6 October 2025

Trading conduct report 28 September – 4 October 2025

Market monitoring weekly report

Trading conduct report 28 September – 4 October 2025

1. Overview

1.1. This week the average spot price increased by $21/MWh to $56/MWh. Spot prices increased from Wednesday onwards when thermal commitment decreased and there was lower wind generation.

1.2. Huntly 5 has shut down for three months from 1 October 2025[1], to allow gas to be made available to commercial and industrial users, subject to a callback period described further below.

1.3. National hydro storage has slightly increased to 65% nominally full and around 107% of the historical average.

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 28 September – 4 October 2025:

(a) The average spot price for the week was $56/MWh, an increase of around $21/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $203/MWh.

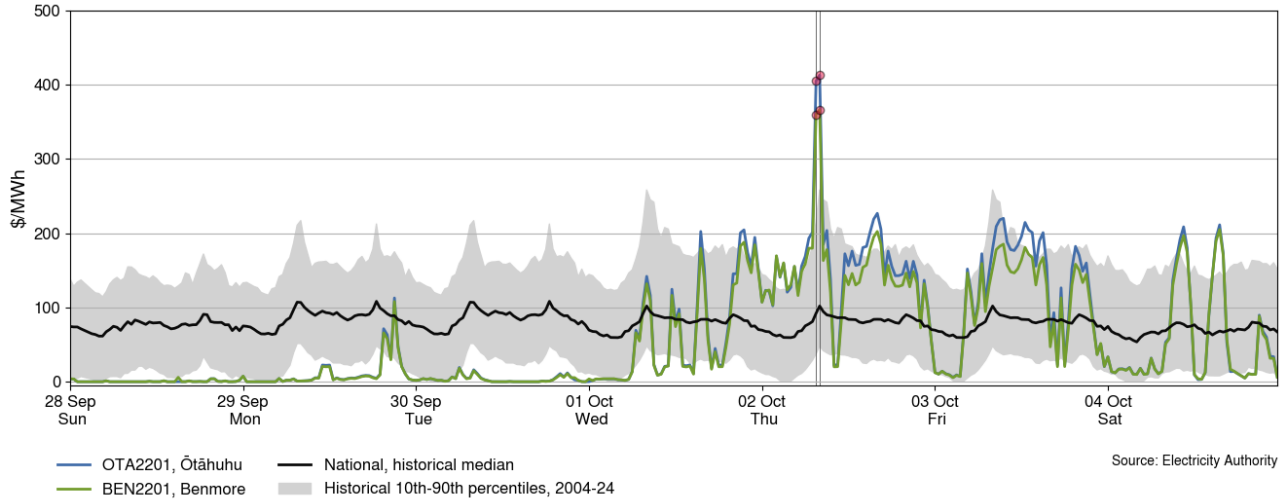
2.3. Spot prices remained low between Sunday and Tuesday. From Wednesday, prices rose and became volatile after Huntly 5 shut down. Huntly 5 has shut down for three months[1], to allow gas to be made available to commercial and industrial users. Excluding 29 October to 24 November, Huntly 5 is available with a callback period of three-to-five days, subject to fuel availability. Wind generation was also low from Wednesday onwards.

2.4. The highest price of the week occurred on Thursday morning between 7.30am-8.00am, with prices reaching around $413/MWh at Ōtāhuhu and ~$366/MWh at Benmore. This coincided with the maximum peak demand for the week. Prices exceeded $1,000/MWh during two 5-minutes trading periods and Stratford peaker 2 was dispatched to meet demand. At 7.30am, demand was higher than forecast by 70MW, and wind was low at around 126MW.

2.5. 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, and above $250/MWh are highlighted with a vertical black line.

[1] Genesis extends Unit 5 outage to support gas consumers | Genesis NZ

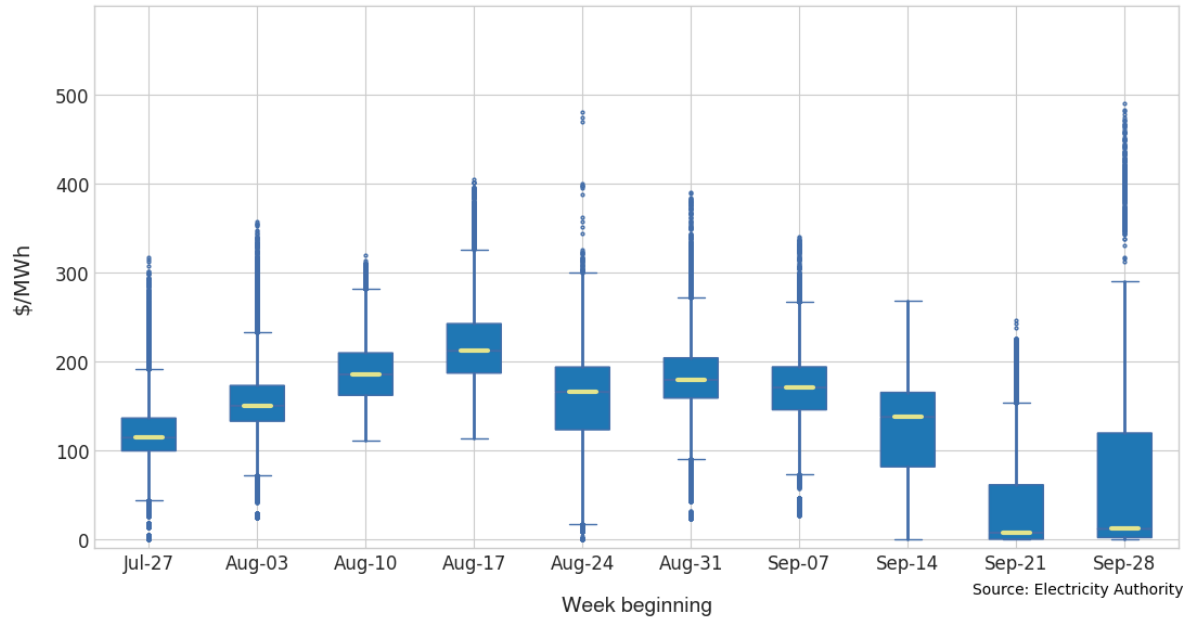
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 28 September – 4 October 2025



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 was wider than last week, with some high-priced outliers above $300/MWh. The median price was $12/MWh and most prices (middle 50%) fell between $2/MWh and $120/MWh.

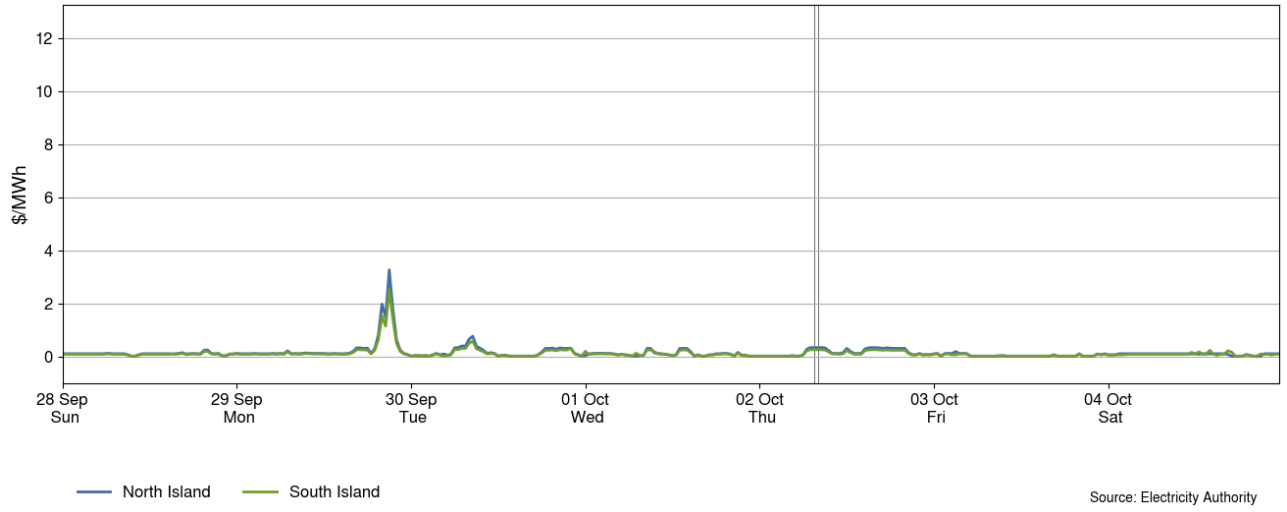
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

