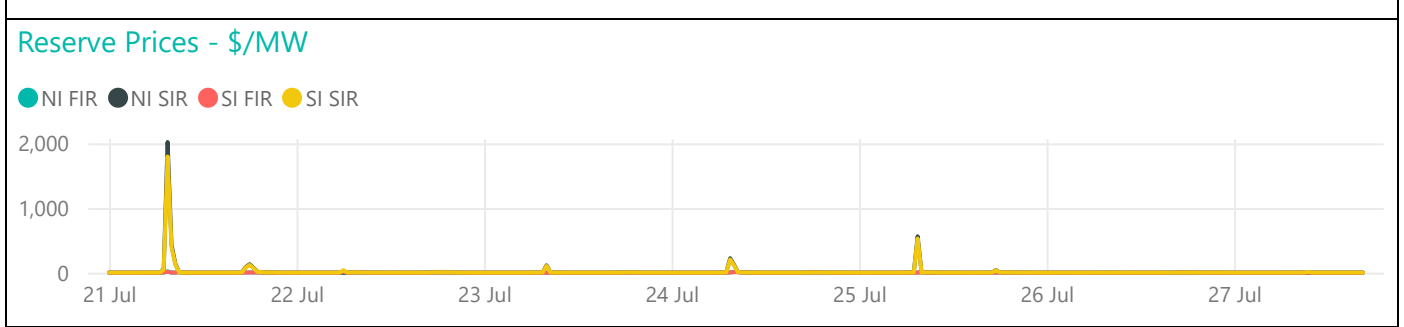


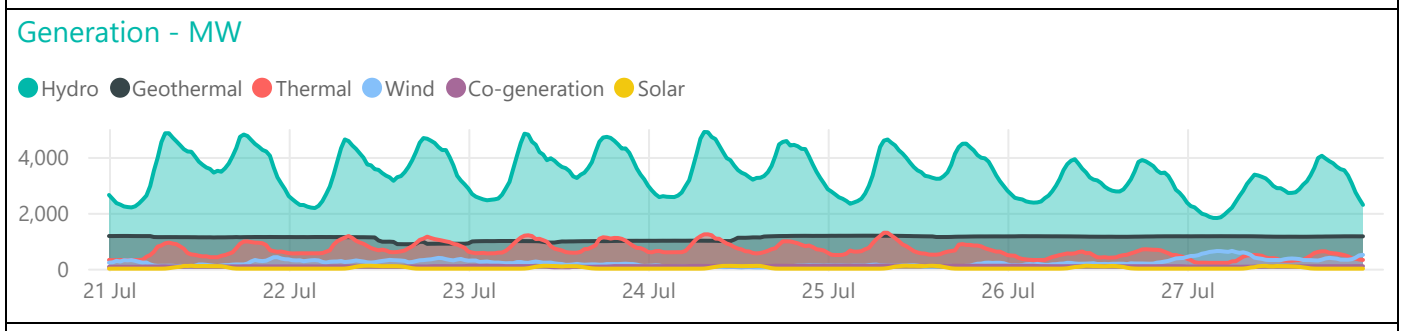


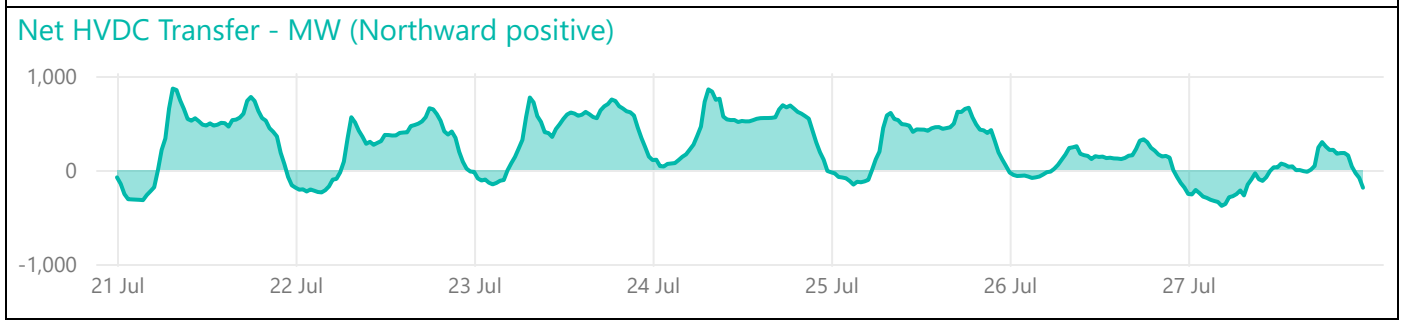








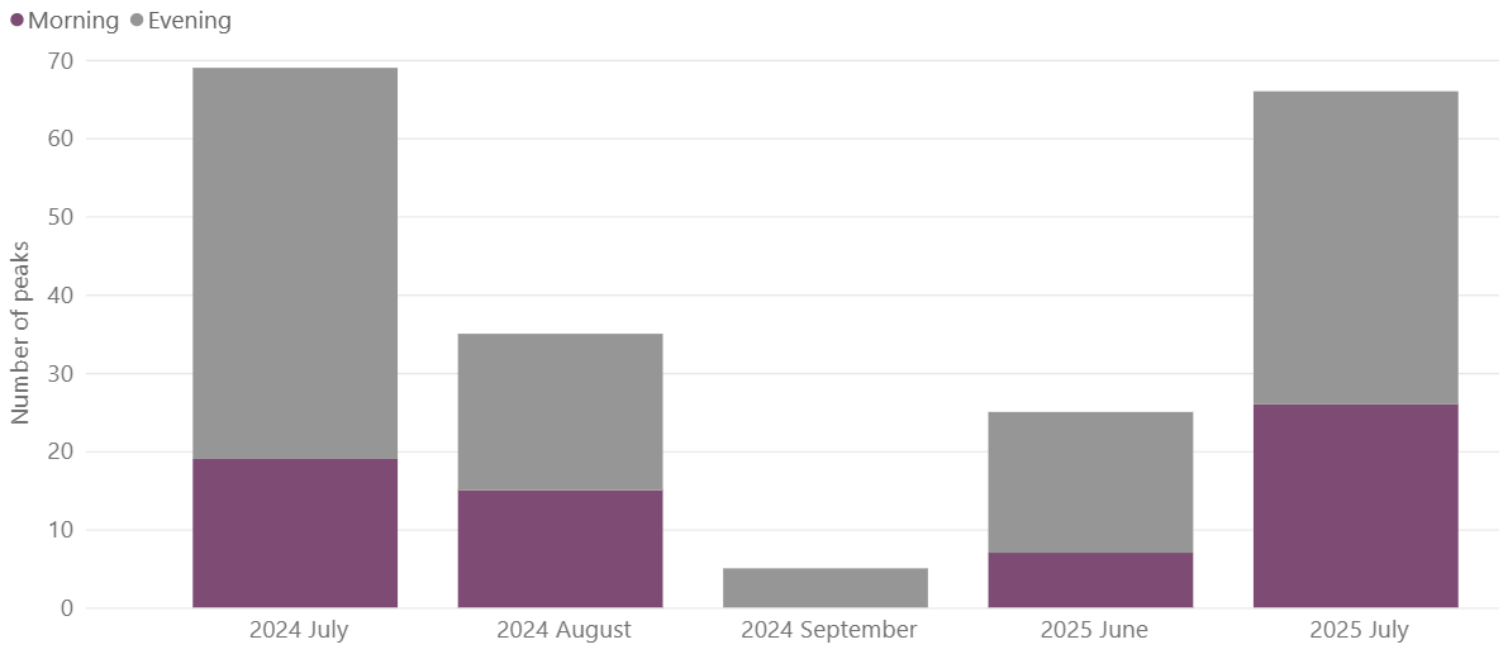




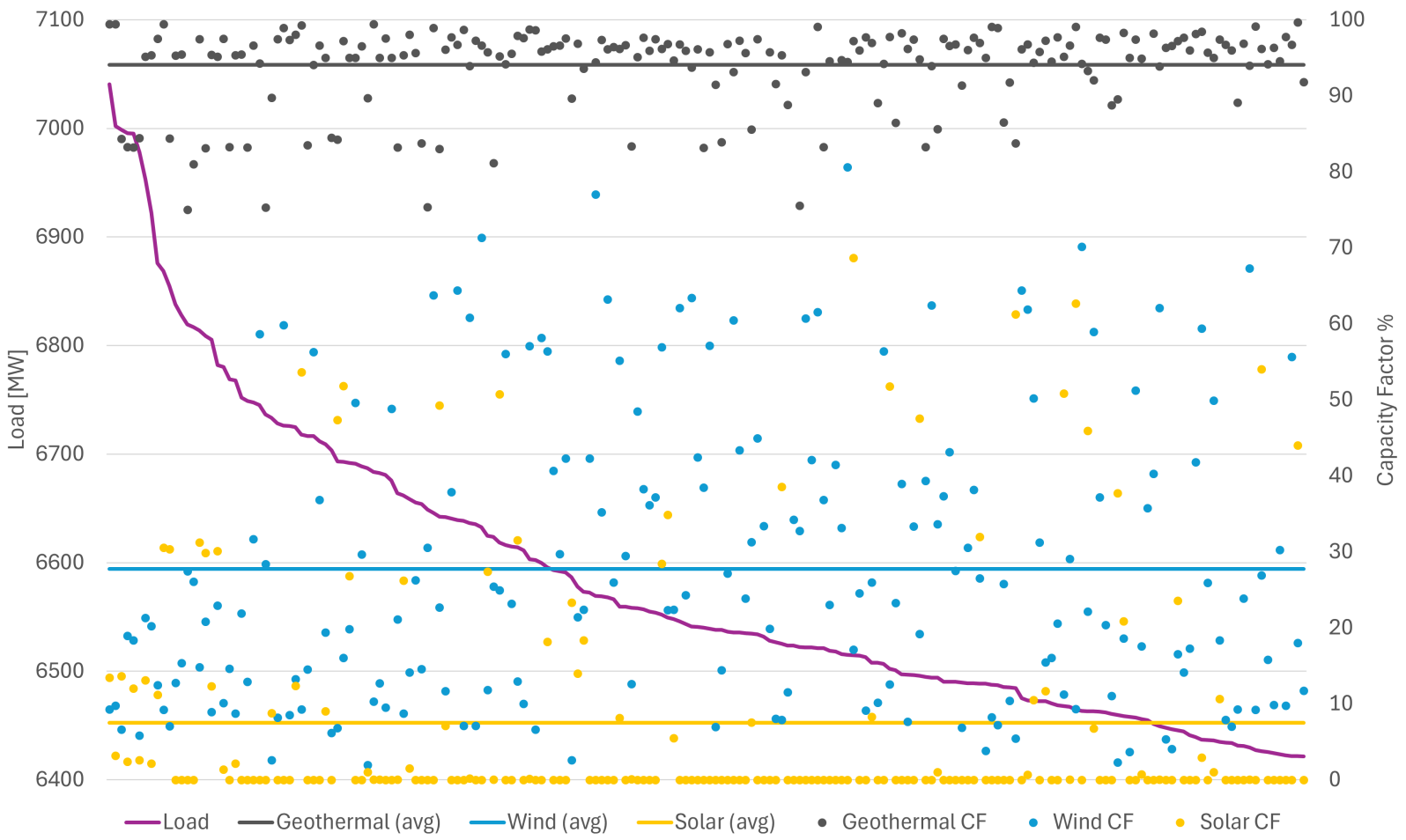
Weekly Insight - Contribution to peak demand from different renewable generation types

In last week's insight we discussed how different types of renewable generation contribute to electricity supply. Specifically, how different generation types have different levels of contribution per installed MW, requiring a diverse range of resources – particularly firm, flexible resources – to enhance system reliability during seasonal or unforeseen fluctuations in output.

This week's insight reinforces the need for diverse, flexible and firm resources by looking at the contribution of the same renewable resources (wind, solar and geothermal) to electricity supply during periods of peak demand. This analysis looks at a series of 200 trading periods[1] which had the highest demand over July 2024 – July 2025. The figure below shows the occurrence of these trading periods by month, and whether the peak occurred in the morning or evening.



The figure shows that highest peak demand periods in New Zealand typically occur over the winter months, predominantly in the evening (5-8pm). Looking at the generation output of geothermal, wind, and solar over the top 200 peak demand periods as a percentage of their respective installed capacities, we can get an idea of how much each generation type contributes to peak demand periods. The results are plotted on the figure below, sorted in order of peak demand.



