23 June 2025

Trading conduct report 15-21 June 2025

Market monitoring weekly report

Trading conduct report 15-21 June 2025

1. Overview

1.1. The average spot price increased by $4/MWh this week to $148/MWh, with most prices within the historical 10^{th}-90^{th} percentile for this time of year. National hydro storage declined slightly to 65% nominally full and ~93% of the historical average. At the start of the week, demand was higher than the previous week due to colder temperatures. On Friday, demand was low due to the Matariki holiday. Wind generation was high on Thursday and Friday. Thermal generation also increased compared to the previous week.

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 15-21 June 2025:

(a) The average spot price for the week was $148/MWh, an increase of around $4/MWh compared to the previous week.

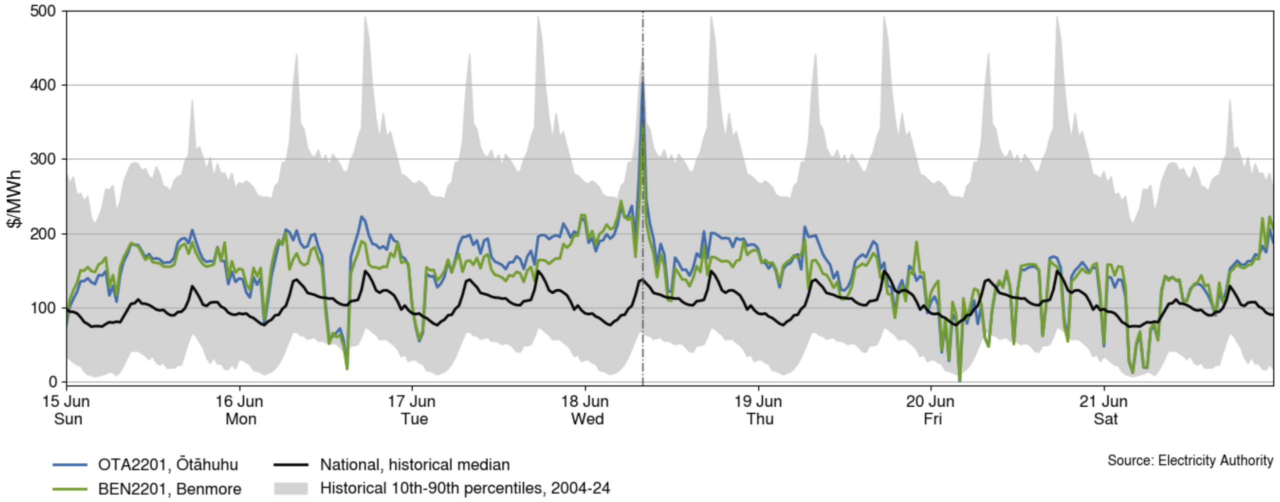
(b) 95% of prices fell between $46/MWh and $220/MWh.

2.3. The highest price of the week occurred on Wednesday at 8.00am, with prices of $402/MWh at Ōtāhuhu and $346/MWh at Benmore. During this time, wind generation was low (31MW), and demand was at its highest of the week (3.35GWh). Demand was also 82MW higher than forecast.

2.4. On Saturday, prices increased in the evening due to decreasing wind generation. That evening from 6.00pm, wind generation was also 17MW to 105MW lower than forecast.

2.5. 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 are marked with black dashed lines.

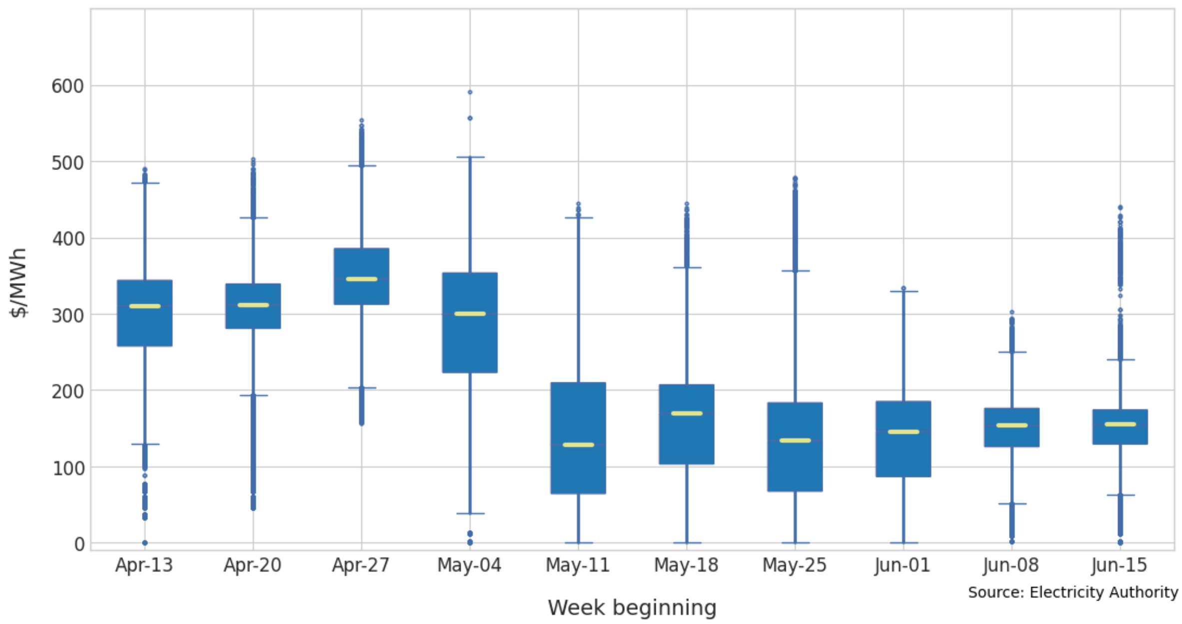
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 15-21 June 2025



2.6. 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.

2.7. The distribution of spot prices this week shows more high-price outliers compared to the previous week. The median price was $148/MWh, and most prices (middle 50%) ranged between $129/MWh and $174/MWh.

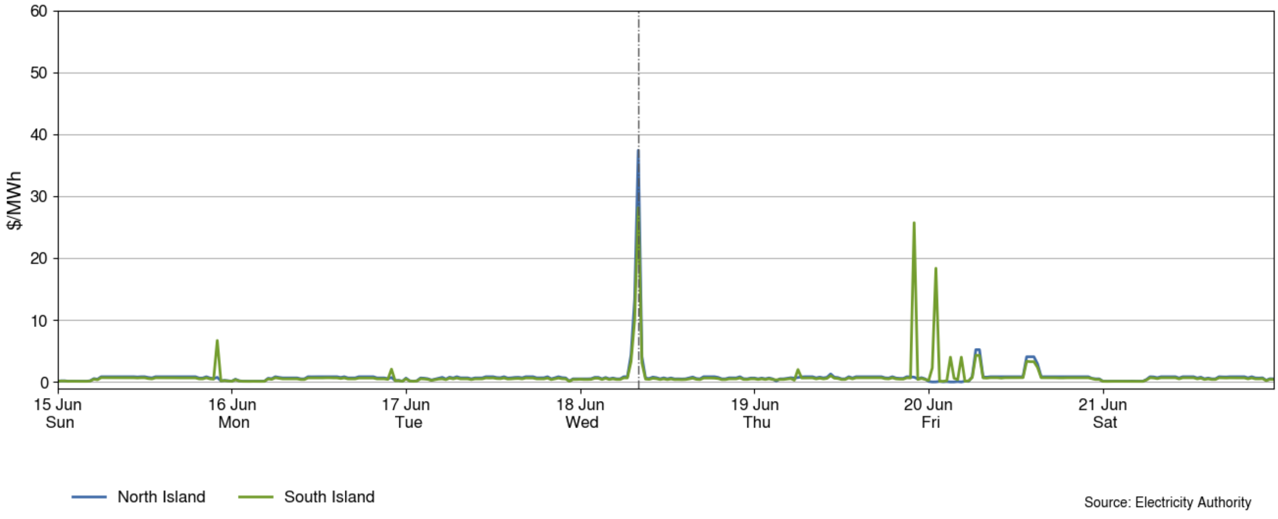
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

