14 April 2025

# Trading conduct report 6-12 April 2025

Market monitoring weekly report

# Trading conduct report 6-12 April 2025

## 1. Overview

1.1. Spot prices decreased to an average of $329/MWh despite less geothermal generation and more thermal generation when compared to the previous week. National hydro storage was steady this week at around 62% nominally full. Colder temperatures resulted in a sharper demand profile, with prices spiking during these times. During mid day periods, when solar generation was high, spot prices fell.

## 2. Spot prices

2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.

2.2. Between 6-12 April 2025:

(a) The average spot price for the week was $329/MWh, a decrease of around $36/MWh compared to the previous week.

(b) 95% of prices fell between $210/MWh and $456/MWh.

(c) The highest prices this week were often near peak demand periods, or during periods of large wind or demand forecast inaccuracies.

2.3. Daily average prices were below $330/MWh on Sunday (due to lower weekend demand) and Monday-Tuesday (due to higher wind generation). Spot prices increased from Wednesday due to higher peak demand and lower wind generation.

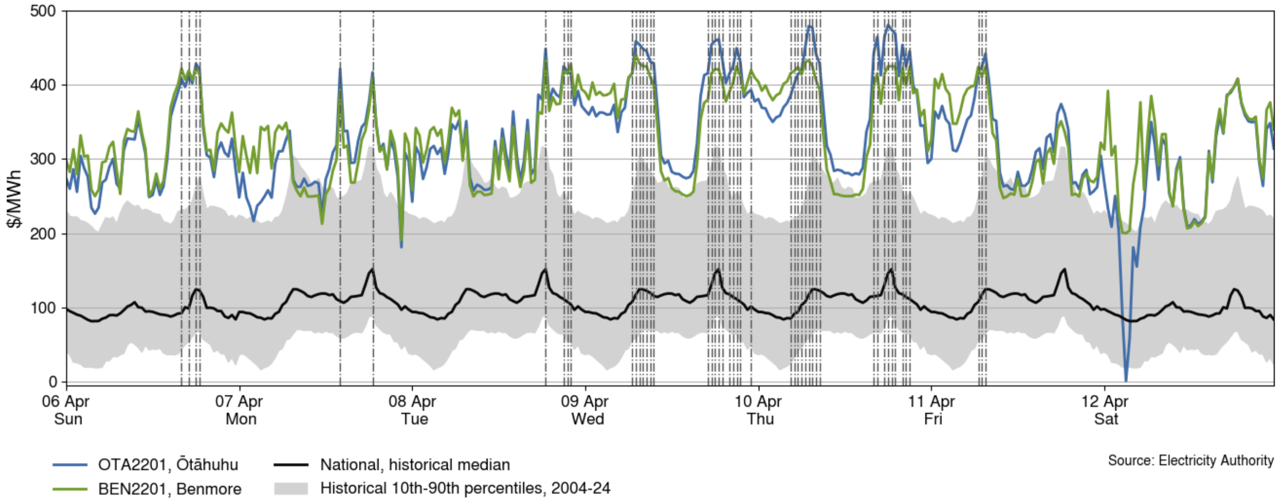
2.4. Spot prices peaked above $400/MWh on Sunday afternoon because of low wind, demand up to 135MW higher than forecast and Tauhara tripping around 6.00pm. Spot prices peaked above $400/MWh again twice on Monday. First at 2.00pm around the time Huntly 4 tripped, and again at 6.30pm during peak demand for the day when wind was 46MW lower than forecast and demand was 41MW higher than forecast.

2.5. The highest spot price at Ōtāhuhu was $481/MWh at 6.00pm on Thursday when wind generation was low (inlcuding 43MW lower than forecast) and just before peak evening demand at 6.30pm. The Benmore spot price at the same time was $425/MWh.

2.6. Spot prices at Ōtāhuhu and Benmore separated early on Saturday morning when HVDC southward flow was near its limit. The separation was greatest at 3.00am when the Ōtāhuhu spot price was $1/MWh and the Benmore spot price was $201/MWh.

2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90$^{th}$ percentiles adjusted for inflation. Prices greater than quartile 3 (75$^{th}$ percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices above $415/MWh are marked with black dashed lines.

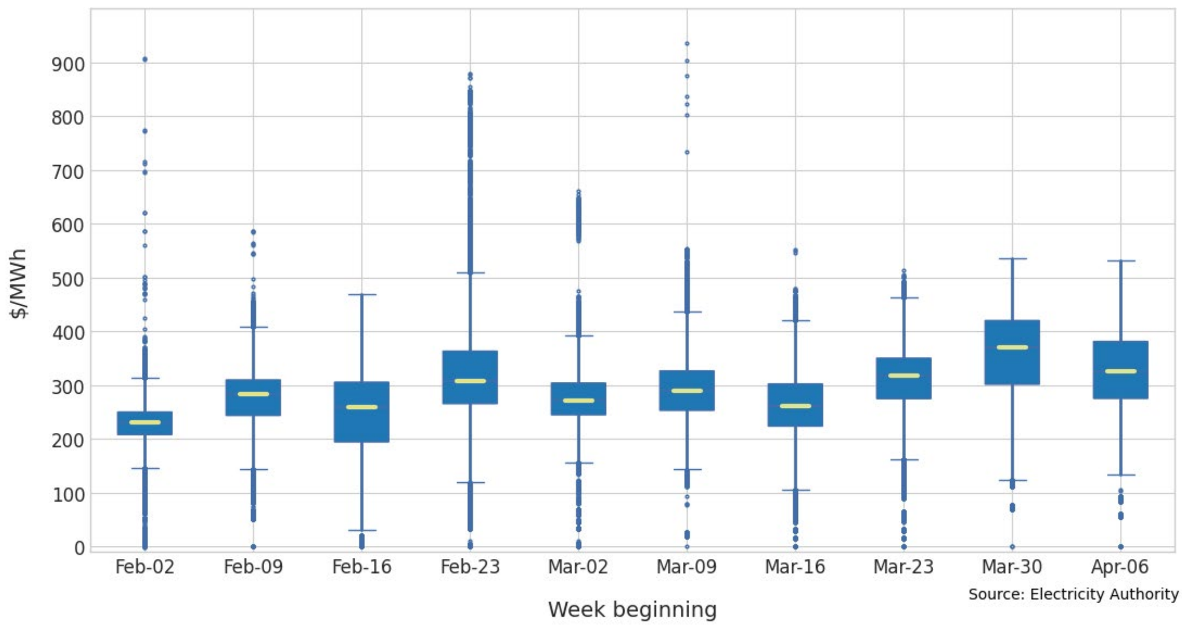
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 6-12 April 2025**




2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.9. The distribution of spot prices this week has shifted downwards compared to last week. The median price was $325/MWh and most prices (middle 50%) fell between $275/MWh and $381/MWh.

**Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks**

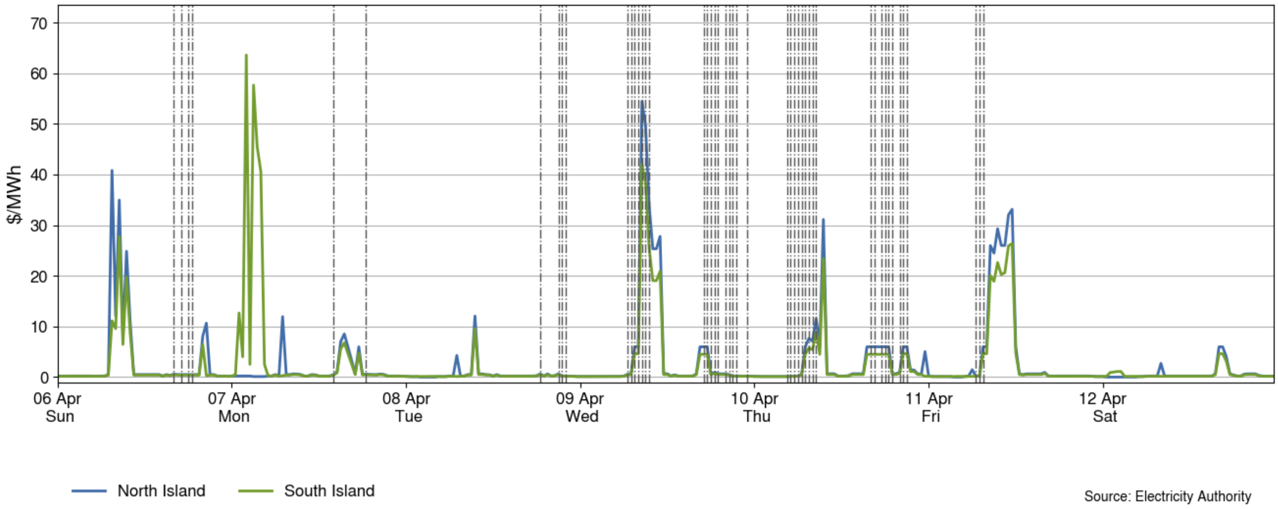


# 3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR separated early on Monday morning when the HVDC was setting the South Island risk during high southward HVDC flow. The South Island FIR price at 2.00am on Monday was $64/MWh and the North Island price at the same time was $0.22/MWh.

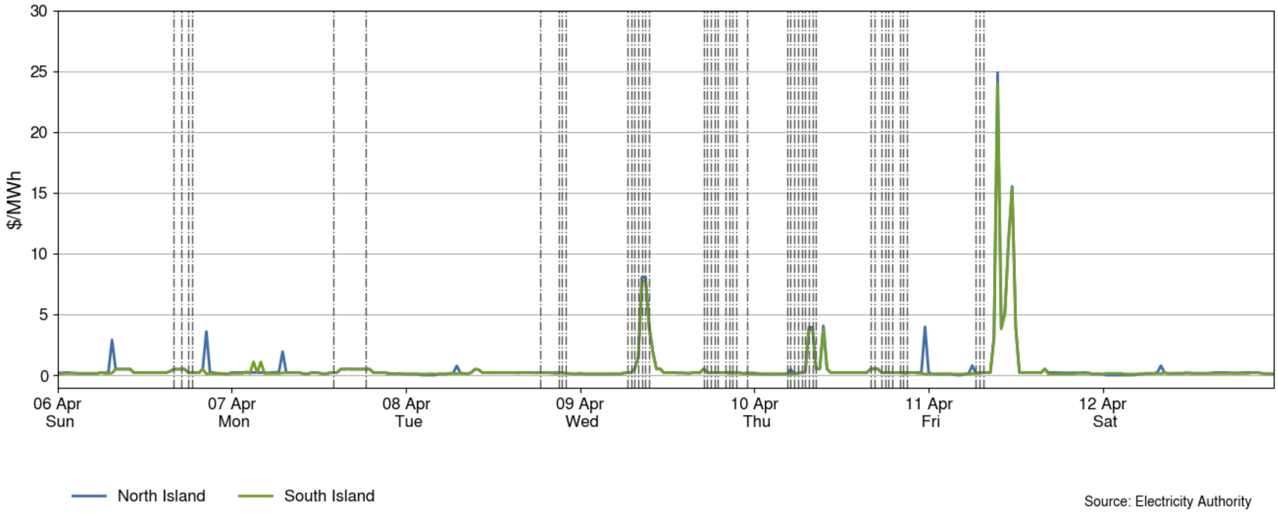
3.2. FIR prices spiked at 8.30am on Wednesday morning to $54/MWh in the North Island and $42/MWh in the South Island when the amount of low-priced reserve decreased.

**Figure 3: Fast instantaneous reserve price by trading period and island, 6-12 April 2025**




3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices spiked at 9.30am on Friday to $25/MWh in the North Island and $24/MWh in the South Island when more expensive SIR was cleared.

**Figure 4: Sustained instantaneous reserve by trading period and island, 6-12 April 2025**



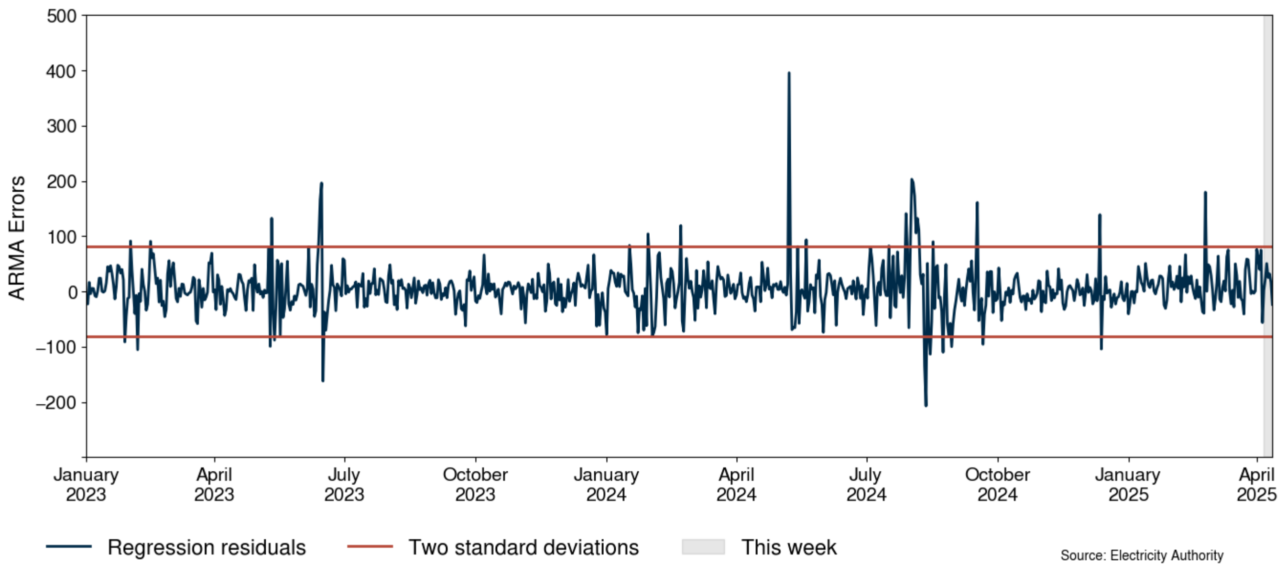
# 4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A.

4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled in the regression analysis.

4.3. This week, there were no residuals above or below two standard deviations, indicating that prices were similar to those predicted by the model.

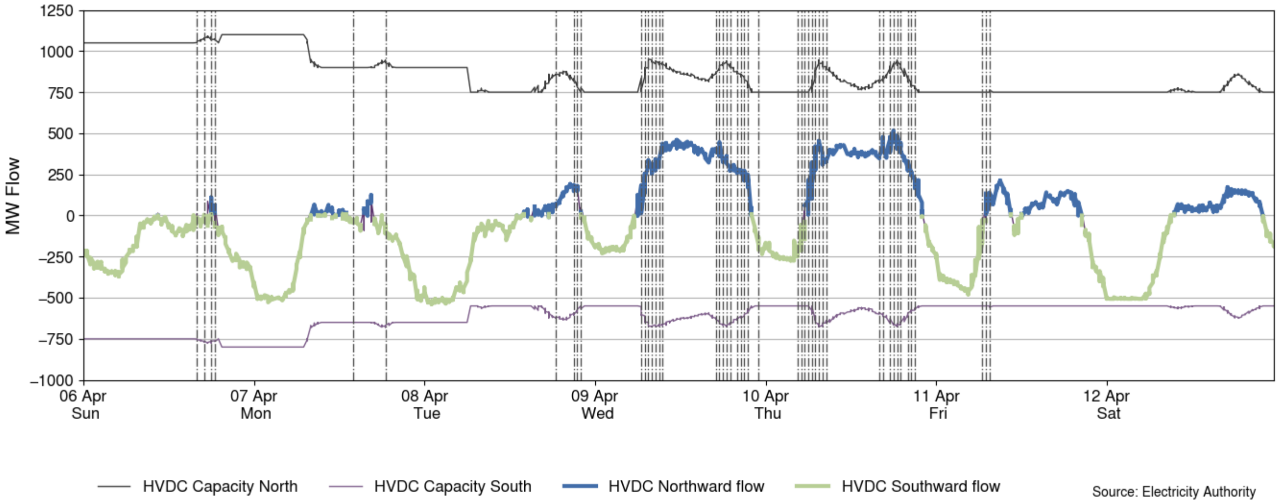
**Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 12 April 2025**




# 5. HVDC

5.1. Figure 6 shows the HVDC flow between 6-12 April 2025. HVDC flows were typically southward overnight or during periods of higher wind generation, and northward during times of lower wind generation or higher demand.