Again, we see that 1 MW of installed capacity does not contribute equally across technology types when considering the contribution to meeting peak demand. The figure shows that on average, geothermal generation contributes firm capacity to meeting periods of peak demand, with an average capacity factor of 94%. As discussed last week, this is due to its availability generally only being affected by plant outages.

As we saw in last week's insight, we need a diverse generation mix to enhance system reliability during seasonal or unforeseen fluctuations in output from different generation types. However, the above figure shows that intermittent generation sources have limitations when it comes to providing a reliable supply contribution to peak demand periods. The generation output over peak periods was much lower for wind and solar than it was for geothermal, at an average of 28% and 7.5% of installed capacity (excluding capacity on outage) respectively.

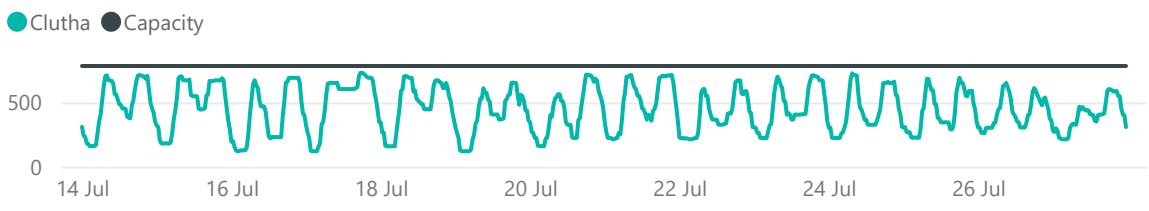
Not only is the output of intermittent generation difficult to forecast and highly variable, but generally the peak demand periods (as we saw in the first figure) occur during winter evenings when the sun has gone down, or frosty winter mornings where there is little wind. To help manage peak capacity risks with the growing supply from intermittent generation we also need growth in firm, flexible resources such as batteries, demand response and peaking generation.

1. Consistent with the Security Standards Assumptions Document published by the Electricity Authority, a measurement we use often to evaluate peak demand in New Zealand is the highest 100 hours of demand in a year, or 200 trading periods.