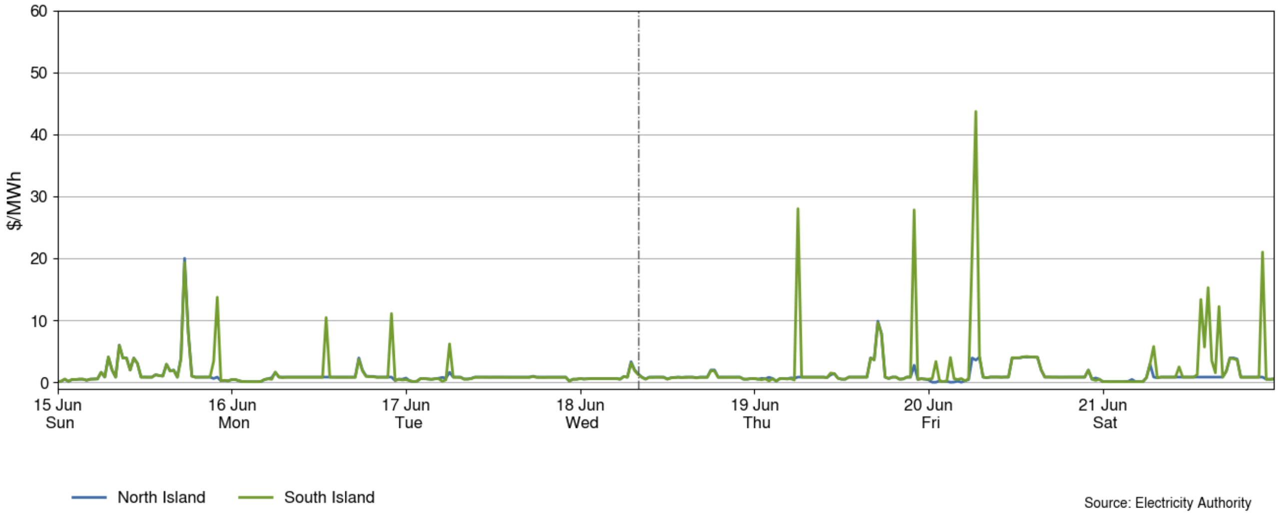
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh with a few spikes. The highest FIR price was $37/MWh at 8.00am on Wednesday in the North Island and $28/MWh in the South Island during peak demand, requiring higher priced reserves to be cleared.

Figure 3: Fast instantaneous reserve price by trading period and island, 15-21 June 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh with a few spikes. The highest SIR price was $44/MWh in the South Island at 6.30am on Friday, the North Island SIR price at the same time was $4/MWh. Spikes in South Island SIR generally occurred when the HVDC was setting the South Island SIR risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 15-21 June 2025



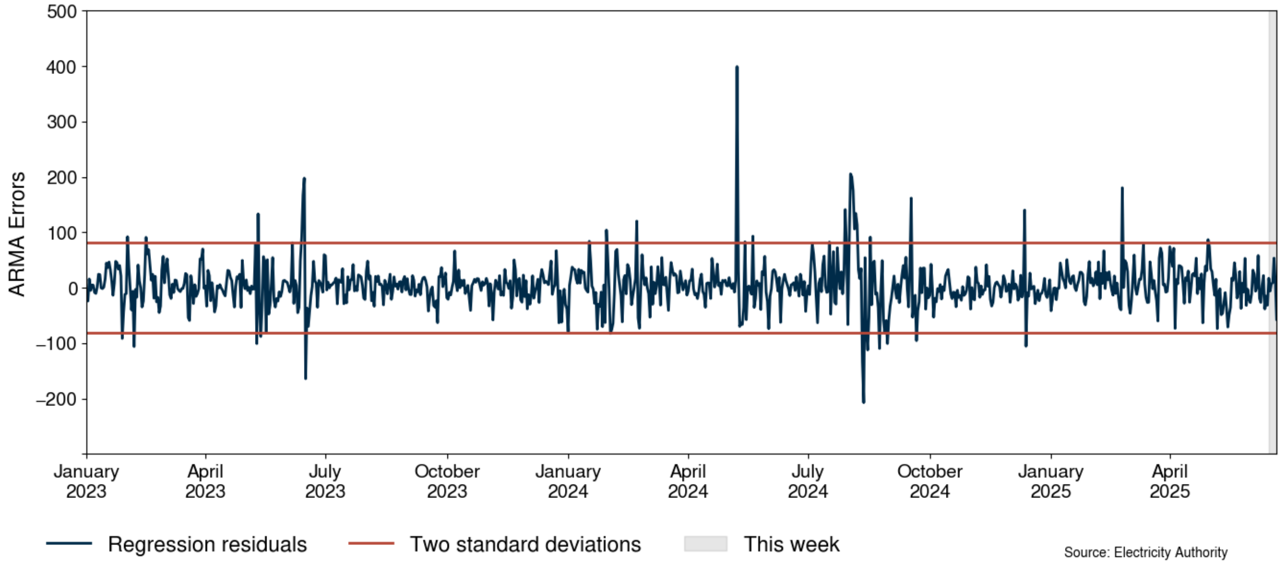
4. Regression residuals

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.

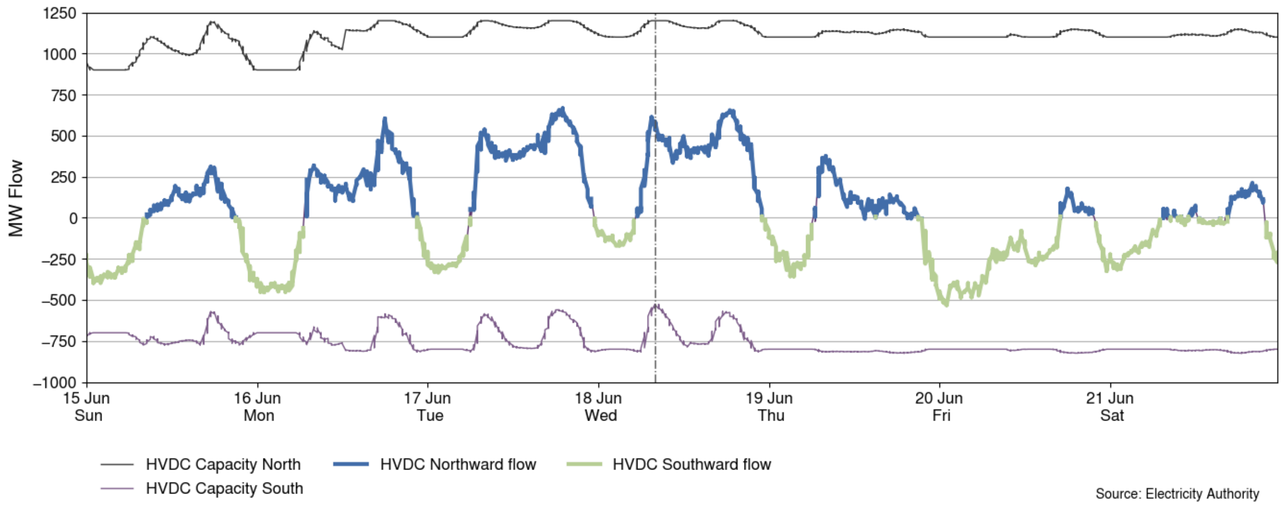
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 21 June 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 15-21 June 2025. HVDC flows were mostly northward during the day and southward overnight. Southward flow was highest on Friday due to higher wind generation and lower demand than previous days. Northward flows reached over 665MW on Tuesday at 7.00pm.

