Weekly Market Movements - Week Ended 10 March 2024

Overview

North Island inflows last week kept national hydro storage at 95% of the historic mean. North Island thermal generation continued to run at increased output due to the planned HVDC outage. North Island wind generation also picked up last week. This lead to healthy residual generation last week despite the HVDC outage. Lodestone's Rangitaiki Solar Farm offered energy into the market for the first time last week.

In this week's insight we look at Net Free Reserves (NFRs) and the potential for fast instantaneous reserve (FIR) requirements to exceed the actual risk set by the risk setter.

Security of Supply

Energy

National hydro storage remains at 95% of the historic mean, reflecting the increased North Island inflows over the past week. North Island storage increased from 147% to 157% of the historic mean while South Island storage decreased from 91% of the historic mean to 90%,

Capacity

Capacity margins were healthy again last week with the lowest residual margin being 639 MW on Wednesday morning. Higher thermal unit commitment and high wind generation assisted in keeping residuals strong during the HVDC outage.

Forecast N-1-G margins are healthy throughout the forecast horizon to late April. The HVDC outages running from 21 February - 14 March are considered in the margin calculation. The lowest N-1-G margin during the forecast period has decreased to 180 MW on 29 April since last week. The latest NZGB report is available on the NZGB website.

Electricity Market Commentary

Weekly Demand

Demand continued to decrease last week from 750 GWh the week prior to 743 GWh, as summer conditions prevailed for most of the week. Demand peaked at 5,391 MW over the morning peak on Wednesday 6 March coinciding with a period of cooler temperatures across the motu.

Weekly Prices

The average wholesale price at Otahuhu decreased last week from $210/MWh the week prior down to $176/MWh, reflecting consistent wind generation throughout the week. However, prices fluctuated throughout the week with multiple periods of price separation. There was interisland price separation caused by high reserve prices due to the HVDC outage. There were also periods of price separation within the South Island caused by spring washer effects. Line outages and high generation in the region caused constraints to bind, therefore limiting power flows.

The Otahuhu price peaked at $434/MWh during the week's highest demand peak at 8:00am on Wednesday 6 March. This coincided with a period of low wind generation, high thermal generation and the HVDC pole 2 outage.

Generation Mix

Wind generation increased last week compared to the week prior, from 8.5% of the mix to 11.9%. This led to an increase in the renewable percentage of the generation mix although it remains below the annual average at 85%. Hydro generation decreased last week from 55.3% to 53.2%, while thermal generation decreased from 14.9% of the mix to 13%.

HVDC

All daytime HVDC flows were northward last week while all overnight flows were southward coinciding with periods of low demand and high North Island wind generation.

Pole 2 will remain on outage until 14 March. For further details see the Customer Advice Notice. Pole 3 is scheduled to go on outage on Sunday 17 March between 4.30am and 9pm. See the Customer Advice Notice for further details.

SOROP consultation is open for cross submissions

SOROP consultation closed on 6 March. The two-week period for cross submissions ends 20 March. Please see our website for further details.

Shoulder ratings take effect

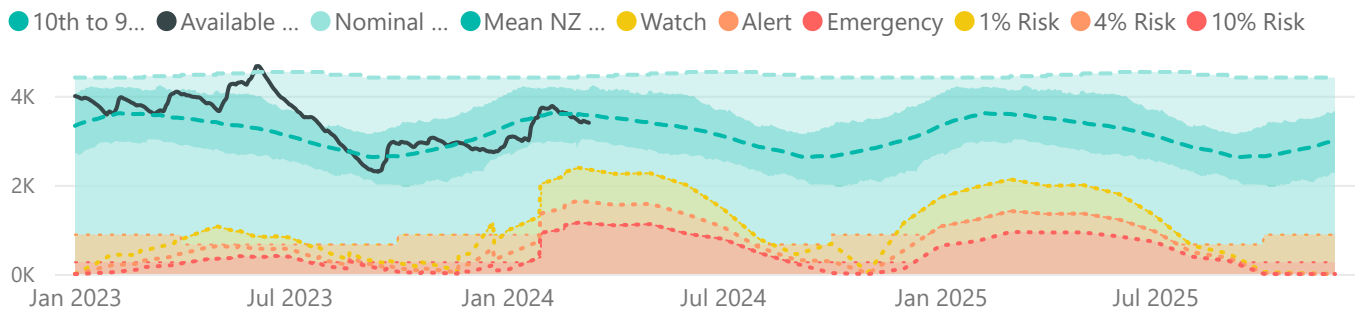
Shoulder ratings will apply to some grid transmission circuit ratings from 15 March to 10 May. See the Customer Advice Notice for more details.

New Zealand Energy Risk

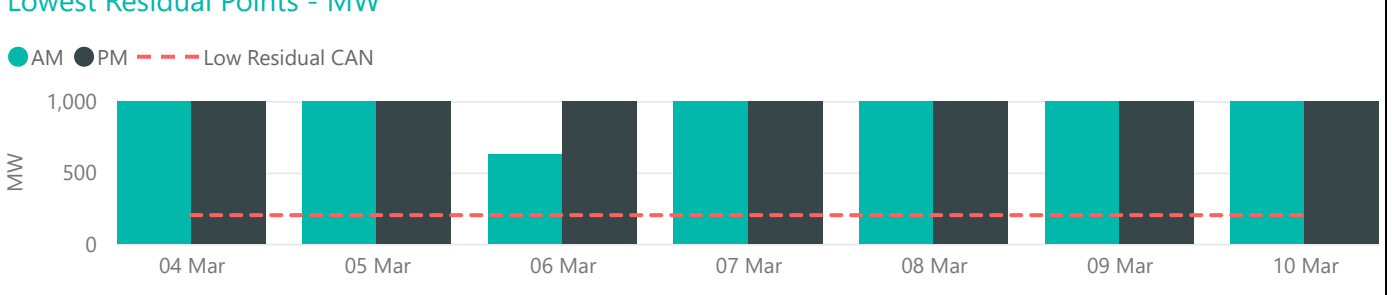
South Island Energy Risk

Normal Watch Alert Emergency

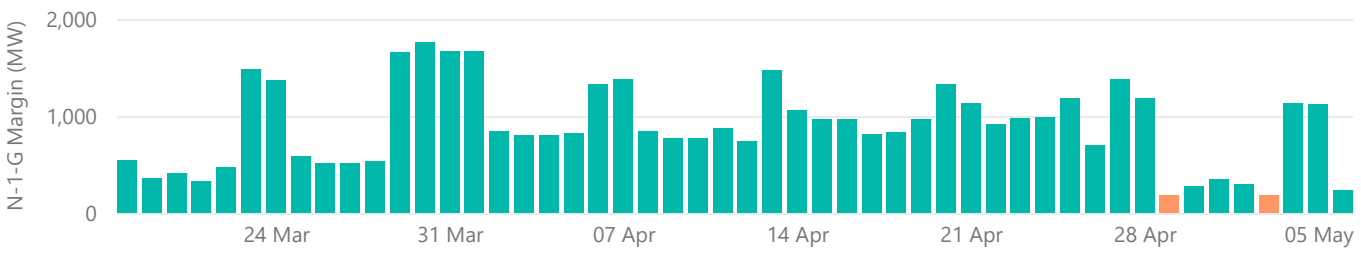
New Zealand Energy Risk Status Curves (Available GWh)



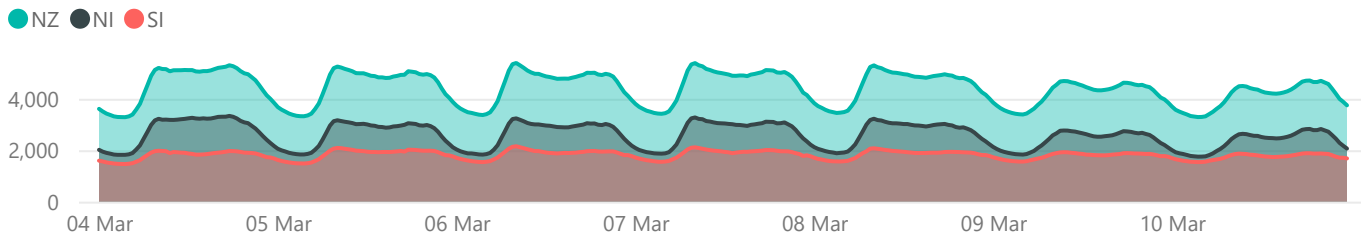
Lowest Residual Points - MW



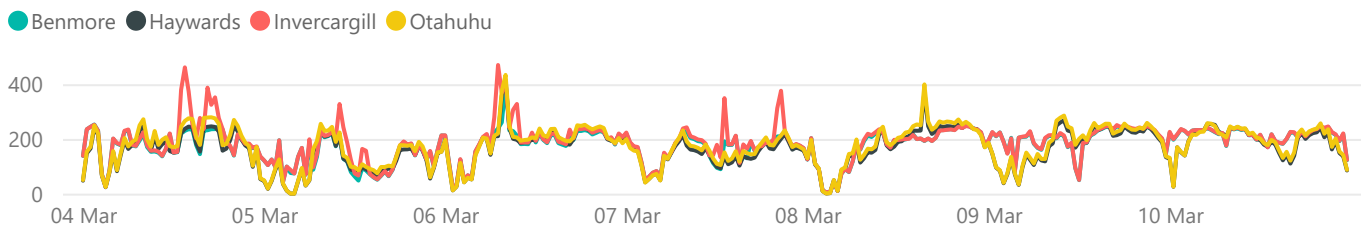
NZGB Look-Ahead (excluding next 7 days)