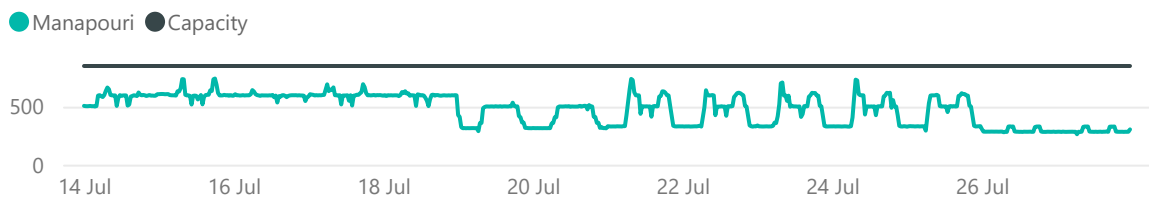
Generation Breakdown - Last Two Weeks

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

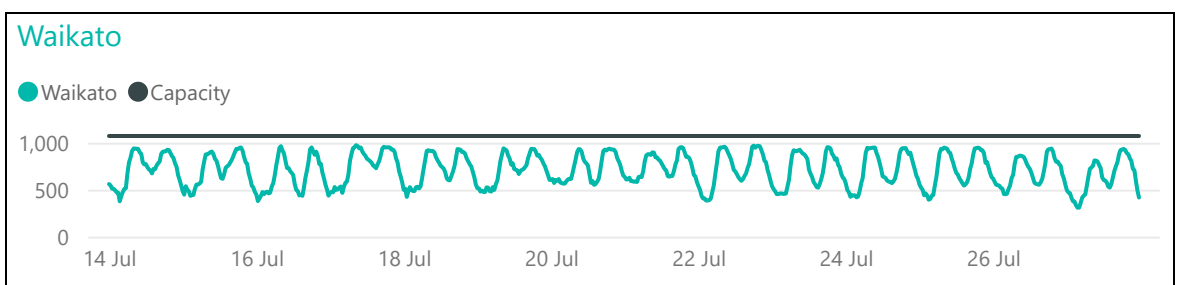
Clutha



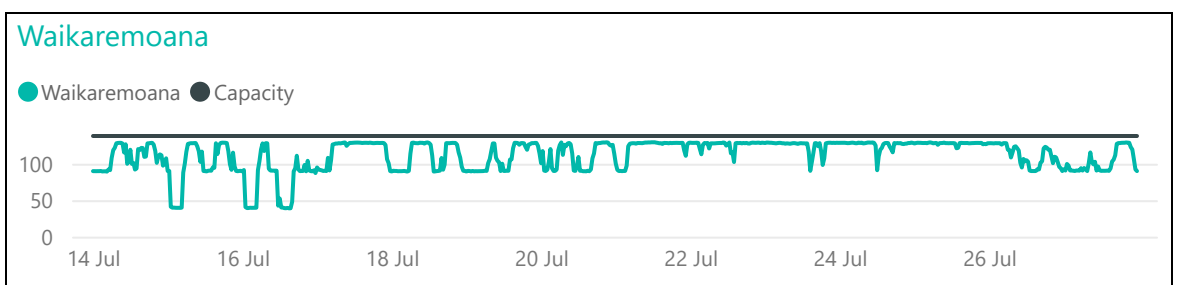
Manapouri



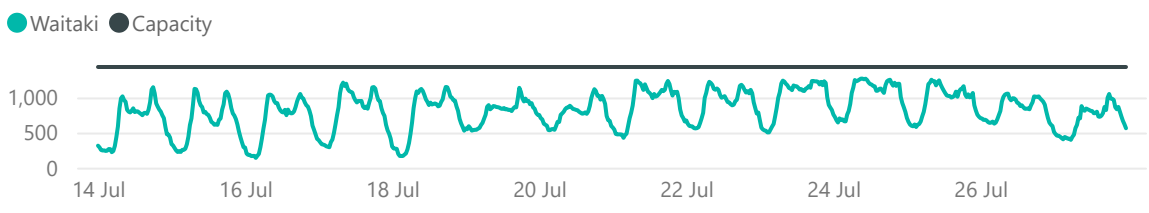
Waikato



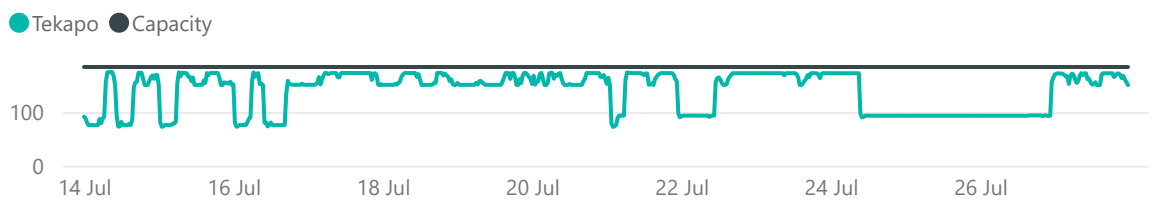
Waikaremoana



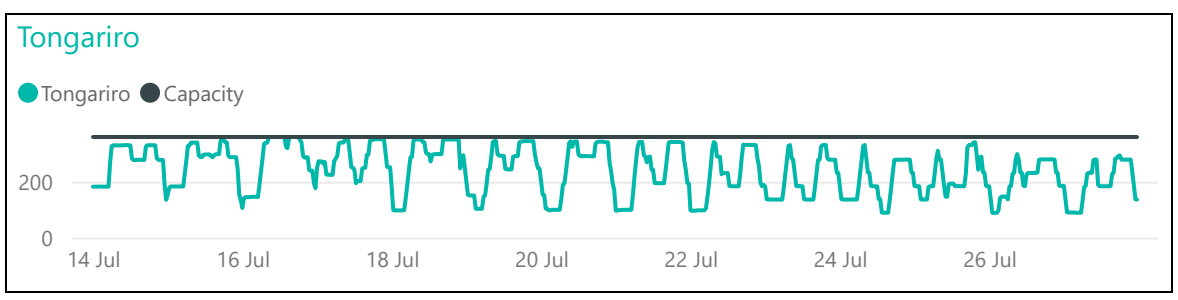
Waitaki



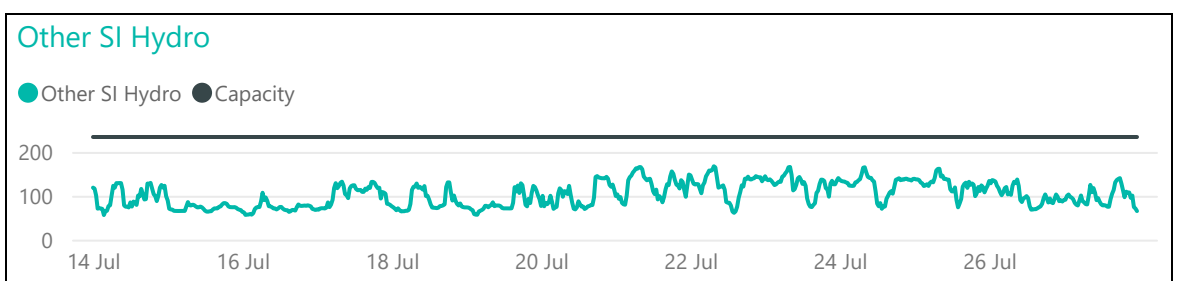
Tekapo



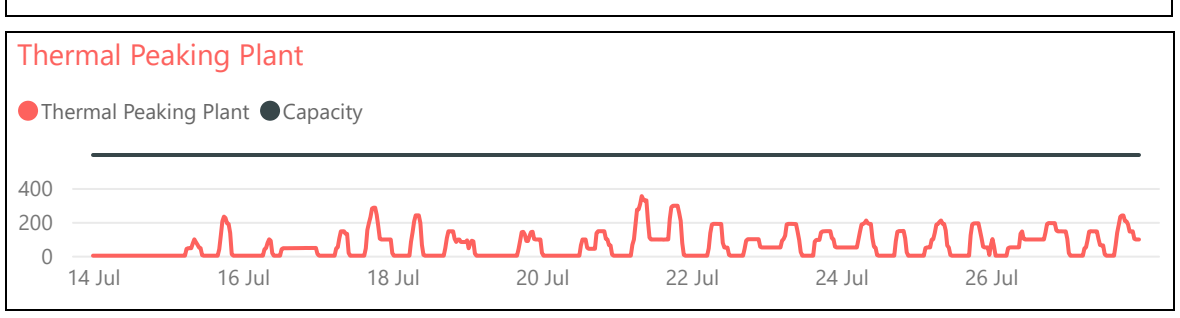
Tongariro



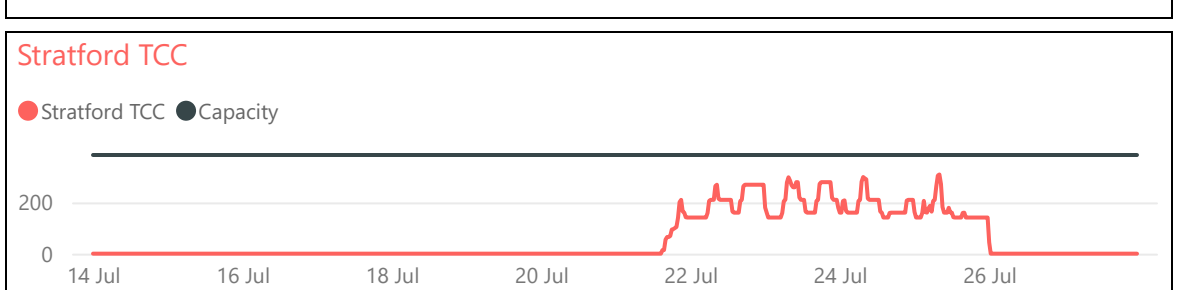
Other SI Hydro



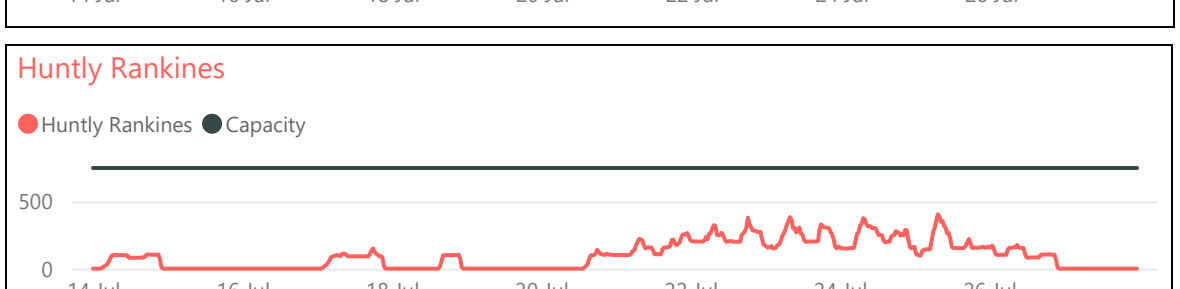