Figure 6: HVDC flow and capacity, 15-21 June 2025



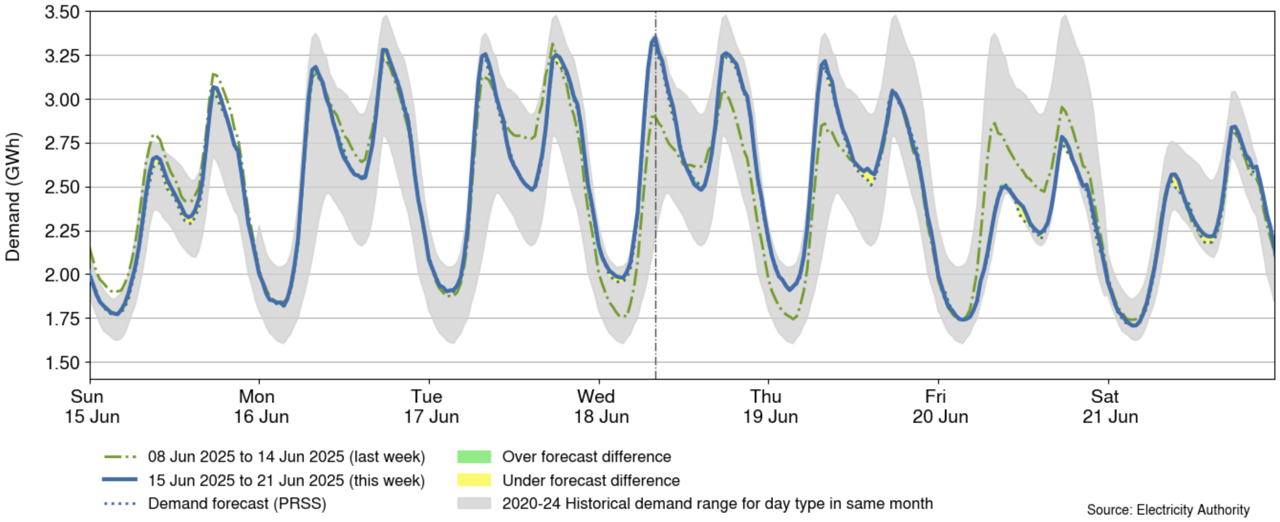
6. Demand

6.1. Figure 7 shows national demand between 15-21 June 2025, compared to the historic range and the demand of the previous week.

6.2. Demand was significantly higher at the start of the week due to colder temperatures, reaching a peak of 3.35GWh at 8.00am on Wednesday. On Friday, demand was low due to the Matariki holiday.

6.3. Following their demand response, New Zealand Aluminium Smelters Limited (NZAS) started to ramp up their production from 16 June 2025, targeting a return to full demand by 11 August 2025.[1]

Figure 7: National demand, 15-21 June 2025 compared to the previous week



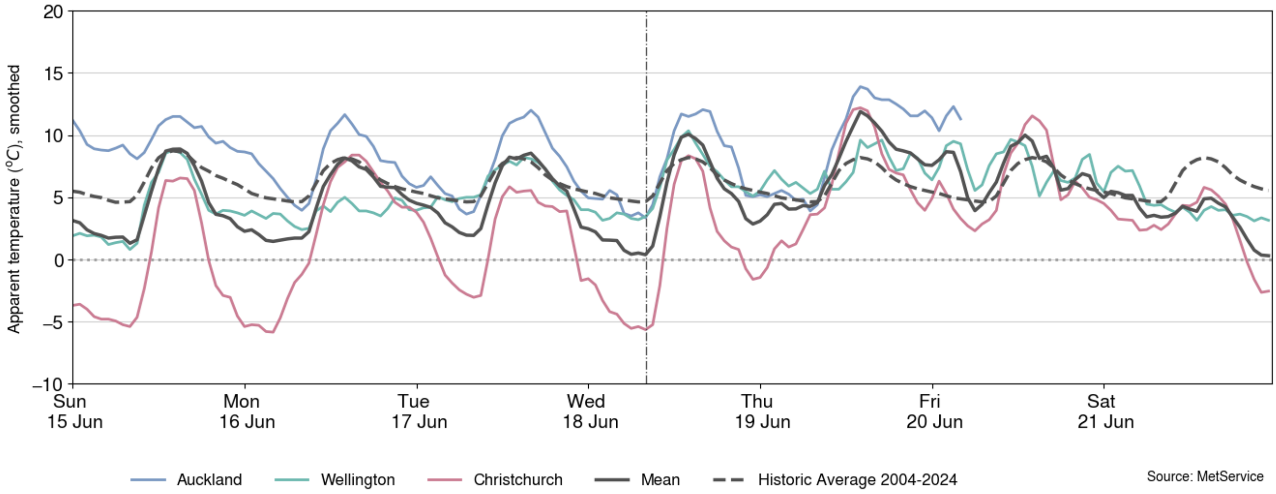
6.4. Figure 8 shows the hourly apparent temperature at main population centres from 15-21 June 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.5. Temperatures were above or around the historic average for Wellington and Auckland. Christchurch experienced cold mornings at the start of the week. However, at the end of the week Christchurch temperatures also hovered around the historic average.

6.6. Apparent temperatures ranged from 3°C to 14°C in Auckland, 1°C to 11°C in Wellington, and -6°C to 12°C in Christchurch.

[1] NZX, New Zealand's Exchange - Announcements, Meridian And Nzas Agree To Shorten Current Demand Response

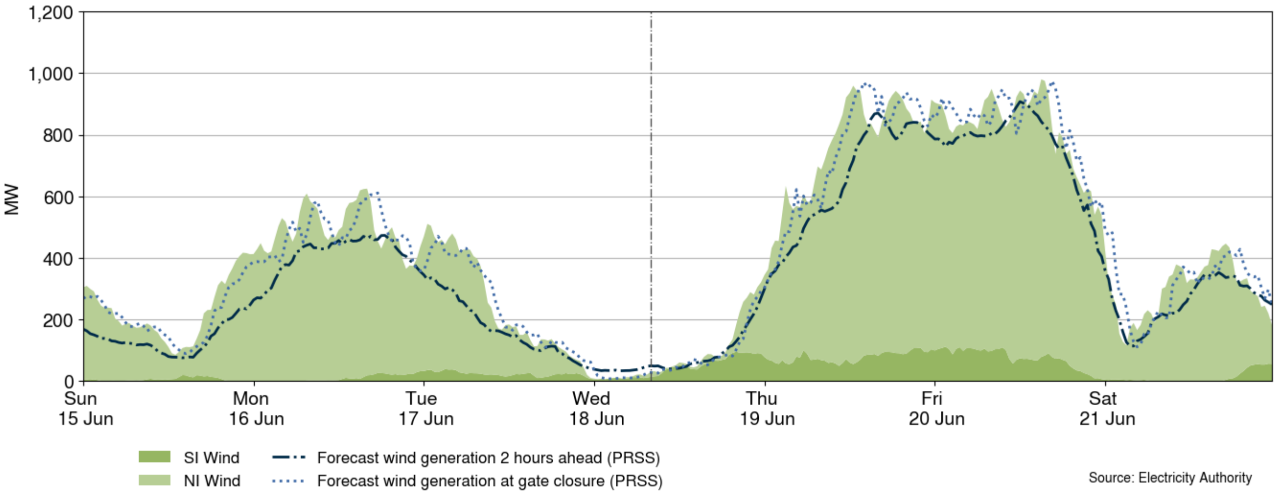
Figure 8: Temperatures across main centres, 15-21 June 2025[2]



7. Generation

7.1. Figure 9 shows wind generation and forecast from 15-21 June 2025. This week wind generation varied between 6MW and 980MW, with a weekly average of 416MW. Wind generation was lowest on Wednesday and highest on Thursday and Friday.