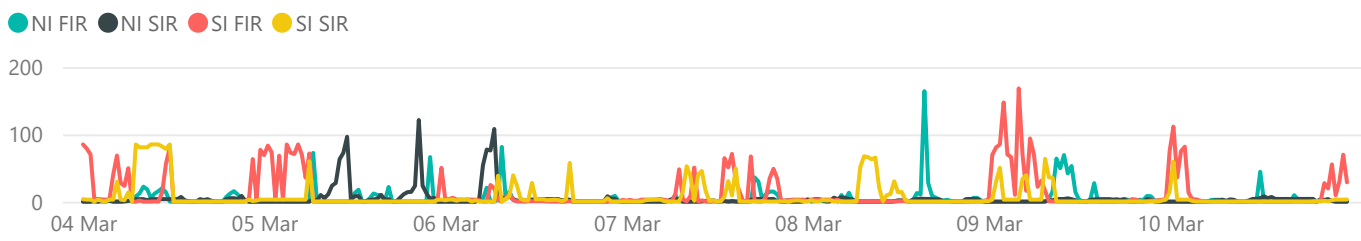
National Demand by Trading period - MW



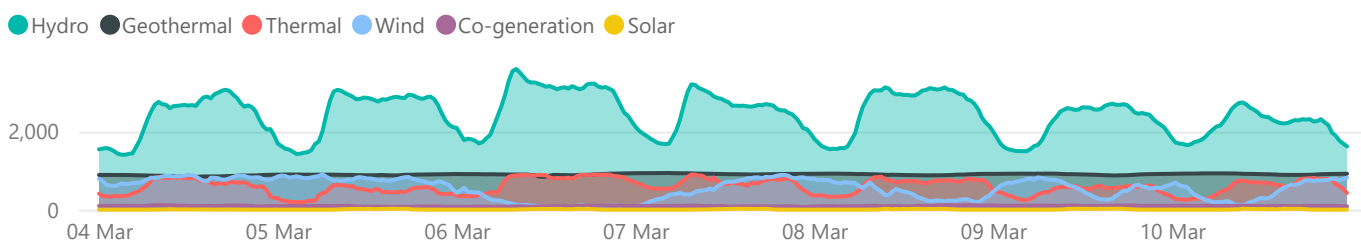
Energy Prices - $/MWh



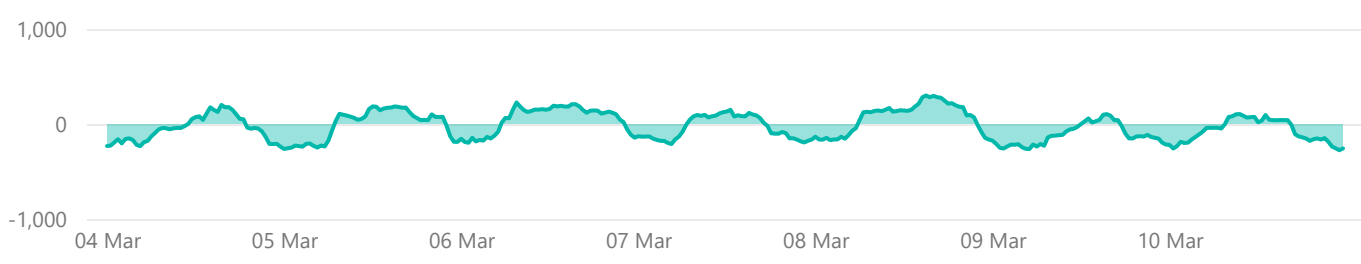
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW



Weekly Summary Insight - Net Free Reserves (NFRs)

Recently we have seen fast instantaneous reserve (FIR) requirements in the South Island exceed the actual risk set by the risk setter in terms of megawatts, while the HVDC is in monopole operation as part of the planned HVDC outage.

Reserves are important because they cover the tripping of an HVDC pole or the largest generating unit on the system, which can result in a significant power loss and a large frequency fluctuation on the power system.

The level of reserves required is calculated as the difference between the level of risk (AC or DC) and the Net Free Reserves (NFRs), which are calculated in the Reserve Management Tool (RMT). NFRs are used to determine the amount of reserve that should be carried to cope with the under-frequency effects of the following risks:

- ACCE - AC Contingent Event, caused by the loss of (usually) one generator unit,
- DCCE - DC Contingent Event, loss of one HVDC Pole,
- ACECE - Loss of an interconnected transformer or a bus bar fault, and
- DCECE - Loss of the HVDC bipole.

They are calculated for both islands, for both types of instantaneous reserve; fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR).

The Code requires that for:

- a Contingent Event (CE), the frequency falls to no less than 48 Hz and recovers to no less than 49.25 Hz within 60 seconds (both islands),
- an Extended Contingent Event (ECE), the frequency falls to no less than 47Hz in the North Island and 45 Hz in the South Island and recovers to no less than 49.25 Hz within 60 seconds, and
- the North Island frequency does not stay below 47.3 Hz for longer than 20 seconds or below 47.1 Hz for longer than 5 seconds.

NFRs represent the net outcome of effects on the reserve required to cover a particular risk. These effects include:

- uncleared or unoffered reserve capability from partly loaded hydro machines (FIR only),
- frequency required to trigger AUFLS (ECE only),
- load damping associated with motors slowing down as frequency falls (FIR only),
- a limited allowance for HVDC reserve sharing (except for DCCE and DCECE),
- cascade tripping of non-compliant generators (generators that do not remain connected to the grid or do not maintain output as the frequency falls) resulting in reduced NFRs, and
- generation considered to be a secondary risk due to on-going testing or commissioning.

To calculate the NFRs, RMT uses:

- cleared generation and HVDC transfer,
- cleared, feasible FIR from interruptible load, partly loaded spinning reserve and tailwater depressed reserve,
- HVDC configuration and capacity, and
- additional frequency keeper MW band (if the risk setter is also a frequency keeper).

The process for calculating NFRs is iterative as the NFR outputs generated by RMT are used as inputs into the next scheduling pricing and dispatch (SPD) model solve.

RMT calculates the NFRs by determining the required FIR and SIR reserves. The required FIR is calculated by scaling the scheduled FIR reserves to find a solution that achieves the frequency objectives. The required SIR is equal to the Risk MW.

For CE events :

- for FIR the NFR is then output as the (Risk MW – Reserves required), and
- for SIR the NFR is usually zero as the SIR required is the Risk MW, but it can be negative if there is generation that has tripped in the solution.

For ECE events:

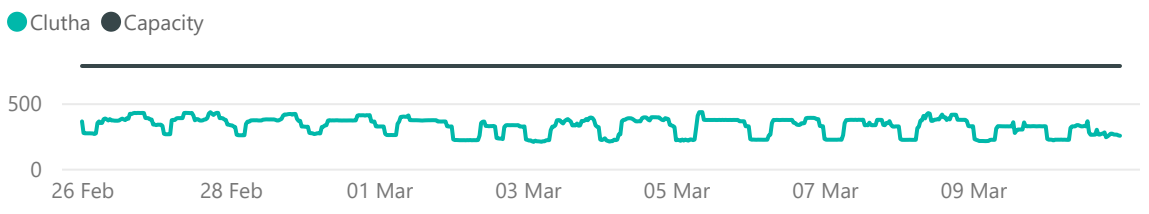
- for FIR the NFR is the (Risk MW – Reserves required) + tripped AUFLS MW + allowance for untripped AUFLS, and
- for SIR the NFR is the (tripped AUFLS MW + allowance for untripped AUFLS - generation that has tripped).

Any of the NFR calculations can be negative, this just means that more reserves must be procured than the MW value of the risk setting event. This occurs quite commonly when there are large secondary risks due to commissioning. It can also occur for FIR when the scheduled FIR reserve providers do not deliver sufficient reserves quickly enough to meet the frequency objectives for the relevant risk event.

