30 June 2025

Trading conduct report 22-28 June 2025

Market monitoring weekly report

Trading conduct report 22-28 June 2025

1. Overview

1.1. Heavy rainfall during the week saw the average spot price decrease by $43/MWh to $105/MWh and national hydro storage increase to ~97% of the historical average. Total demand reduced compared to the previous week, with a lower proportion of thermal generation and higher proportion of geothermal and wind generation. On Friday, demand between 10.00am and 4.30pm was 100MW to 274MW higher than forecast. There was also an unplanned HVDC pole outage on Saturday between 8.30am-9.30am.

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 22-28 June 2025:

(a) The average spot price for the week was $105/MWh, a decrease of around $43/MWh compared to the previous week.

(b) 95% of prices fell between $46/MWh and $154/MWh.

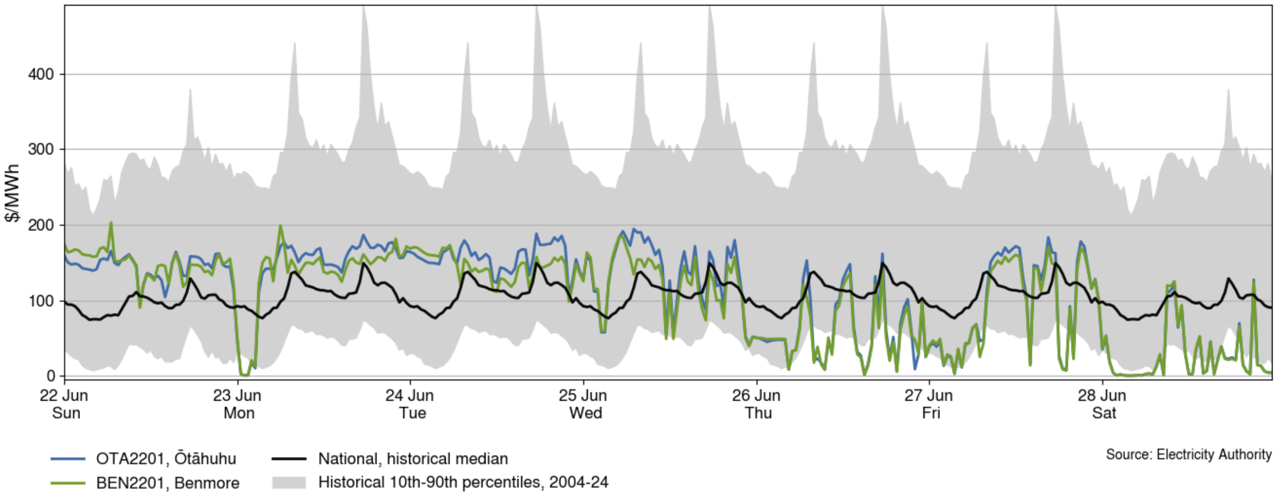
2.3. Spot prices hovered slightly above the historic average until heavy rainfall from Wednesday saw spot prices drop below the historic average.

2.4. The maximum spot price this week was $203/MWh at Benmore at 6.30am on Sunday. The Ōtāhuhu spot price at the same time was $165/MWh. At this time, wind generation was below 200MW and demand was 78MW higher than forecast.

2.5. On Friday, prices increased slightly as demand between 10.00am and 4.30pm was 100MW to 274MW higher than forecast.

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th 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.

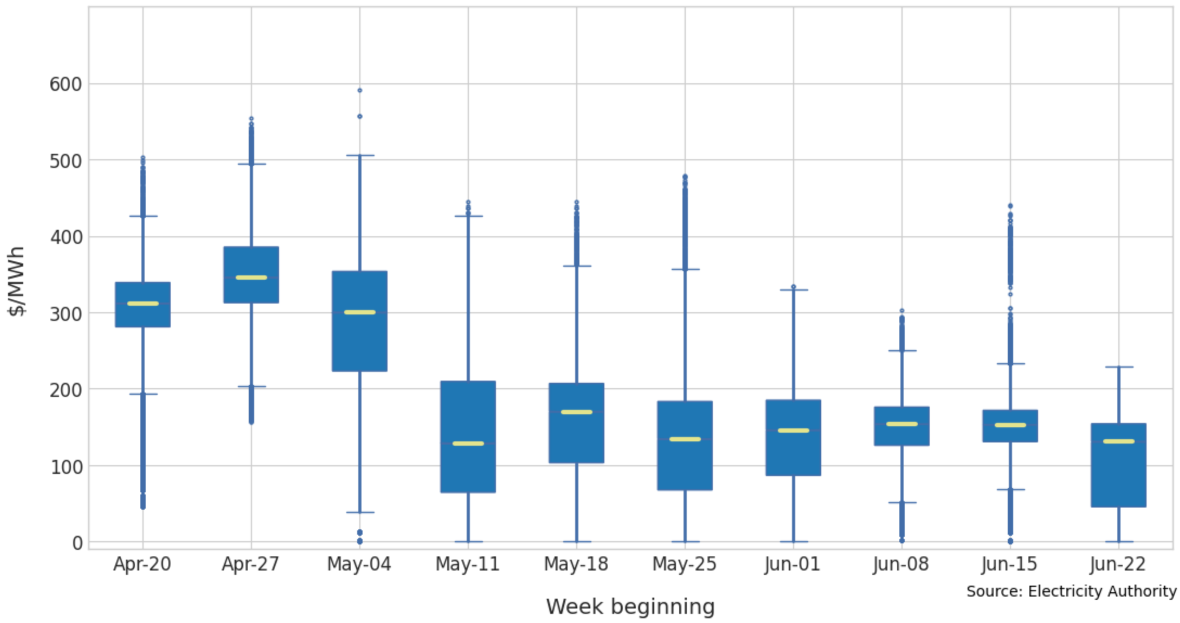
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 22-28 June 2025



2.7. 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.

2.8. The distribution of spot prices this week was wider compared to the previous week, with no significant high-priced outliers. The median price was $130/MWh and most prices (middle 50%) fell between $45/MWh and $154/MWh.

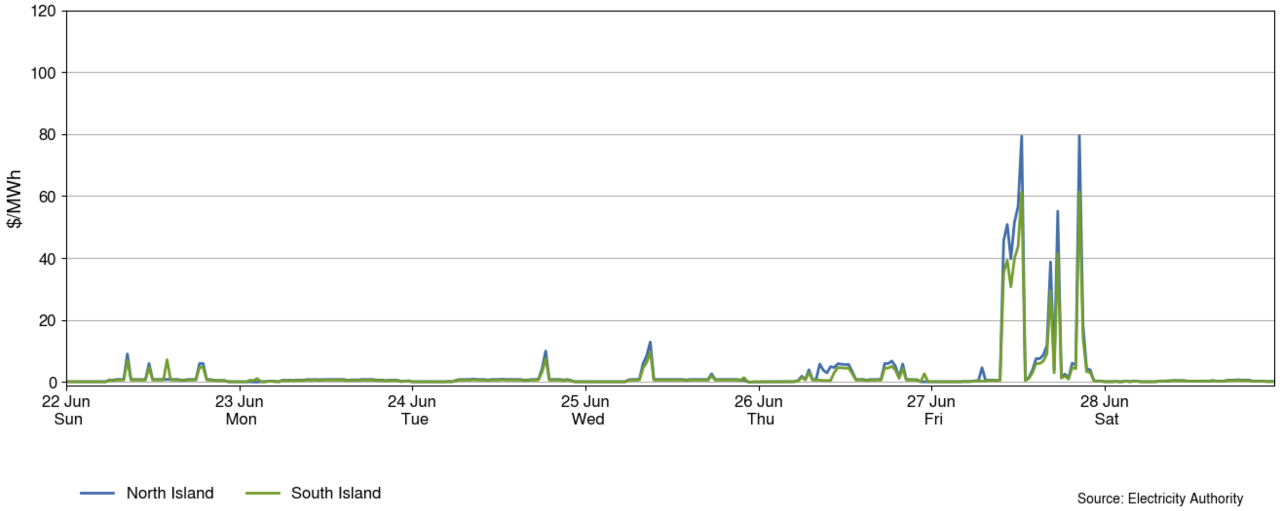
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