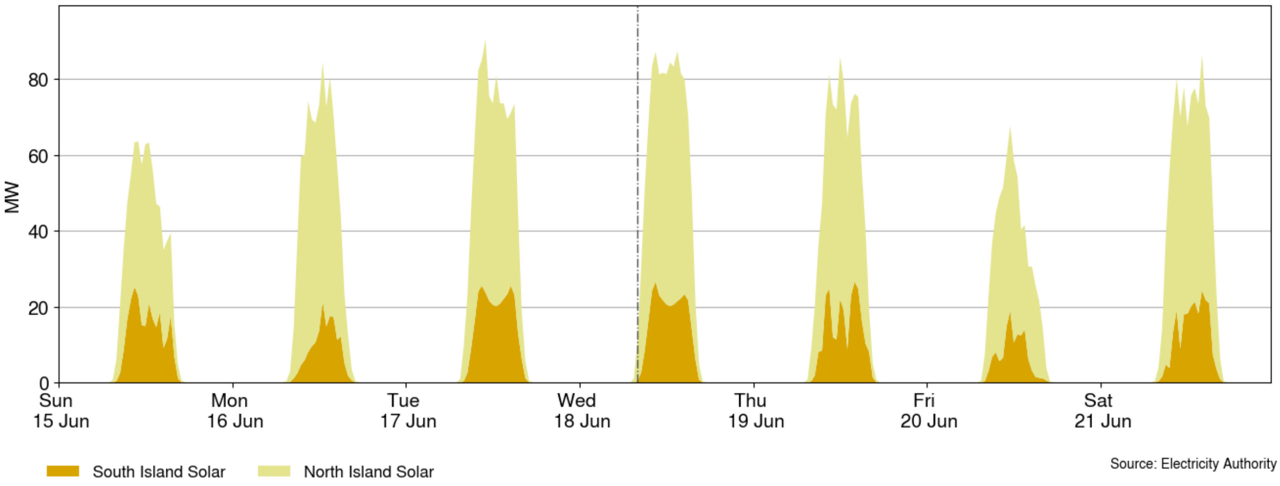
Figure 9: Wind generation and forecast, 15-21 June 2025



7.2. Figure 10 shows grid connected solar generation from 15-21 June 2025. Solar generation peaked above 50MW every day, with a maximum of 90MW at 11.00am on Tuesday.

[2] Weather data for Auckland is missing from 20 June 2025.

Figure 10: Grid connected solar generation, 15-21 June 2025

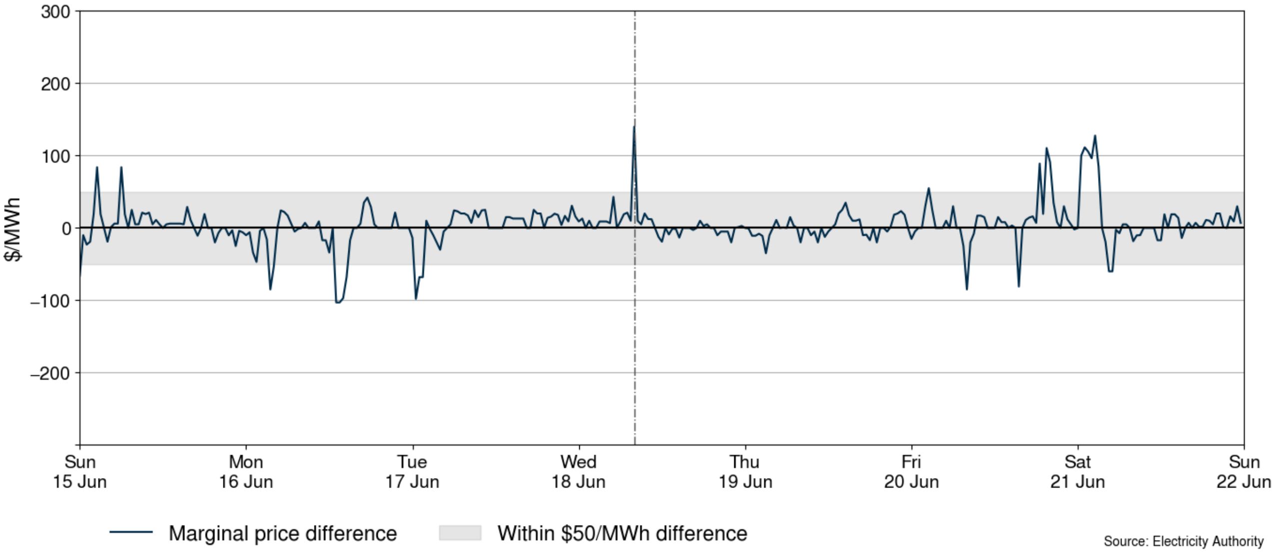


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[3]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 on Sunday, Friday, and Saturday had positive marginal price differences which were driven by wind and demand forecasting errors. The largest positive price difference of +$140/MWh occurred at 8.00am on Wednesday during peak demand and when demand was over 82MW higher than forecast.

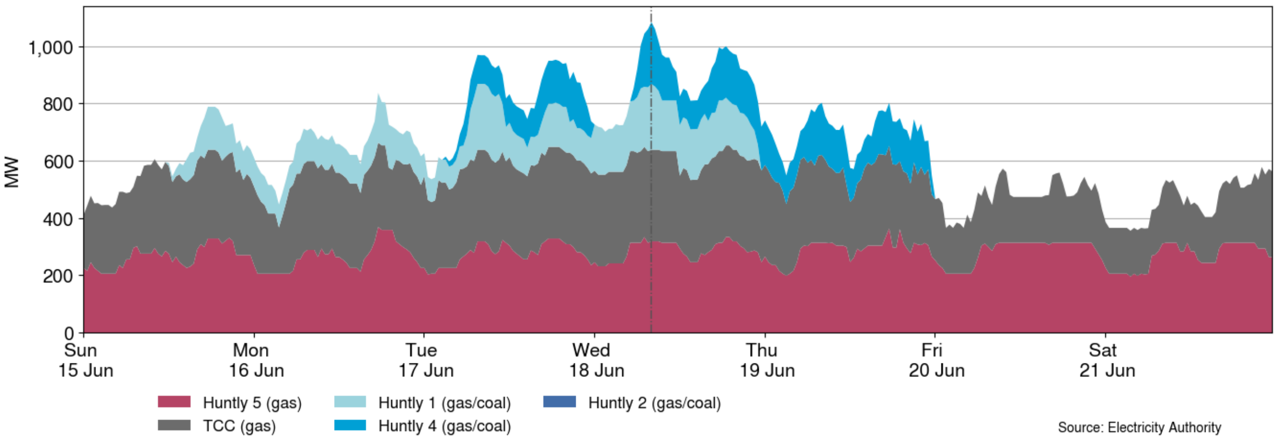
[3] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 15-21 June 2025