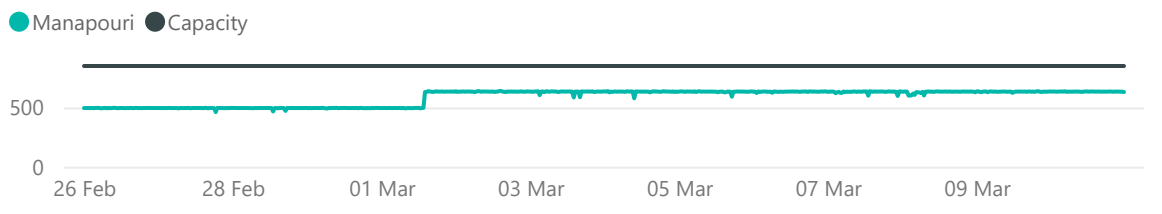
Generation Breakdown - Last Two Weeks

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

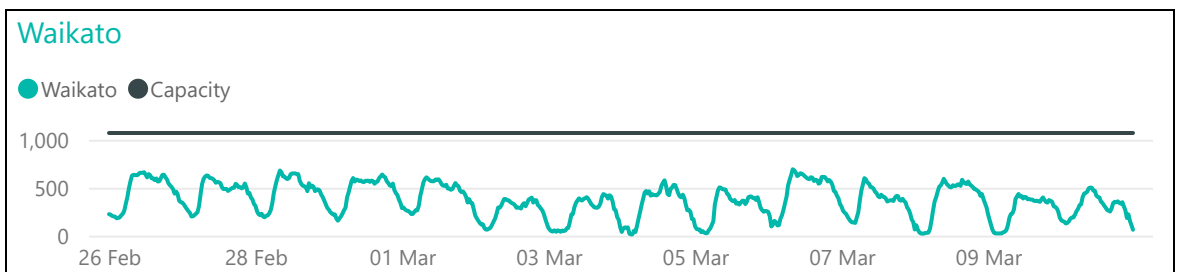
Clutha



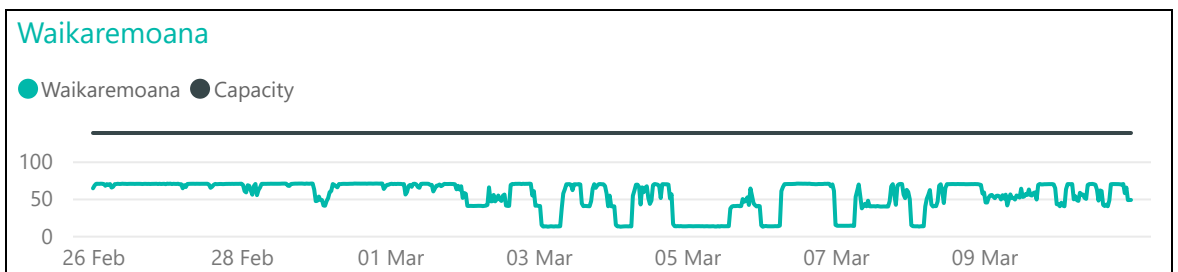
Manapouri



Waikato

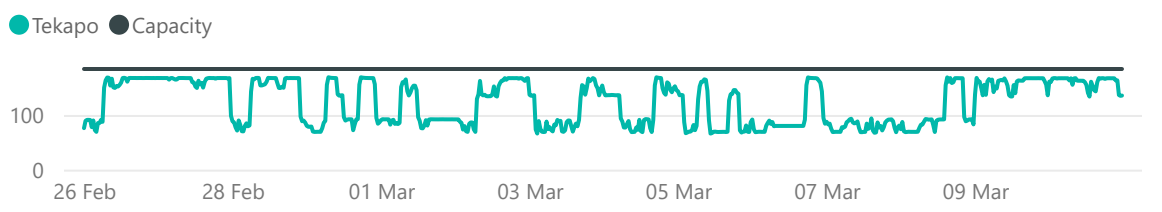


Waikaremoana

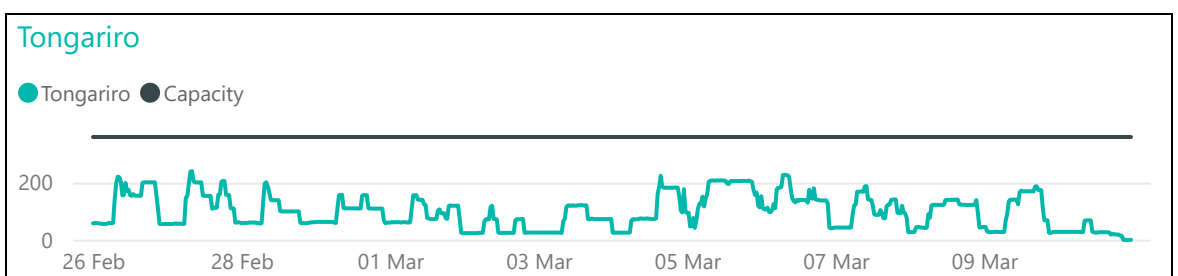


Waitaki

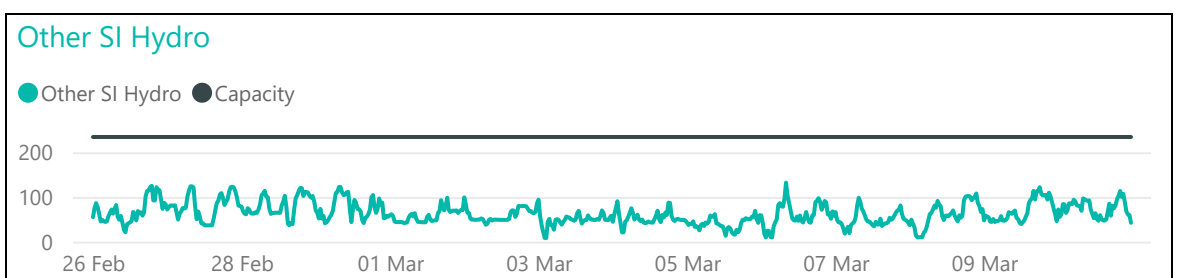
Tekapo



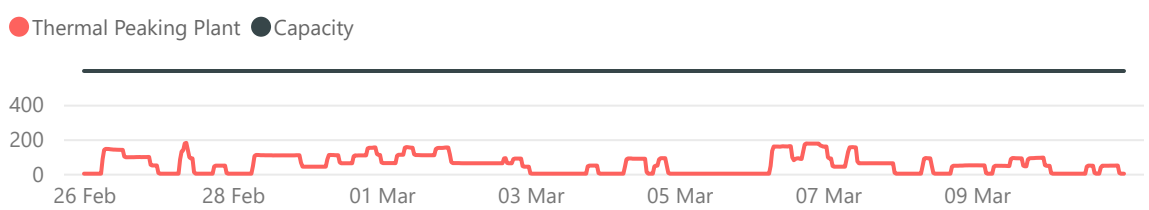
Tongariro



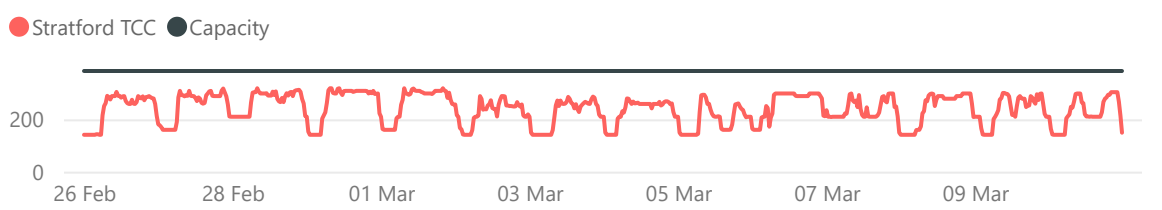
Other SI Hydro



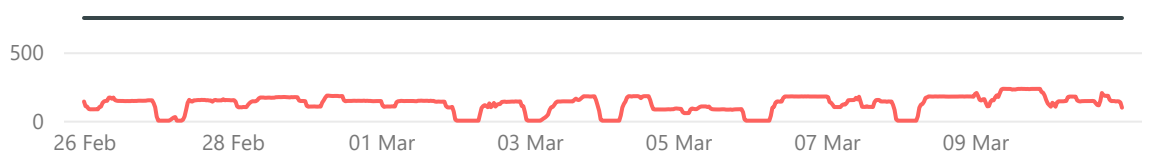
Thermal Peaking Plant