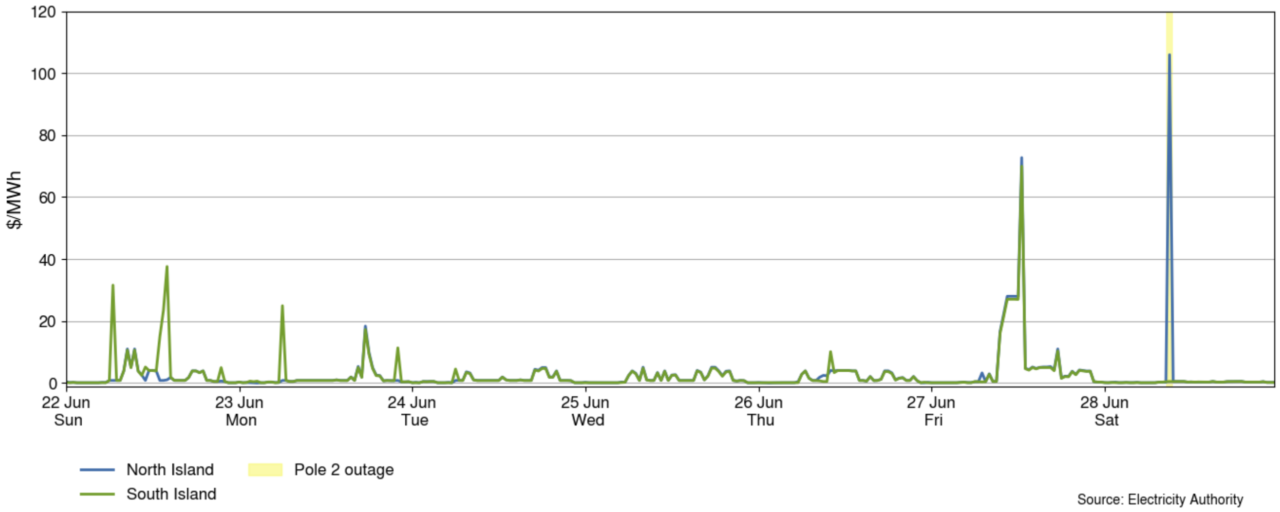
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh with a few spikes on Friday. Significant FIR price spikes occurred on Friday at 12.30pm and 8.30pm, with prices reaching around $79/MWh in the North Island and $61/MWh in the South Island at both times. At these times, Huntly 5 was the risk setter, and its generation increased, requiring more reserves to be cleared to cover the risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 22-28 June 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. The highest SIR price was $106/MWh in the North Island at 9.00pm on Saturday during the unplanned HVDC outage, the South Island SIR price at the same time was $0.50/MWh. SIR prices spiked on Friday at the same time as the FIR prices, due to Huntly 5 setting the risk and requiring more reserves to be cleared.

Figure 4: Sustained instantaneous reserve by trading period and island, 22-28 June 2025



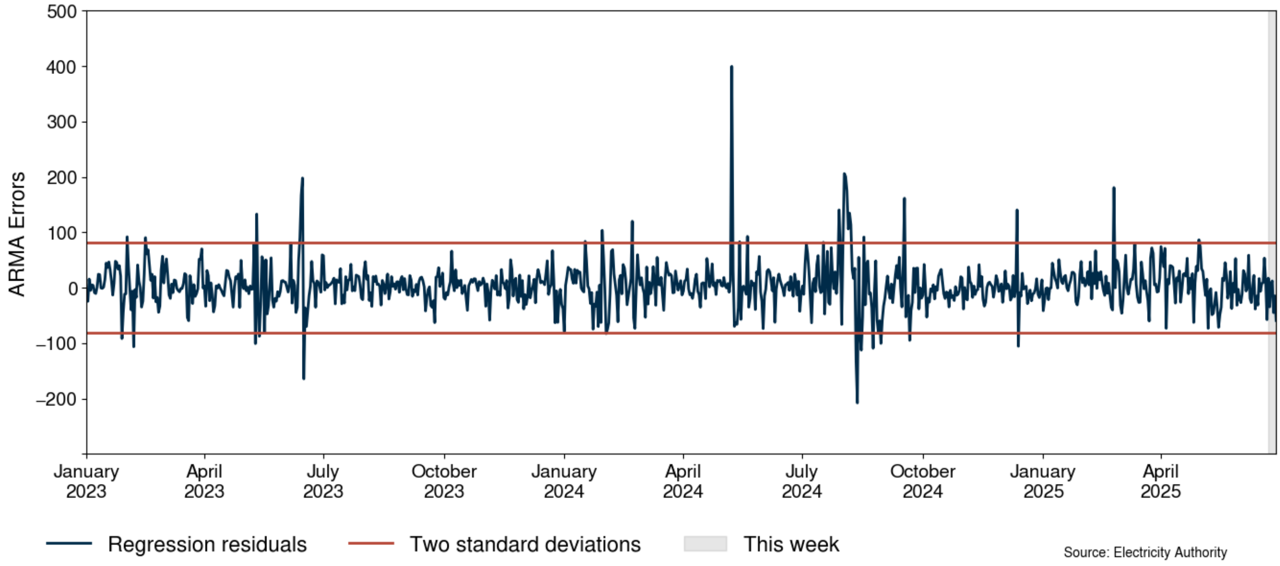
4. Regression residuals

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 – 28 June 2025



5. HVDC

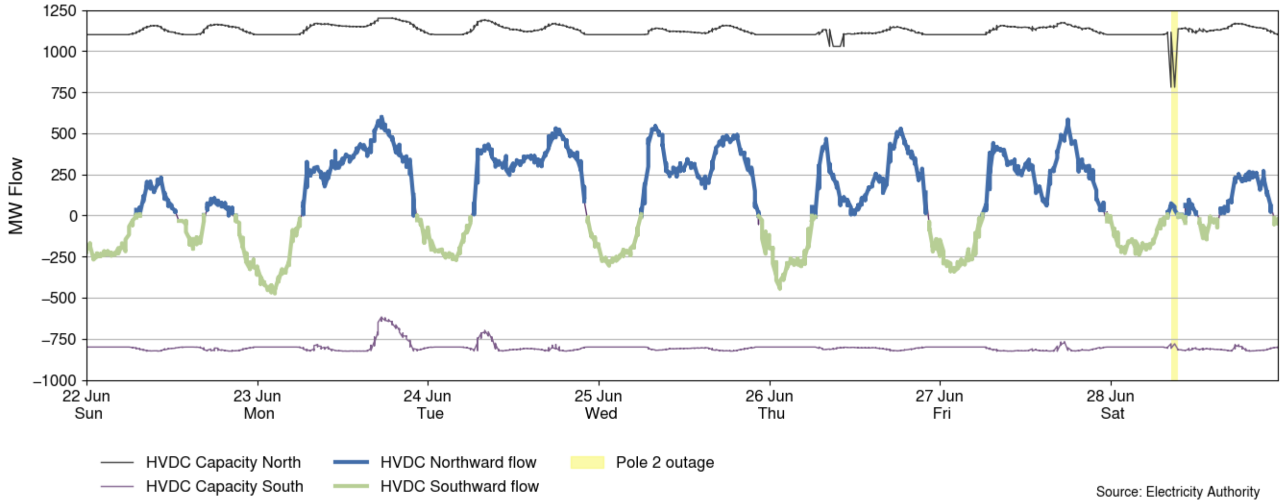
5.1. Figure 6 shows the HVDC flow between 22-28 June 2025. HVDC flows were mostly northward during the day and southward overnight.