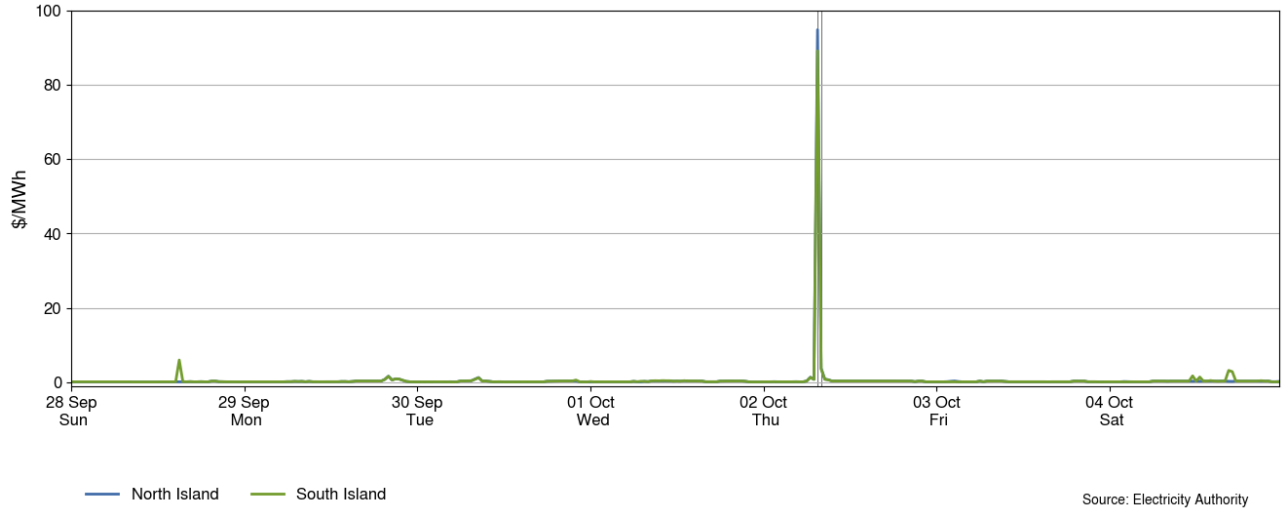
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices across both the North and South Island were below $4/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 28 September – 4 October 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were below $6/MWh except on Thursday at 7.30am, coinciding with the spot price spike. During that time, SIR prices reached around $95/MWh in the North Island and ~$89/MWh in the South Island. Huntly 1 was setting the risk, and more expensive reserve was needed for one 5-minute period (7:55 am).

Figure 4: Sustained instantaneous reserve by trading period and island, 28 September – 4 October 2025



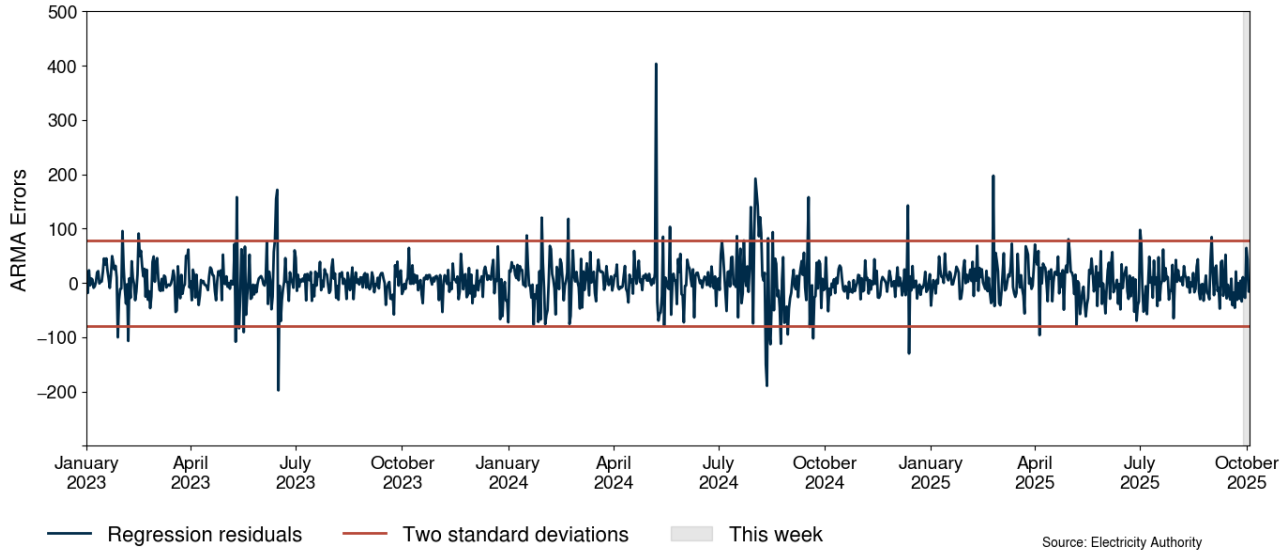
4. Regression residuals

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.

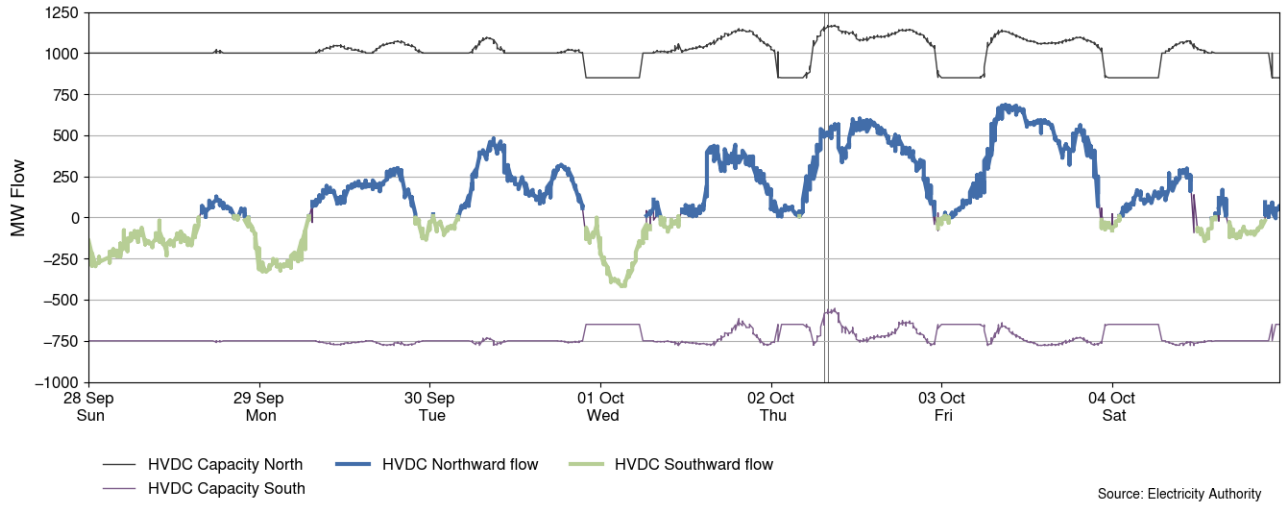
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 4 October 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 28 September – 4 October 2025. From Sunday to Wednesday, HVDC flows were northward during the day and southward overnight. From Thursday, flows were mostly northward with a small southward flow. Northward flows reached around 684MW on Friday at 9.00am. Southward flow was high (~417MW) on Wednesday at 3.30am when wind was high.