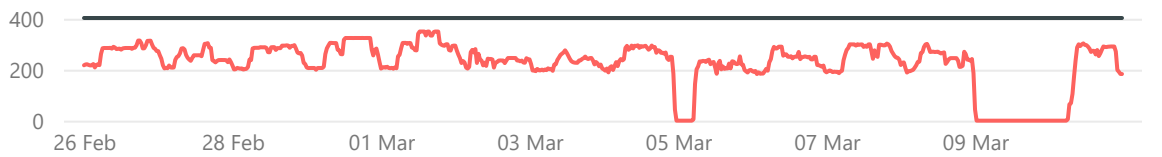
Stratford TCC



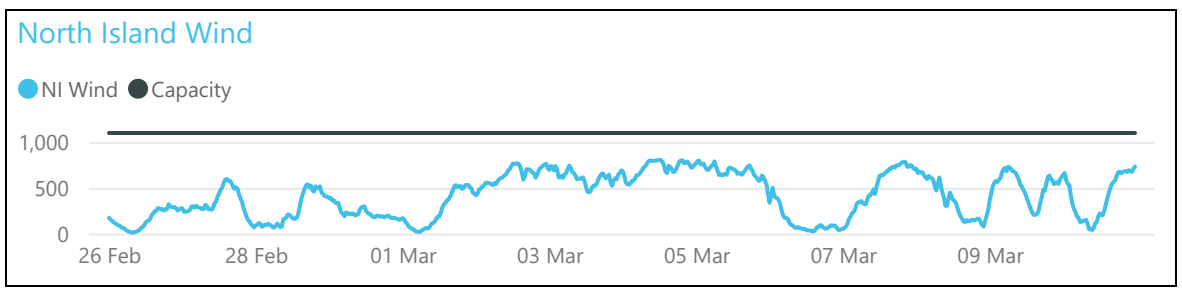
Huntly Rankines



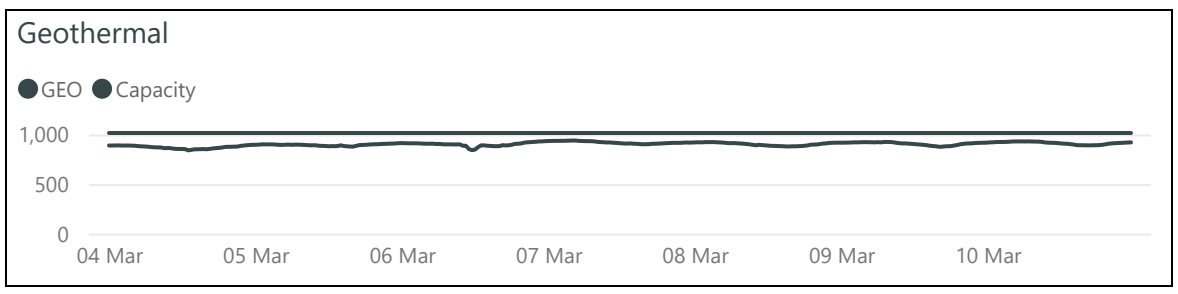
Huntly U5



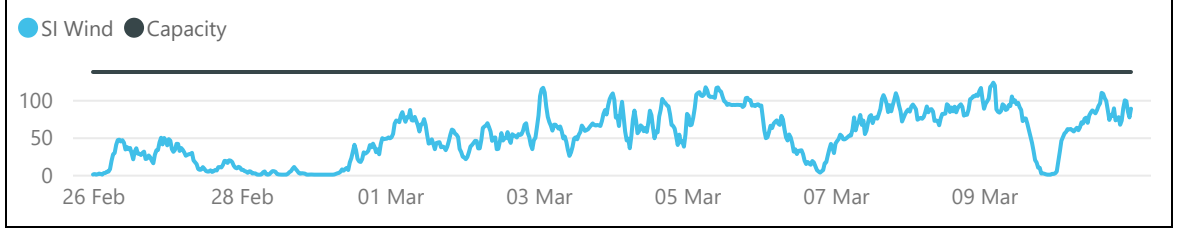
North Island Wind



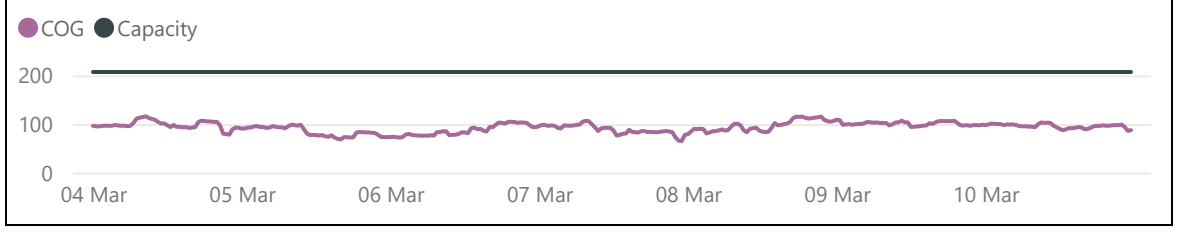
Geothermal



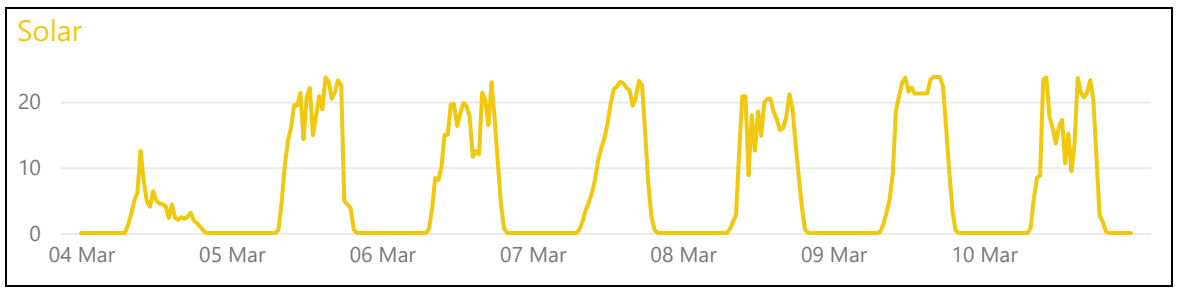
South Island Wind



Co-Generation

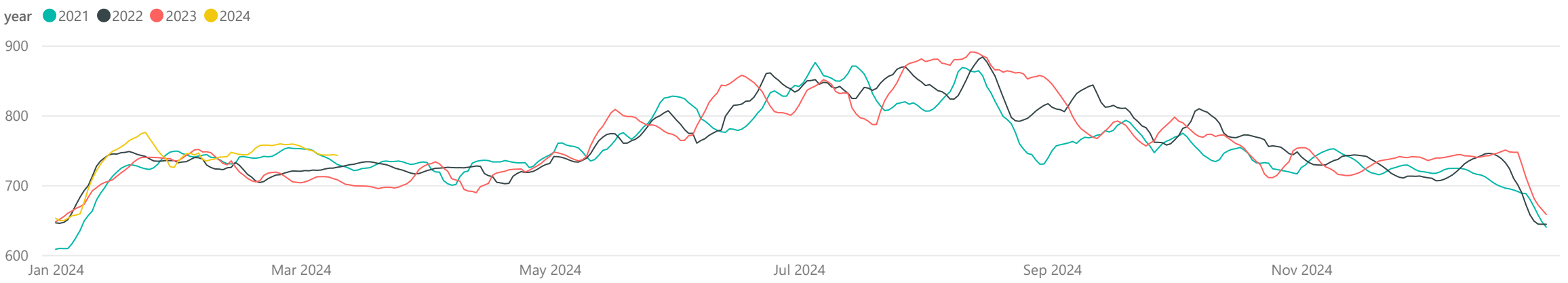


Solar

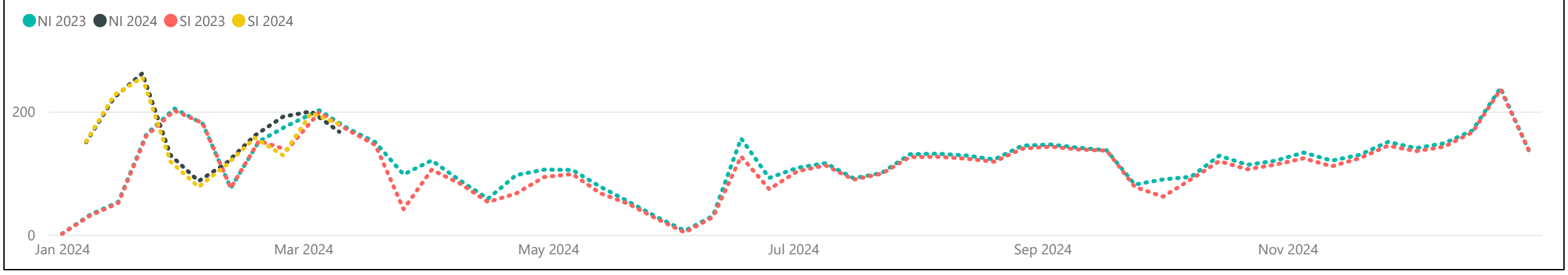


Weekly Profiles

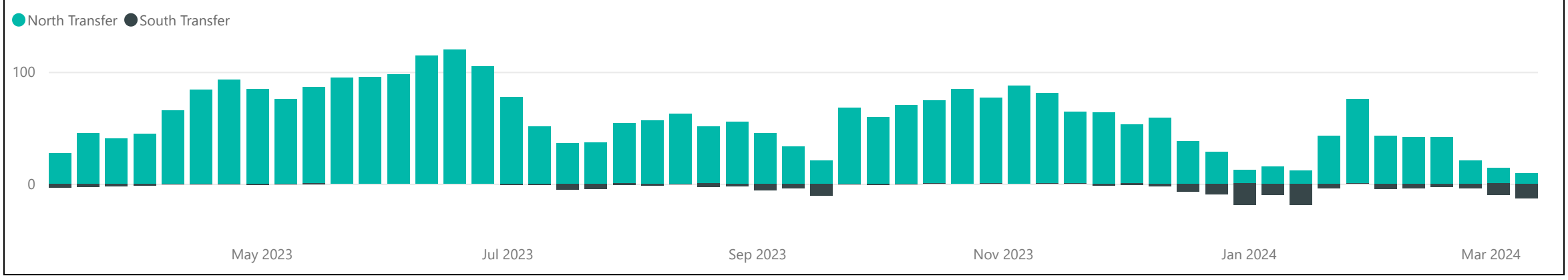
National Weekly Demand - GWh - 7 Day Rolling