Thermal Peaking Plant



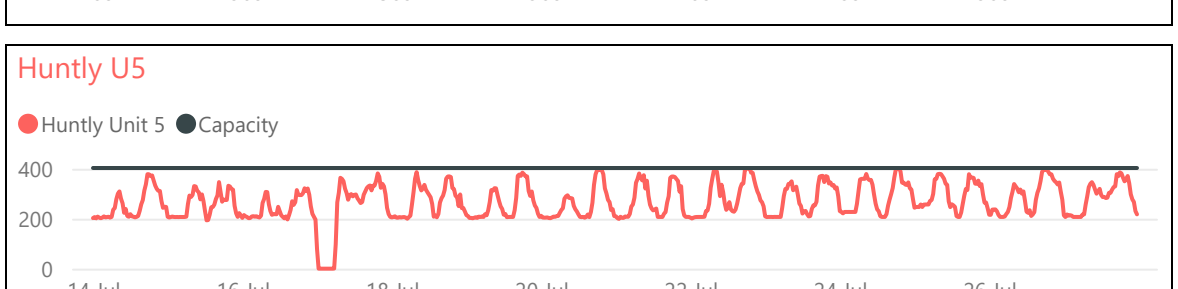
Stratford TCC



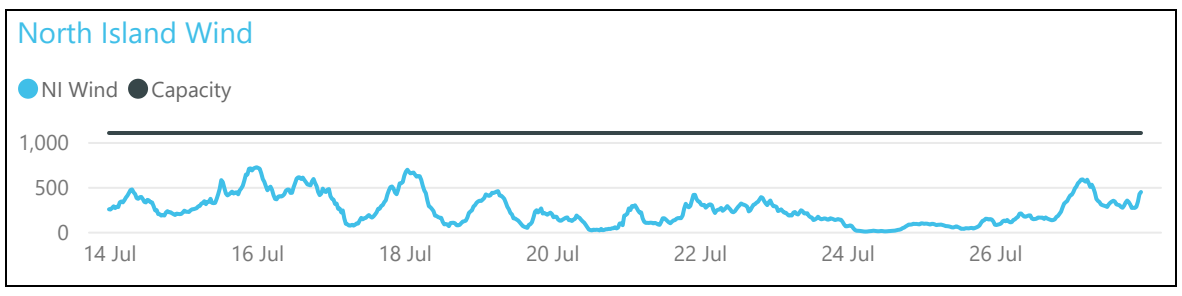
Huntly Rankines



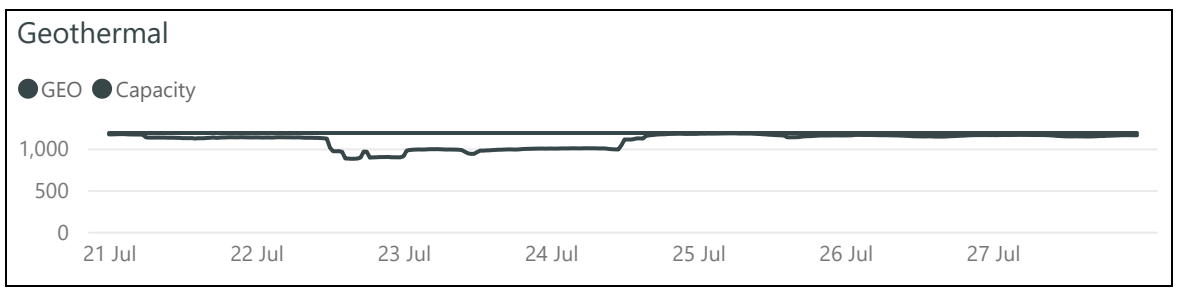
Huntly U5



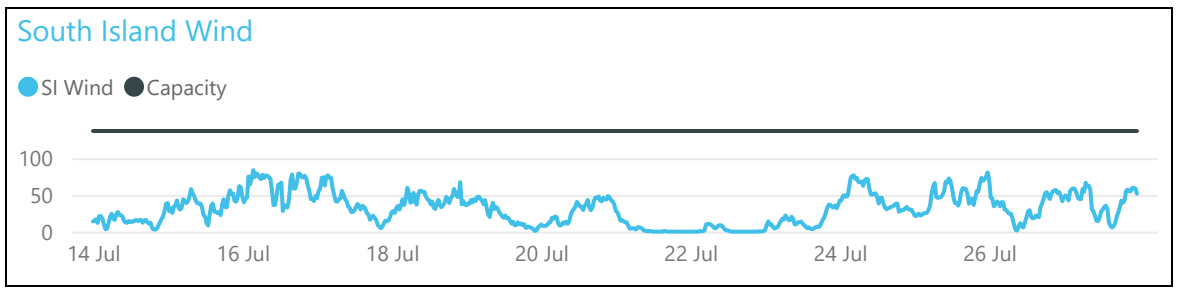
North Island Wind



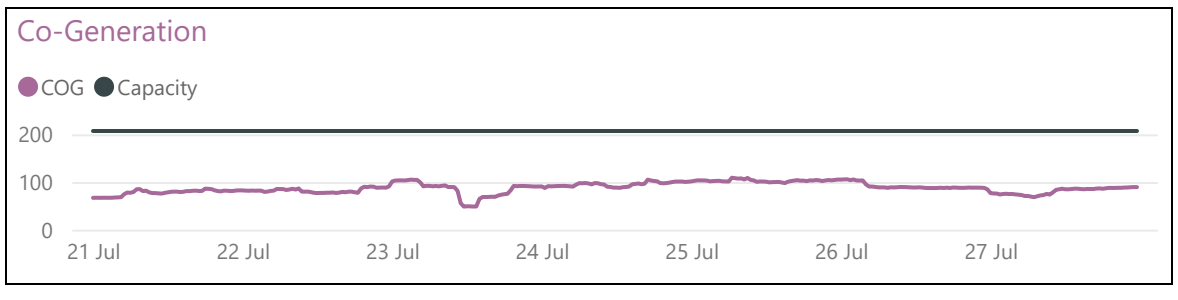
Geothermal



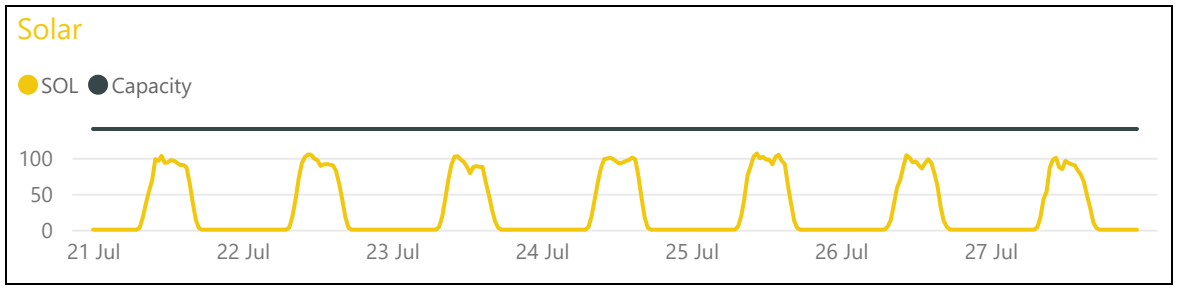
South Island Wind



Co-Generation

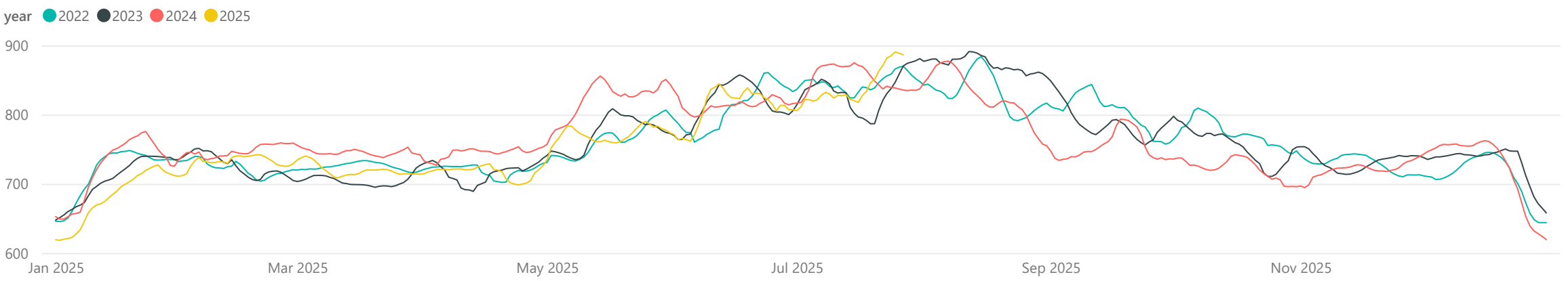


Solar

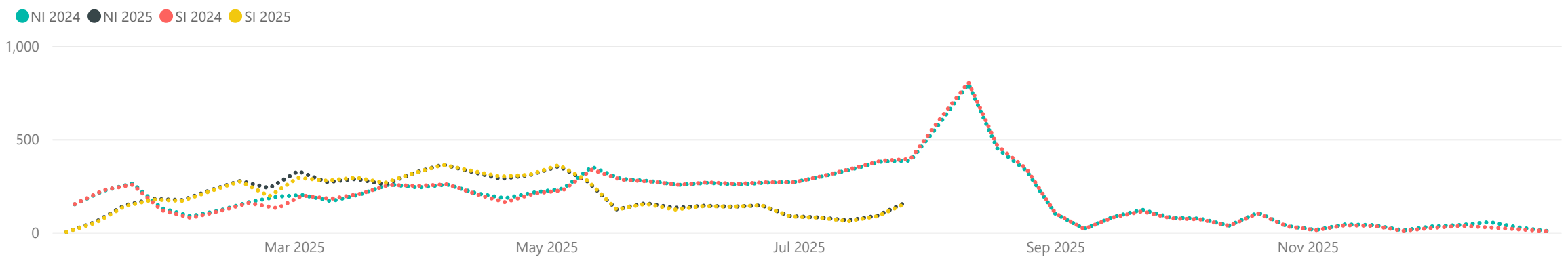


Weekly Profiles

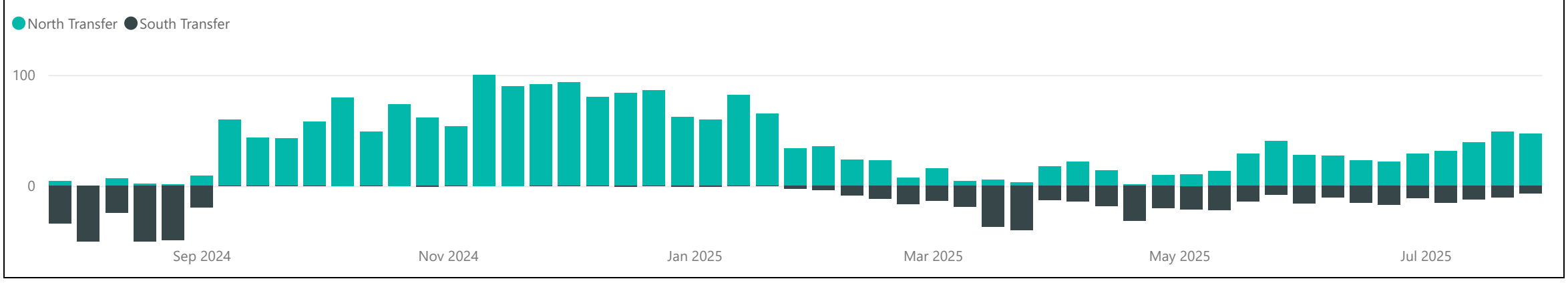
National Weekly Demand - GWh - 7 Day Rolling