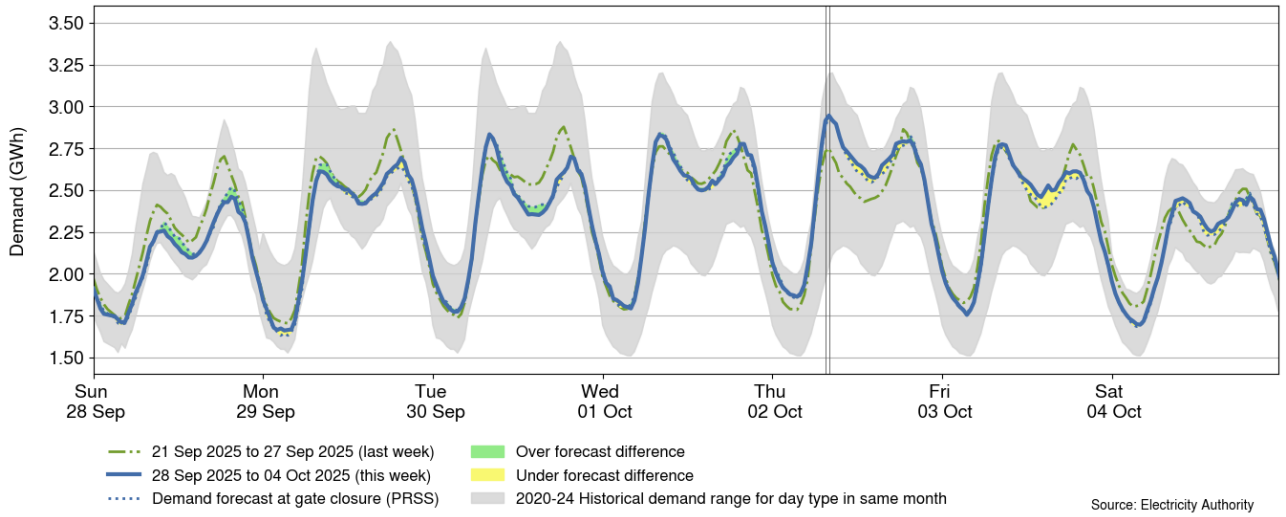
Figure 6: HVDC flow and capacity, 28 September – 4 October 2025



6. Demand

6.1. Figure 7 shows national demand between 28 September – 4 October 2025, compared to the historic range and the demand of the previous week. Overall, demand remained low this week. The highest demand of the week was around 2.95GWh at 8.00am on Thursday during the morning peak and the spot price spike.

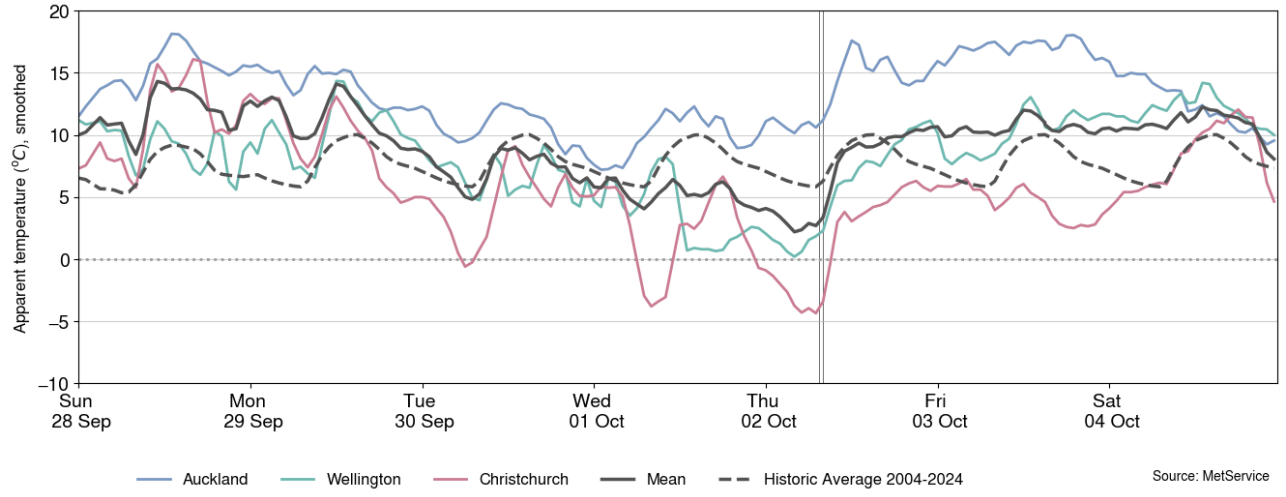
Figure 7: National demand, 28 September – 4 October 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 28 September – 4 October 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.

6.3. Apparent temperatures ranged from 7°C to 19°C in Auckland, 0°C to 16°C in Wellington, and -5°C to 17°C in Christchurch. Christchurch recorded the lowest apparent temperature of the week during the spot price spike.

Figure 8: Temperatures across main centres, 28 September – 4 October 2025



7. Generation

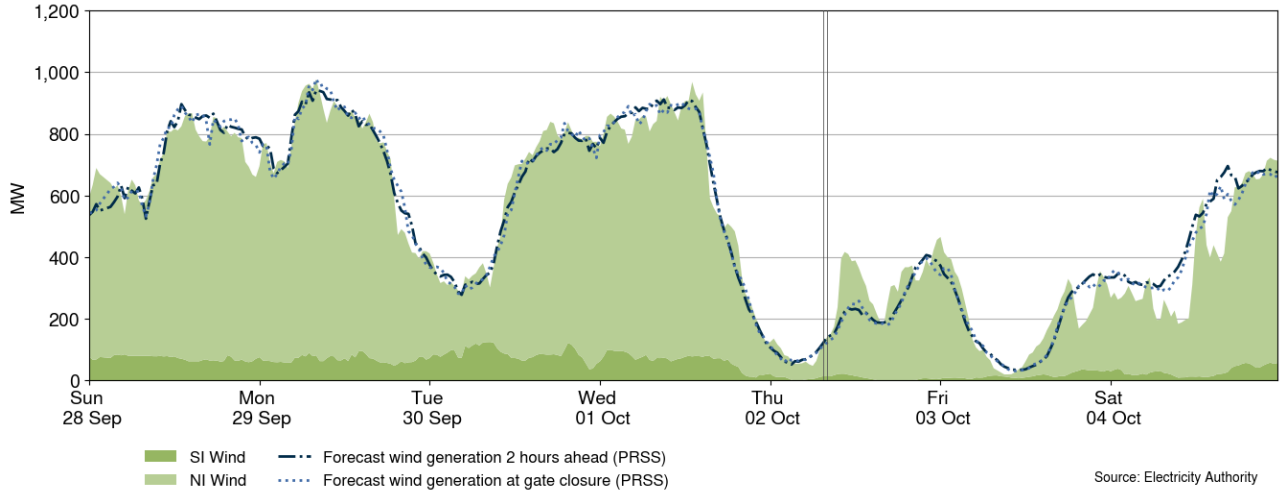
7.1. Figure 9 shows wind generation and forecast from 28 September – 4 October 2025. This week wind generation varied between 19MW and 977MW, with a weekly average of 510MW.