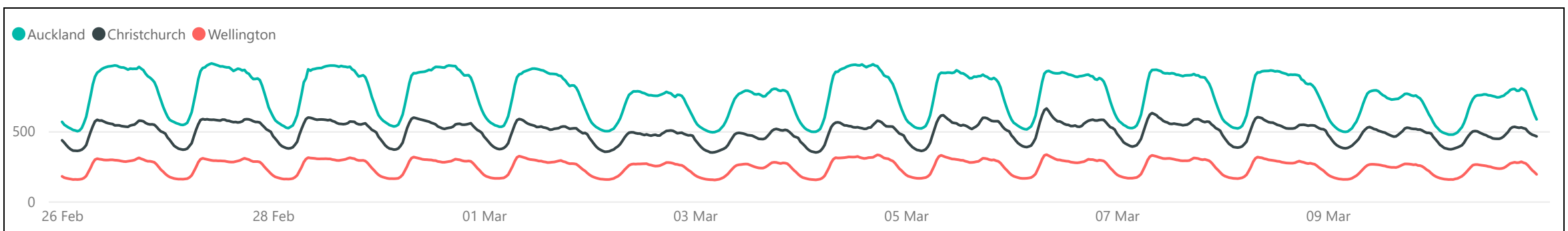
Weekly Spot Price - $/MWh



HVDC Transfer - Weekly GWh



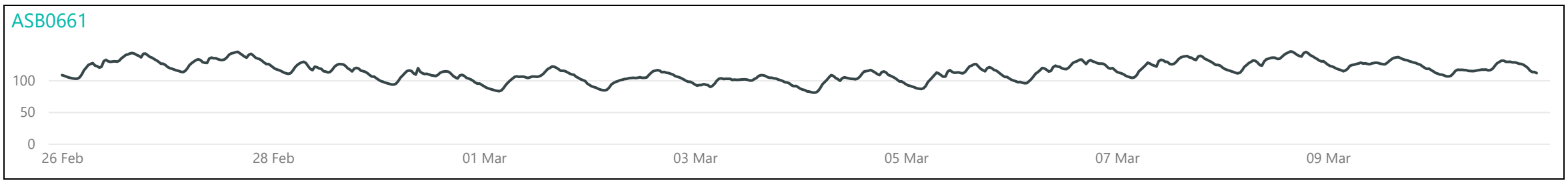
Conforming Load Profiles - Last Two Weeks *Measured in MW shown by region*



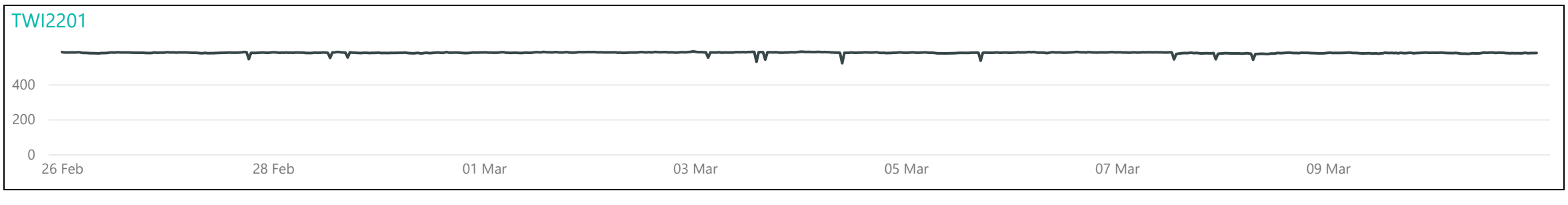
Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*

GLN0331

ASB0661



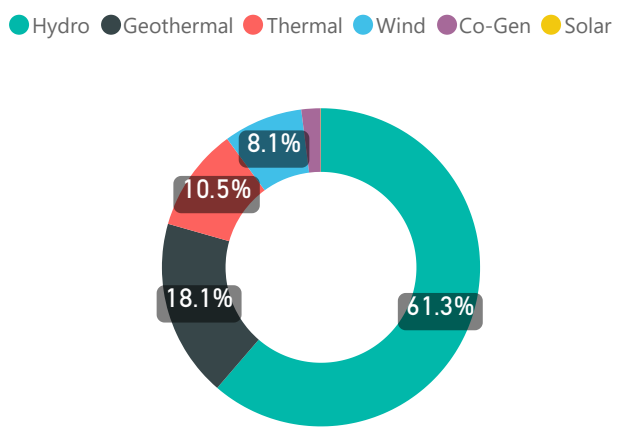
TWI2201



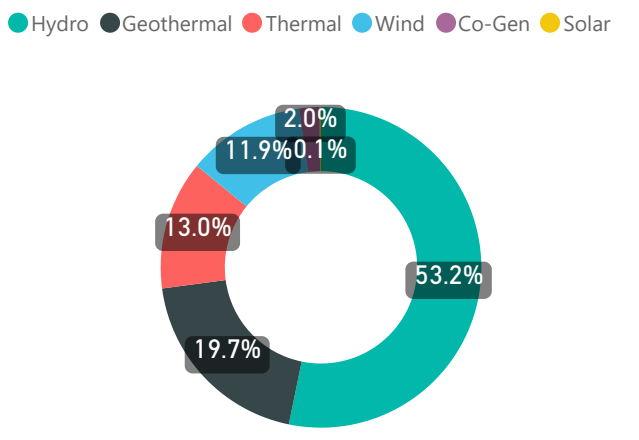
TRANSPOWER

Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



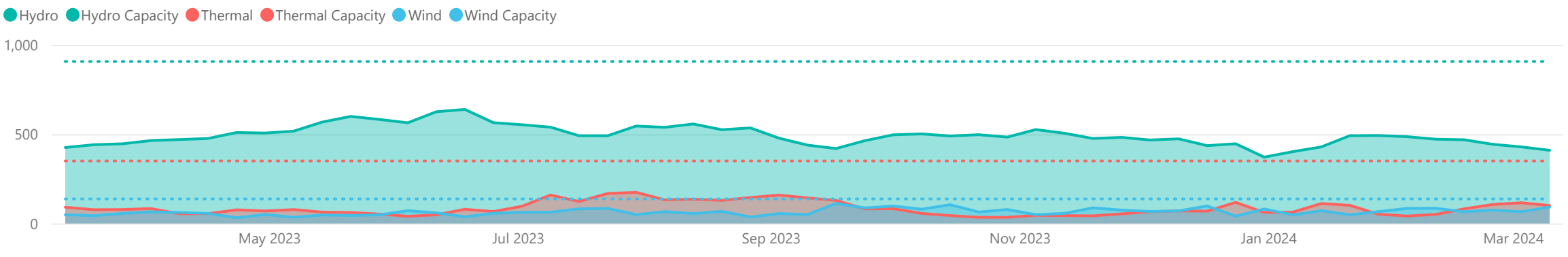
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
85%	64,860	83.2

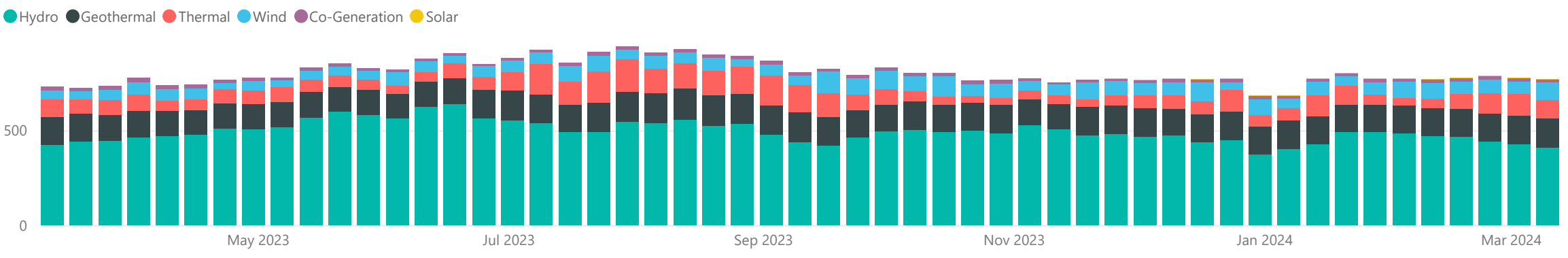
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
88%	59,538	72.8