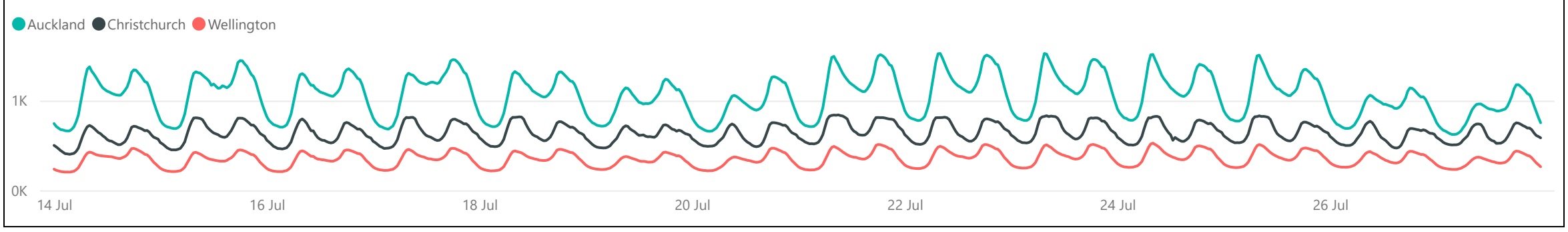
Weekly Spot Price - $/MWh



HVDC Transfer - Weekly GWh

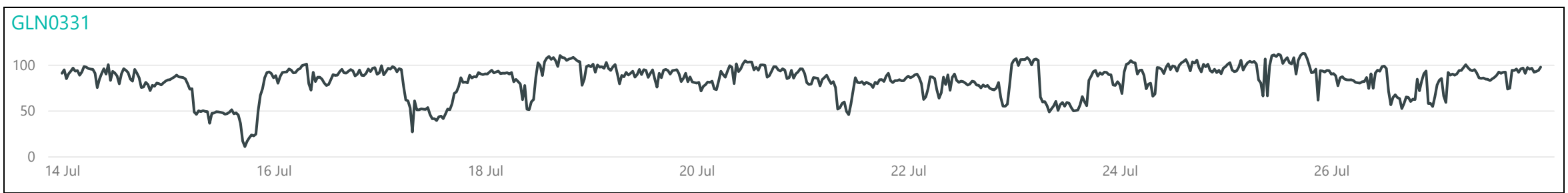


Conforming Load Profiles - Last Two Weeks *Measured in MW shown by region*



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

GLN0331



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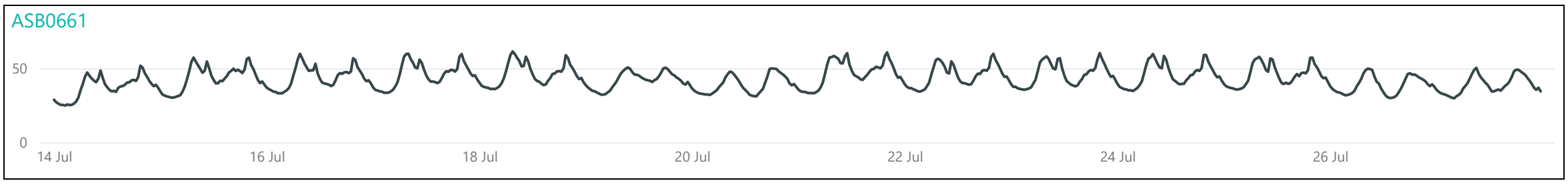

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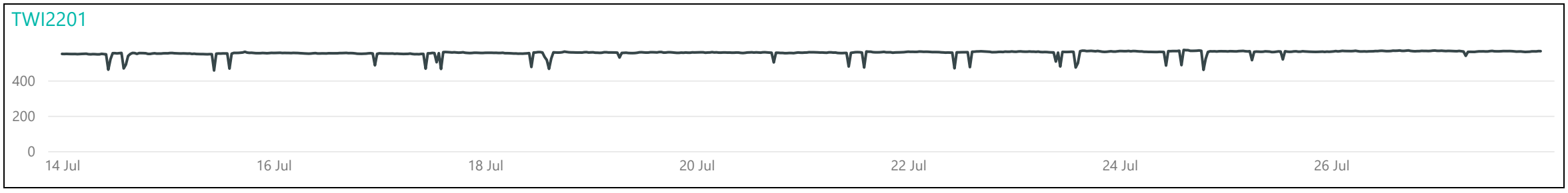
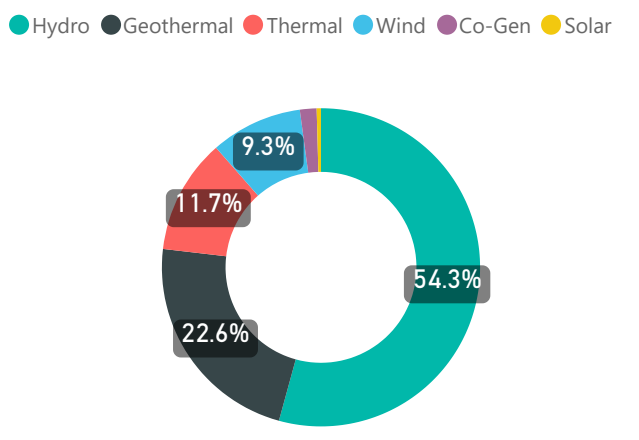


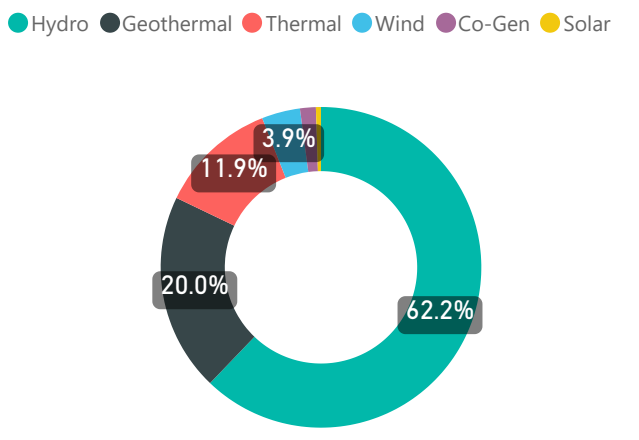
TRANSPOWER

Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



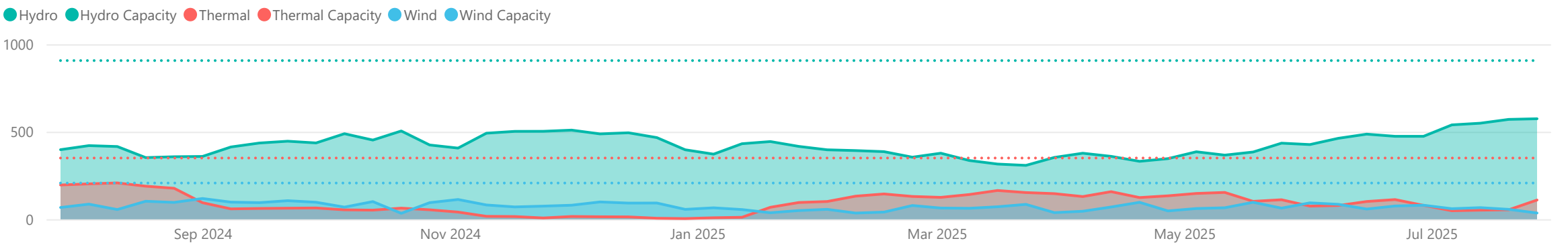
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
87%	82,805	88.2

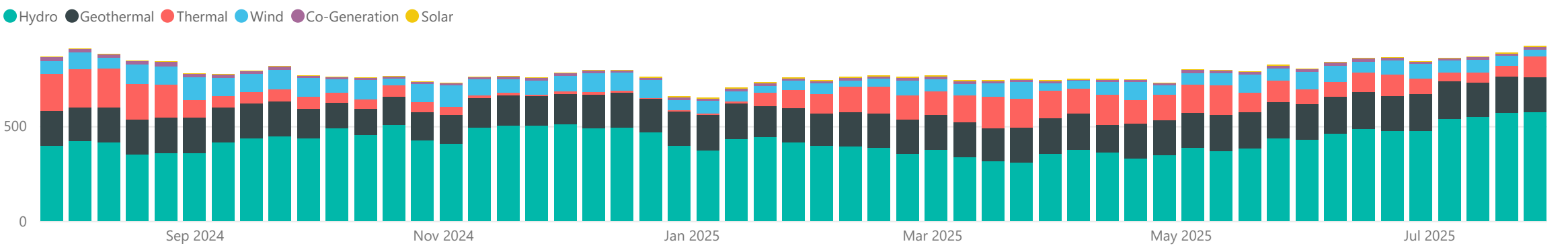
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
87%	73,247	92.4