5.2. HVDC round power was disabled during the day from Monday to Wednesday due to live line work.[1] There was also an unplanned HVDC pole outage on Saturday between 8.30am-9.30am.[2]

5.3. Northward flows peaked around 600MW on Monday at 5.30pm when wind generation was low during the evening demand peak.

[1] CAN Round power status change 6402710392.pdf
[2] CAN Unplanned Outage HVDC Pole 2 6402259484.pdf

Figure 6: HVDC flow and capacity, 22-28 June 2025



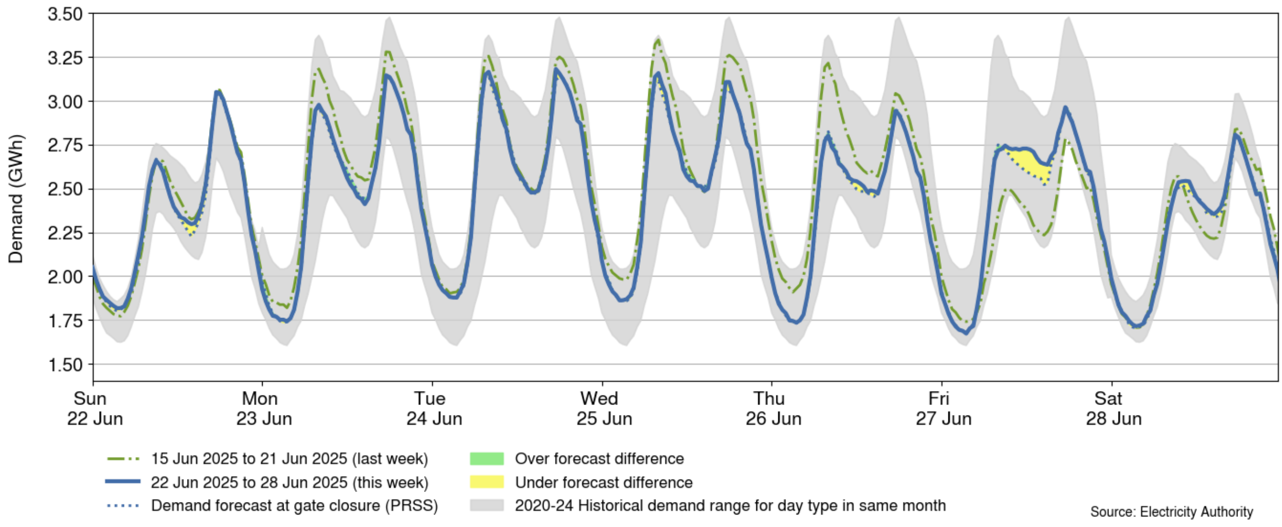
6. Demand

6.1. Figure 7 shows national demand between 22-28 June 2025, compared to the historic range and the demand of the previous week. Demand was mostly lower than the previous week due to mild temperatures, except for last Friday as the preceding Friday was a public holiday.

6.2. The maximum demand this week was around 3.18GWh (6.36GW) at 5.30pm on Tuesday.

6.3. On Friday, demand was 102MW-274MW under-forecasted between 10.00am-4.30pm, with the maximum forecast error of 274MW occurring at 12.30pm and 1.00pm.

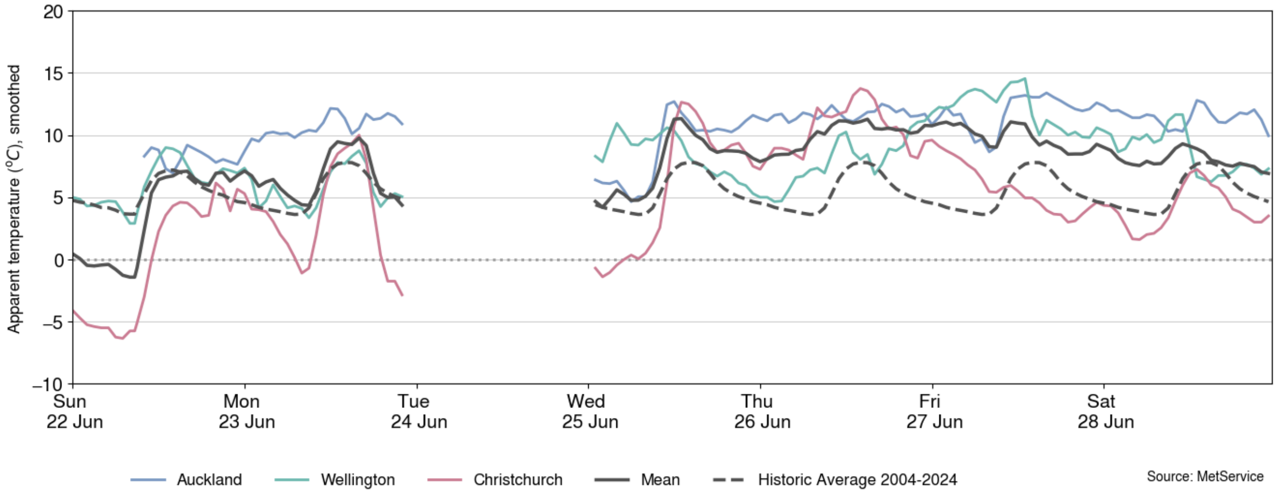
Figure 7: National demand, 22-28 June 2025 compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 22-28 June 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. Data is missing for Tuesday

6.5. Apparent temperatures ranged from 5°C to 14°C in Auckland, 2°C to 15°C in Wellington, and -7°C to 14°C in Christchurch. Temperatures were mostly above or around the historic average, although Christchurch experienced below freezing temperatures on Sunday morning.

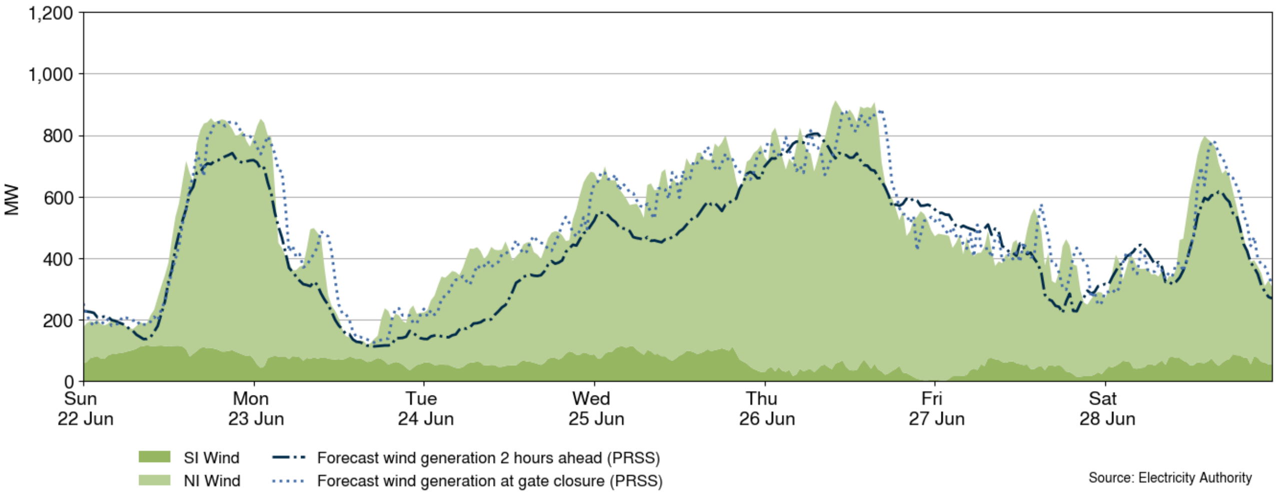
Figure 8: Temperatures across main centres, 22-28 June 2025[3]