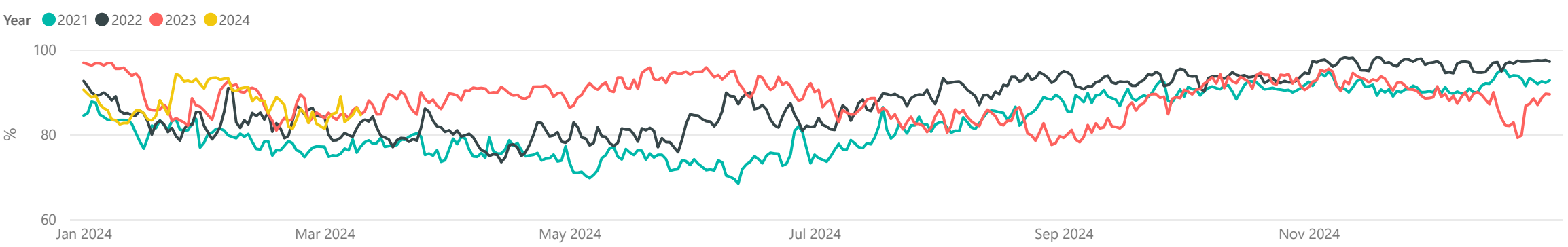
Weekly Generation Mix vs Capacity - GWh



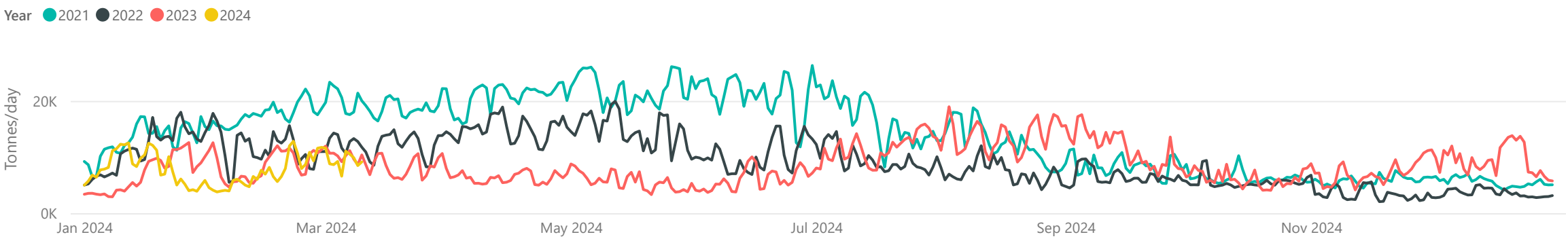
Weekly Generation Mix - GWh



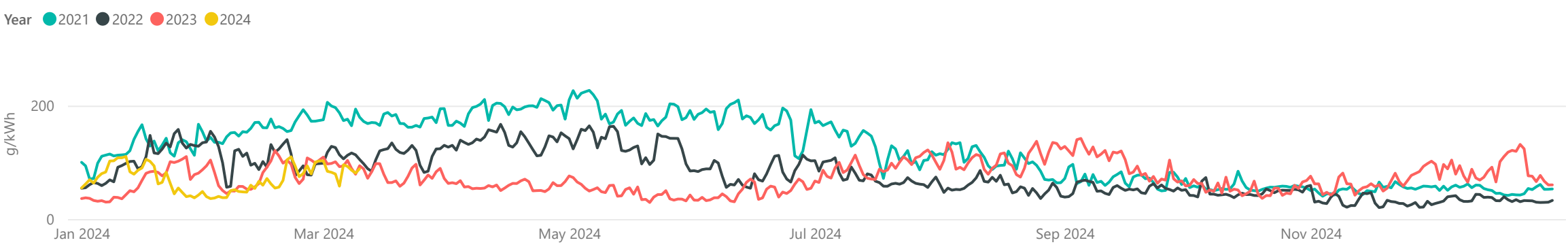
NZ Renewable Percentage



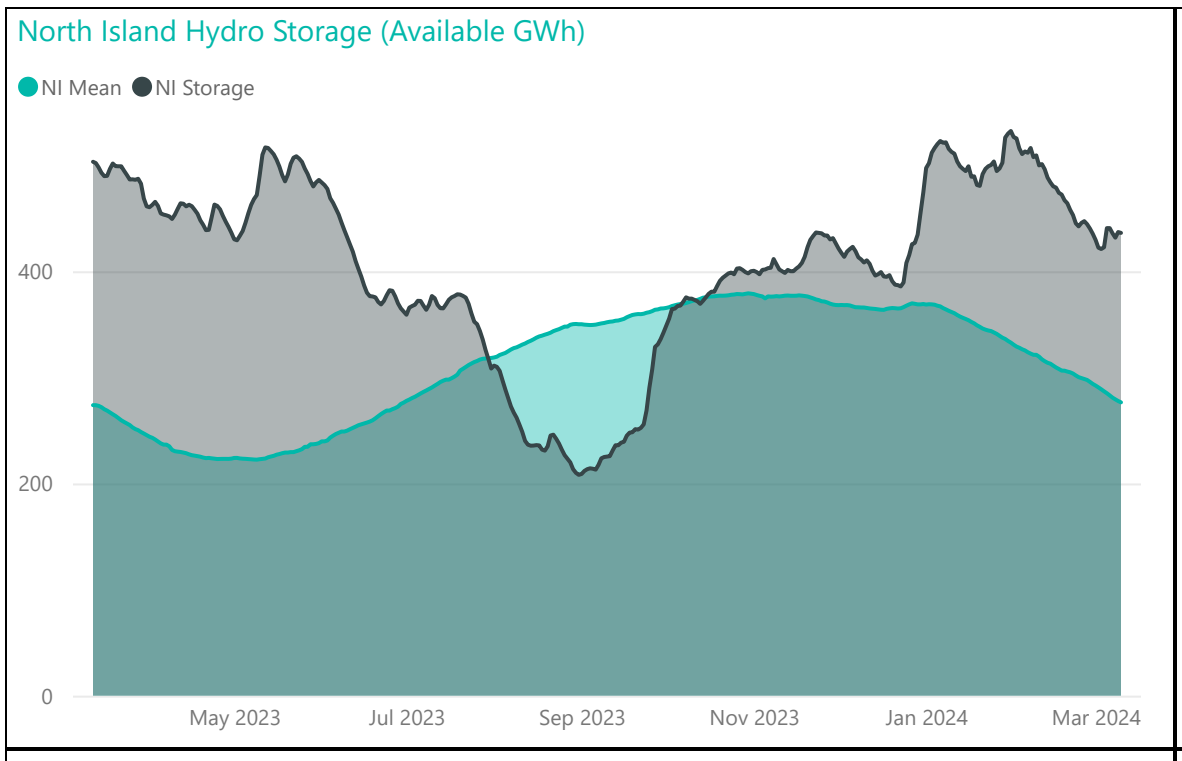
CO2 Tonnes/Day

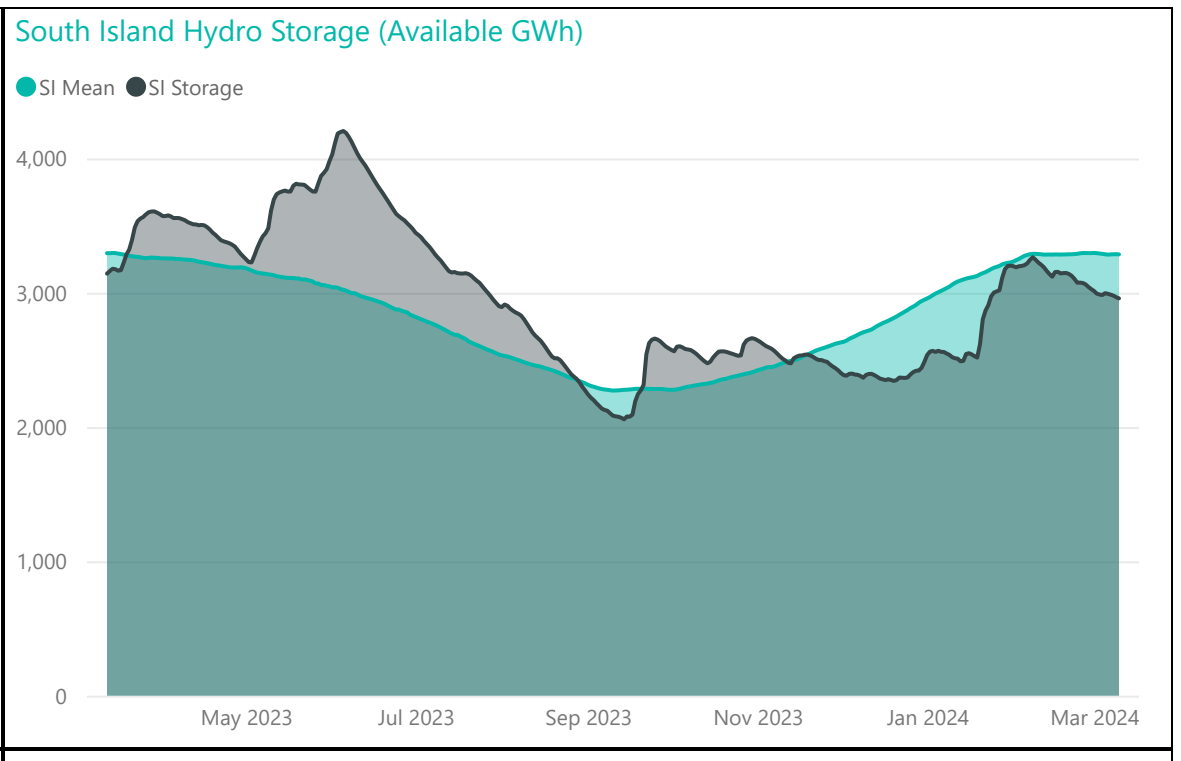