**Figure 6: HVDC flow and capacity, 6-12 April 2025**

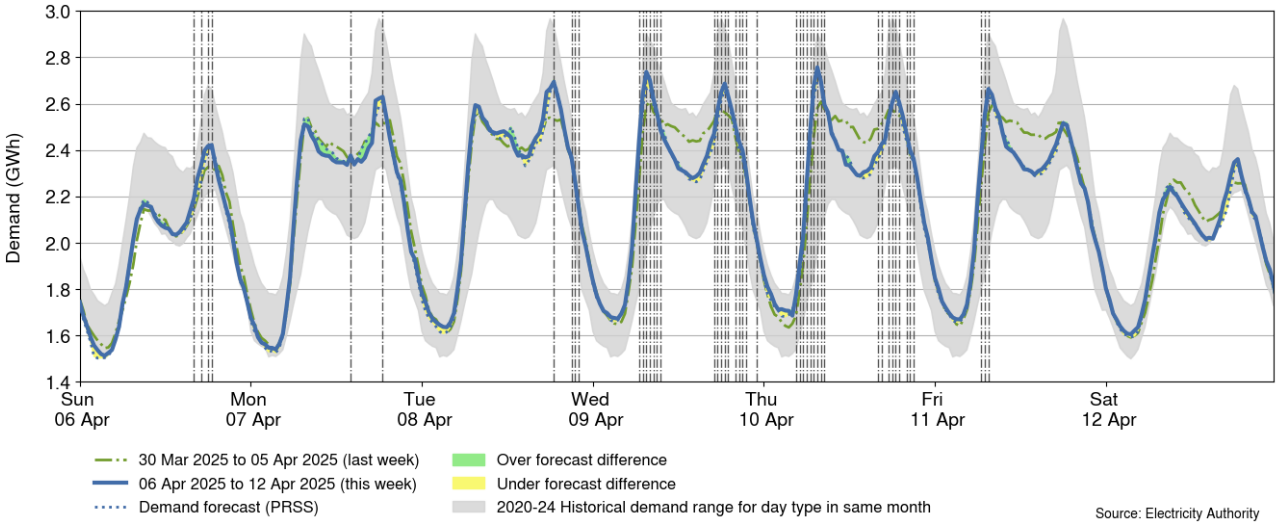



# 6. Demand

6.1. Figure 7 shows national demand between 6-12 April 2025, compared to the historic range and the demand of the previous week. Demand had a sharper profile from Wednesday when national temperatures dropped.

6.2. Peak demand was 2.76GWh (5.51GW) at 7.30am on Thursday. Wednesday and Thursday had the highest peak morning demand periods of the week, but also had the lowest midday demand of all the weekdays.

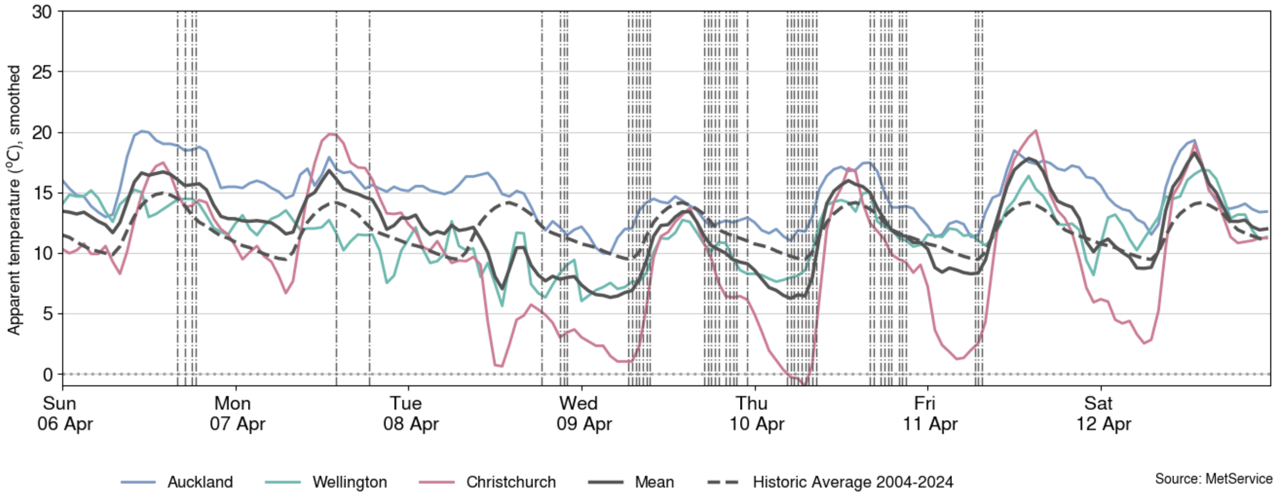
**Figure 7: National demand, 6-12 April 2025 compared to the previous week**




6.3. Figure 8 shows the hourly apparent temperature at main population centres from 6-12 April 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. National temperatures dropped from Tuesday afternoon with apparent temperatures ranging from 10°C to 20°C in Auckland, 5°C to 17°C in Wellington, and -1°C to 20°C in Christchurch. During time colder mornings prices tended to spike due to the higher demand.

**Figure 8: Temperatures across main centres, 6-12 April 2025**

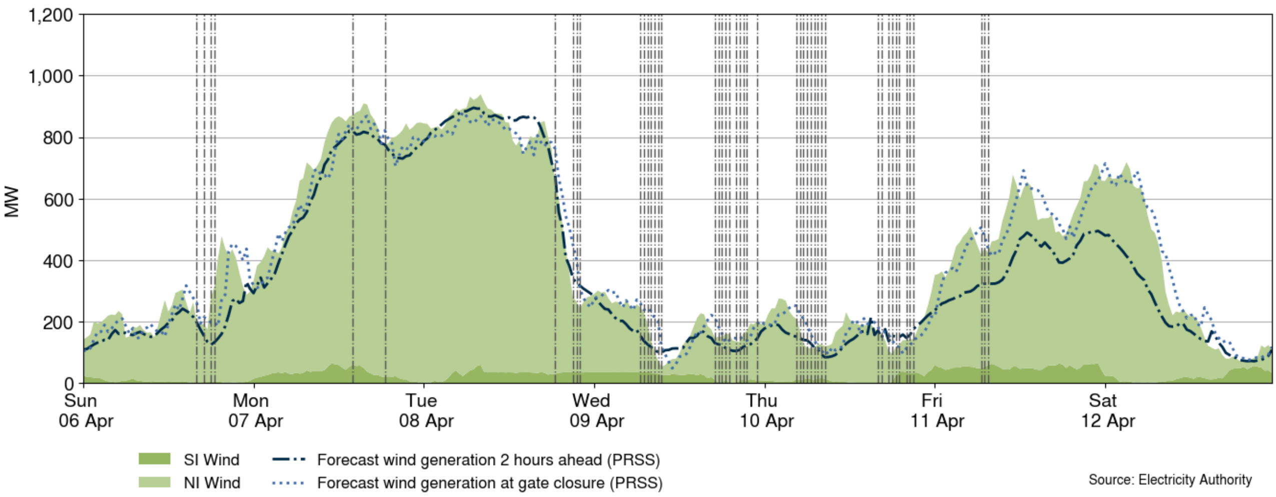



# 7. Generation

7.1. Figure 9 shows wind generation and forecast from 6-12 April 2025. This week wind generation varied between 53MW and 939MW, with a weekly average of 414MW. Wind generation was lowest on Wednesday and Thursday.