7.2. Wind generation remained mostly high through Sunday and Monday. It began to decline gradually from Monday evening and was low on Tuesday night. From Tuesday morning,

wind generation increased steadily but started to decline again from Wednesday afternoon. Wind was relatively low on Thursday and Friday.

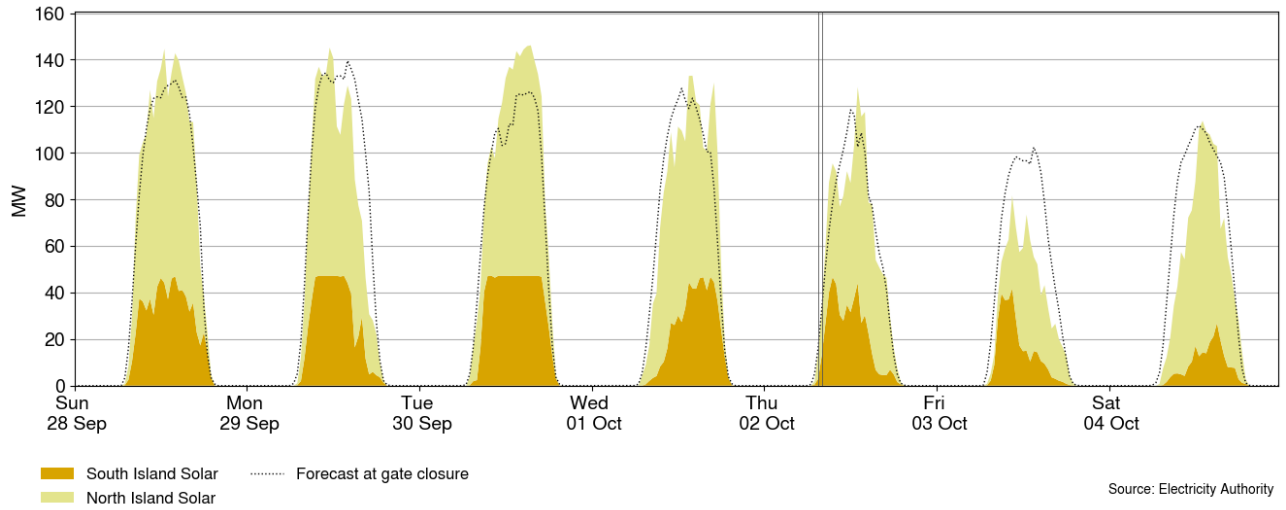
7.3. On Saturday, wind remained low during the day and increased toward the end of the day, with a maximum forecast error of around 250MW at 3.00pm.

Figure 9: Wind generation and forecast, 28 September – 4 October 2025



7.4. Figure 10 shows grid connected solar generation from 28 September – 4 October 2025. Solar generation typically peaked above 100MW, except on Friday when it was low. Solar generation peaked at a maximum of around 146MW on Tuesday at 3.30pm.

Figure 10: Grid connected solar generation, 28 September – 4 October 2025



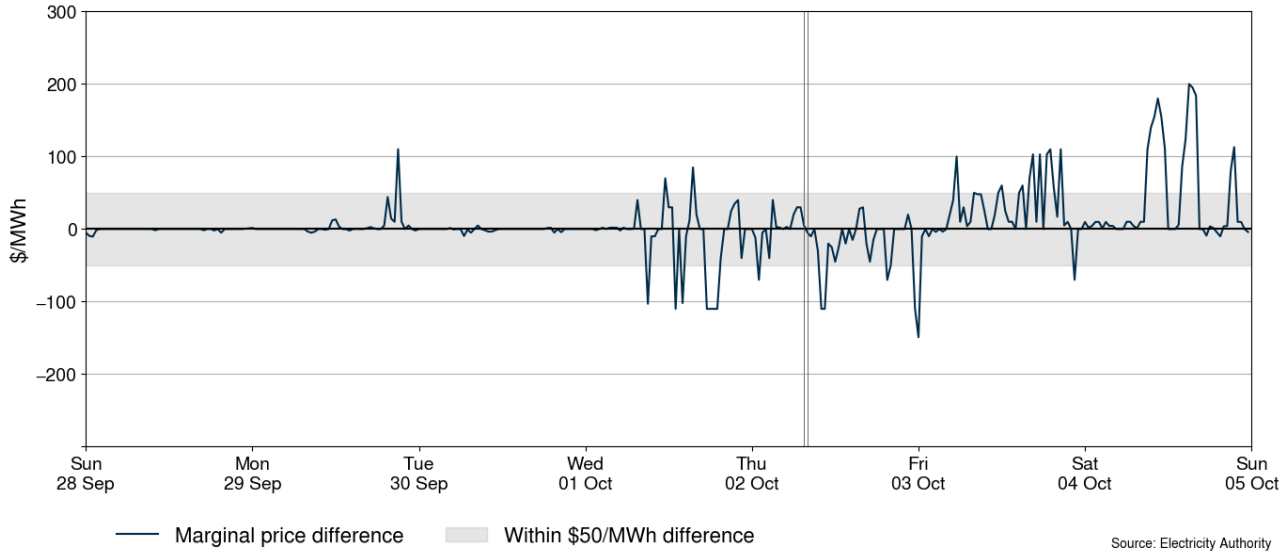
7.5. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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

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

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.

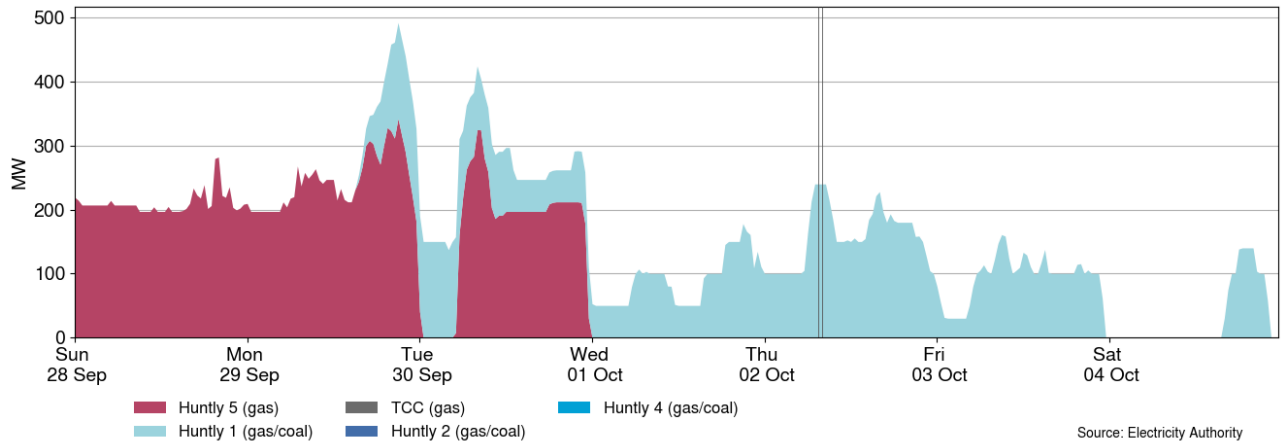
7.6. Several trading periods this week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors from Wednesday onwards. The largest positive price difference of +$200/MWh occurred at 3.00pm on Saturday, when demand was 99MW higher than forecast, and wind was 194MW lower than forecast.