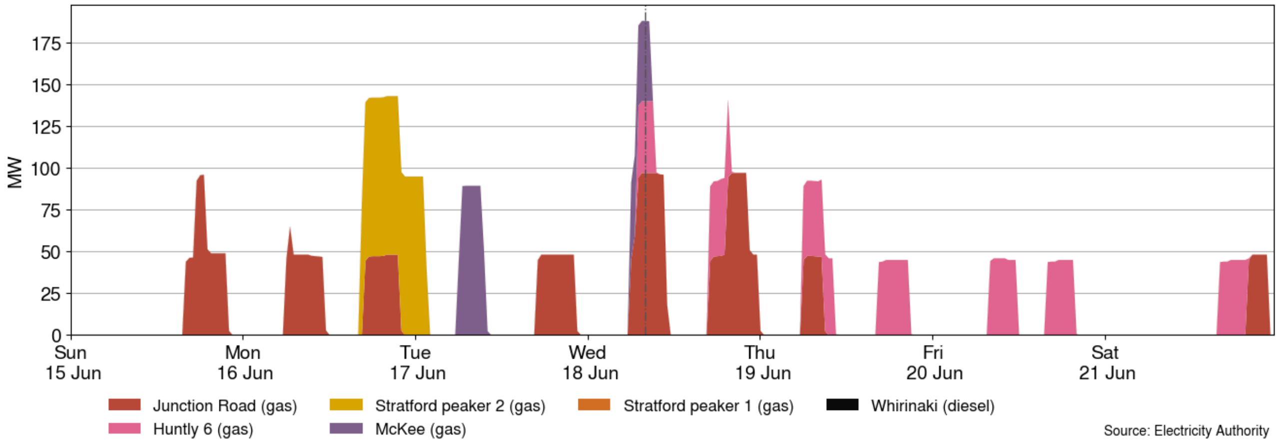
7.5. Figure 12 shows the generation of thermal baseload between 15-21 June 2025. Huntly 5 and TCC ran as baseload this week. Huntly 1 ran from Sunday to Wednesday, and Huntly 4 ran from Tuesday to Thursday.

Figure 12: Thermal baseload generation, 15-21 June 2025



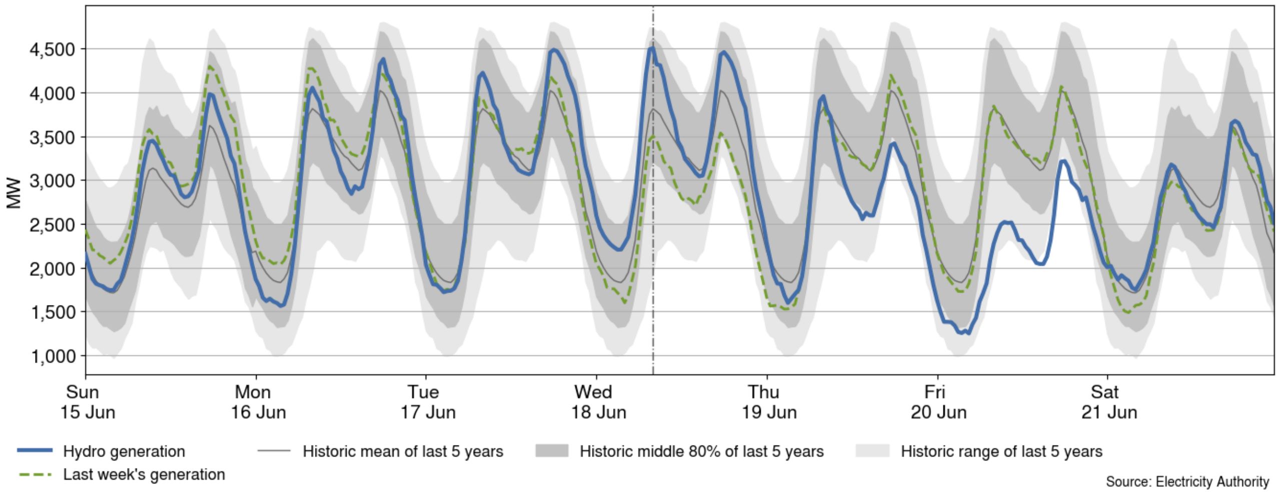
7.6. Figure 13 shows the generation of thermal peaker plants between 15-21 June 2025. Junction road ran during peak periods, except on Friday. Huntly 6 ran during peak periods from Wednesday to Saturday. Stratford peaker 2 ran on Monday evening. McKee generated during Tuesday and Wednesday morning peaks.

Figure 13: Thermal peaker generation, 15-21 June 2025



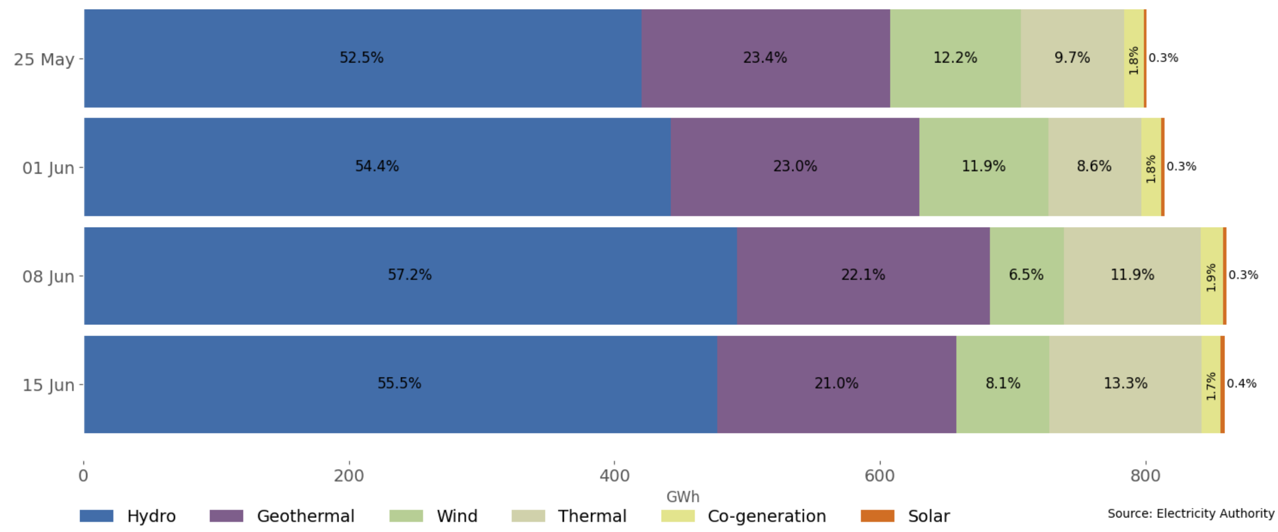
7.7. Figure 14 shows hydro generation between 15-21 June 2025. Hydro generation was high at the start of the week due to high demand, and lower on Thursday evening and Friday due to lower demand and higher wind generation than earlier in the week.

Figure 14: Hydro generation, 15-21 June 2025



7.8. As a percentage of total generation, between 15-21 June 2025, total weekly hydro generation was 55.5%, geothermal 21.0%, wind 8.1%, thermal 13.3%, co-generation 1.7%, and solar (grid connected) 0.4%, as shown in Figure 15. The amount of geothermal generation was lower this week due to a trip and partial outage at Tauhara.