7. Generation

7.1. Figure 9 shows wind generation and forecast from 22-28 June 2025. This week wind generation varied between 118MW and 913MW, with a weekly average of 504MW. Wind generation was relatively high on Sunday evening but dropped significantly by Monday evening. It remained mostly above 600 MW on Wednesday and Thursday. On Friday and Saturday, wind generation was lower but generally stayed above 300 MW.

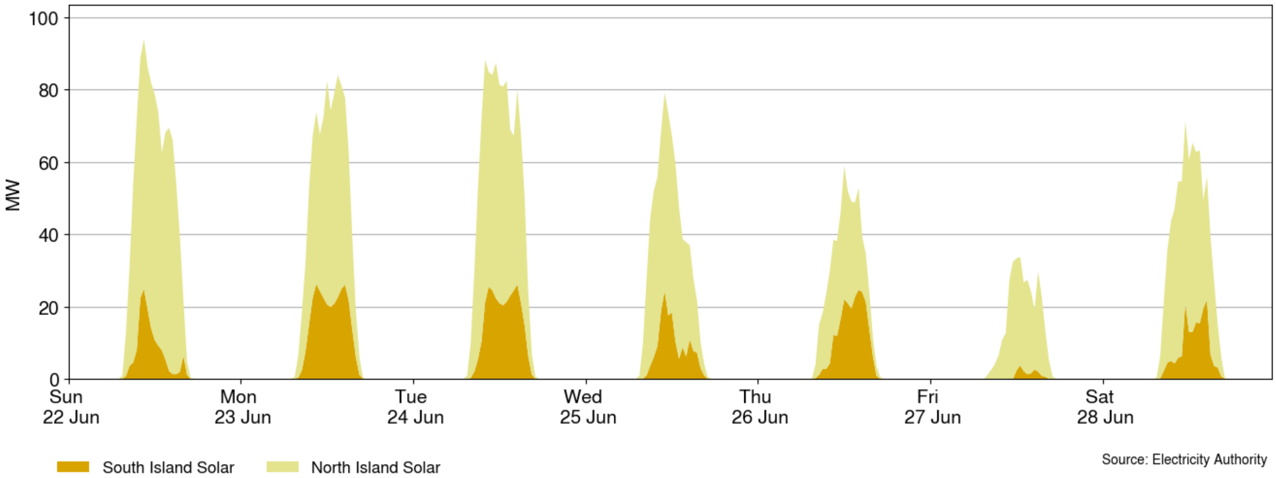
Figure 9: Wind generation and forecast, 22-28 June 2025



7.2. Figure 10 shows grid connected solar generation from 22-28 June 2025. Solar generation was lowest on Friday. Except for Friday, solar generation typically peaked above 40MW, with a maximum of 94MW at 10.30am on Sunday.

[3] Data is missing for Tuesday.

Figure 10: Grid connected solar generation, 22-28 June 2025

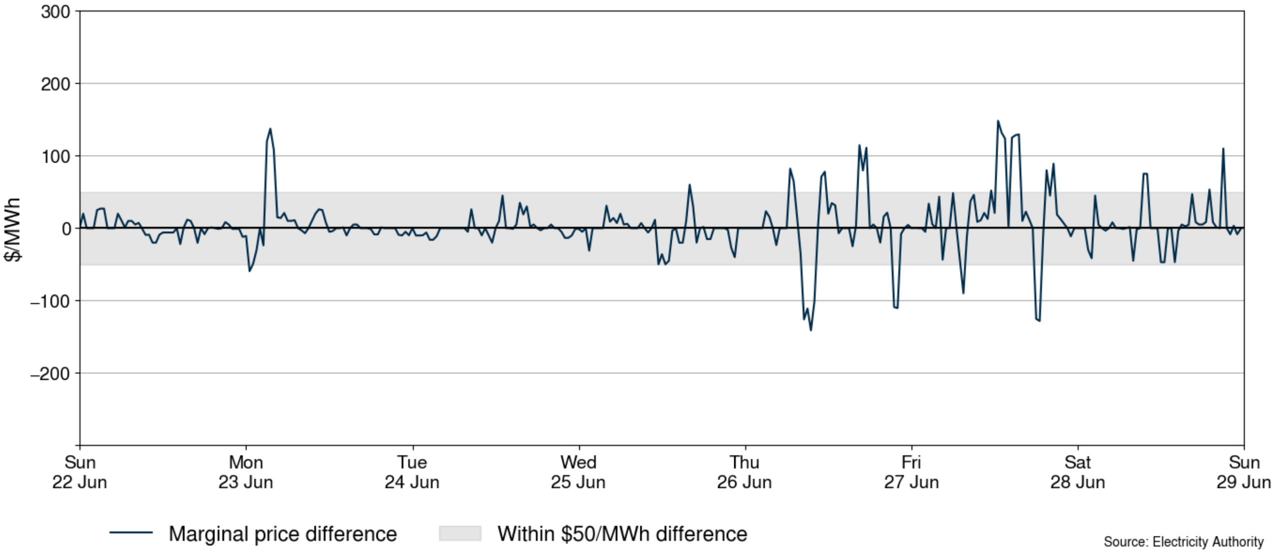


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[4]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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.

7.4. A few trading periods between Thursday and Saturday had positive marginal price differences which were driven by wind and demand forecasting errors. On Monday there was a positive marginal price difference of +$137/MWh at 3.30am. The largest positive price difference of +$148/MWh occurred at 12.30am on Friday when demand was over 274MW higher than forecast.

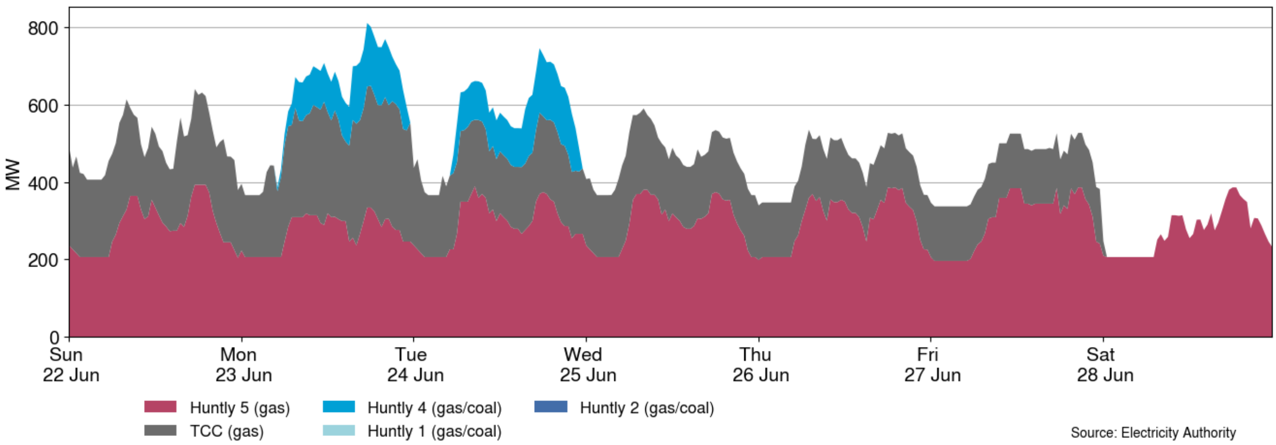
[4] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 22-28 June 2025