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, 28 September – 4 October 2025



7.7. Figure 12 shows the generation of thermal baseload between 28 September – 4 October 2025. Huntly 5 ran from Sunday to Tuesday before shutting down, while Huntly 1 ran from Monday to Saturday. On Saturday, Huntly 1 generated only during the evening peak period.

Figure 12: Thermal baseload generation, 28 September – 4 October 2025



7.8. Figure 13 shows the generation of thermal peaker plants between 28 September – 4 October 2025. From Wednesday, thermal peaker plants generation increased as Huntly 5 was shut down and wind was low.

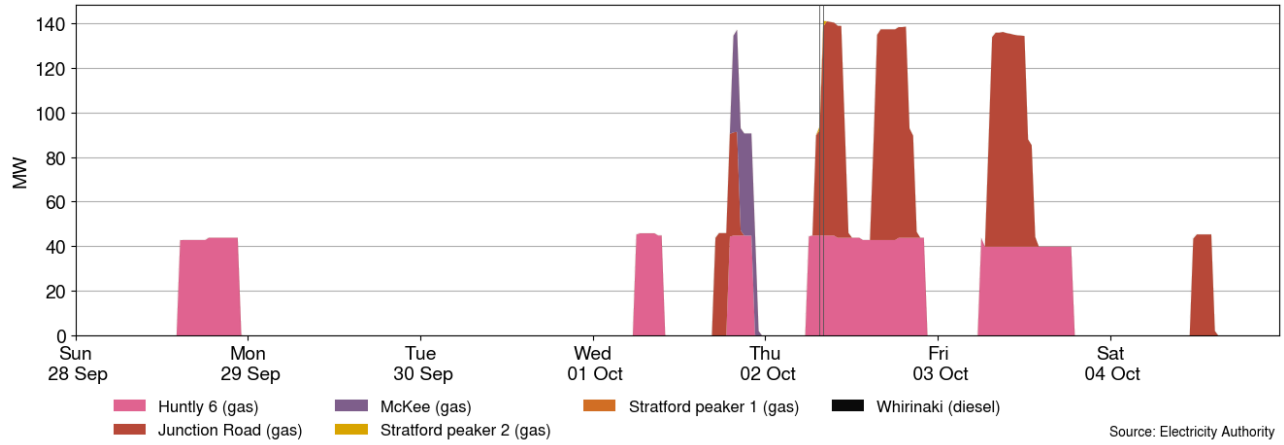
7.9. Junction Road ran from Wednesday to Saturday during the peak demand periods.

7.10. Huntly 6 ran on Sunday evening, Wednesday during both morning and evening peaks, and on Thursday and Friday continuously between the morning and evening peaks.

7.11. McKee ran only on Wednesday during the evening peak demand period.

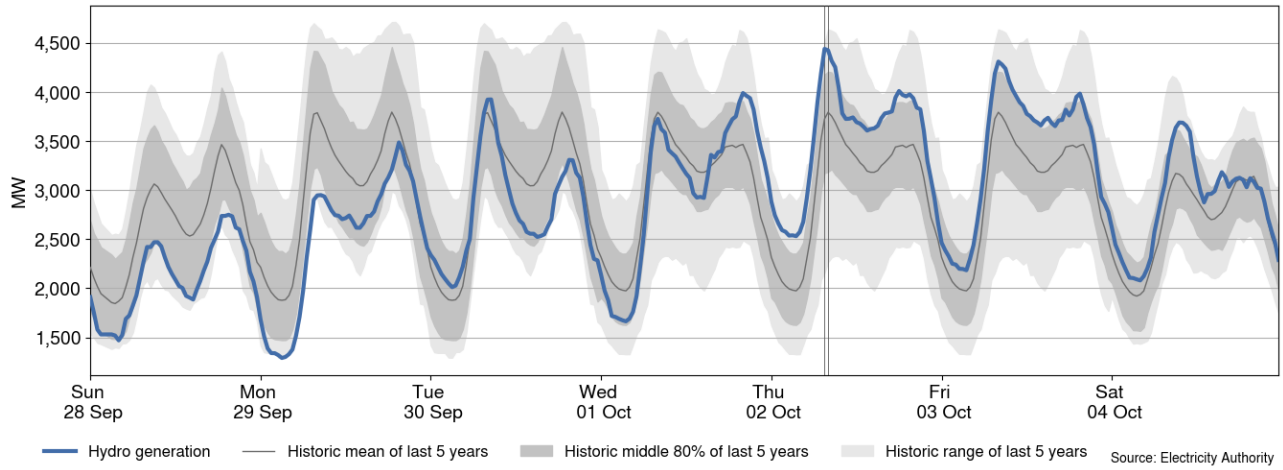
7.12. Stratford peaker 2 ran for two 5-minute trading periods on Thursday during the price spike.

Figure 13: Thermal peaker generation, 28 September – 4 October 2025



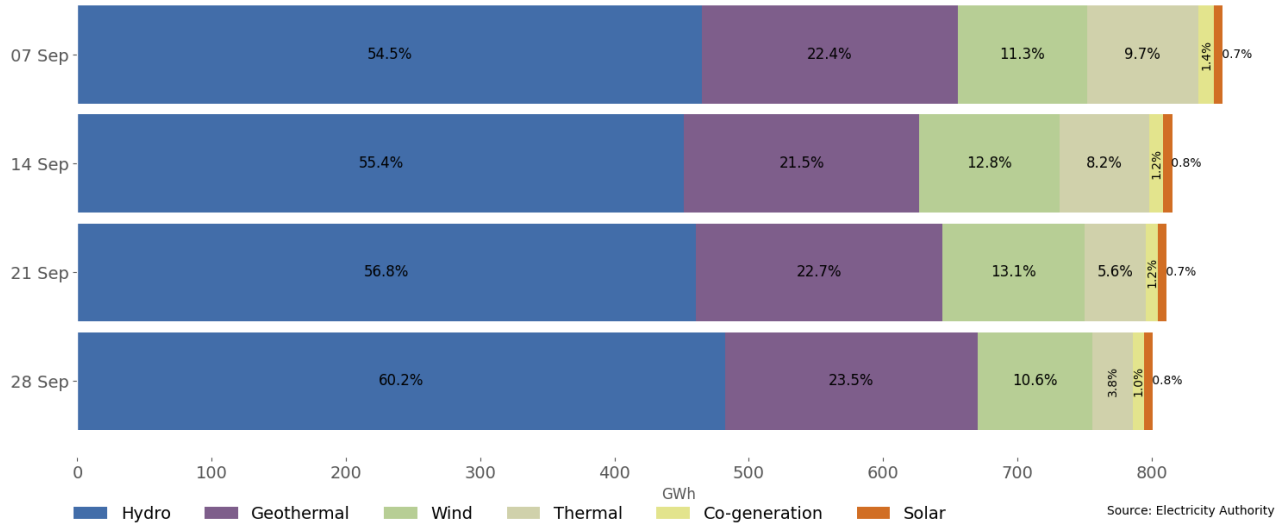
7.13. Figure 14 shows hydro generation between 28 September – 4 October 2025. Hydro generation remained mostly below or around the historical average until Wednesday. From Thursday onward, reduced thermal and low wind generation led to increased hydro generation.

Figure 14: Hydro generation, 28 September – 4 October 2025



7.14. As a percentage of total generation, between 28 September – 4 October 2025, total weekly hydro generation was 60.2%, geothermal 23.5%, wind 10.6%, thermal 3.8%, co-generation 1.0%, and solar (grid connected) 0.8%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 7 September and 4 October 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 28 September – 4 October 2025 ranged between ~1,313MW and ~2,096MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 was on outage between 1-2 October 2025.