Figure 15: Total generation by type as a percentage each week, between 25 May 2025 and 21 June 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 15-21 June 2025 ranged between ~662MW and ~1,376MW. 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) Manapōuri unit 4 is on outage until 12 June 2026.

(c) Tauhara geothermal was on outage on 16 June following a trip,[4] and then on partial outage until 20 June 2025.

(d) Ruakākā battery is on outage between 13-27 June 2025.

(e) Benmore unit 4 was on outage from 9-19 June 2025.

(f) Takapō unit 3 was on outage from 17-20 June 2025.

[4] EXN Voltage North Island Tauhara Generation Tripped 6367231458.pdf

Figure 16: Total MW loss from generation outages, 15-21 June 2025

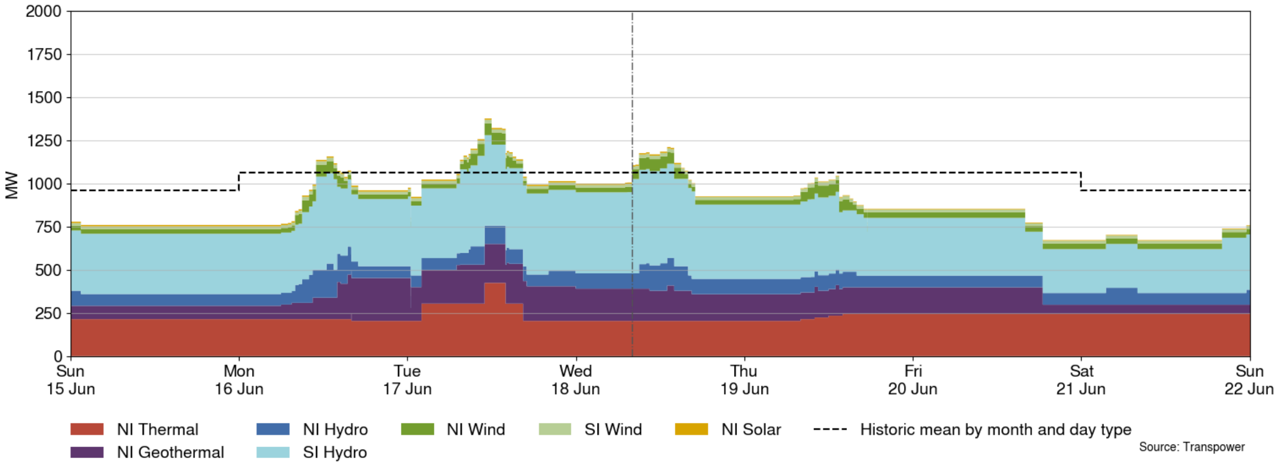
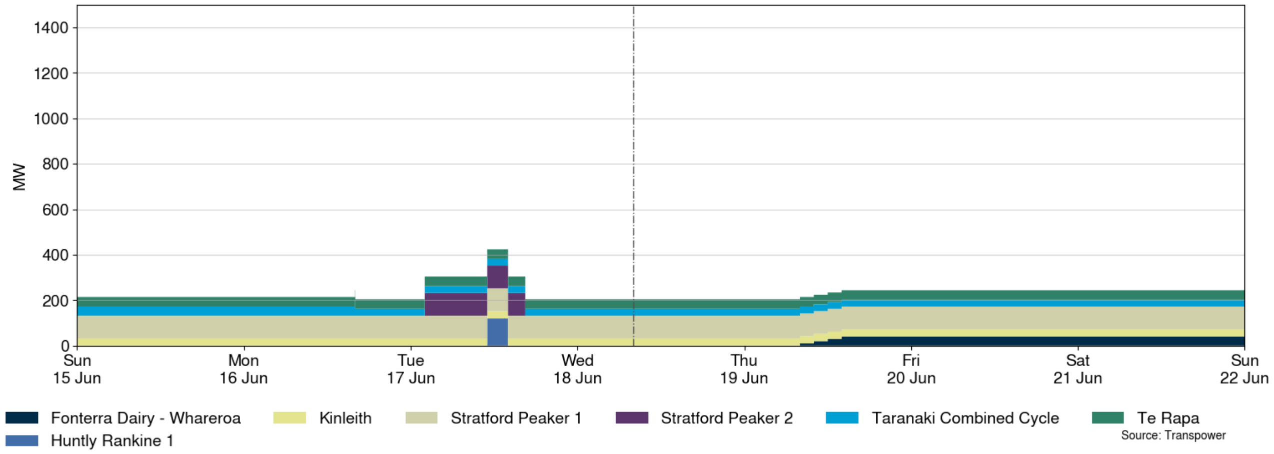


Figure 17: Total MW loss from thermal outages, 15-21 June 2025

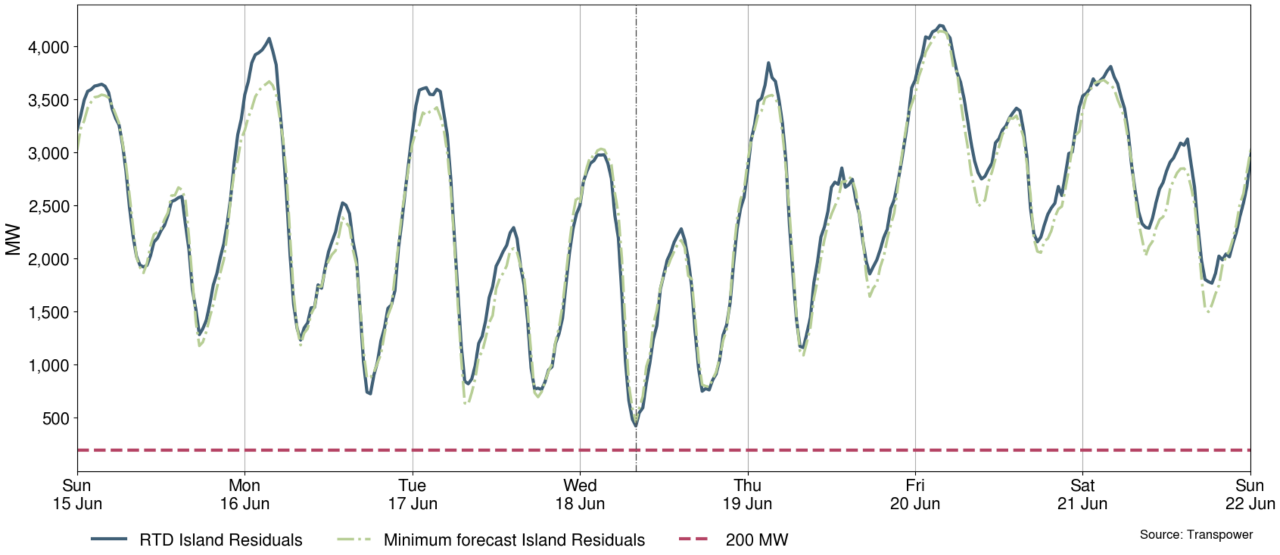


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 15-21 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 423MW on Wednesday at 8.00am during peak demand for the week.

Figure 18: National generation balance residuals, 15-21 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 10th to 90th percentiles.

10.2. As of 20 June 2025, national controlled storage was 65% nominally full and ~93% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (59% full)[5] is between its historical 10th percentile and mean, while storage at Lake Takapō (43% full) has fallen below its 10th percentile.