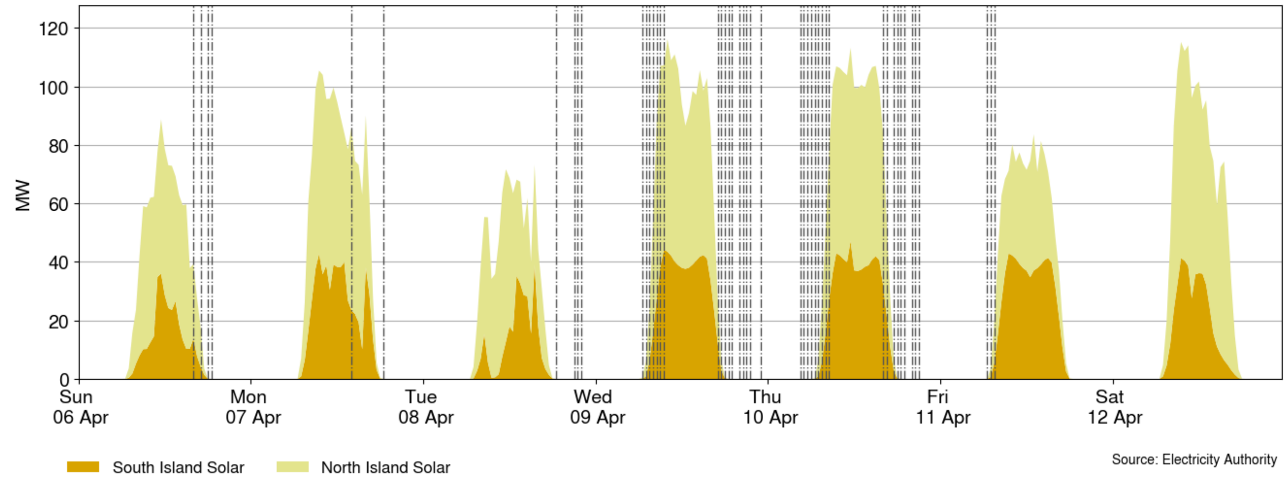
7.2. Wind generation was 171MW lower than forecast at 9.00pm on Tuesday when total wind generation was reducing quickly. Prices were highest this week when wind generation was generally below 200MW and demand was high due to cooler temperatures.

**Figure 9: Wind generation and forecast, 6-12 April 2025**




7.3. Figure 10 shows grid connected solar generation from 6-12 April 2025. Solar generation peaked at 116MW at 10am on Wednesday. Prices fell during the mid-day period this week, especially when compared to prices during peak, the reduction in demand and the contribution of 80-100MW of solar generation most days likely contributed to this.

**Figure 10: Grid connected solar generation, 6-12 April 2025**

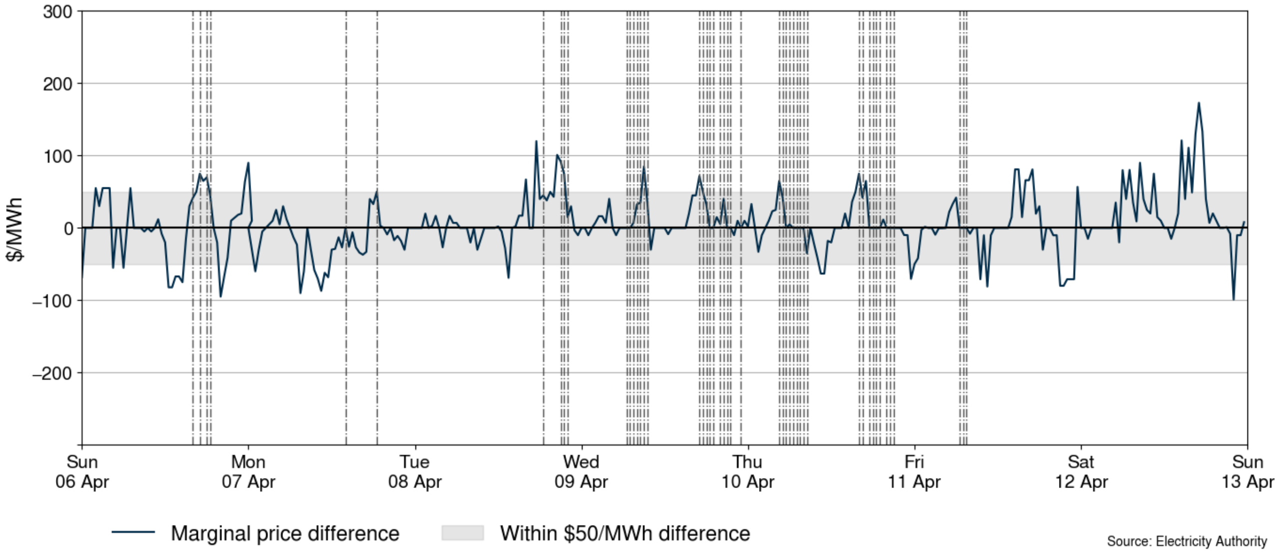



7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.5. Marginal price differences were above $100/MWh on Saturday at 2.30pm, 3.30pm and 4.30pm-5.30pm due to wind and demand forecast errors. The largest marginal price difference was +$173/MWh at 5.00pm on Saturday when wind generation was 58MW lower than forecast and demand was 153MW higher than forecast.

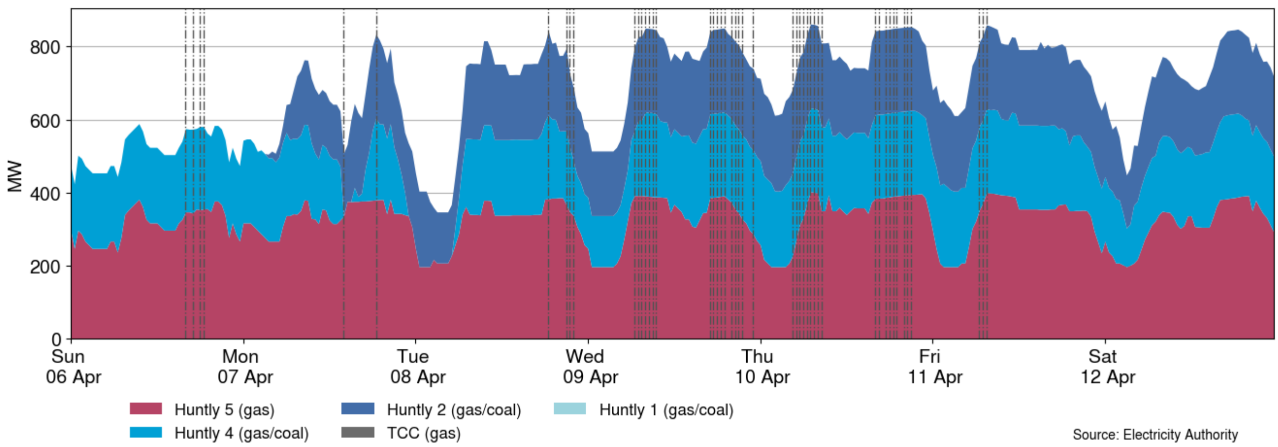
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

**Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 6-12 April 2025**




7.6. Figure 12 shows the generation of thermal baseload between 6-12 April 2025. Huntly units 2, 4 and 5 provided baseload generation this week. Huntly 4 tripped twice on Monday afternoon,[2,3] interrupting generation.

**Figure 12: Thermal baseload generation, 6-12 April 2025**




7.7. Figure 13 shows the generation of thermal peaker plants between 6-12 April 2025. Stratford 1, Junction Road and McKee provided baseload generation this week, with Stratford 2 and Huntly 6 running for short periods.

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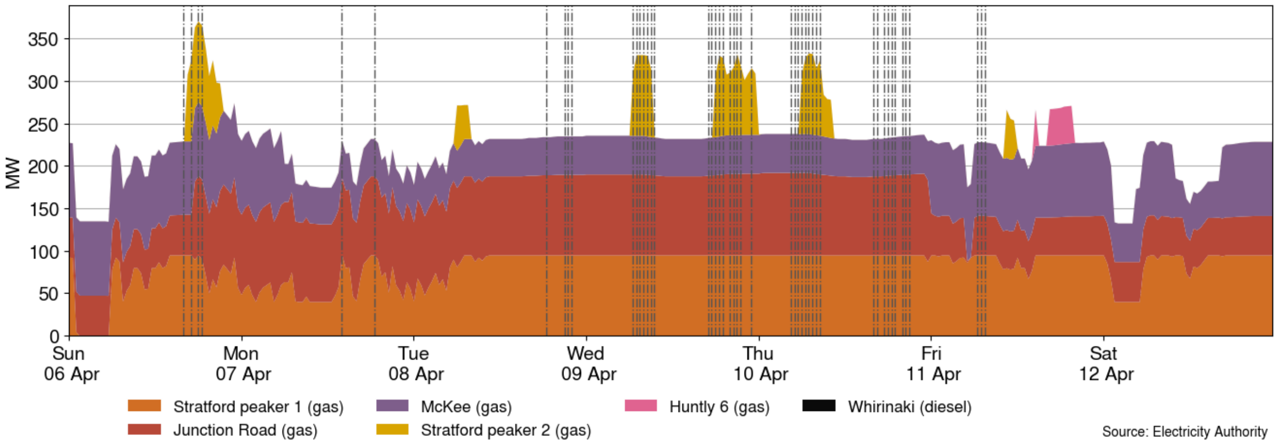
[2] EXN Voltage North Island Huntly Generation Tripped 6156676474.pdf

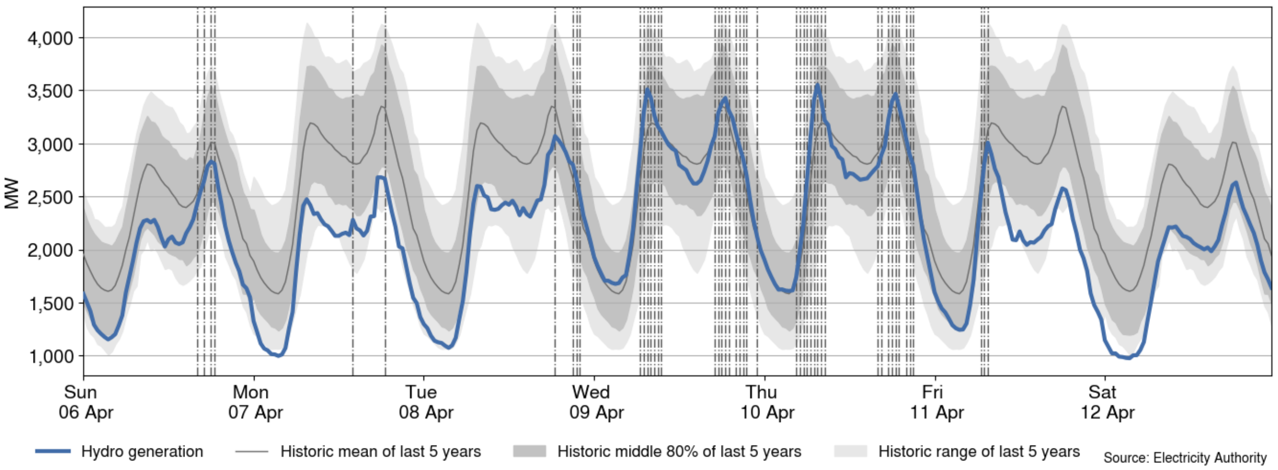
[3] EXN Frequency North Island Huntly Generation Tripped 6156675583.pdf

**Figure 13: Thermal peaker generation, 6-12 April 2025**




7.8. Figure 14 shows hydro generation between 6-12 April 2025. Hydro generation was highest on Wednesday and Thursday when peak demand and spot prices were highest.

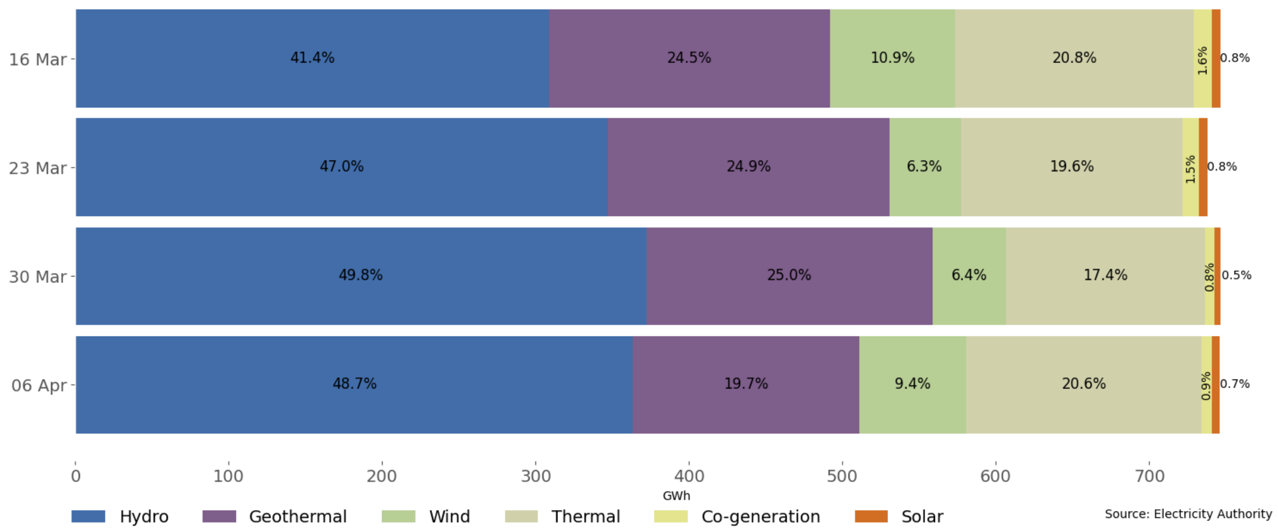
**Figure 14: Hydro generation, 6-12 April 2025**




7.9. As a percentage of total generation, between 6-12 April 2025, total weekly hydro generation was 48.7%, geothermal 19.7%, wind 9.4%, thermal 20.6%, co-generation 0.9%, and solar (grid connected) 0.7%, as shown in Figure 15.

7.10. Total generation volume was similar to last week. Increased wind and thermal generation this week made up for lower geothermal generation due to plant outages.

**Figure 15: Total generation by type as a percentage each week, between 16 March-12 April 2025**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 6-12 April 2025 ranged between 1,379MW and 2,394MW, which is mostly above average for this time of year. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 2 June.

(b) Tokaanu was on outage for periods during the day on 10-12 April.

(c) Ōhau B and C had ~300MW total on outage on 12 April.

(d) Tauhara was on outage during the evening on 6 April following its trip,[4] and then on planned outage from 8-14 April.

(e) Nga Awa Pūrua was on outage from 7-10 April.

(f) Ngā Tamariki was on outage from 6-11 April.

(g) Manapōuri unit 2 is on outage until 17 April.

(h) Manapōuri unit 4 is on outage until 12 June 2026.

(i) Manapōuri unit 6 was on outage on 11 April.

(j) Clyde unit 1 is on outage until 23 May.

(k) West Wind returned from outage on 9 April.

[4] EXN Frequency National Tauhara Generation Tripped 6153959336.pdf

**Figure 16: Total MW loss from generation outages, 6-12 April 2025**

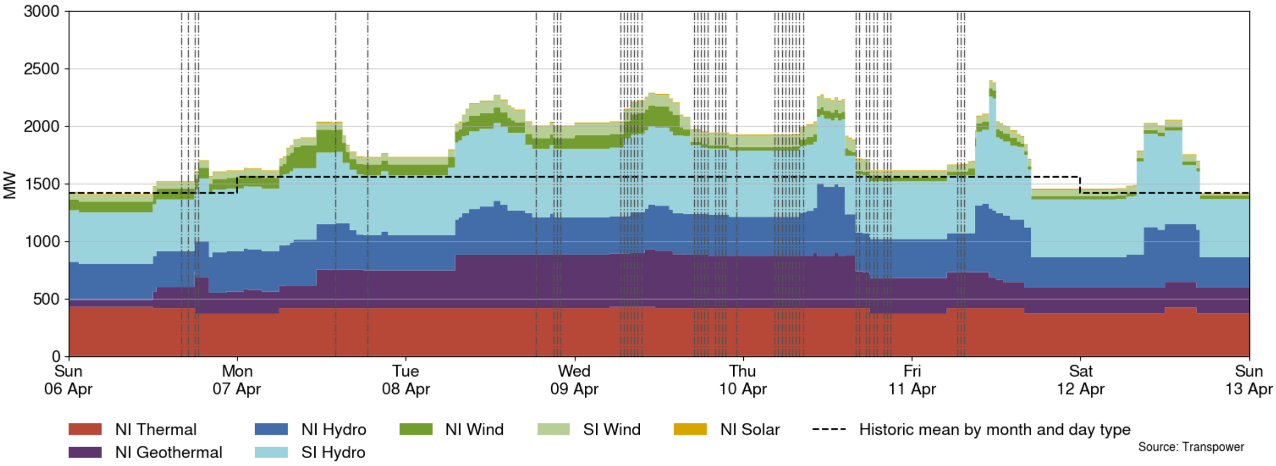
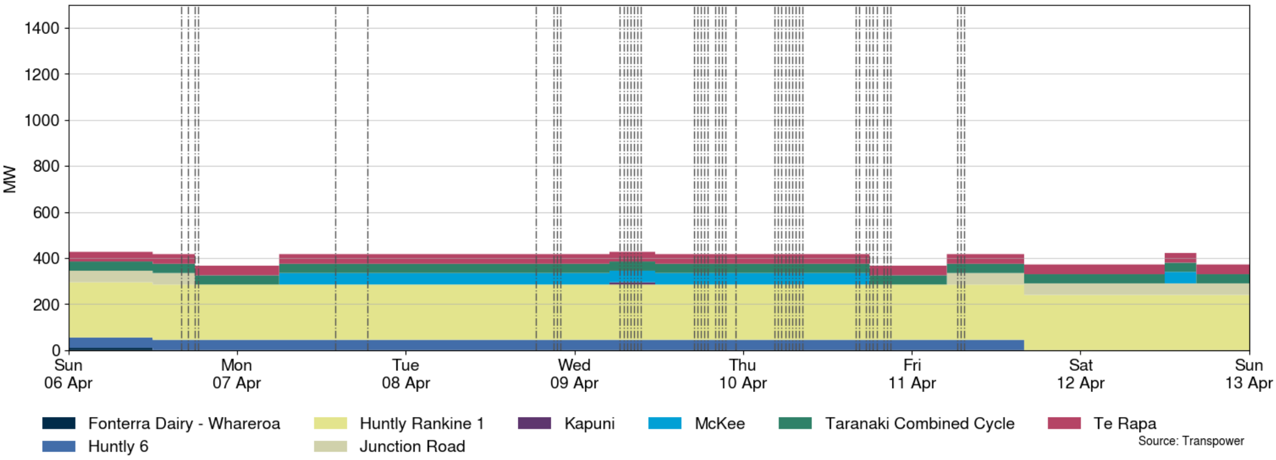



**Figure 17: Total MW loss from thermal outages, 6-12 April 2025**

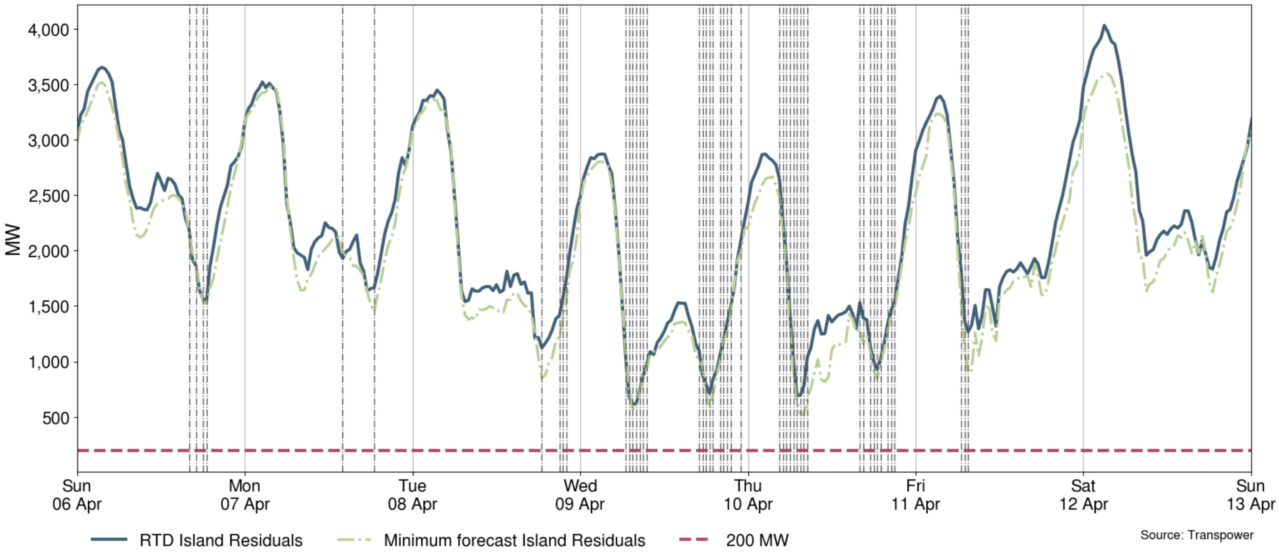



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 6-12 April 2025. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Residuals were mostly healthy this week. The minimum North Island residual was 321MW at 6.30pm on Wednesday.

**Figure 18: National generation balance residuals, 6-12 April 2025**




# 10. Storage/fuel supply

10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National controlled storage held steady this week. As of 12 April, national storage was 62% nominally full and ~80% of the historical average for this time of the year.

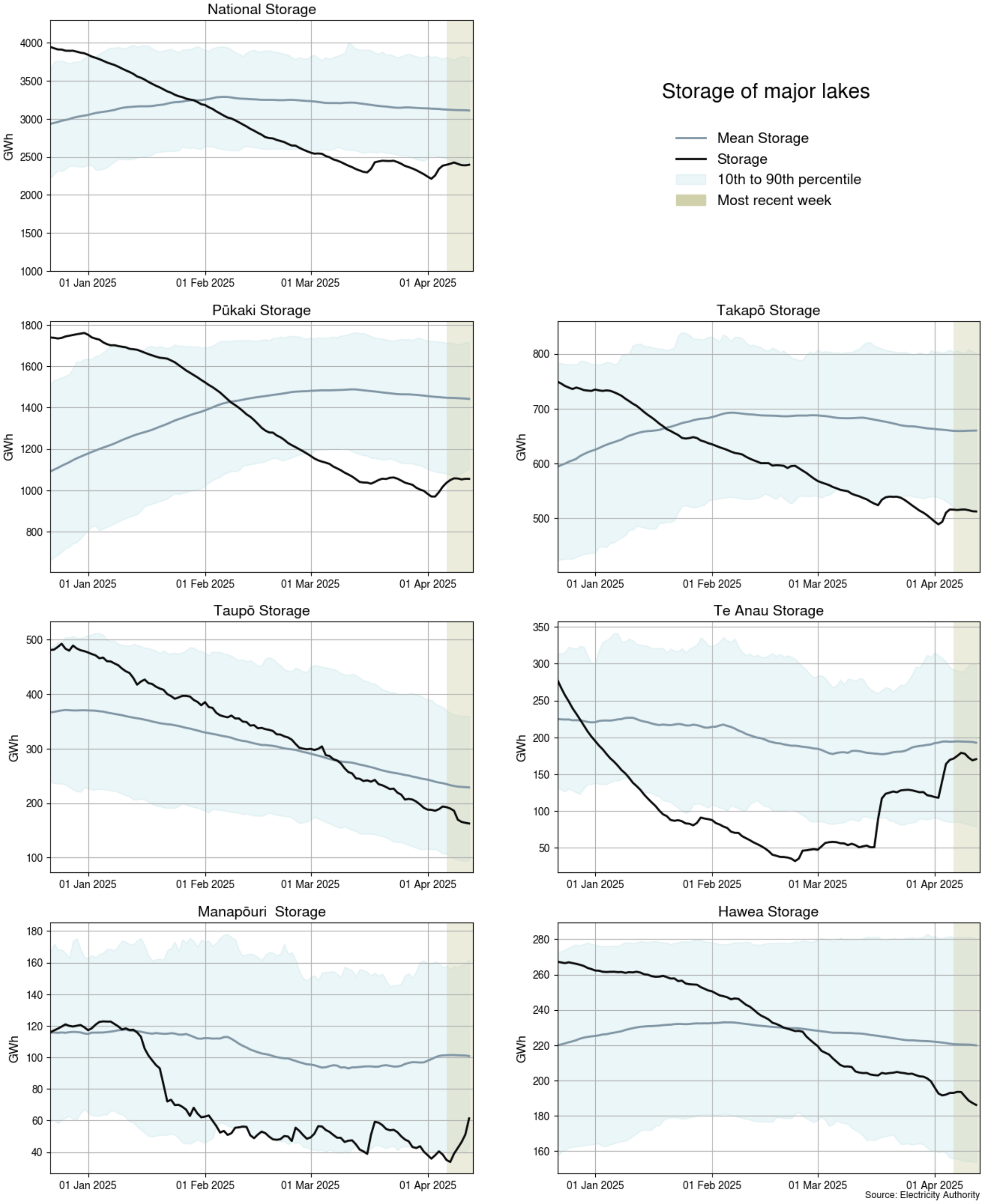
10.3. Storage at lakes Pūkaki (60% full) [5] and Takapō (63% full) held steady near their respective historical 10th percentiles.

10.4. Storage and lakes Taupō (28% full) and Hawea (65% full) decreased in the last week, with both lakes between their respective historical average and 10th percentiles.

10.5. Storage at Lake Te Anau held steady just below its historical average, and storage at Lake Manapōuri increased above its historical 10th percentile.

[5] Percentage full values sourced from NZX Hydro.

**Figure 19: Hydro storage**



# 11. Prices versus estimated costs

11.1. In a competitive market, prices should be close to (but not necessarily at) the short-run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).

11.2. The SRMC (excluding opportunity cost of storage) for thermal fuels is estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.

11.3. Figure 20 shows an estimate of thermal SRMCs as a monthly average up to 1 April. The SRMC for gas fuelled generation has increased compared to last month. The SRMC for coal fuelled generation has reduced slightly and the SRMC diesel fuelled generation remains similar.

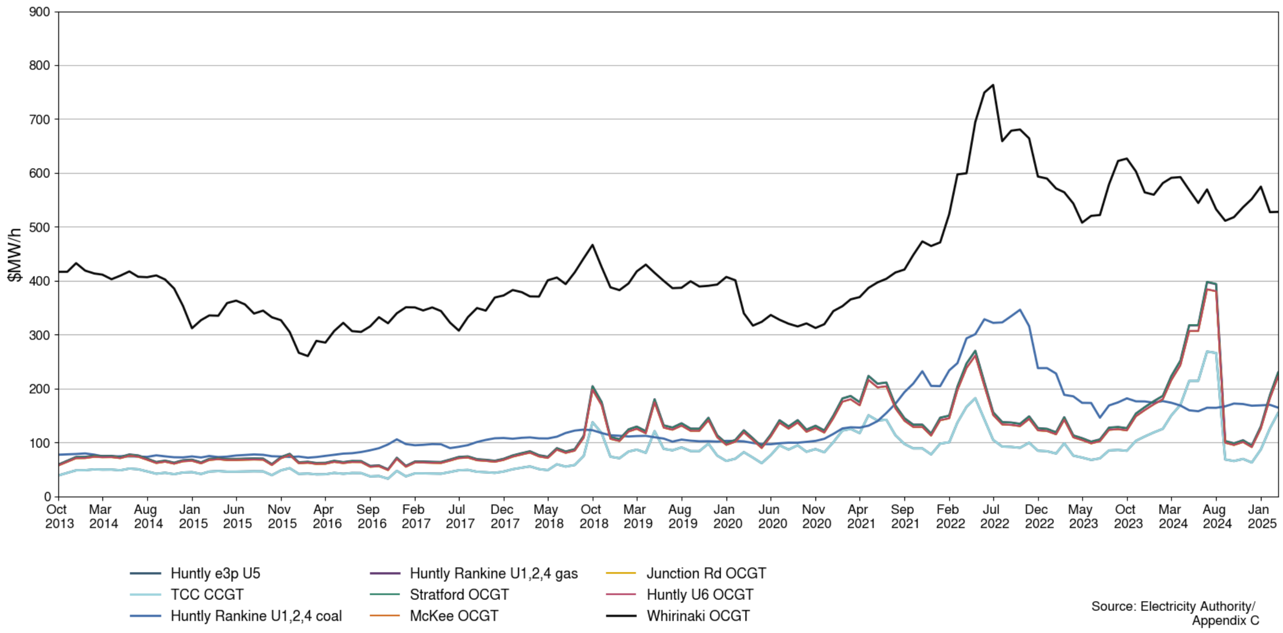
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$160/MWh, with the cost of running the Rankines on gas more expensive at ~$250/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $168/MWh and $250/MWh.

11.6. The SRMC of Whirinaki is still ~$528/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

**Figure 20: Estimated monthly SRMC for thermal fuels**

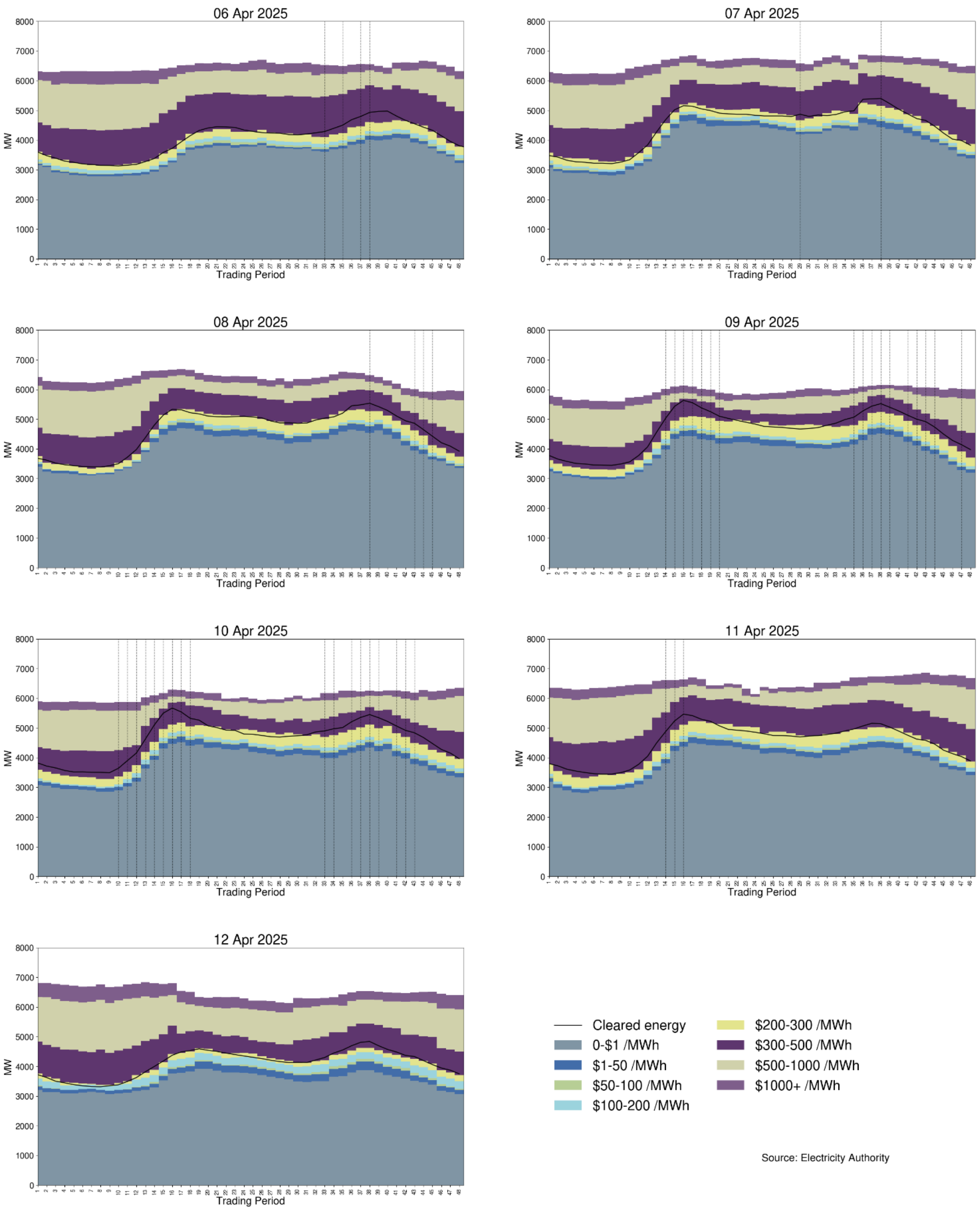



# 12. Offer behaviour

12.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. The volume of offers in the $50/MWh-300/MWh increased as the week progressed. Most offers were clearing in the $200/MWh-$300/MWh or the $300/MWh-$500/MWh range this week, with hydro generation continuing to be marginal most often.

**Figure 21: Daily offer stacks**



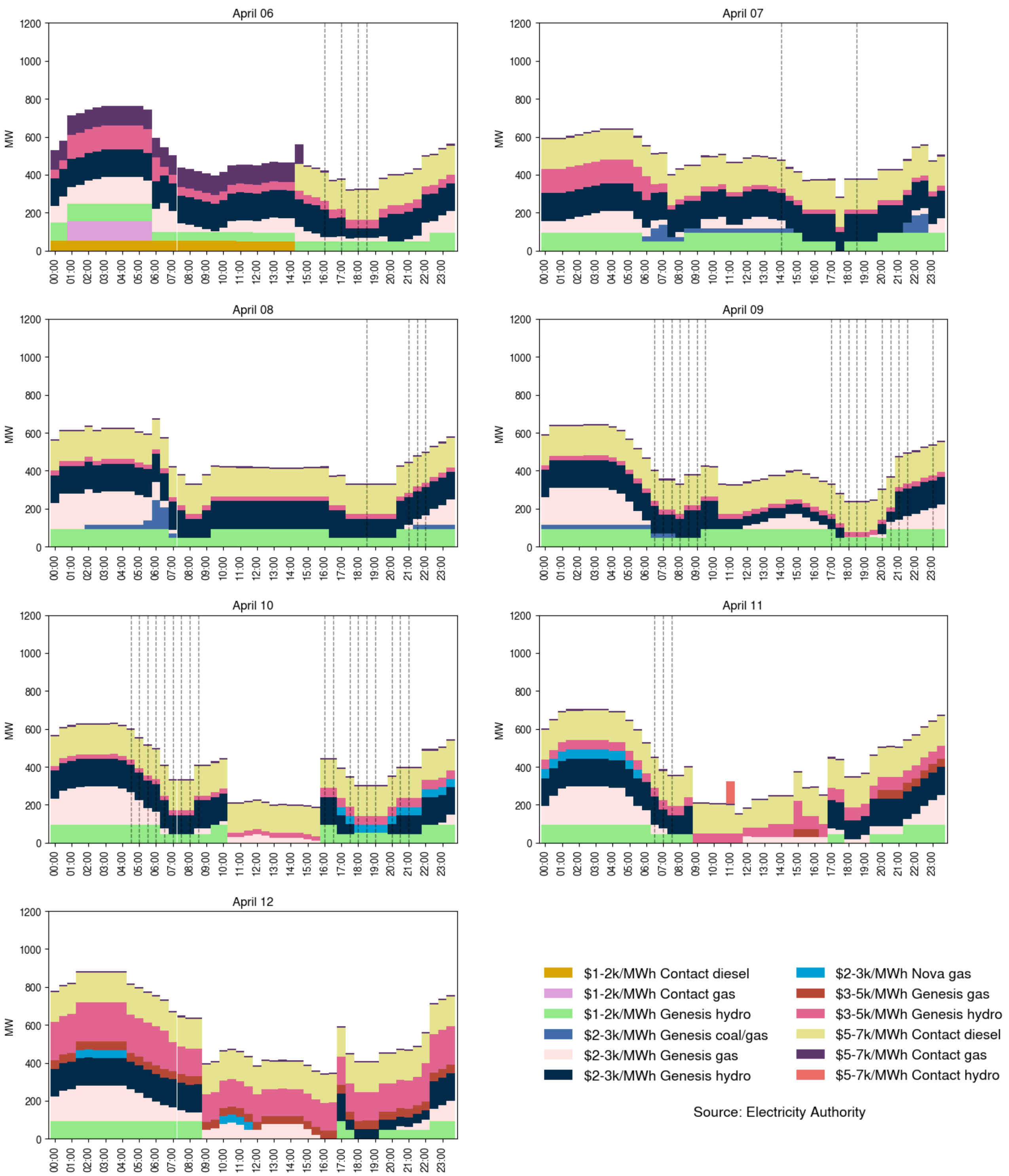

Source: Electricity Authority

12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.4. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren't expecting to run. These high prices reflect increased operating costs of running for only a short time. So, if demand is unexpectedly high, wind generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.5. On average 480MW per trading period was priced above $1,000/MWh this week, which is roughly 8.6% of the total energy available and a reduction compared to last week.

**Figure 22: High priced offers**




Source: Electricity Authority

# 13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. The monitoring team is looking further into wind forecasts by NZ wind farms and offers at Takapō.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

**Table 1: Trading periods identified for further analysis**

| Date | Trading period | Status | Participant | Location | Enquiry topic |
|---|---|---|---|---|---|
| **14/06/2023-15/06/2023** | 15-17/ 15-19 | Back with monitoring for analysis | Genesis | Multiple | High energy prices associated with high energy offers |
| **22/09/2023-30/09/2023** | Several | Back with monitoring for analysis | Contact | Multiple | High hydro offers |
| **3-4/09/2024 and 13-18/09/2024** | Several | Further analysis | Contact | Clutha scheme | Hydro offers |
| **18/03/2025** | 23-27 | Further analysis | Genesis | Huntly | Unplanned outage |
| **27/03/2025** | 20-28 | Further analysis | Contact | Stratford peakers and TCC | Offers |
| **4/04/2025** | Several | Further analysis | Genesis | Huntly | Offers removed |
| **2/04/2025-4/04/2025** | Several | Further analysis | Genesis | Takapō and Tokaanu | Offers |
| **6/04/2025-12/04/2025** | Several | Further analysis | NZ wind farms | Te Rere Hau | Wind forecasts |
| **7/04/2025-11/04/2025** | Several | Further analysis | Genesis | Takapō | Offers |