(b) Huntly 4 is on extended outage until 17 October 2025.

(c) Huntly 6 is on outage from 4-10 October 2025.

(d) Ruakākā battery was on outage between 29 September – 6 October 2025.

(e) West wind farm is on partial outage until 9 October 2025.

(f) Benmore unit 6 is on outage until 21 November 2025.

(g) Rangipo unit 5 is on outage until 13 October 2025.

Some longer term outages include:

(h) Ohau A is on partial outage until 4 February 2026.

(i) Ohau B is on partial outage until 17 October 2025.

(j) Ohau C is on partial outage until 13 January 2026.

(k) Roxburgh unit 5 is on outage until 25 February 2026.

(l) Rangipo unit 6 is on outage until 29 March 2026.

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

Figure 16: Total MW loss from generation outages, 28 September – 4 October 2025

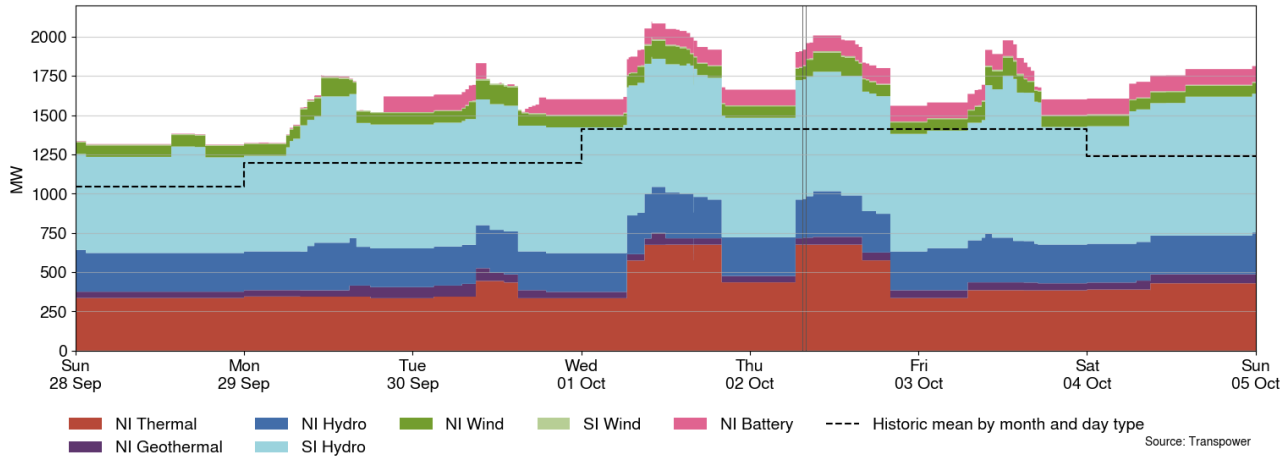
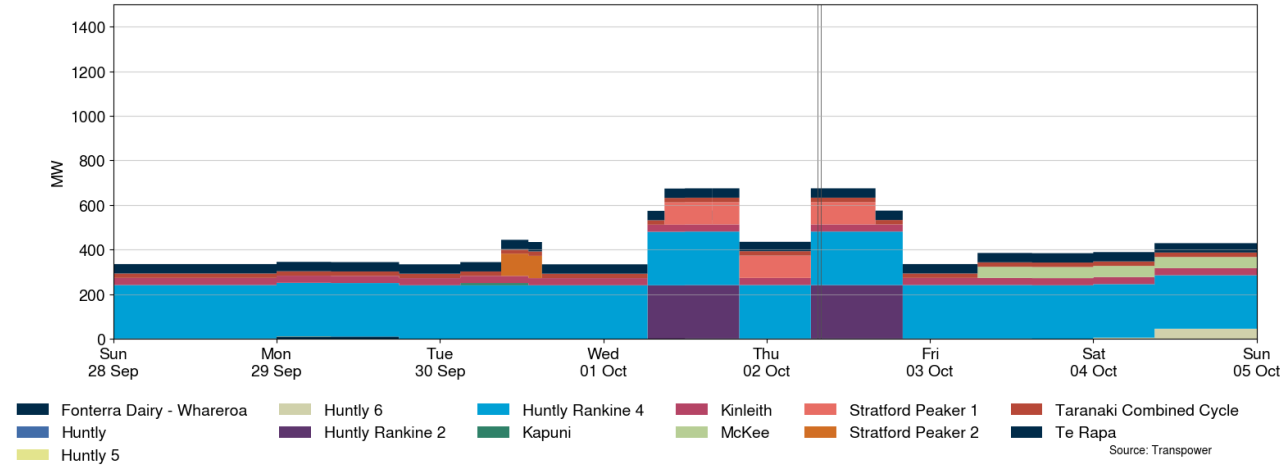


Figure 17: Total MW loss from thermal outages, 28 September – 4 October 2025

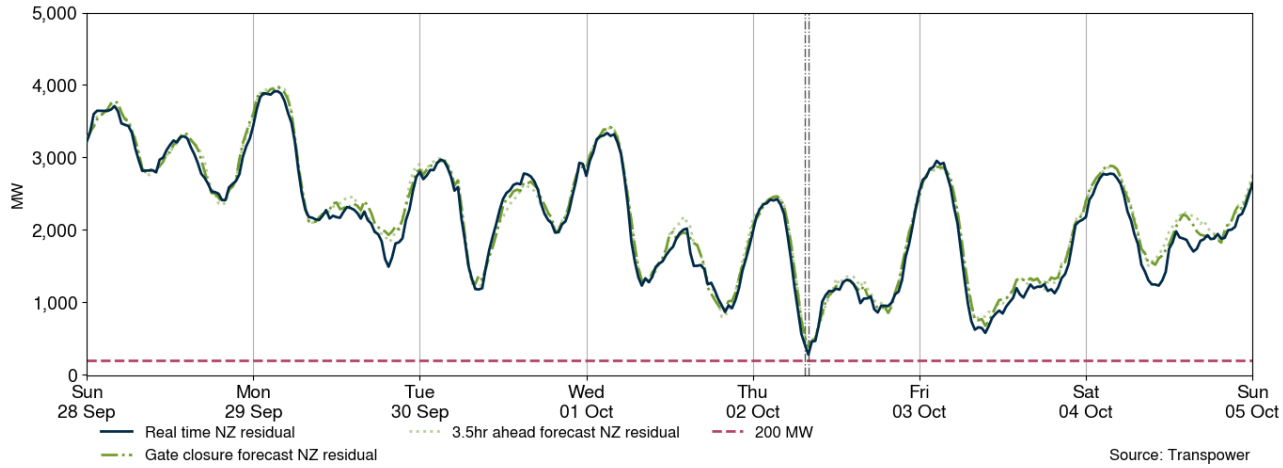


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 28 September – 4 October 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 declined from Wednesday onwards following the shutdown of Huntly. The lowest national residual was 280MW on Thursday at 8.00am during the spot price spike.

Figure 18: National generation balance residuals, 28 September – 4 October 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 4 October 2025, national controlled hydro storage had slightly increased to 65% of nominal full and ~107% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (43% full[3]) and Lake Takapō (43% full) is slightly below their respective historic mean.