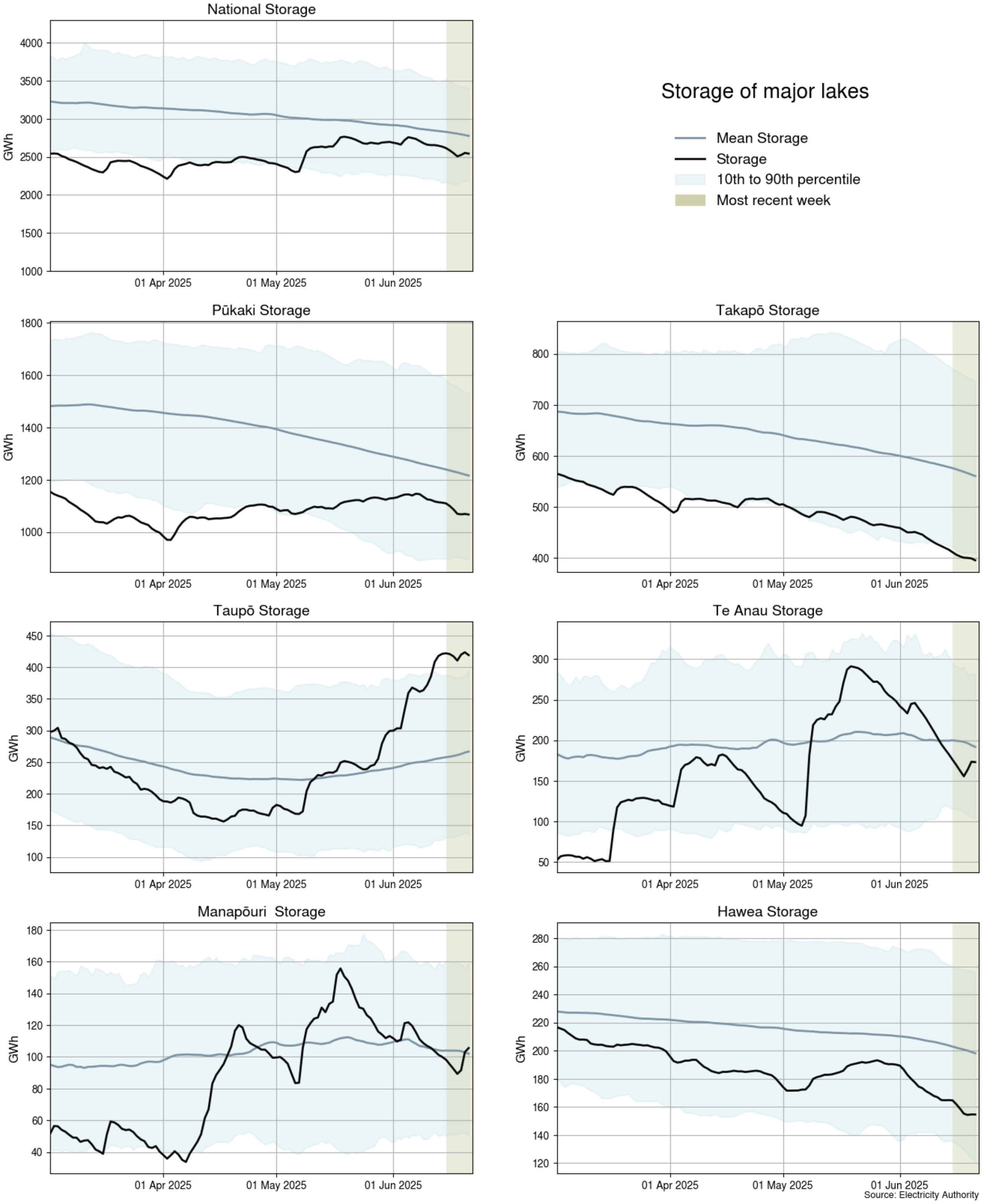
10.4. Lakes Te Anau (66% full) and Manapōuri (71% full) increased during the week. Storage at Manapōuri is slightly above its mean and storage at Te Anau is slightly below its mean.

10.5. Storage at Lake Taupō (72% full) decreased slightly but remains above its 90th percentile.

10.6. Storage at Lake Hawea (54% full) decreased and remains between its historical 10th percentile and mean.

[5] Percentage full values sourced from NZX hydrological summary 23 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.

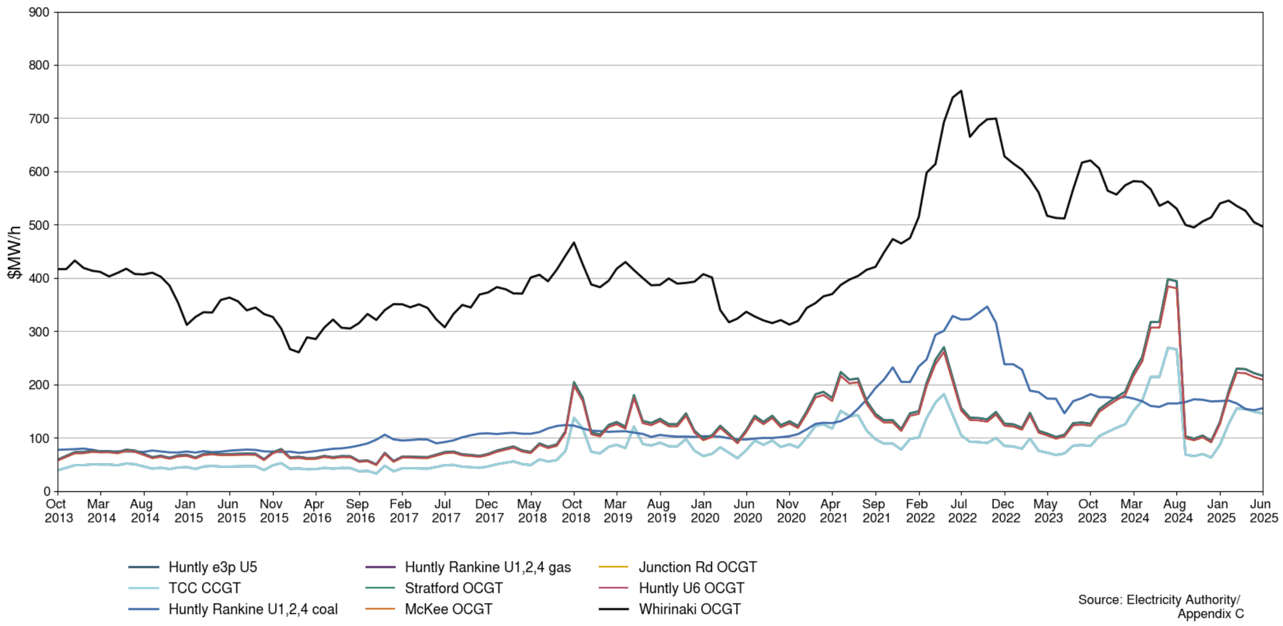
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$155/MWh. The cost of running the Rankines on gas is ~$216/MWh.