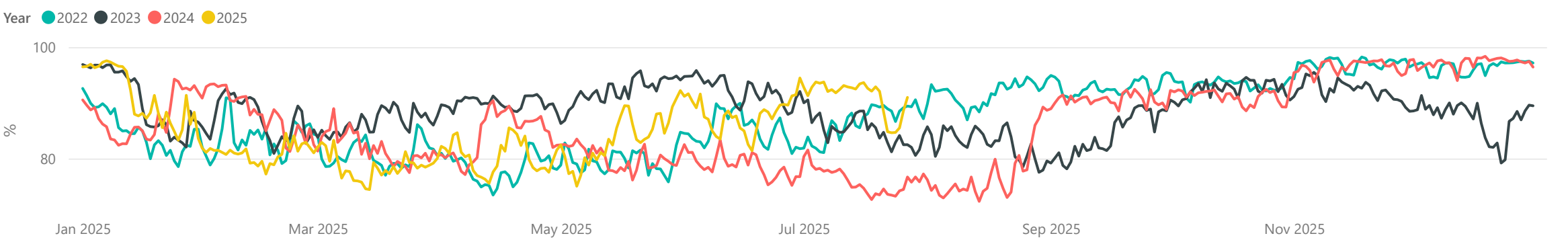
Weekly Generation Mix vs Capacity - GWh



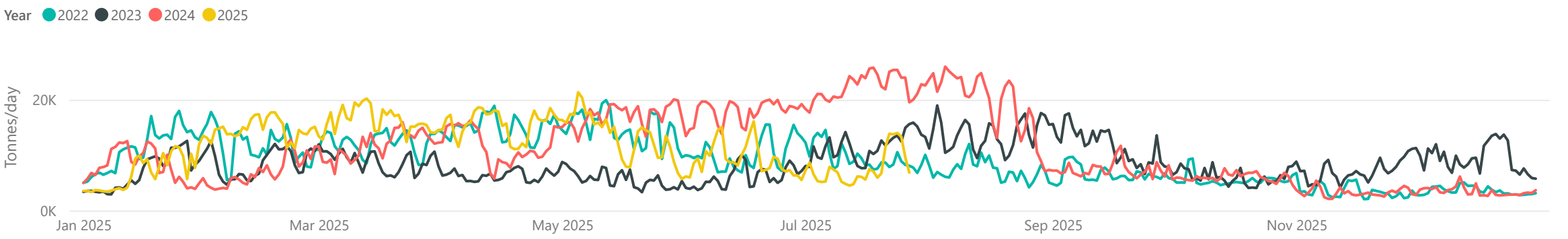
Weekly Generation Mix - GWh



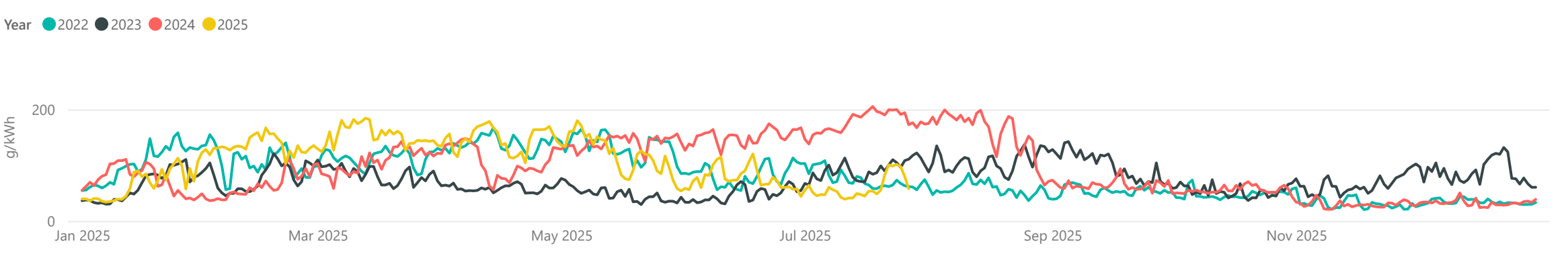
NZ Renewable Percentage



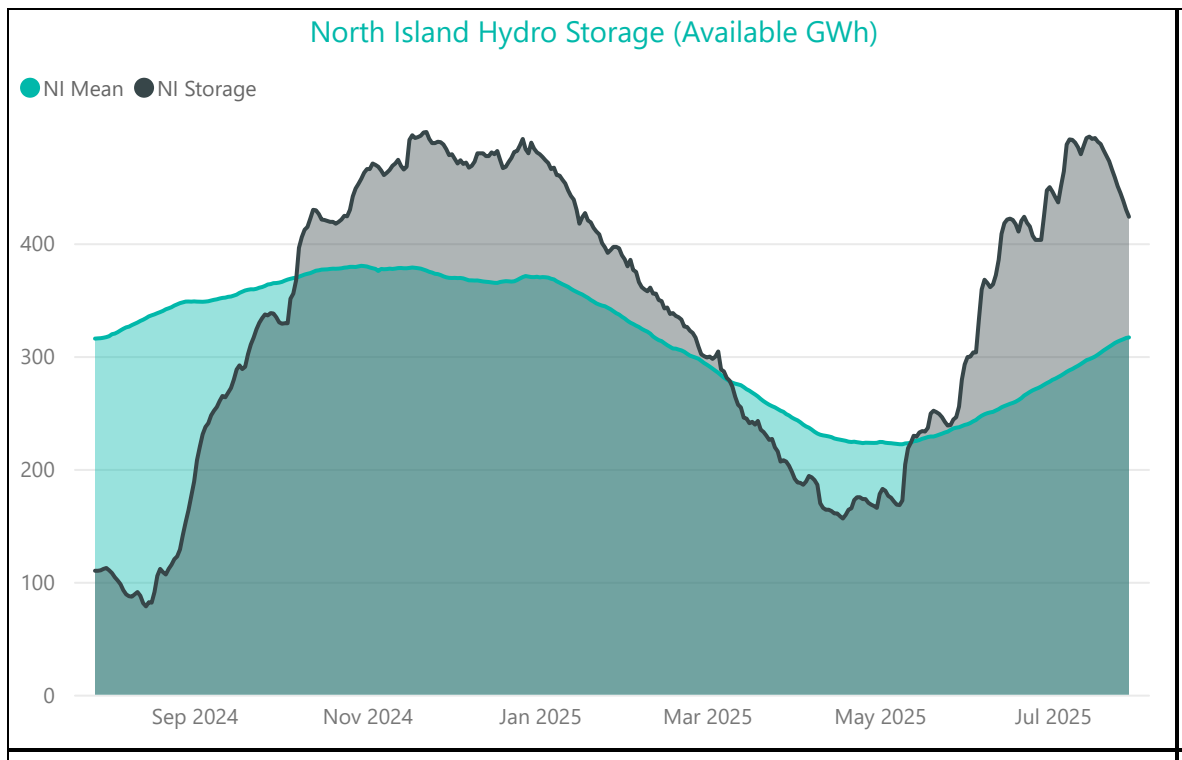
CO2 Tonnes/Day

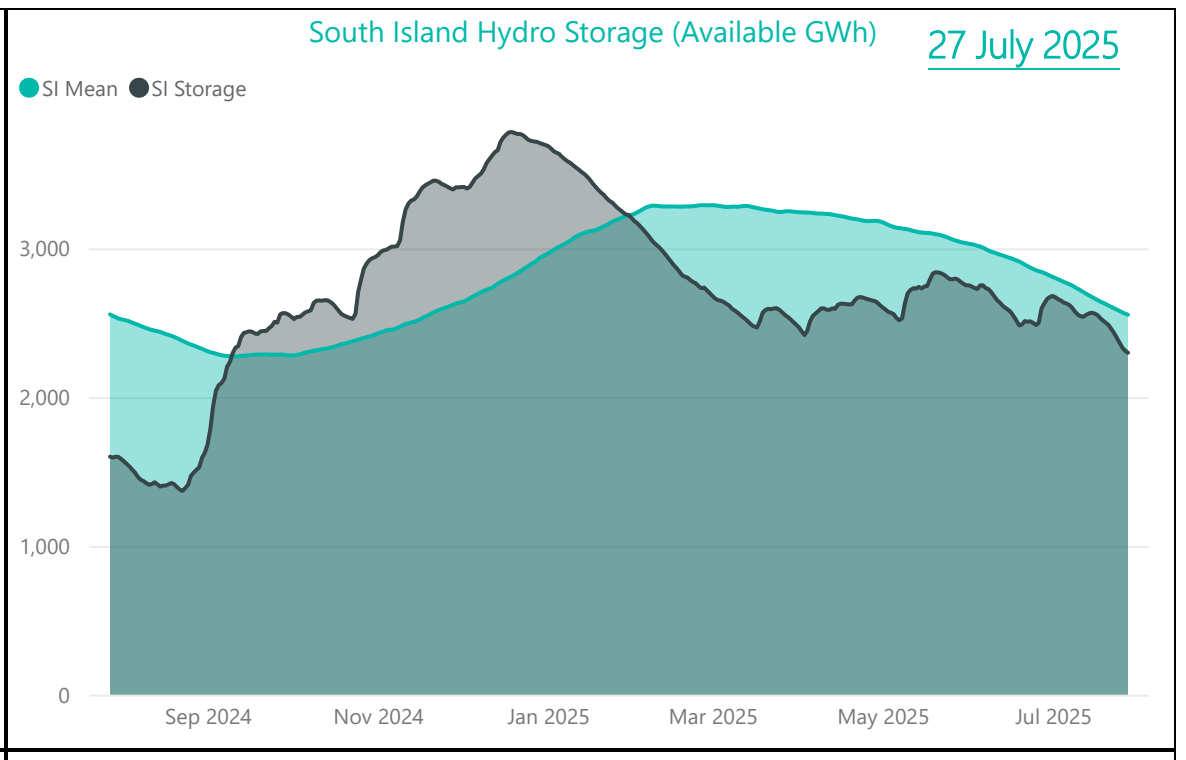