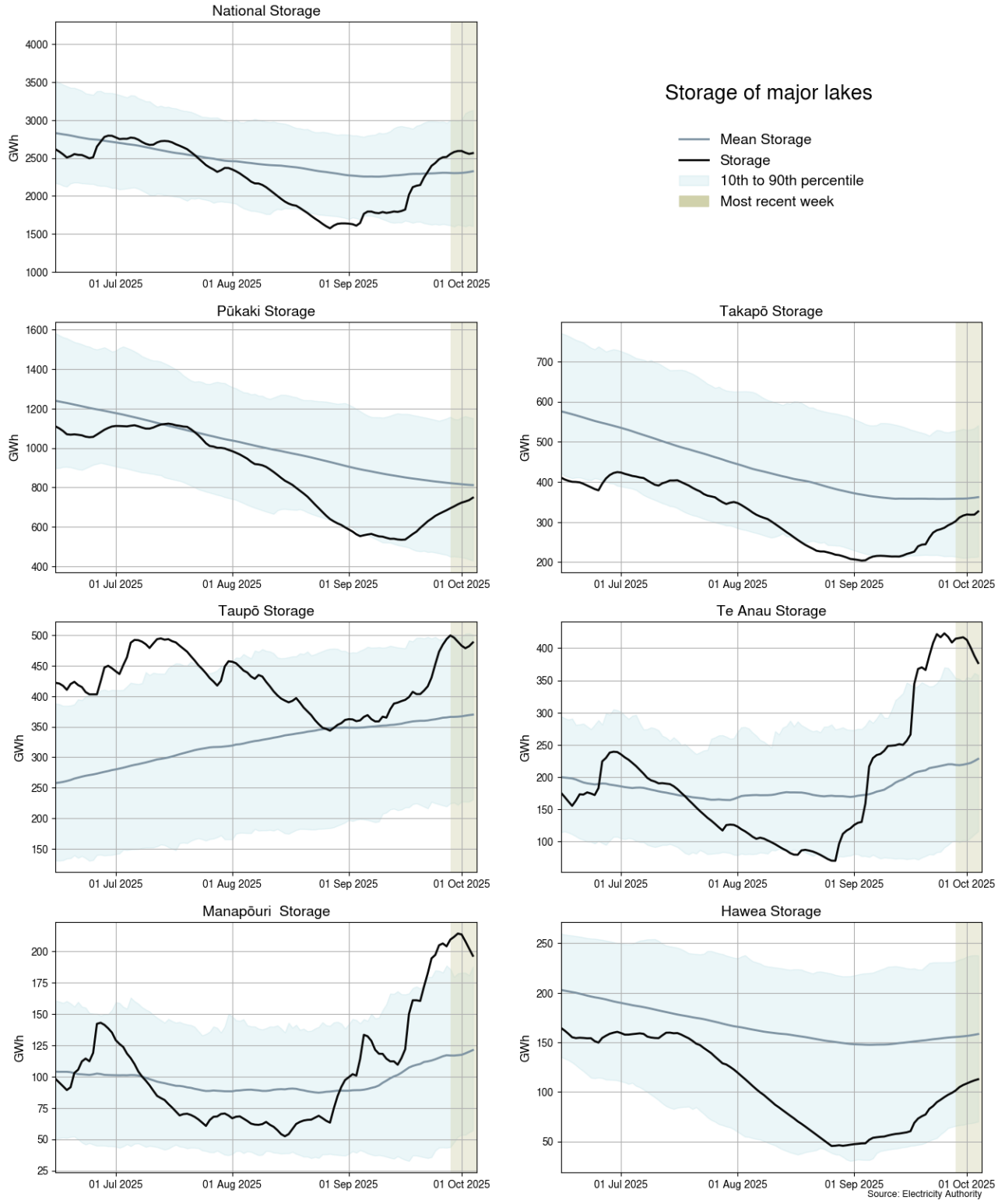
10.4. Storage at Lake Te Anau (140% full) and Lake Manapōuri (122% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (85% full) is touching its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (40% full) is between its historic mean and 10th percentile.

[3] Percentage full values sourced from NZX hydrological summary 5 October 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 October 2025 (excluding coal which was last updated on 1 August). The SRMCs for gas powered generation have decreased, while the SRMC for diesel fuelled generation has remained stable.

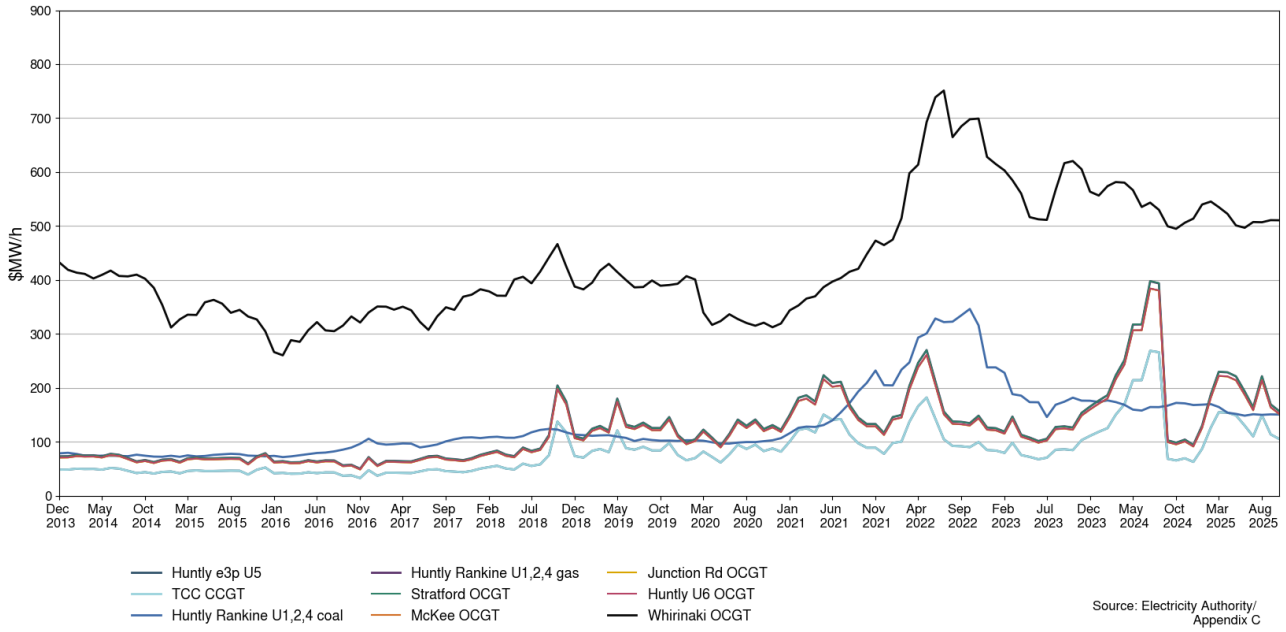
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$157/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $105/MWh and $157/MWh.