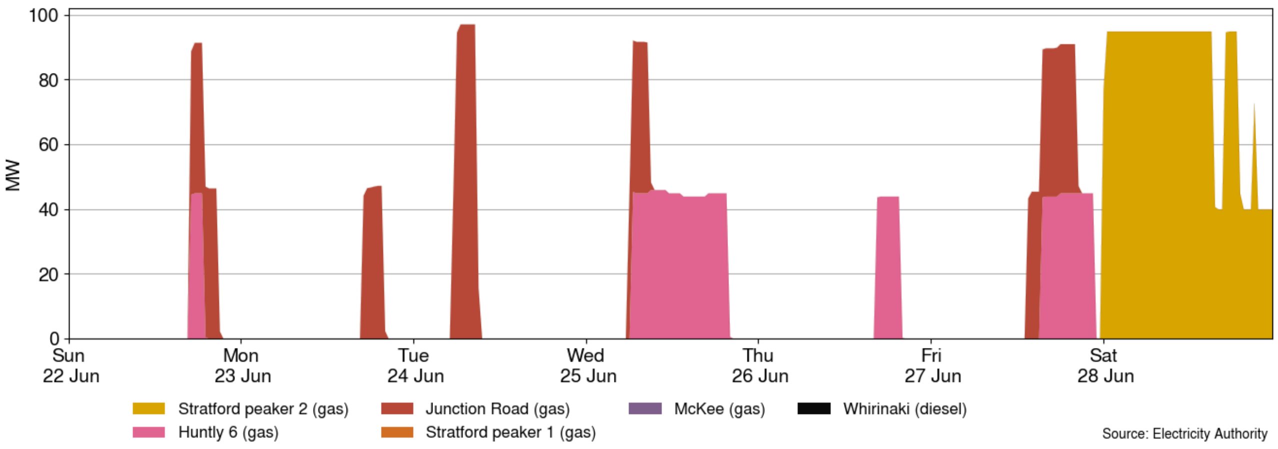
7.5. Figure 12 shows the generation of thermal baseload between 22-28 June 2025. Huntly 5 ran as baseload this week and TCC ran until Friday. Huntly 4 ran on Monday and Tuesday.

Figure 12: Thermal baseload generation, 22-28 June 2025



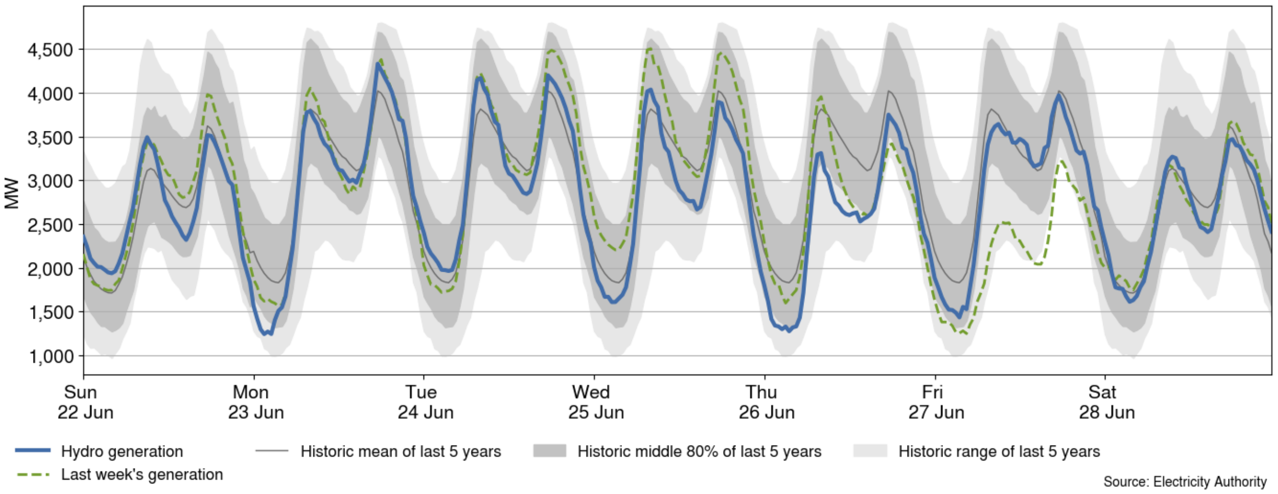
7.6. Figure 13 shows the generation of thermal peaker plants between 22-28 June 2025. Junction Road ran during peak periods, except on Thursday. Huntly 6 ran on Sunday during the evening peak, and for periods from Wednesday to Friday. Stratford peaker 2 ran on Saturday after TCC turned off.

Figure 13: Thermal peaker generation, 22-28 June 2025



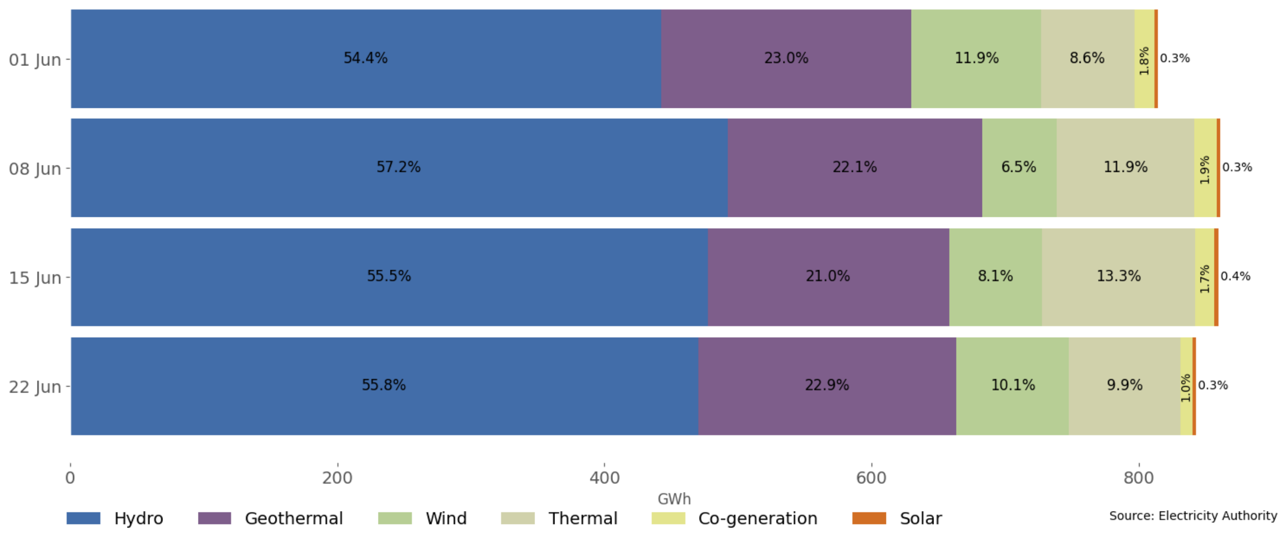
7.7. Figure 14 shows hydro generation between 22-28 June 2025. Hydro generation at the start of the week was similar to the previous week. On Wednesday, it dropped due to relatively higher wind generation. However, generation was higher on Friday, driven by increased demand compared to the previous Friday which was a public holiday.