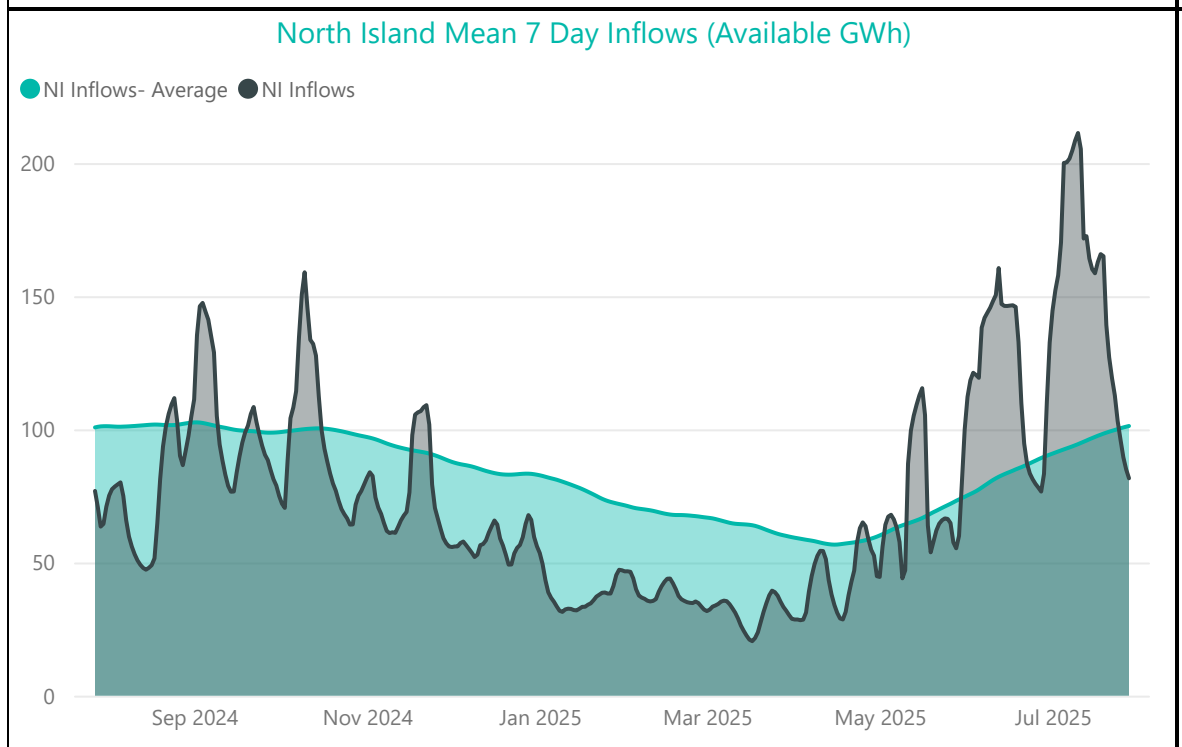
CO2 g/kWh

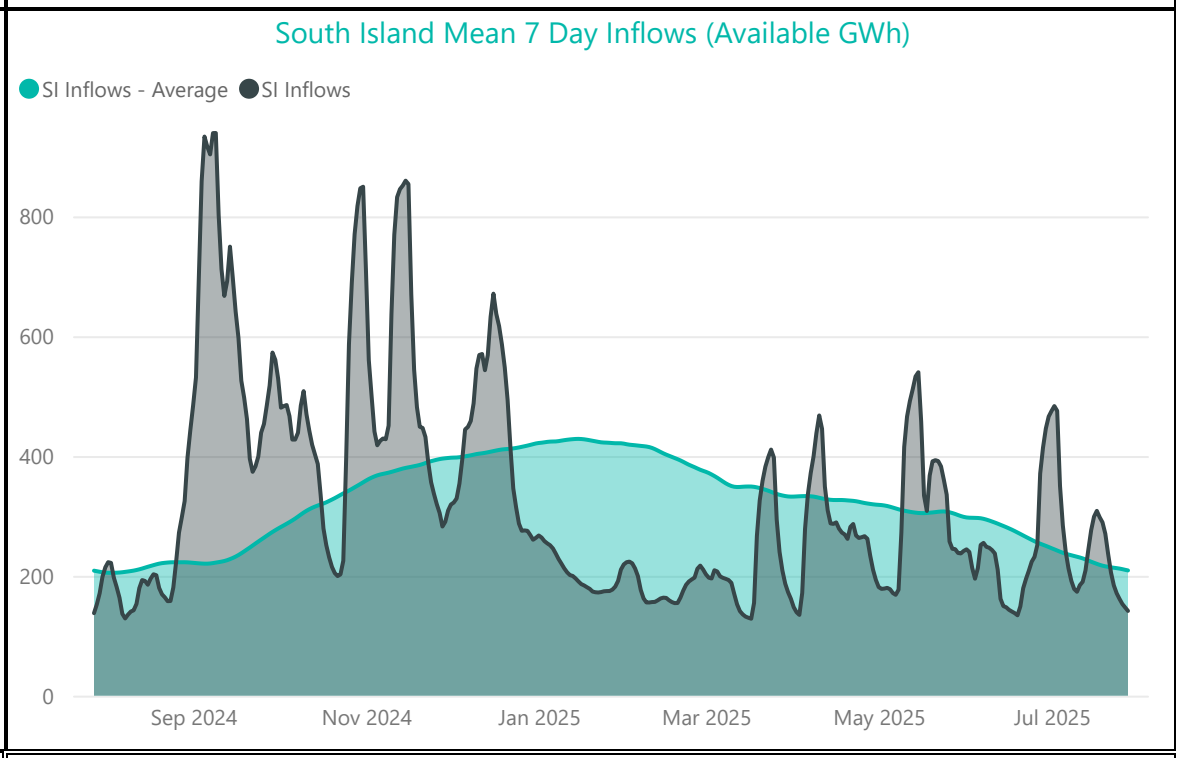


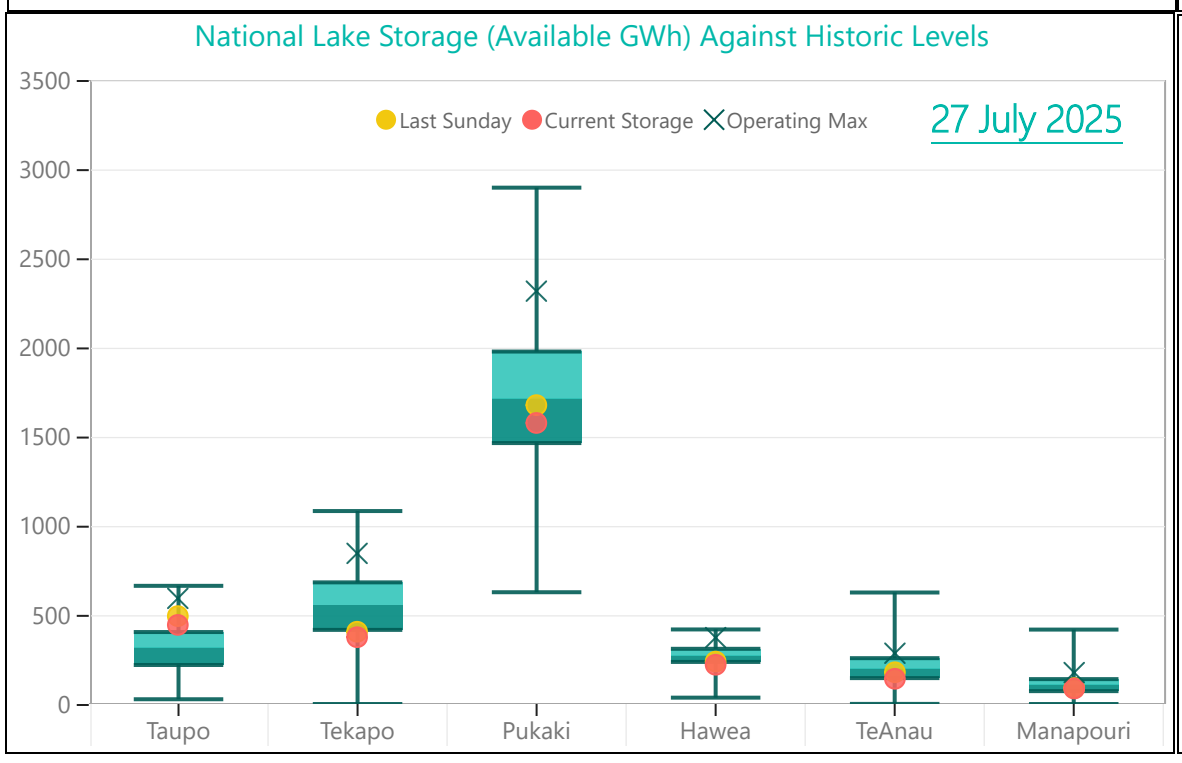
Hydro Storage

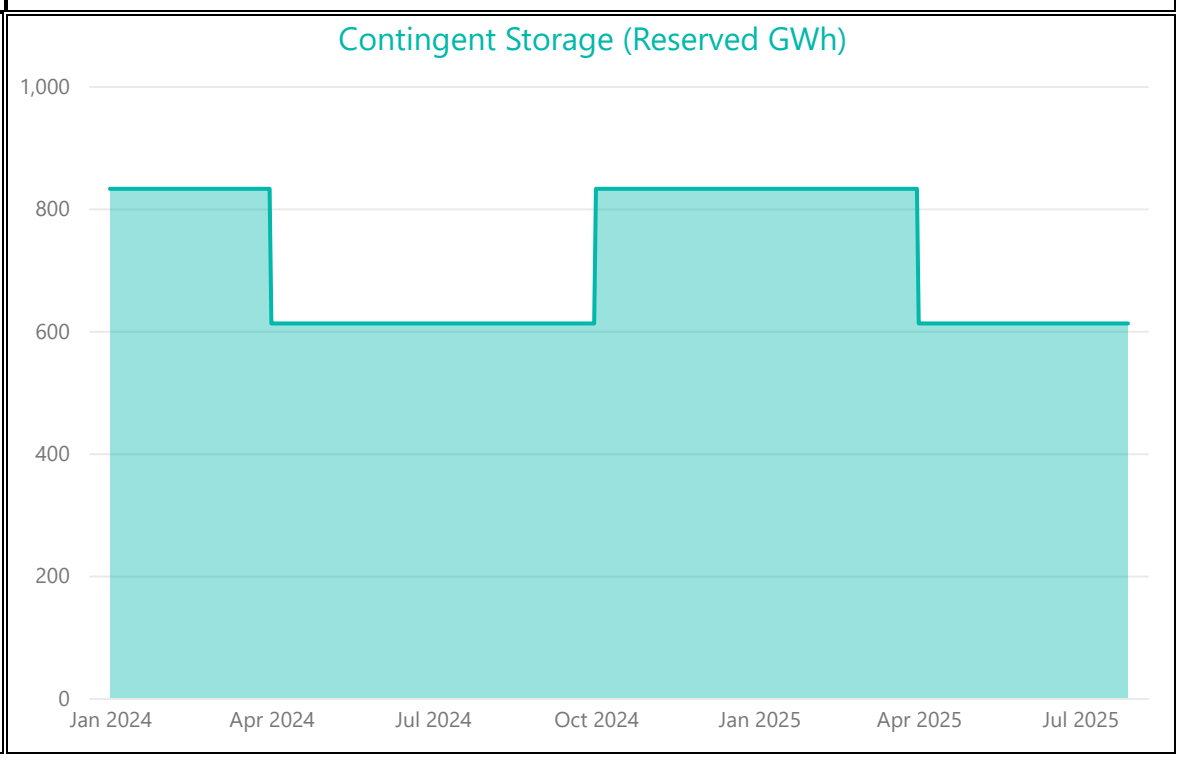












For further information on security of supply and Transpower's responsibilities as the System Operator, refer to our webpage here: https://www.transpower.co.nz/system-operator/security-supply