11.6. The SRMC of Whirinaki is ~$510/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.

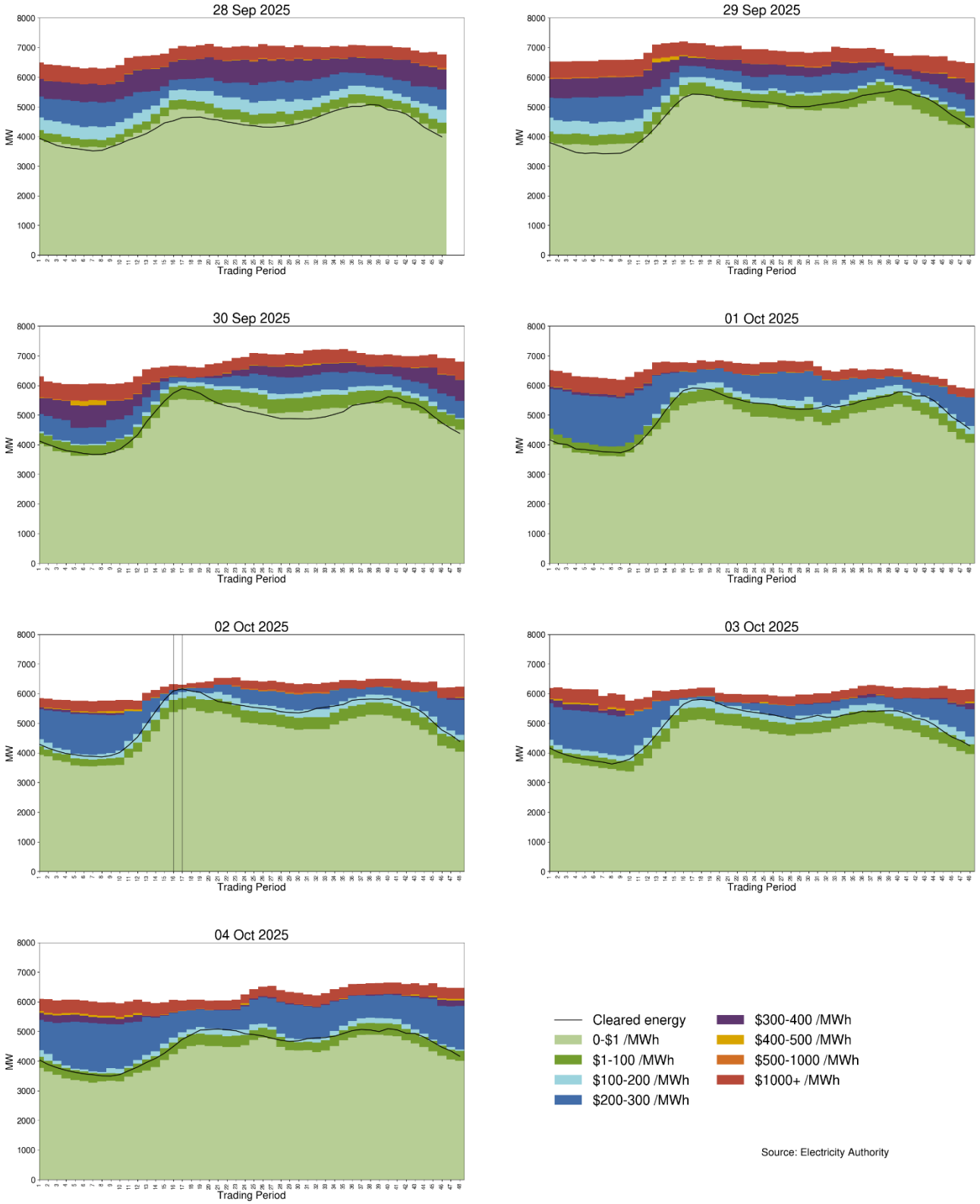
12.2. From Sunday to Tuesday this week, most offers cleared in the $0-$100/MWh range. From Wednesday onwards, most offers cleared in the $0-$200/MWh range. Due to wind and/or demand forecast errors, energy cleared into the next pricing band.

12.3. The stack from Wednesday became steeper with little generation priced between $300/MWh and $1,000/MWh.

12.4. On Thursday, during the spot price spike, the energy bands available beyond the $200-$300/MWh were very narrow. Therefore, price spiked into significantly higher bands.

12.5. A few hydro generation offers were priced down from Wednesday into the next lower tranche of $200-$300/MWh.

Figure 21: Daily offer stacks[4]



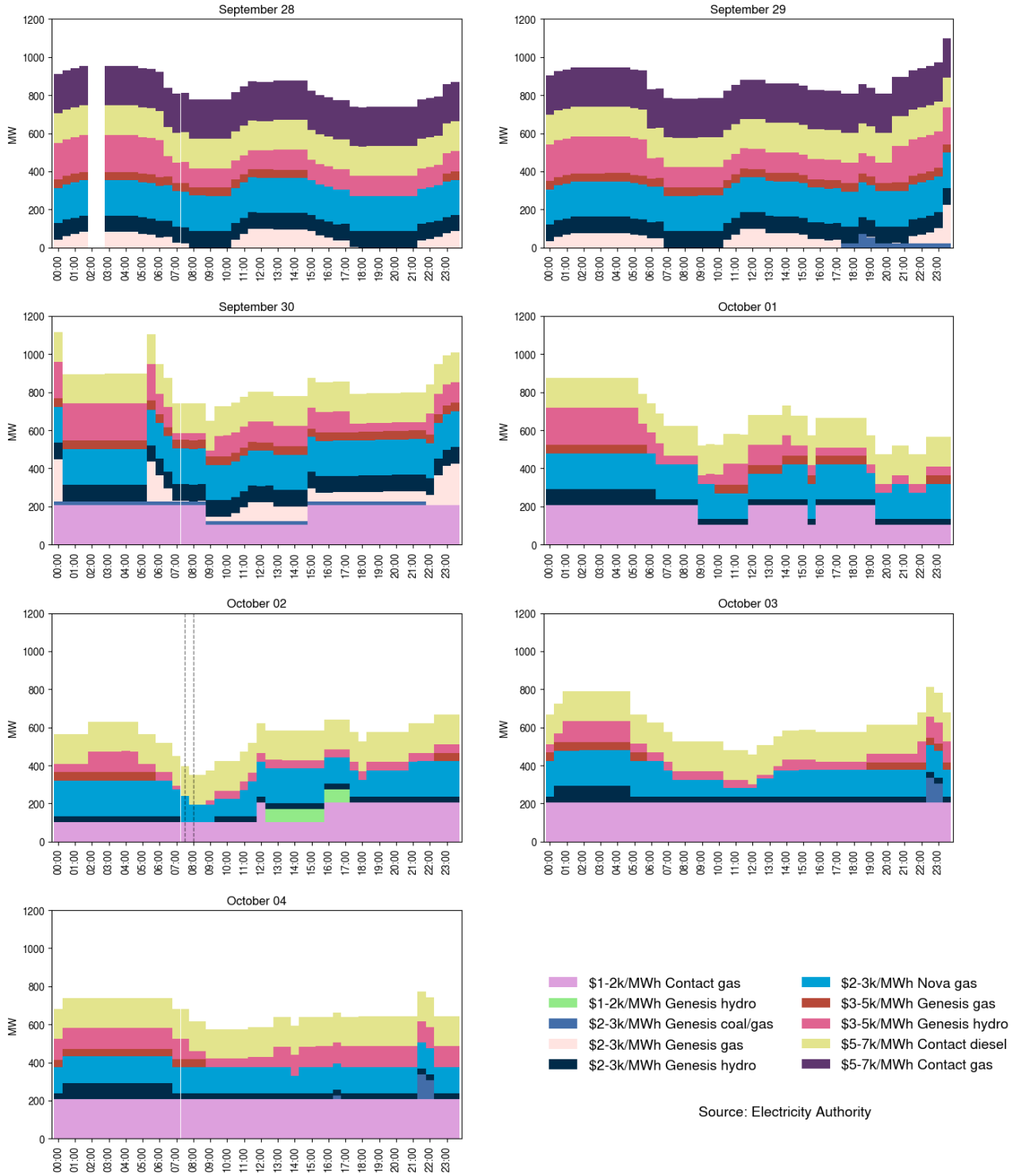
[4] Two trading periods are missing for 28 September 2025 due to the daylight-saving time transition

12.6. 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.

12.7. 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.

12.8. On average 723MW per trading period was priced above $1,000/MWh this week, which is roughly 13% of the total energy available.

Figure 22: High priced offers



13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. The monitoring is looking further into the pricing of Rankine generation from 1 October onwards.

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
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
21/09/2025-26/09/2025	Several	Further analysis	Genesis	Takapō	Offers
01/10/2025-04/-10/2025	Several	Further analysis	Genesis	Huntly	Offers