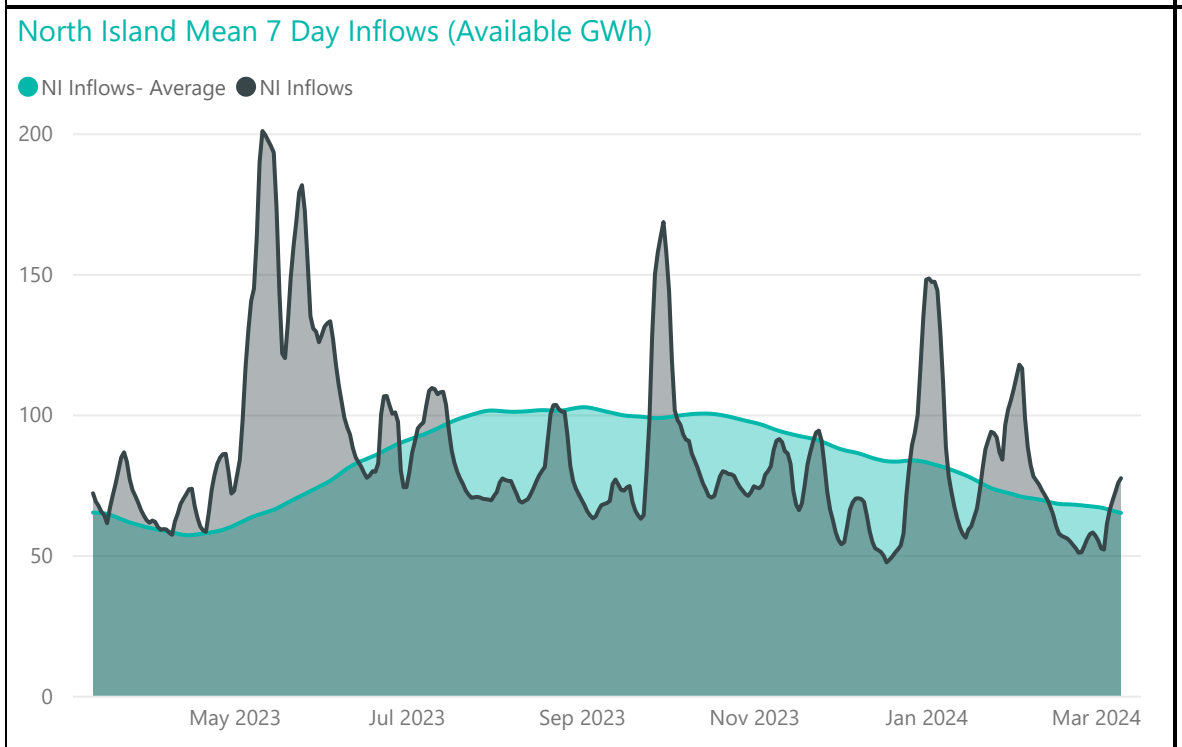
CO2 g/kWh

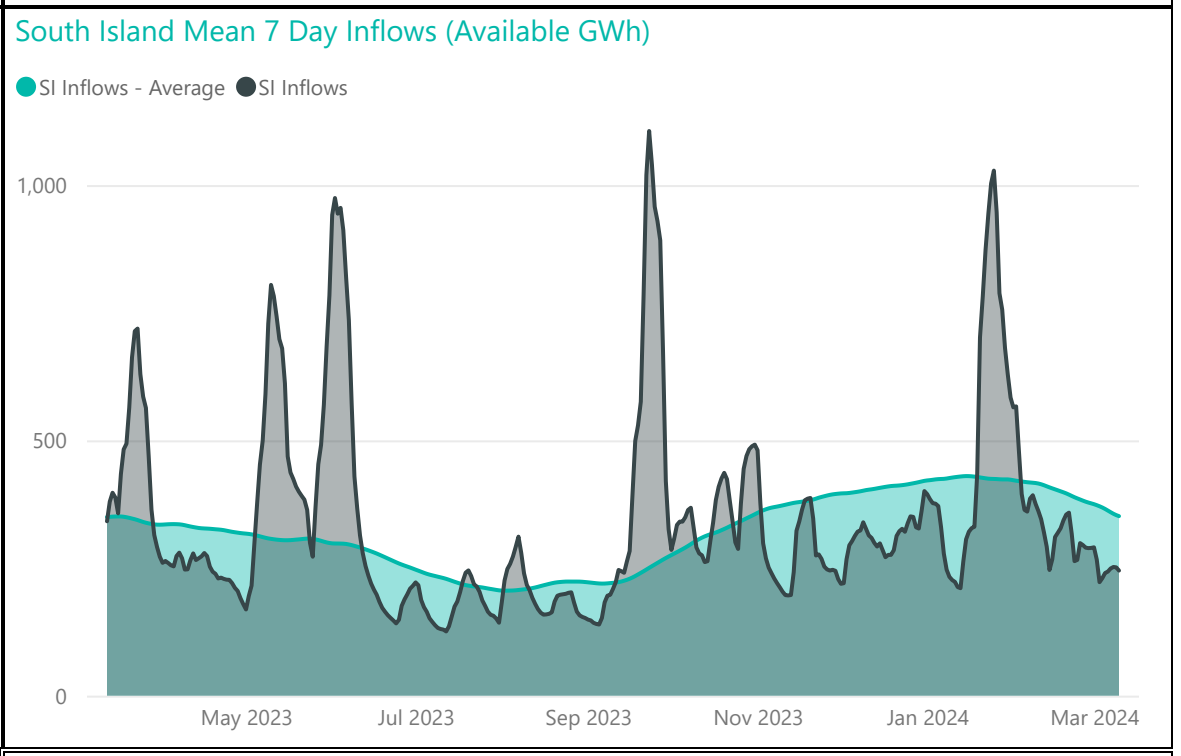


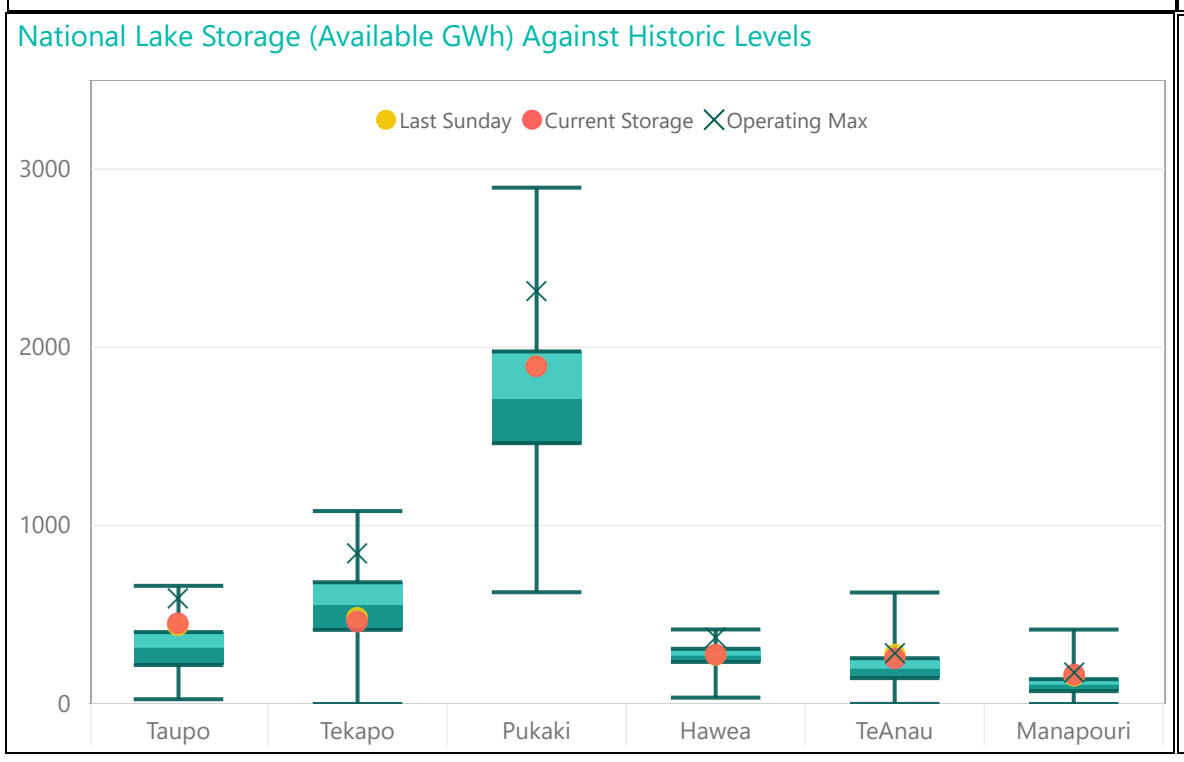
Hydro Storage

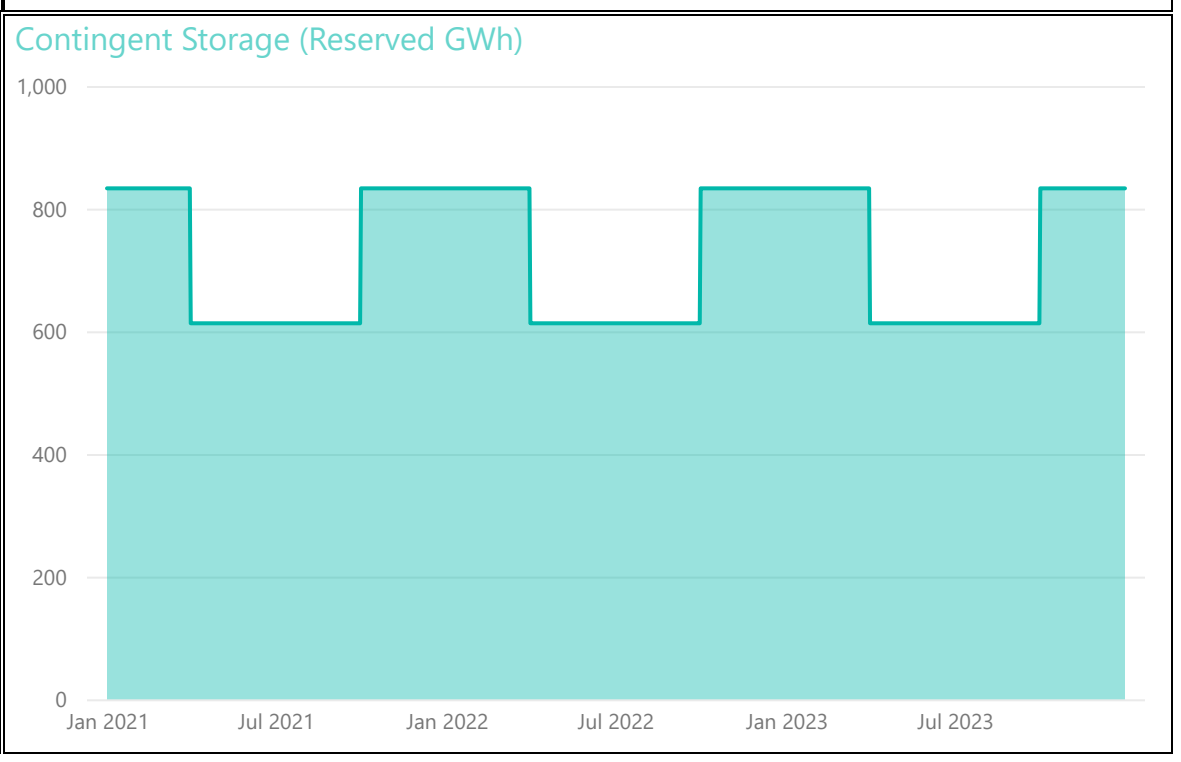












For further information on security of supply and Transpower's responsibilities