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

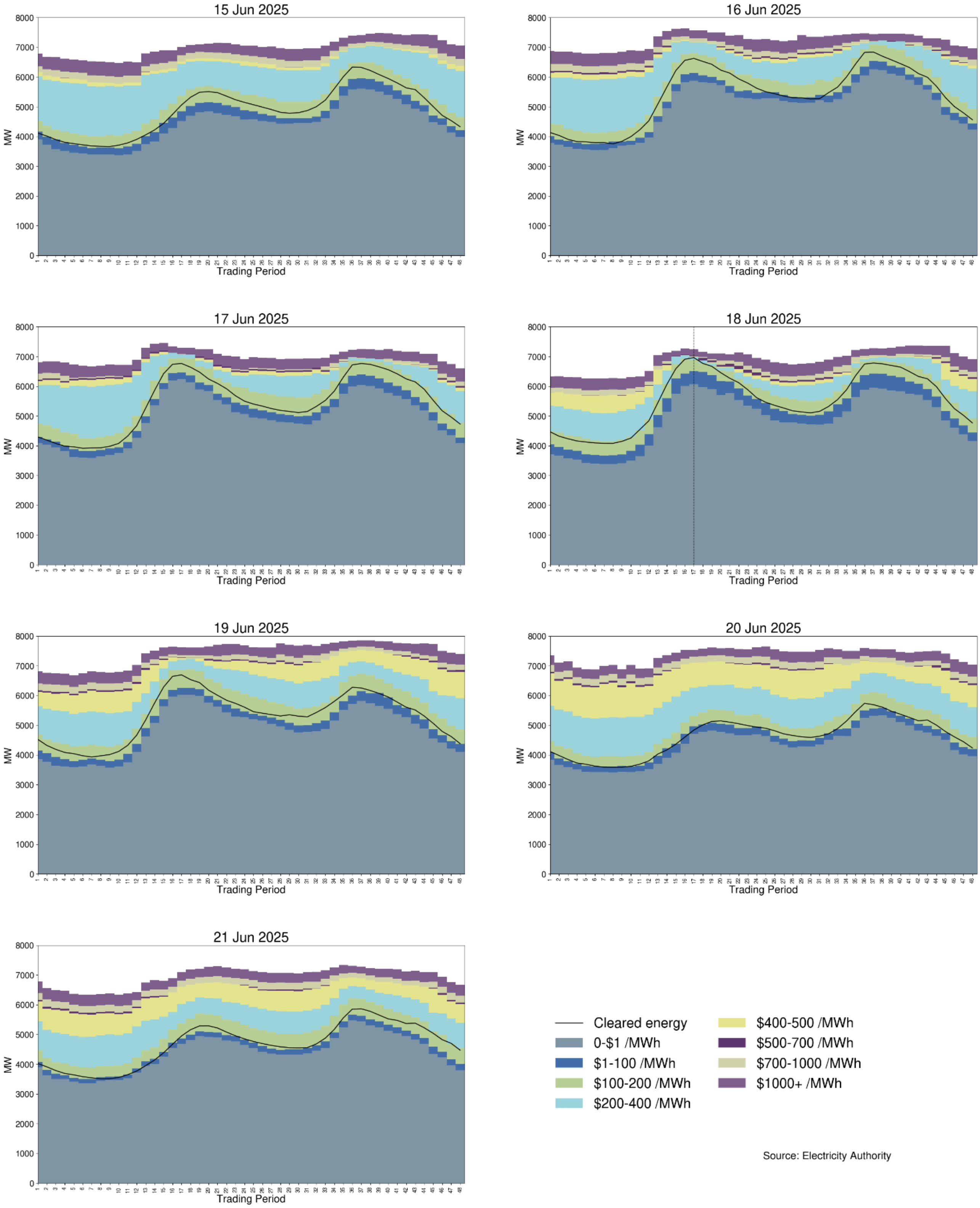


12. Offer behaviour

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. For a few trading periods, high demand and/or low wind resulted in cleared energy moving into the next band of $200-$400/MWh.

Figure 21: Daily offer stacks



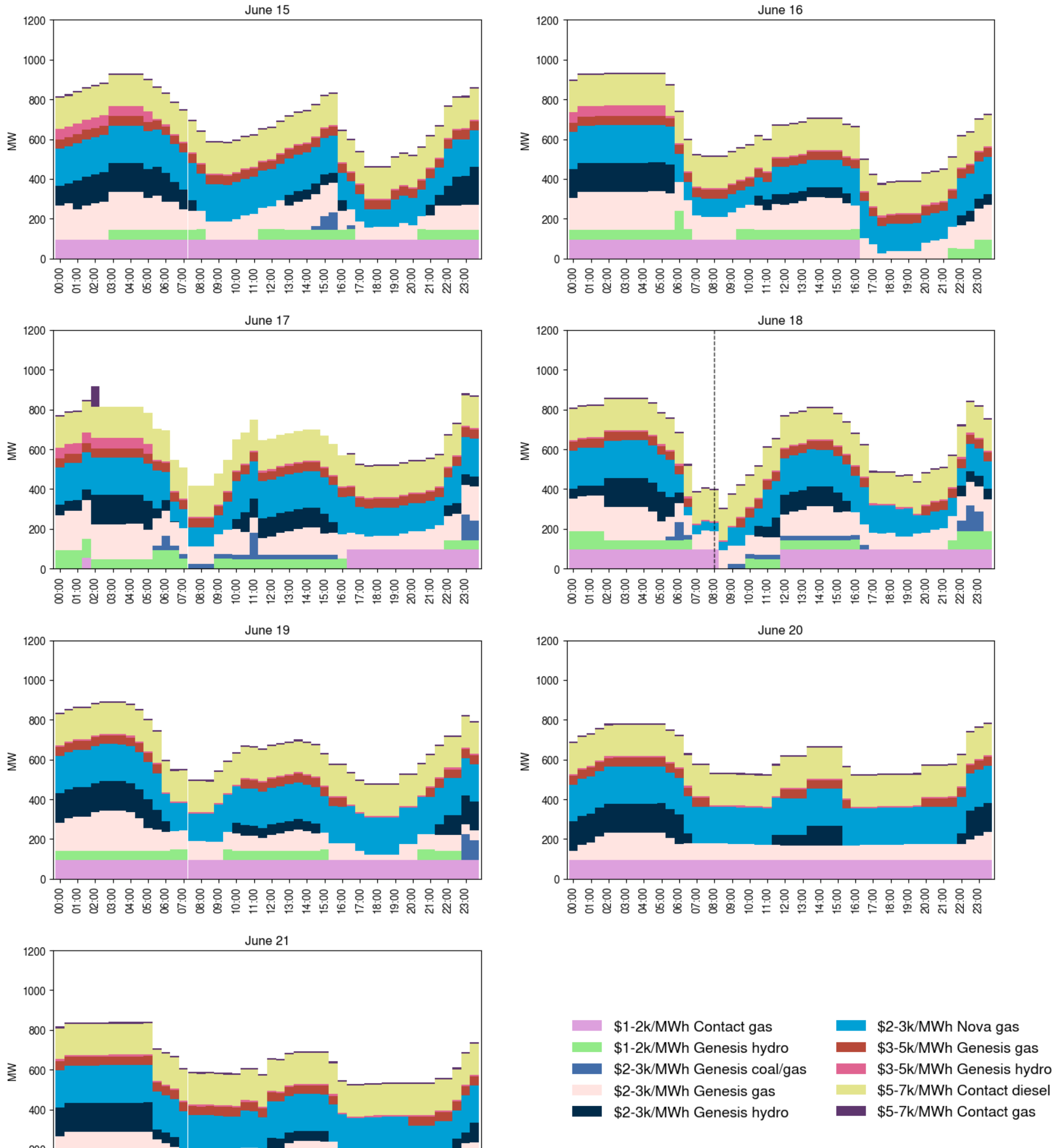
Source: Electricity Authority

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 665MW per trading period was priced above $1,000/MWh this week, which is roughly 10.7% 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