Figure 14: Hydro generation, 22-28 June 2025



7.8. As a percentage of total generation, between 22-28 June 2025, total weekly hydro generation was 55.8%, geothermal 22.9%, wind 10.1%, thermal 9.9%, co-generation 1%, and solar (grid connected) 0.3%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 1 Jun 2025 and 28 June 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 22-28 June 2025 ranged between ~762MW and ~1,577MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford peaker 1 is on outage until 31 July 2025.

(b) Huntly 4 was on outage between 26-30 June 2025.

(c) Huntly 2 was on outage between 27-30 June 2025.

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

(e) Ruakākā battery outage has been extended to end on 4 July 2025.

Figure 16: Total MW loss from generation outages, 22-28 June 2025

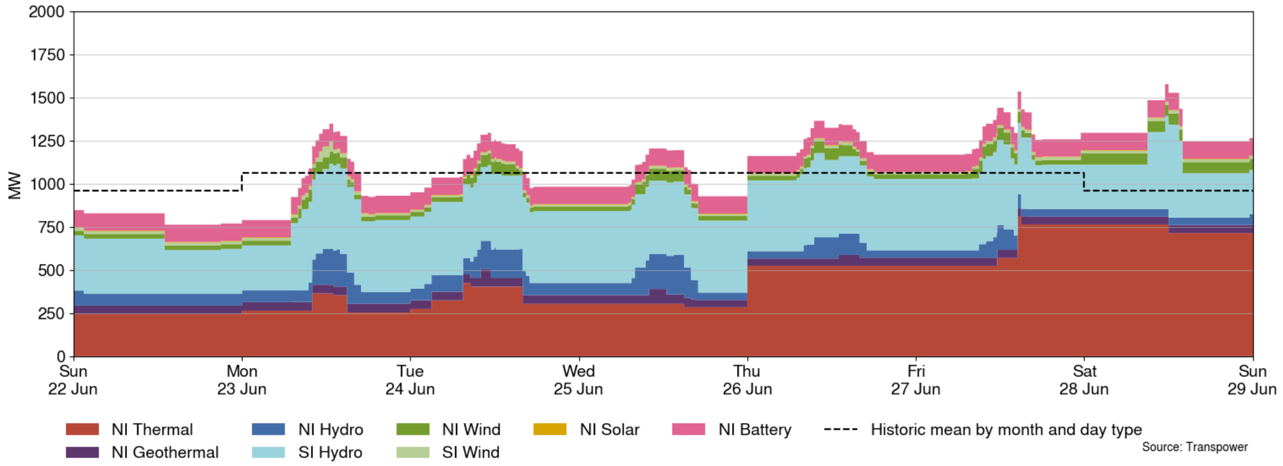
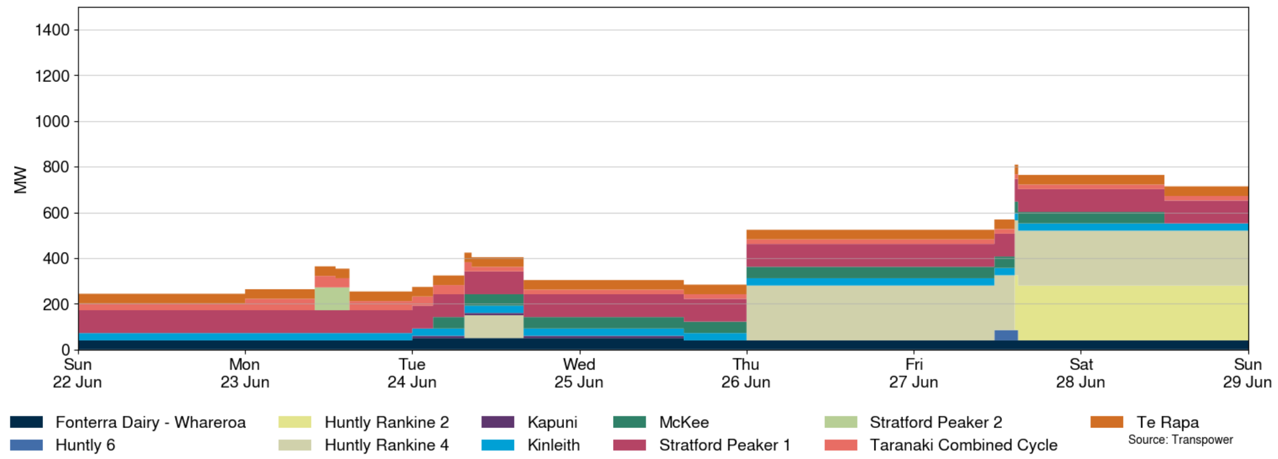


Figure 17: Total MW loss from thermal outages, 22-28 June 2025

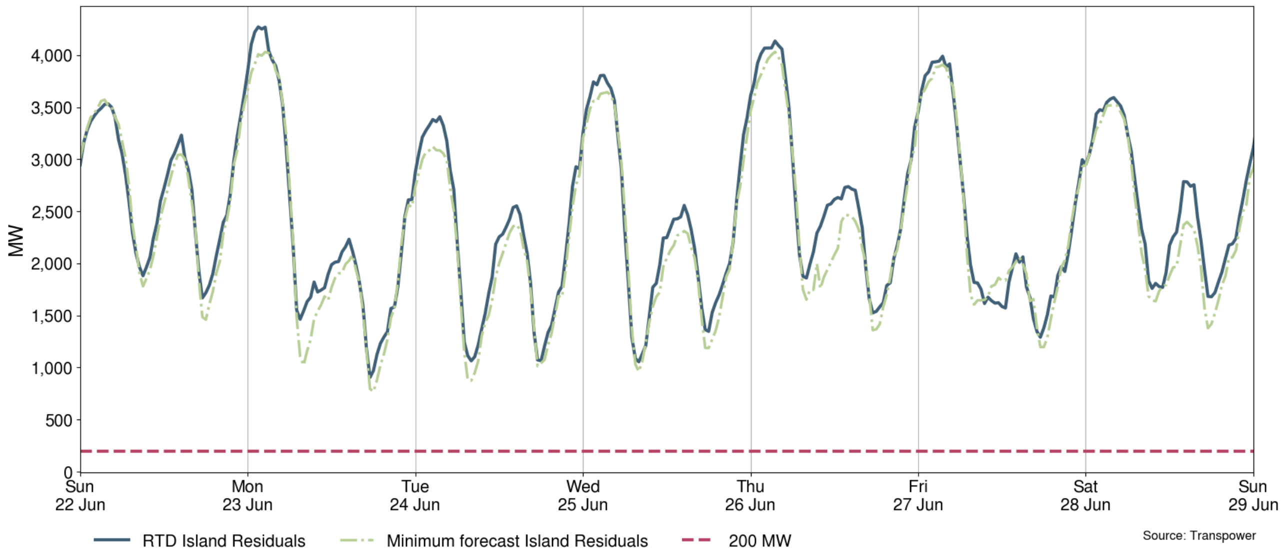


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 22-28 June 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 healthy this week. The lowest national residual was 905MW on Monday at 5.30am.

Figure 18: National generation balance residuals, 22-28 June 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 10^{th} to 90^{th} percentiles.

10.2. As of 27 June 2025, national controlled storage was 67% nominally full and ~97% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (61% full)[5] increased and is between its historical 10^{th} percentile and mean, while storage at Lake Takapō (47% full) also increased to just above its 10^{th} percentile.