as the System Operator, refer to our webpage here: https://www.transpower.co.nz/system-operator/security-supply

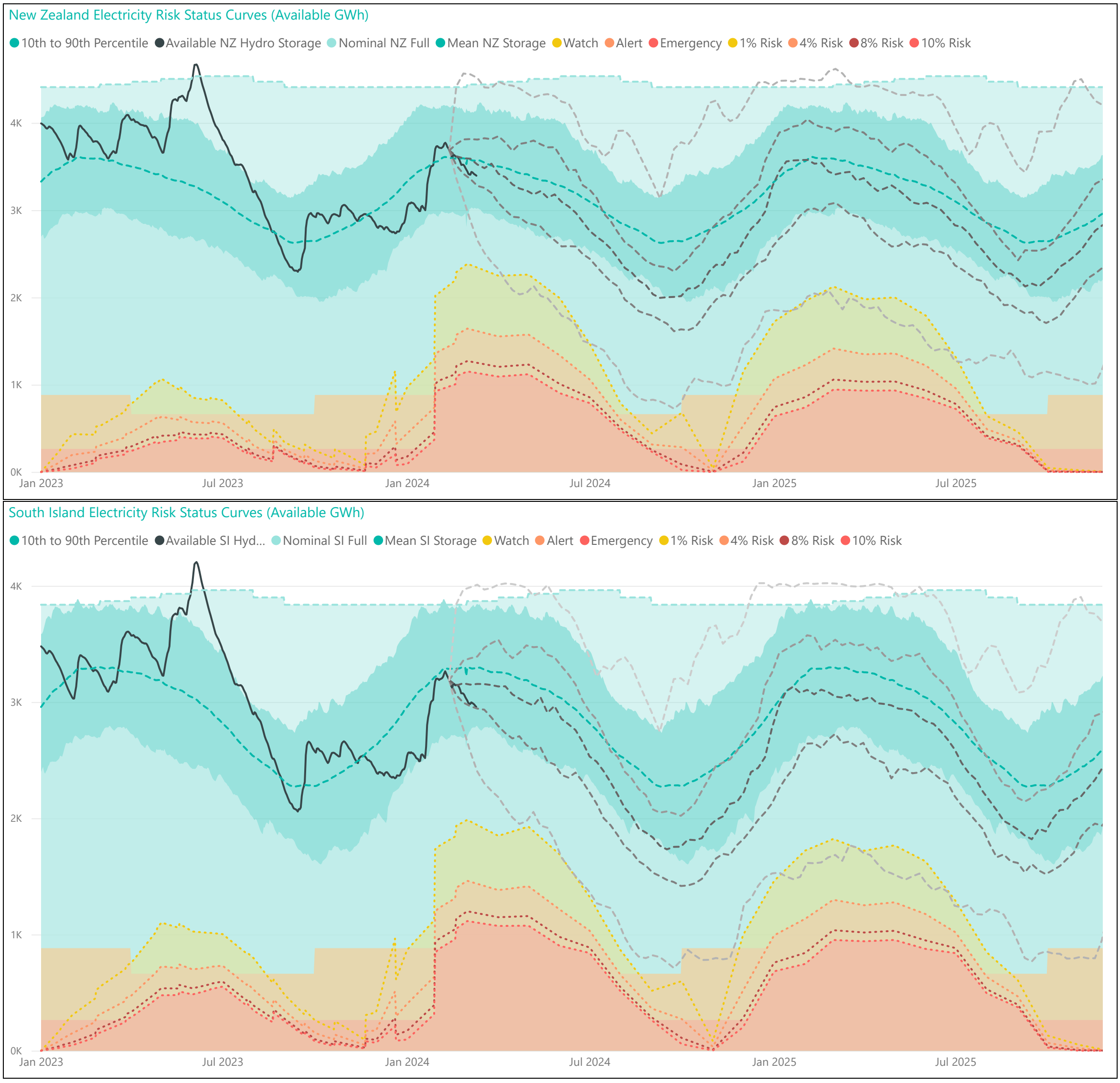
For any inquiries related to security of supply contact market.operations@transpower.co.nz

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).