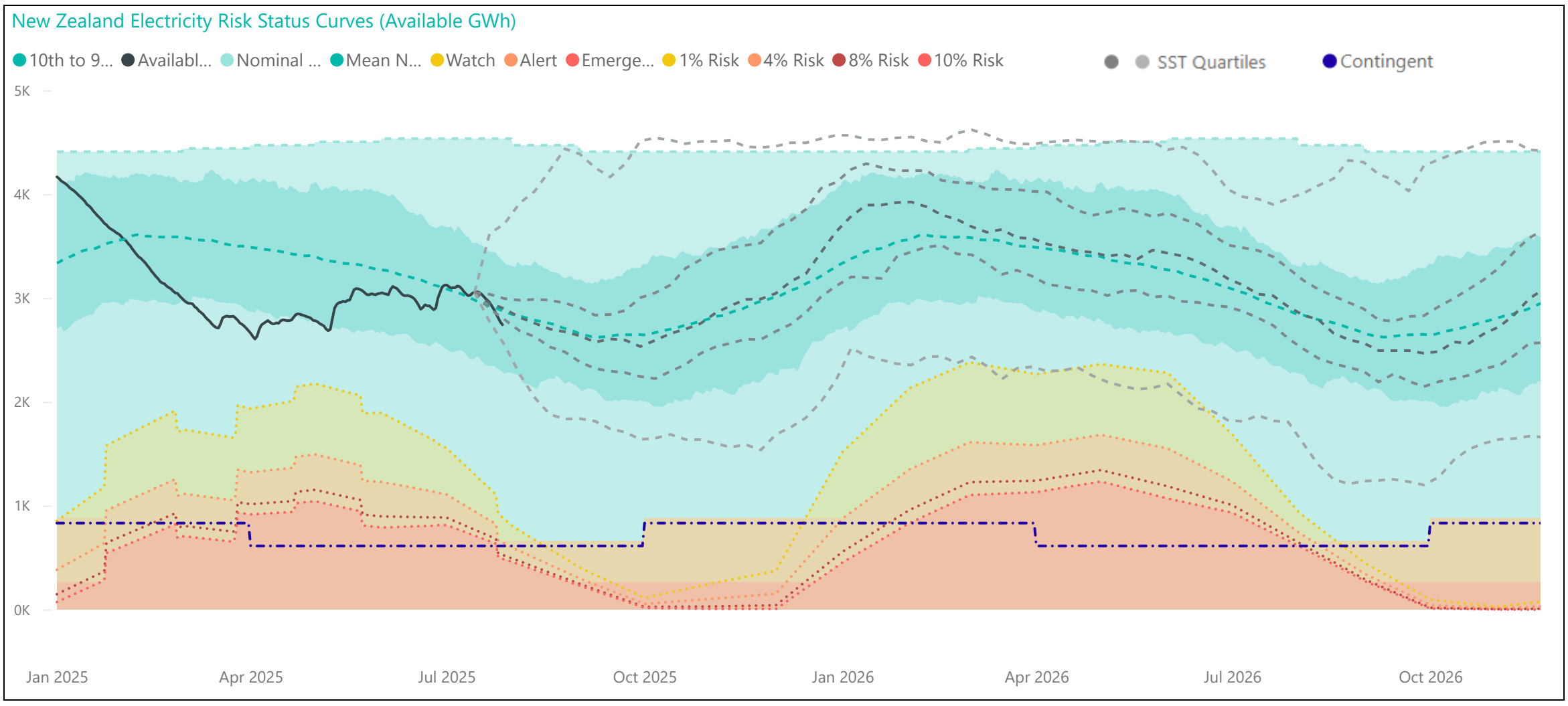
For any inquiries related to security of supply contact market.operations@transpower.co.nz

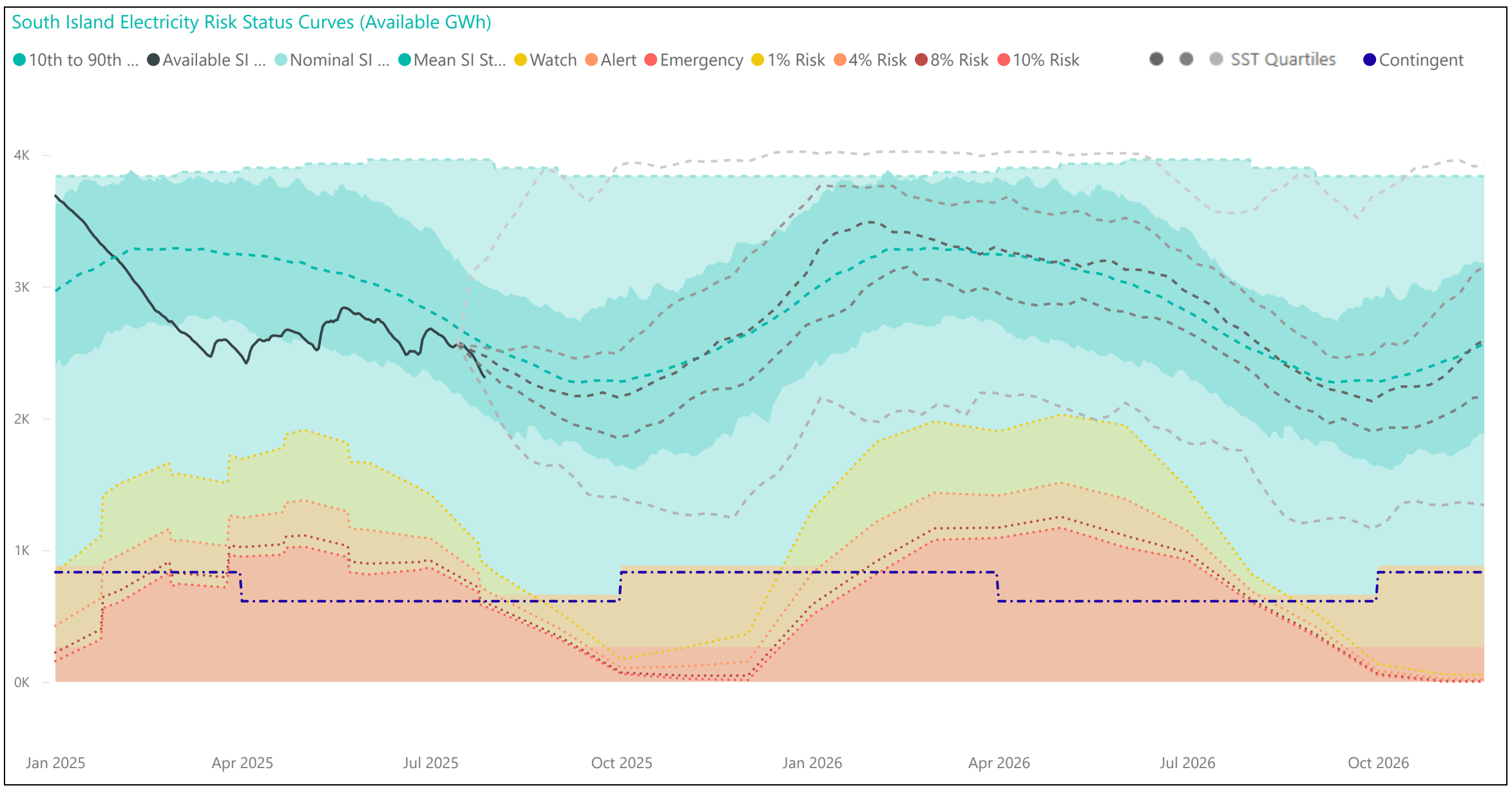
Hydro data used in this report is sourced from *NZX Hydro*.

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).