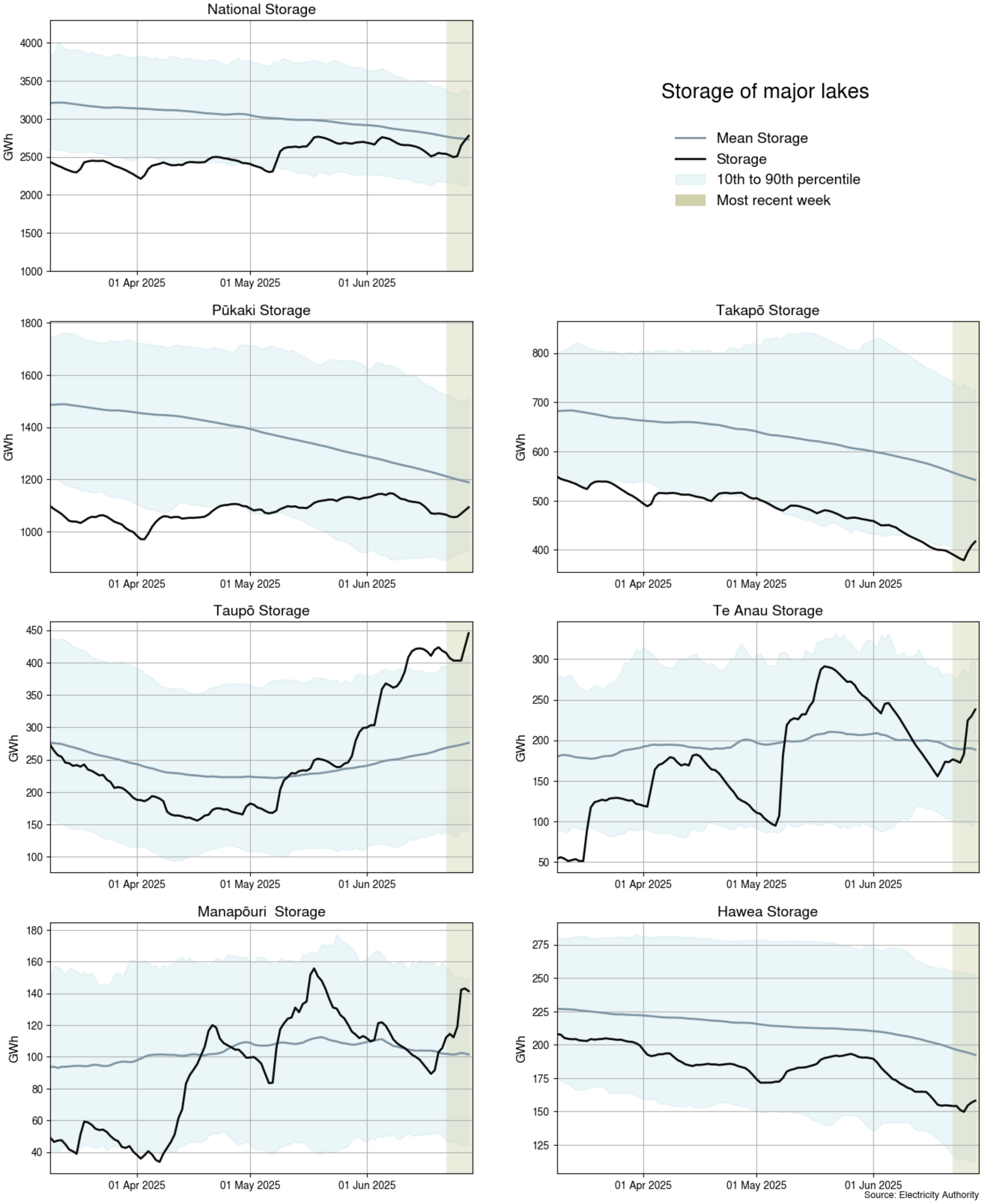
10.4. Storage at lakes Te Anau (90% full) and Manapōuri (88% full) increased during the week. Both lakes are now above their historical means.

10.5. Storage at Lake Taupō (78% full) increased and remains above its 90^{th} percentile.

10.6. Storage at Lake Hawea (56% full) increased slightly and remains between its historical 10^{th} percentile and mean.

[5] Percentage full values sourced from NZX hydrological summary 30 June 2025.

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 June 2025. The SRMCs for gas powered generation have decreased slightly while coal and diesel fuelled generation slightly increased.

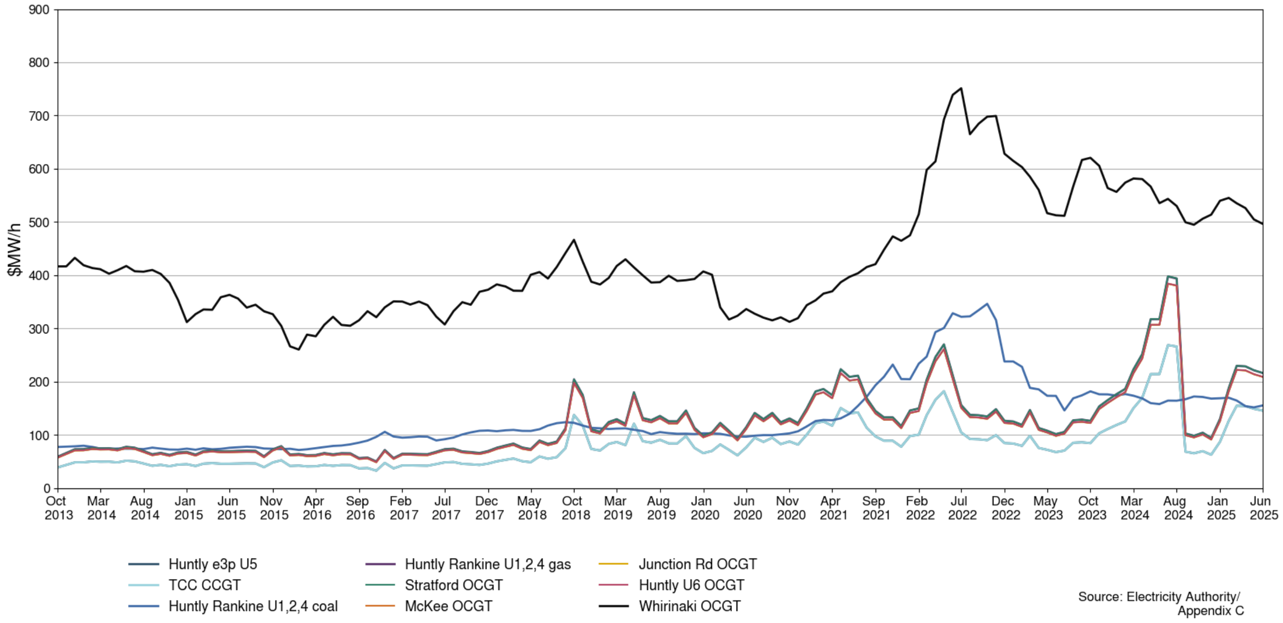
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$155/MWh. The cost of running the Rankines on gas is ~$216/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $145/MWh and $216/MWh.

11.6. The SRMC of Whirinaki is ~$496/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

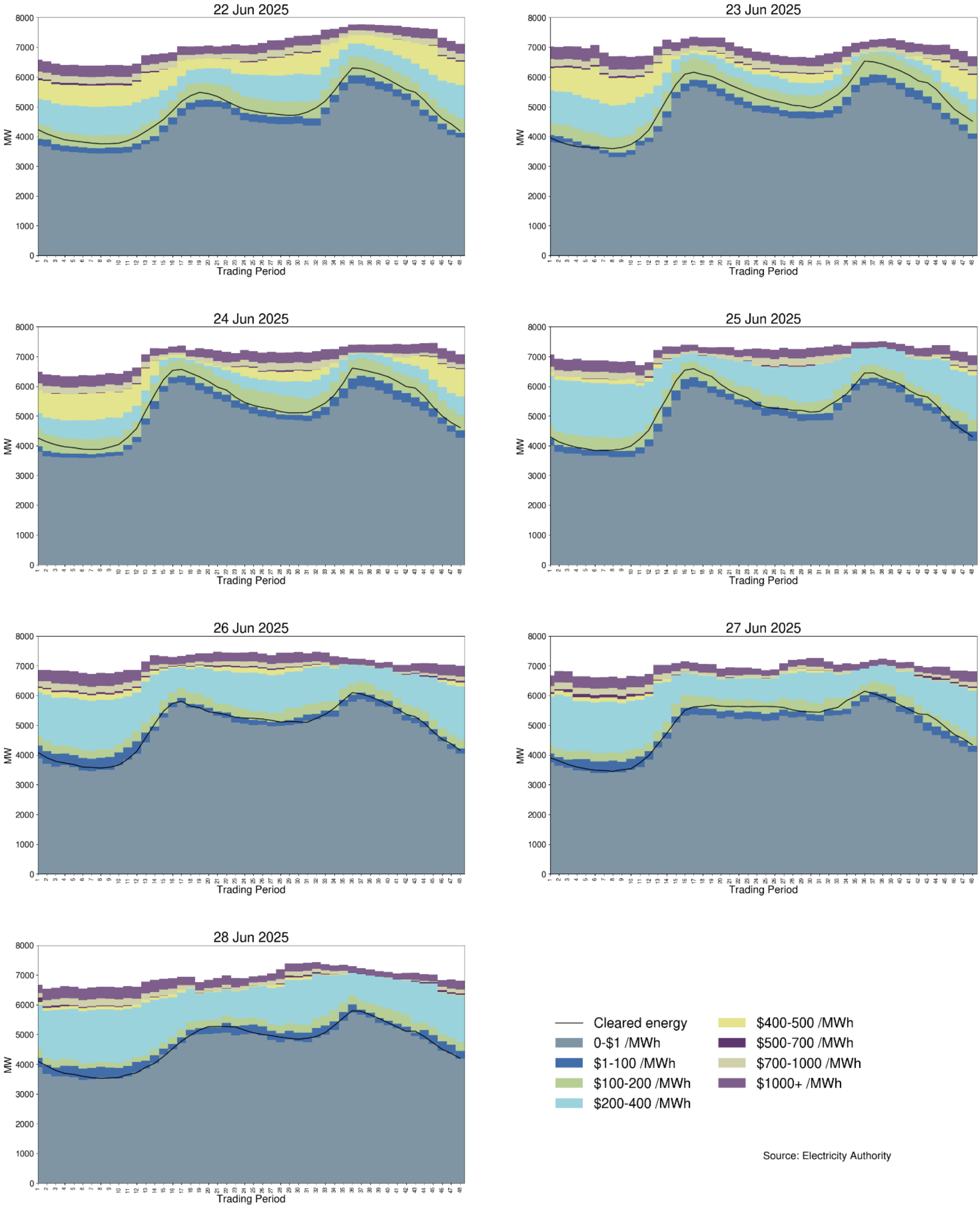


12. Offer behaviour

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. This week most offers cleared in the $1-$200/MWh range. The volume of offers in the $200-$400/MWh range increased from 25 June due to hydro offers being priced down.

Figure 21: Daily offer stacks

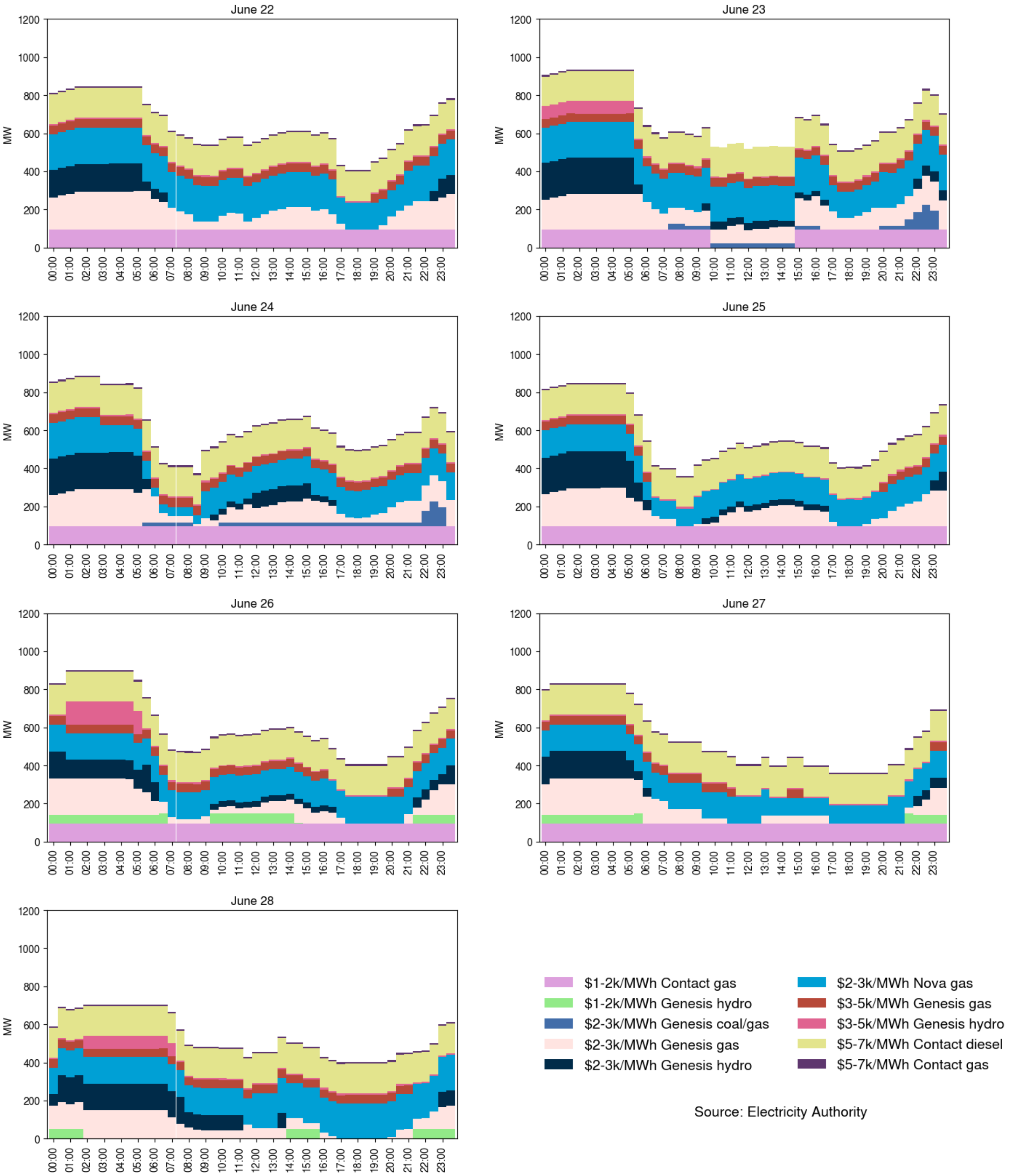


12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 607MW per trading period was priced above $1,000/MWh this week, which is roughly 10% of the total energy available.

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.

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
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers