29 September 2025

Trading conduct report 21-27 September 2025

Market monitoring weekly report

Trading conduct report 21-27 September 2025

1. Overview

1.1. This week the average spot price decreased by \$87/MWh to \$35/MWh. Spot prices decreased likely due to an increase in hydro storage, high wind generation, and decreased demand due to mild temperatures. Wind generation was relatively high this week, while thermal generation decreased. National hydro storage increased to 62% nominally full and around 105% 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 21-27 September 2025:

(a) The average spot price for the week was \$35/MWh, a decrease of around \$87/MWh compared to the previous week.

(b) 95% of prices fell between \$0.02/MWh and \$163/MWh.

2.3. Spot prices were low and volatile throughout the week. Between Sunday and Wednesday, low overnight prices were observed. From Thursday onward, spot prices remained low.

2.4. On Monday morning, high prices were observed between 6.30am-7.00am, and 9.30am-10.00am. Prices ranged between \$173-\$190/MWh at Ōtāhuhu, and \$151-\$163/MWh at Benmore. Between 6.30am-7.00am, demand was 133MW-173MW higher than forecast, and wind was 89MW-97MW lower than forecast. Between 9.30am-10.00am period, HVDC pole 3[1] was on outage.

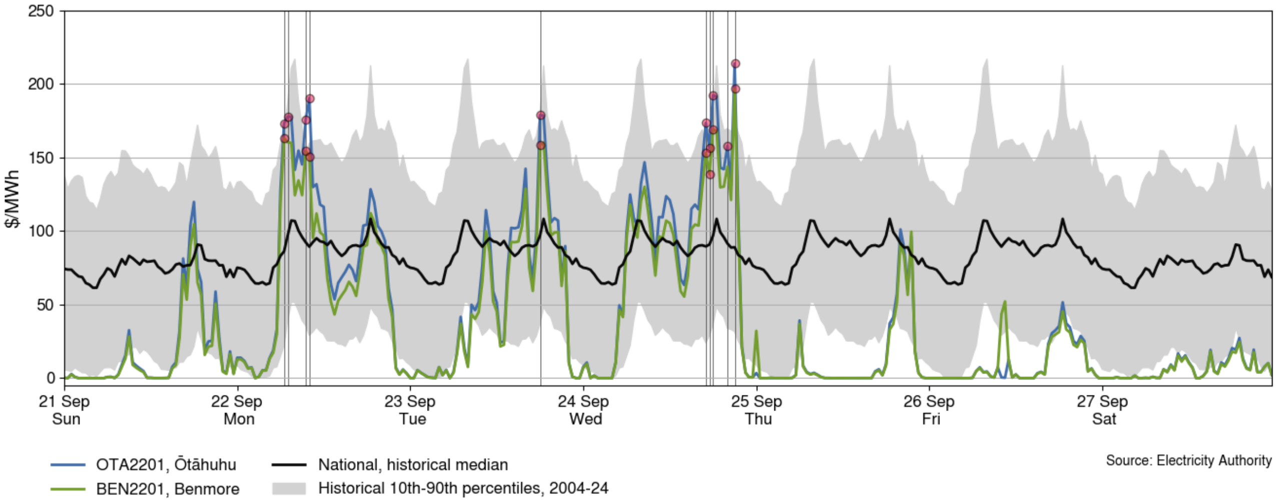
2.5. On Tuesday at 6.00pm, prices reached \$179/MWh at Ōtāhuhu and \$159/MWh at Benmore. At that time, demand was 145 above forecast and wind was 82MW below forecast.

2.6. On Wednesday evening, between 5.00pm and 9.00pm, higher prices were again observed. Prices ranged between \$157-\$214/MWh at Ōtāhuhu, and \$139-\$197/MWh at Benmore. During these high price spike periods, demand was 17MW-98MW higher than forecast, and wind was 31MW-63MW lower than forecast.

2.7. 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.

[1] CAN Planned Outage HVDC Pole 3, HVDC Cable 6 6675471114.pdf

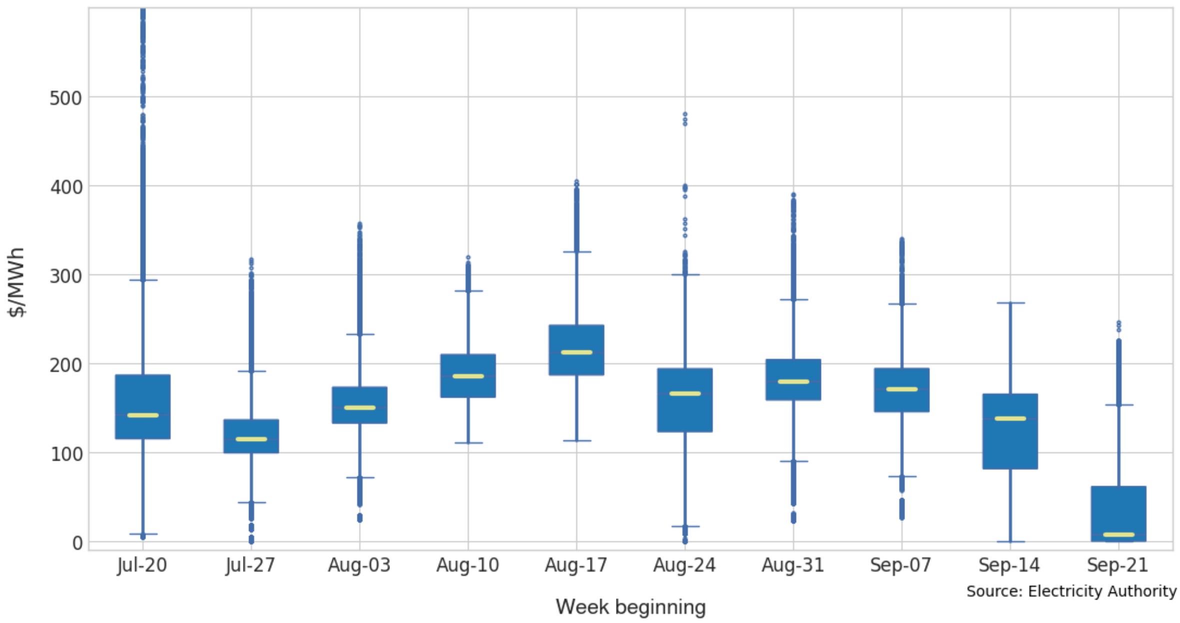
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 21-27 September 2025



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 was narrower than last week. The median price was $7/MWh and most prices (middle 50%) fell between $0.20/MWh and $61/MWh.

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



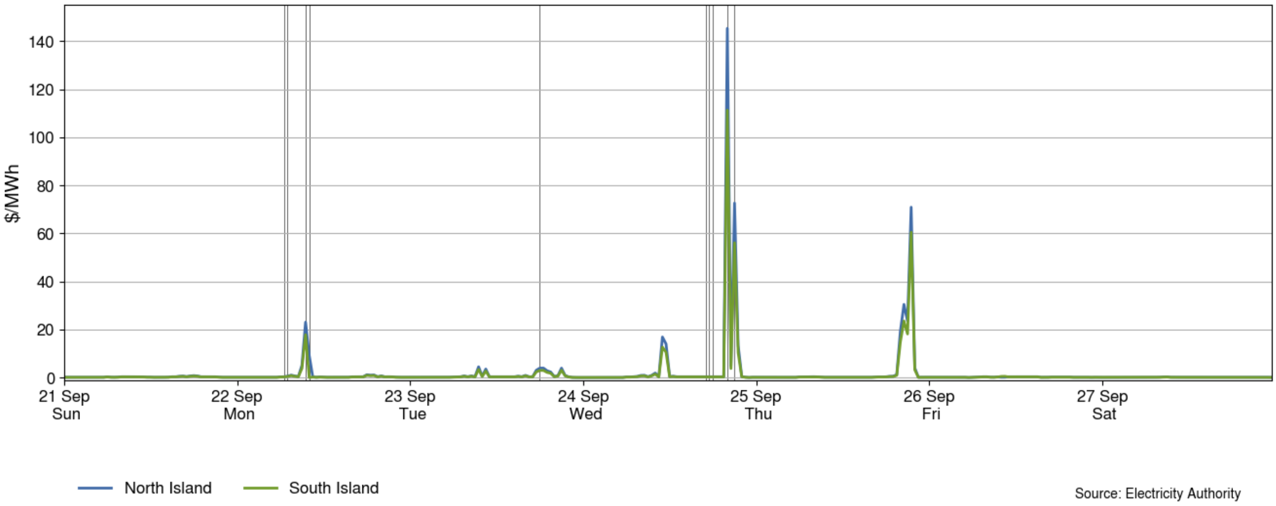
3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were below $5/MWh with a few price spikes.

3.2. A significant FIR price spike occurred on Wednesday at 8.00pm, with prices reaching around $145/MWh in the North Island and $111/MW in the South Island. At 9.00pm another spike occurred with prices around 73/MWh in the North Island and $56/MW in the South Island. During that time the Ruakākā battery was not offering FIR.

3.3. Another significant price spike occurred on Thursday at 9.30pm, with prices reaching around $71/MWh in the North Island and $60/MW in the South Island.

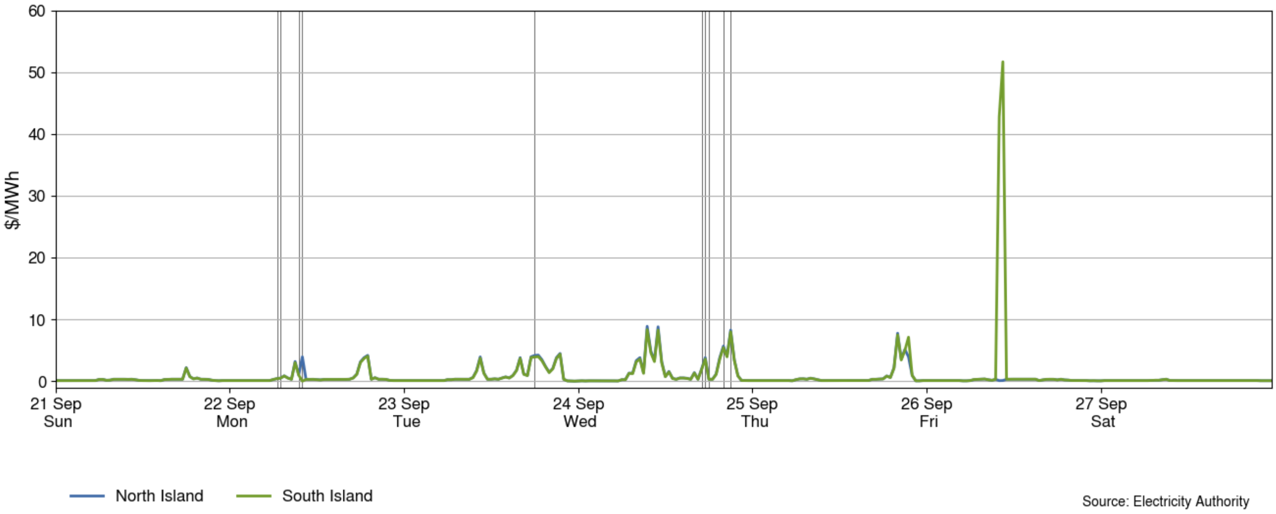
Figure 3: Fast instantaneous reserve price by trading period and island, 21-27 September 2025



3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were below $10/MWh, except on Thursday.

3.5. On Thursday, at 10.00am and 10.30am SIR prices in the South Island reached around $43/MWh and $52/MWh, respectively, while SIR prices in the North Island remained around $0.10/MWh. During this period, HVDC pole 3 was on planned outage, which disabled round power[2] and limited the ability of the HVDC to share reserve from the North to the South Island. More expensive South Island reserve was hence dispatched to cover the risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 21-27 September 2025



[2] Round power is the ability to operate each pole of the HVDC link in opposite directions. This will circulate power through each pole without necessarily providing a net power transfer between the islands.

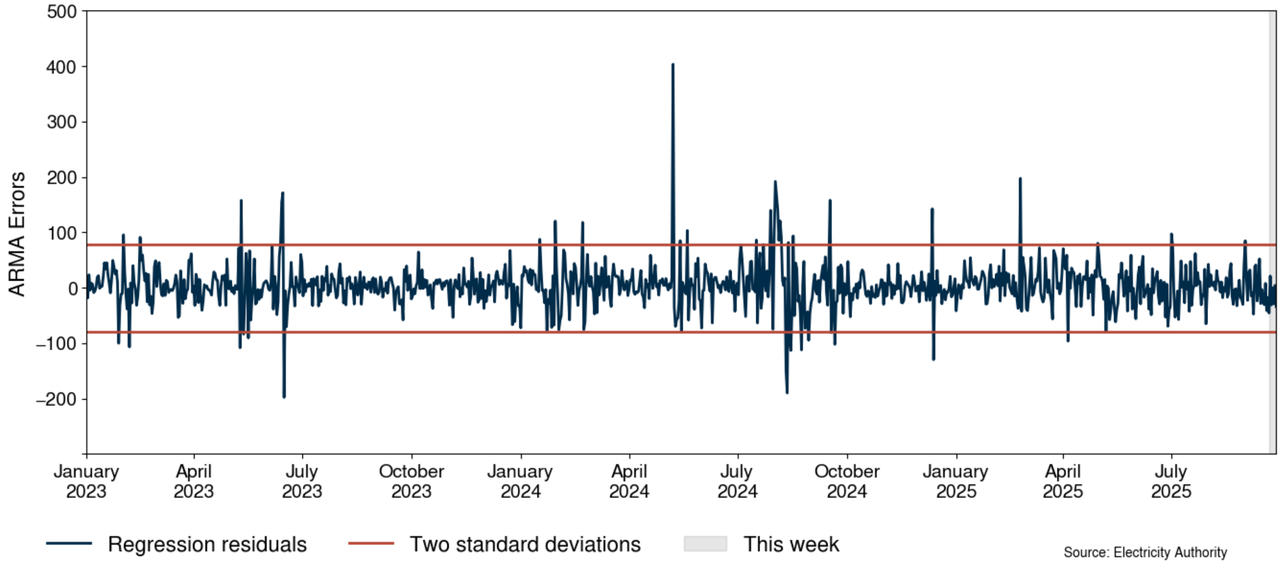
4. Regression residuals

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 - 27 September 2025

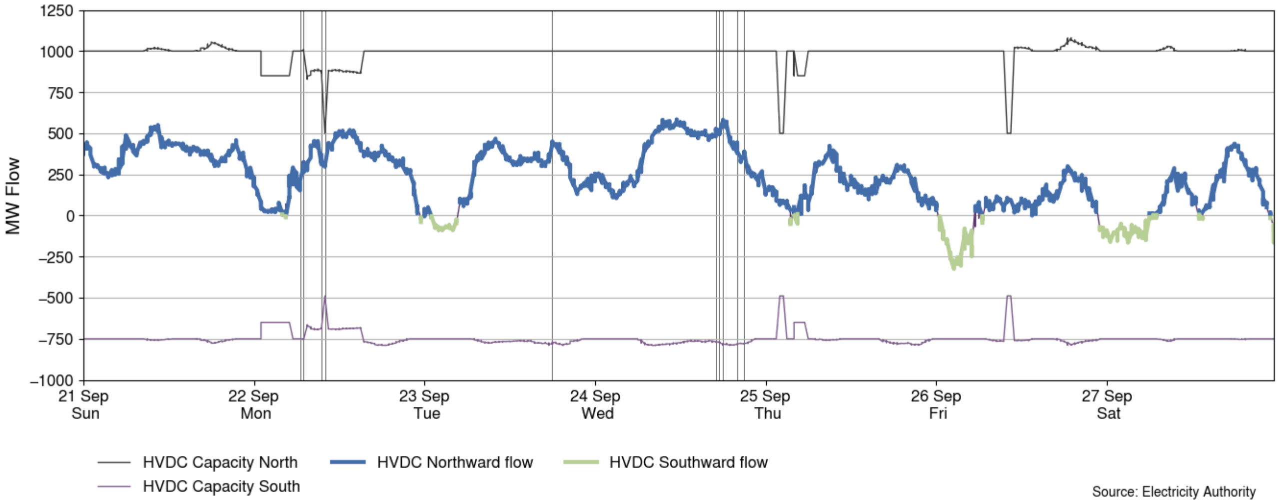


5. HVDC

5.1. Figure 6 shows the HVDC flow between 21-27 September 2025. HVDC flows were mostly northward with a small southward flow. Northward flows reached around 583MW on Wednesday at 11.30am. The HVDC pole 3 was on planned outage on Monday between 10.00am-10.30am[3], Thursday 1.53am-3.00am[4], and on Friday between 10.00am-11.00am, which limited the HVDC's maximum transfer capacity.

[3] CAN Planned Outage HVDC Pole 3, HVDC Cable 6 6675471114.pdf
[4] CAN Unplanned Outage HVDC Pole 3 6671823366.pdf

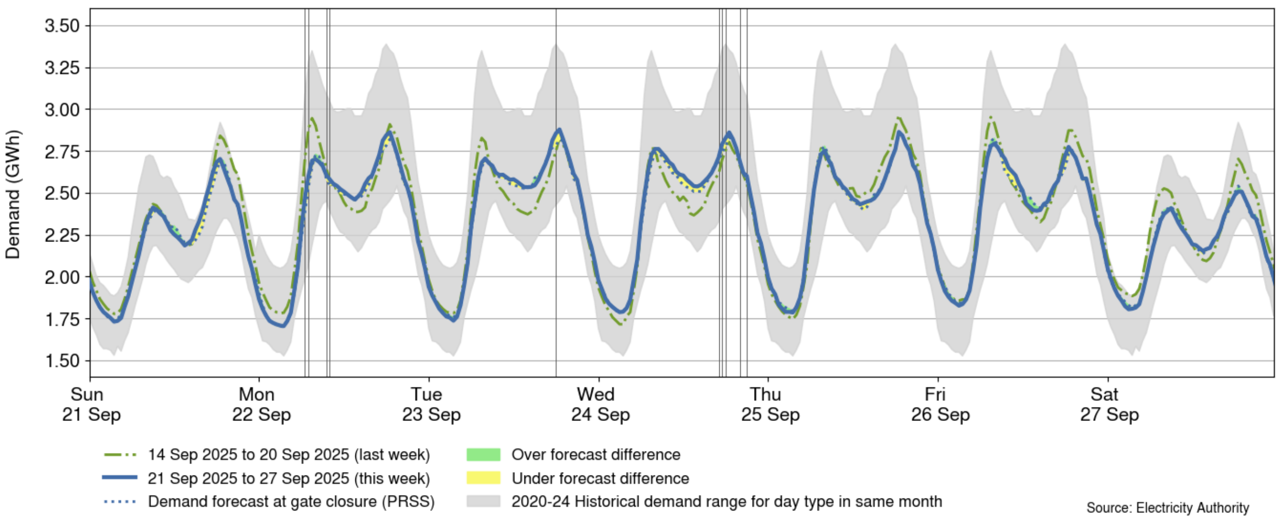
Figure 6: HVDC flow and capacity, 21-27 September 2025



6. Demand

6.1. Figure 7 shows national demand between 21-27 September 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 2.88GWh at 6.30pm on Tuesday during the evening peak.

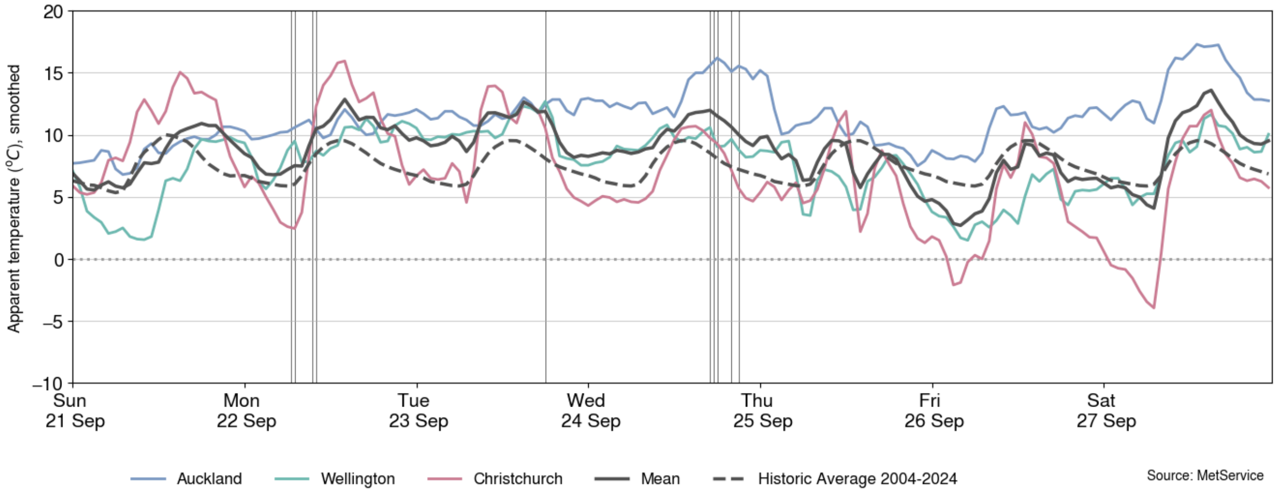
Figure 7: National demand, 21-27 September 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 21-27 September 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 18°C in Auckland, 1°C to 13°C in Wellington, and -4°C to 17°C in Christchurch.

Figure 8: Temperatures across main centres, 21-27 September 2025

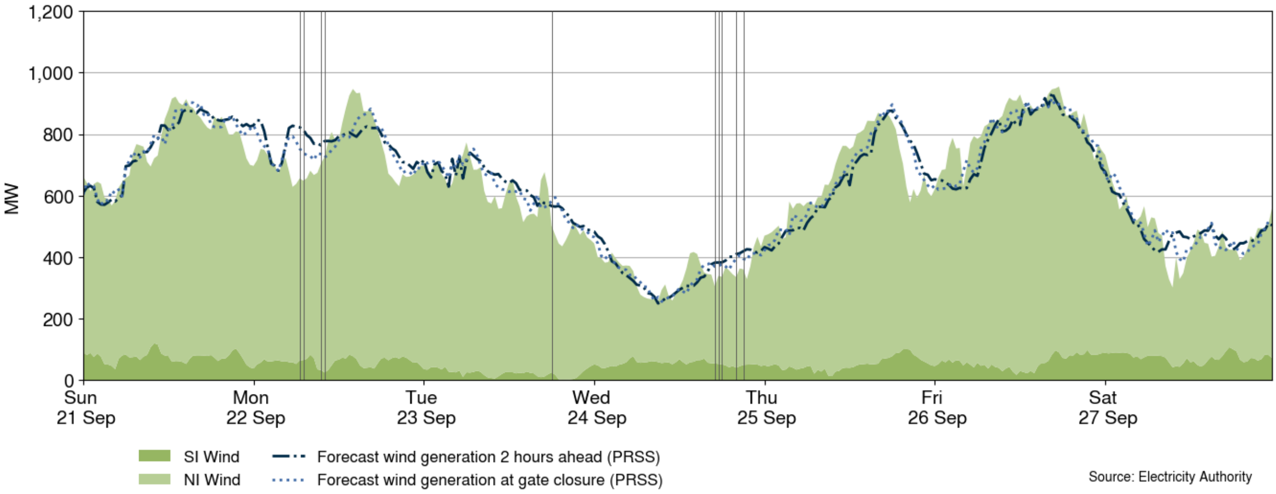


7. Generation

7.1. Figure 9 shows wind generation and forecast from 21-27 September 2025. This week wind generation varied between 257MW and 954MW, with a weekly average of 630MW.

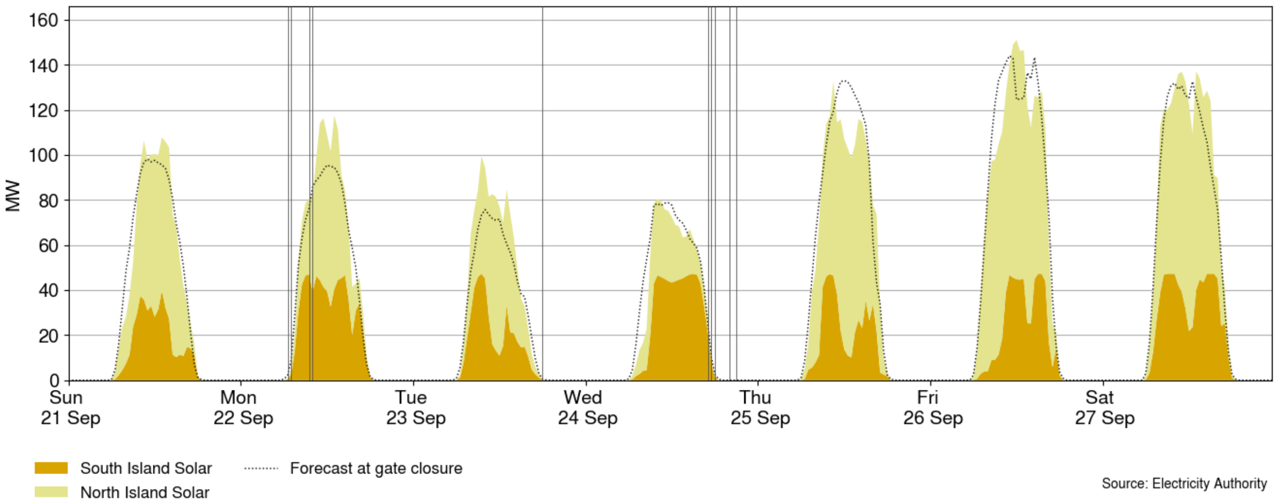
7.2. Wind generation remained mostly high through Sunday and Monday. It began to decline gradually from Tuesday and was low on Wednesday. From Wednesday morning, wind generation increased steadily. Wind was high between Thursday and Friday, then declined again on Saturday.

Figure 9: Wind generation and forecast, 21-27 September 2025



7.3. Figure 10 shows grid connected solar generation from 21-27 September 2025. Solar generation was low at the start of the week and high between Thursday and Saturday. Solar generation peaked at a maximum of around 150MW on Friday at 12.00pm.

Figure 10: Grid connected solar generation, 21-27 September 2025

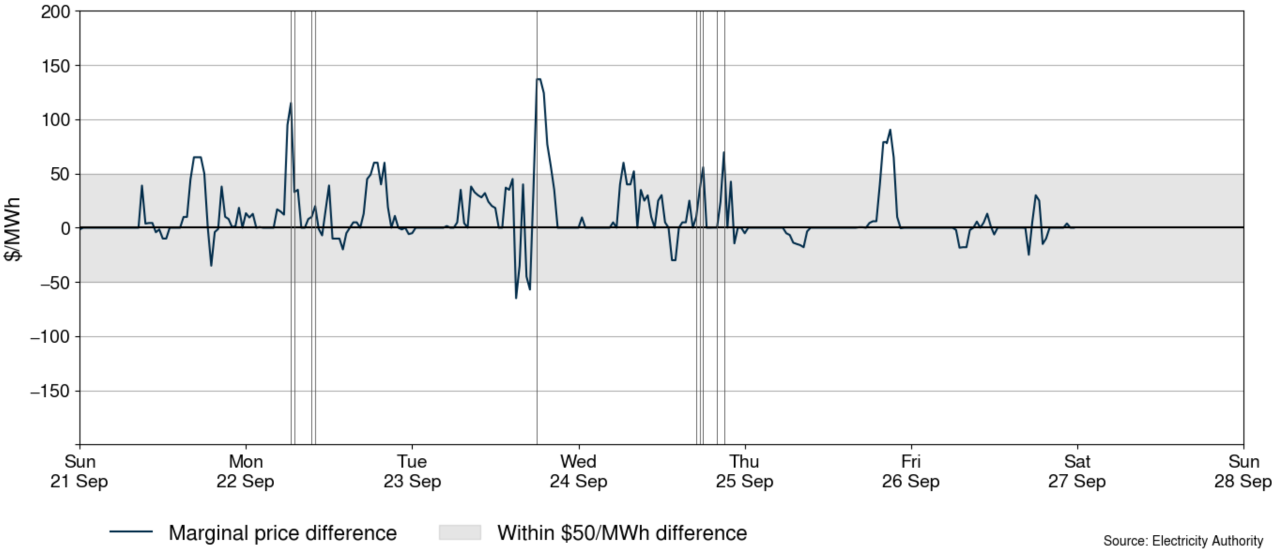


7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[5]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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. A few trading periods this week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$137/MWh occurred at 6.00pm on Tuesday during the spot price spike, when demand was 145MW higher than forecast, and wind was 82MW lower than forecast.

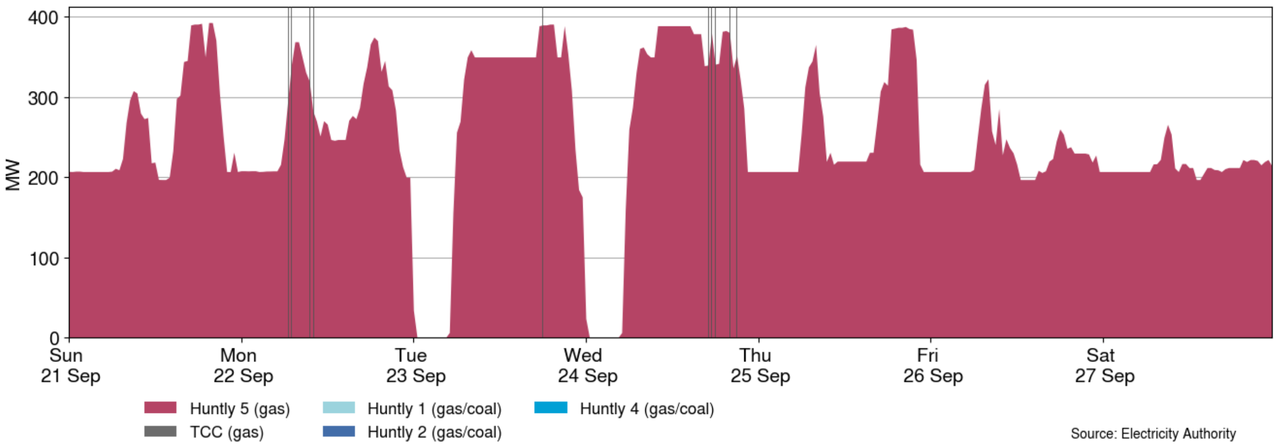
[5] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 21-27 September 2025



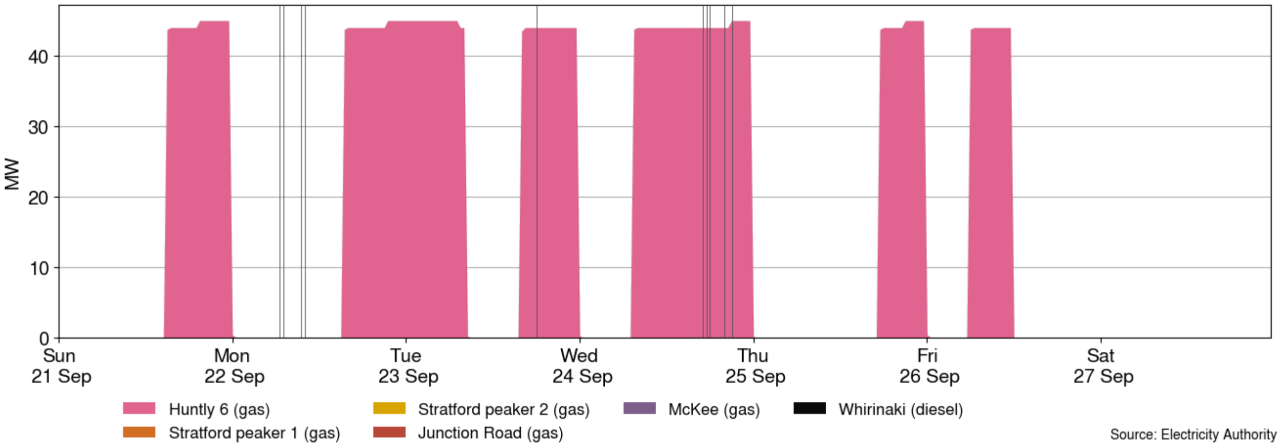
7.6. Figure 12 shows the generation of thermal baseload between 21-27 September 2025. Huntly 5 ran as baseload throughout the week, except on Tuesday and Wednesday nights.

Figure 12: Thermal baseload generation, 21-27 September 2025



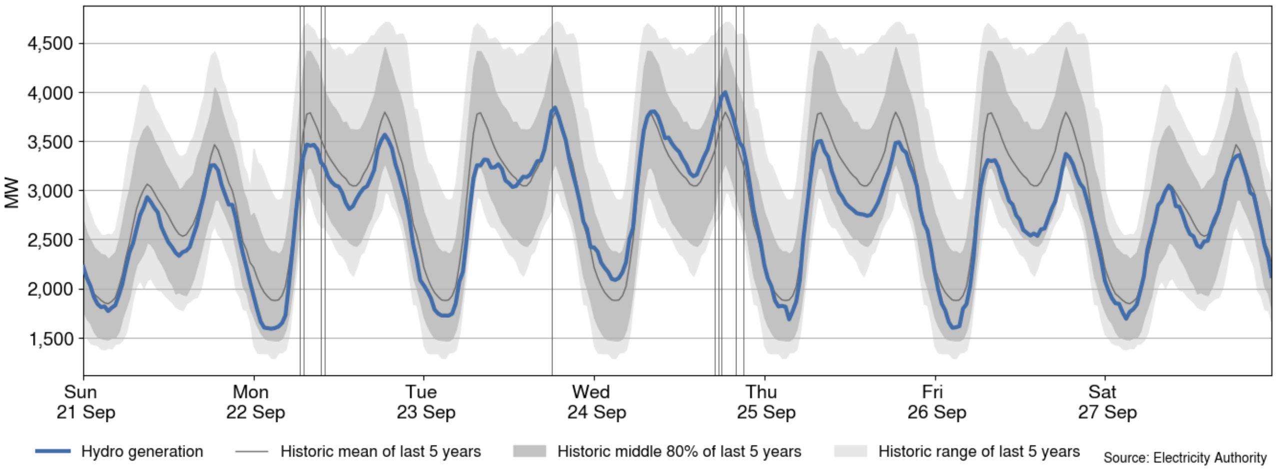
7.7. Figure 13 shows the generation of thermal peaker plants between 21-27 September 2025. Huntly 6 ran daily this week, except on Saturday.

Figure 13: Thermal peaker generation, 21-27 September 2025



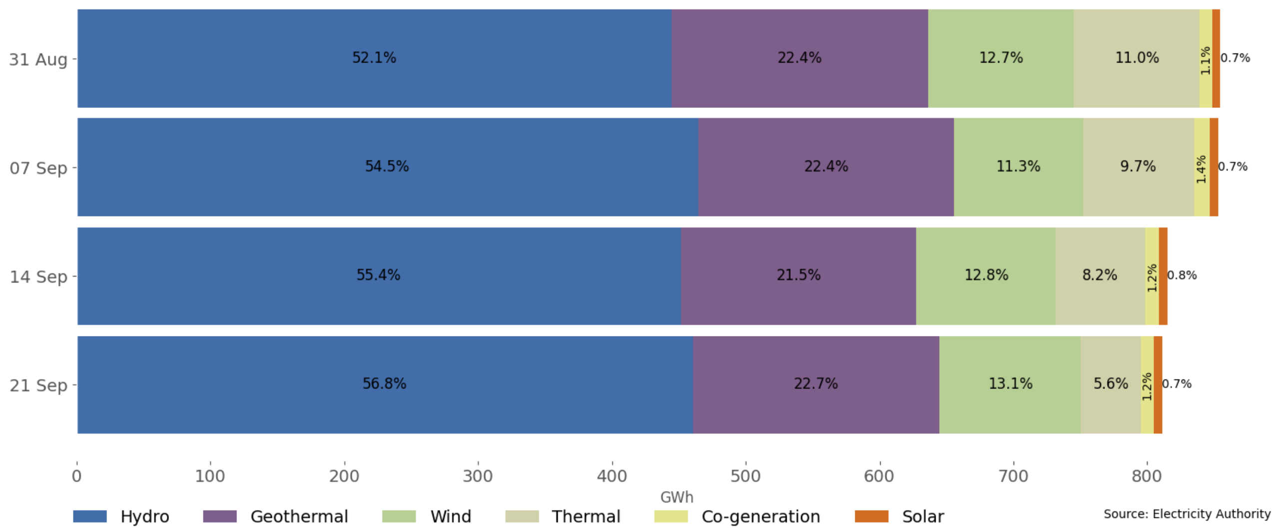
7.8. Figure 14 shows hydro generation between 21-27 September 2025. Hydro generation remained mostly below the historic average, except on Wednesday, when low wind generation led to increased hydro generation. On Saturday, hydro generation was close to the historic average.

Figure 14: Hydro generation, 21-27 September 2025



7.9. As a percentage of total generation, between 21-27 September 2025, total weekly hydro generation was 56.8%, geothermal 22.7%, wind 13.1%, thermal 5.6%, co-generation 1.2%, and solar (grid connected) 0.7%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 31 August and 27 September 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 21-27 September 2025 ranged between ~1,135MW and ~1,926MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 was on outage between 19-21 September 2025.

(b) Huntly 4 is on outage until 11 October 2025.

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

(d) Geothermal Te Mihi was on outage until 22 September 2025.

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

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

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

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

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

(j) A few small hydro stations were on planned outages.

Figure 16: Total MW loss from generation outages, 21-27 September 2025

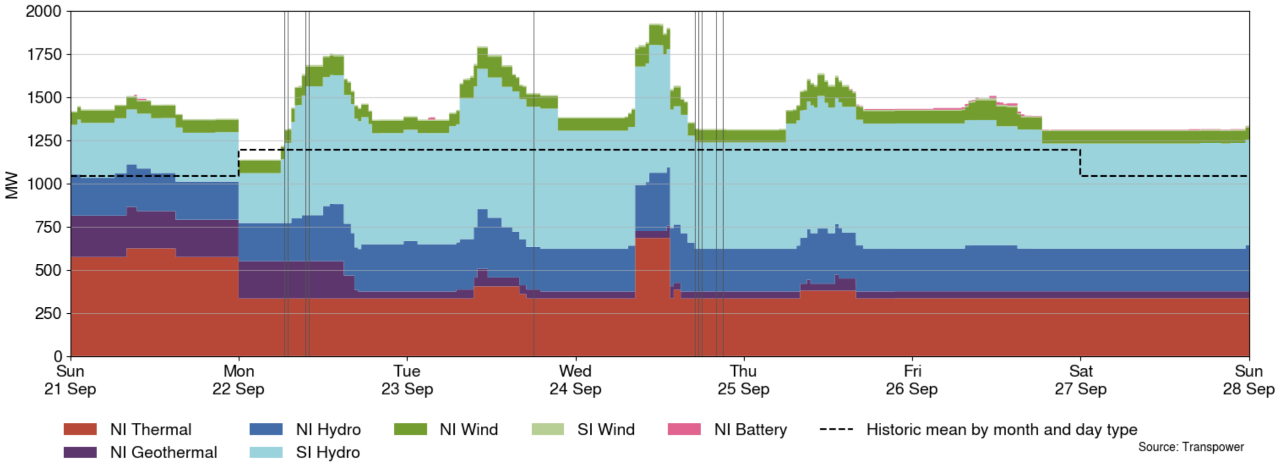
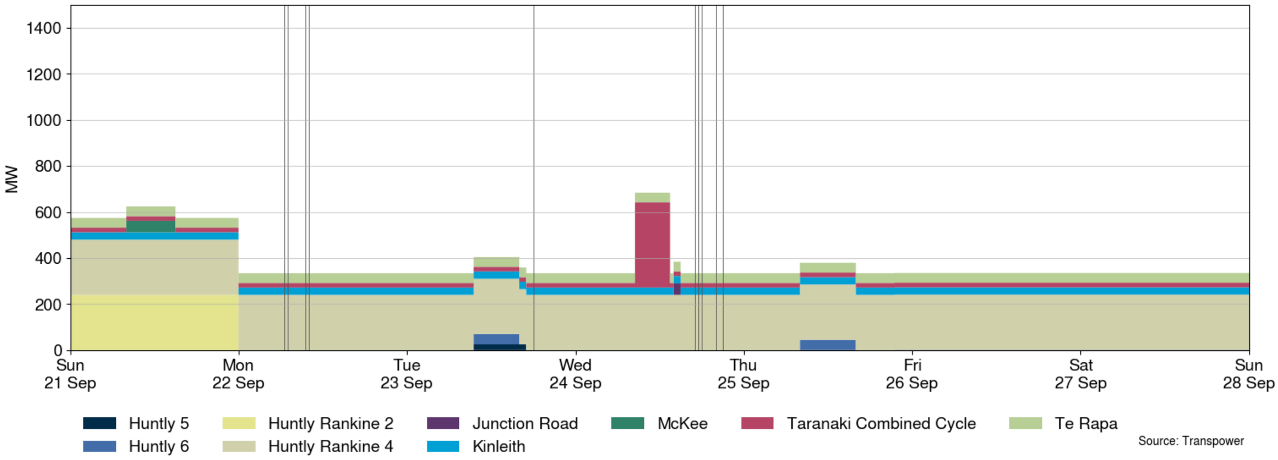


Figure 17: Total MW loss from thermal outages, 21-27 September 2025

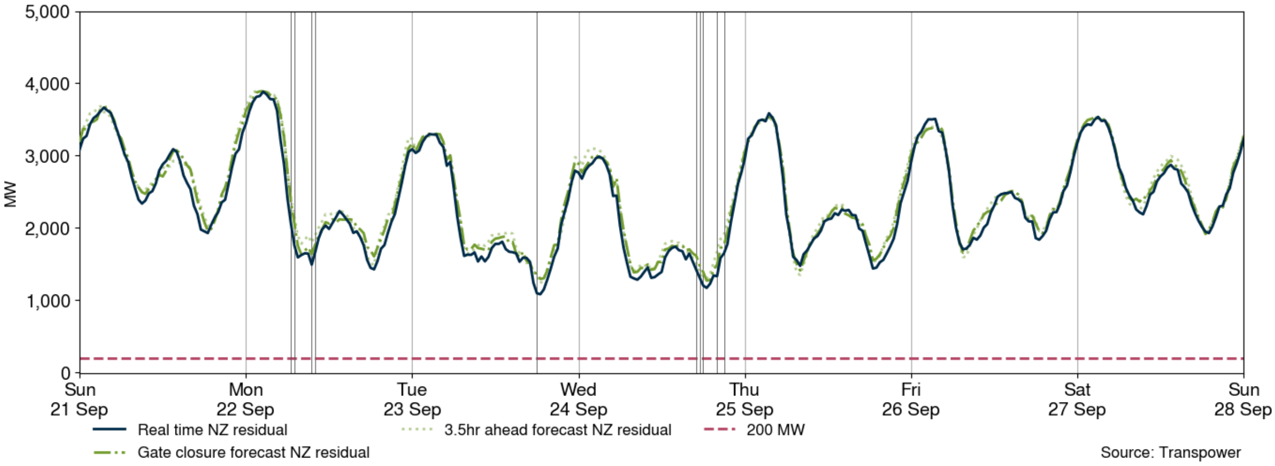


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 21-27 September 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 1,083MW on Tuesday at 6.30pm.

Figure 18: National generation balance residuals, 21-27 September 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 27 September 2025, national controlled hydro storage had increased to 62% of nominal full and ~105% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (40% full[6]) and Lake Takapō (39% full) is between their respective historic mean and 10th percentiles.

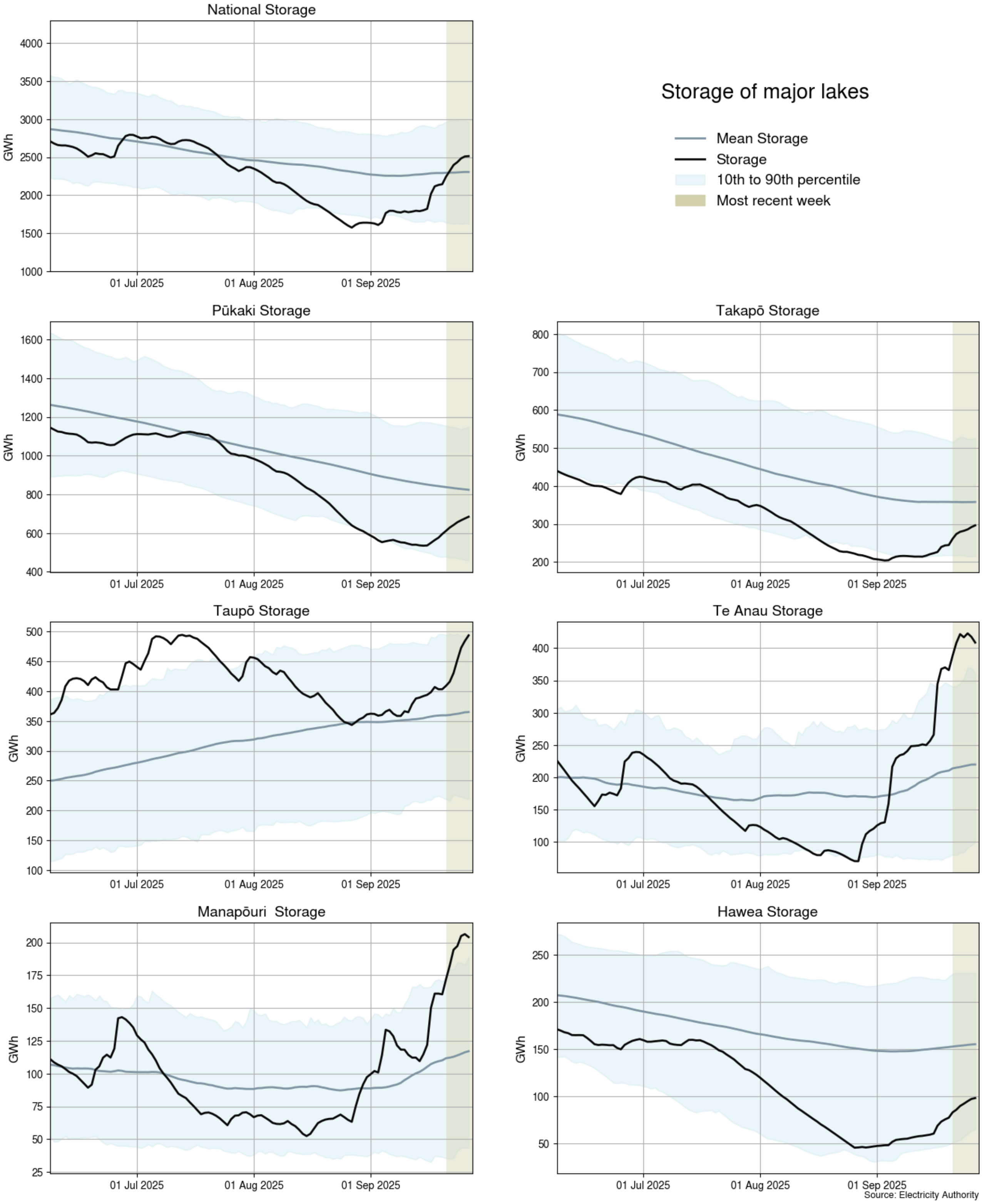
10.4. Storage at Lake Te Anau (156% full) and Lake Manapōuri (133% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (87% full) is touching its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (35% full) is below its historic mean.

[6] Percentage full values sourced from NZX hydrological summary 28 September 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 August 2025. The SRMCs for gas powered generation have increased, while the SRMC for diesel fuelled generation has remained stable.

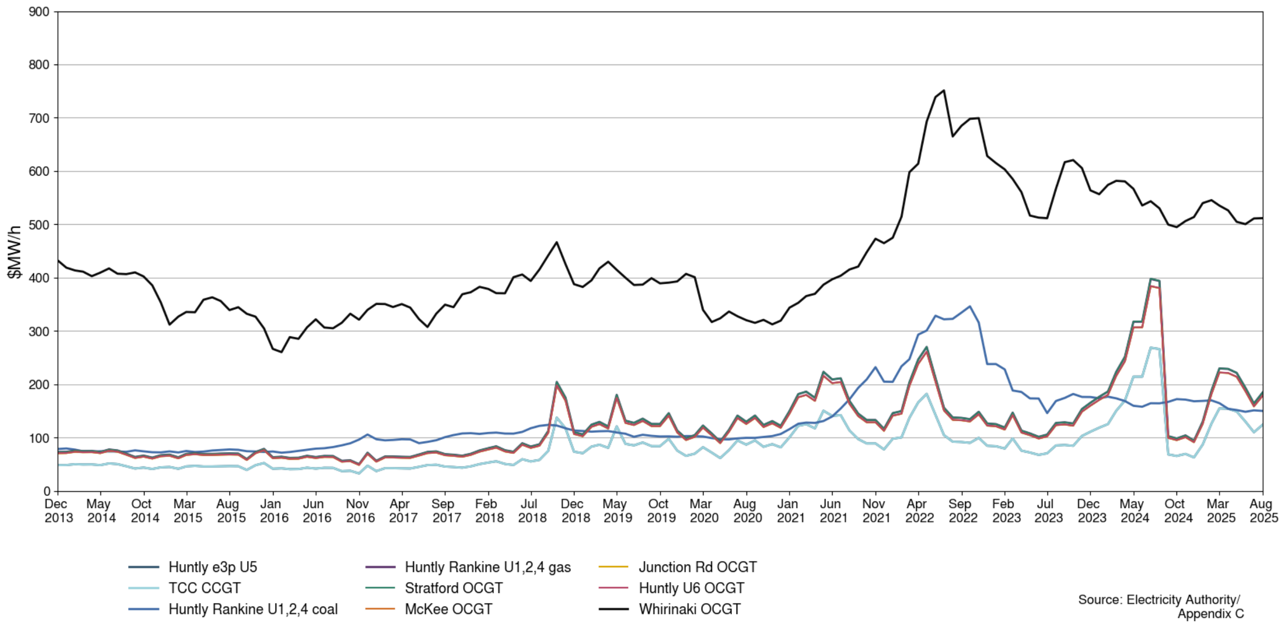
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $124/MWh and $184/MWh.

11.6. The SRMC of Whirinaki is ~$512/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

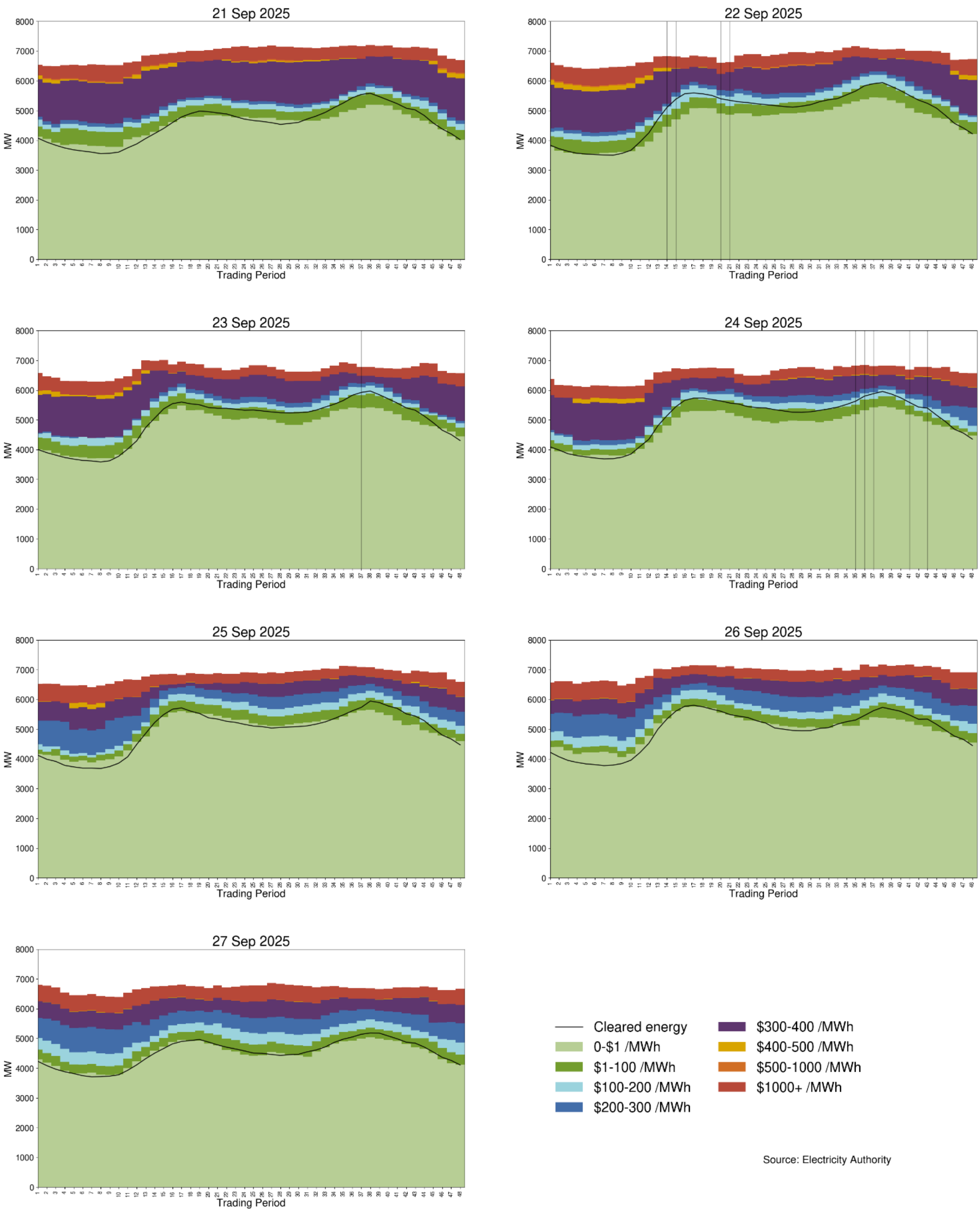


12. Offer behaviour

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 $0-$200/MWh range. Due to wind and/or demand forecast errors, energy cleared into the next band. A few hydro generation offers were priced down from Thursday in the next lower tranche of $200-$300/MWh, as hydro storage increased.

Figure 21: Daily offer stacks

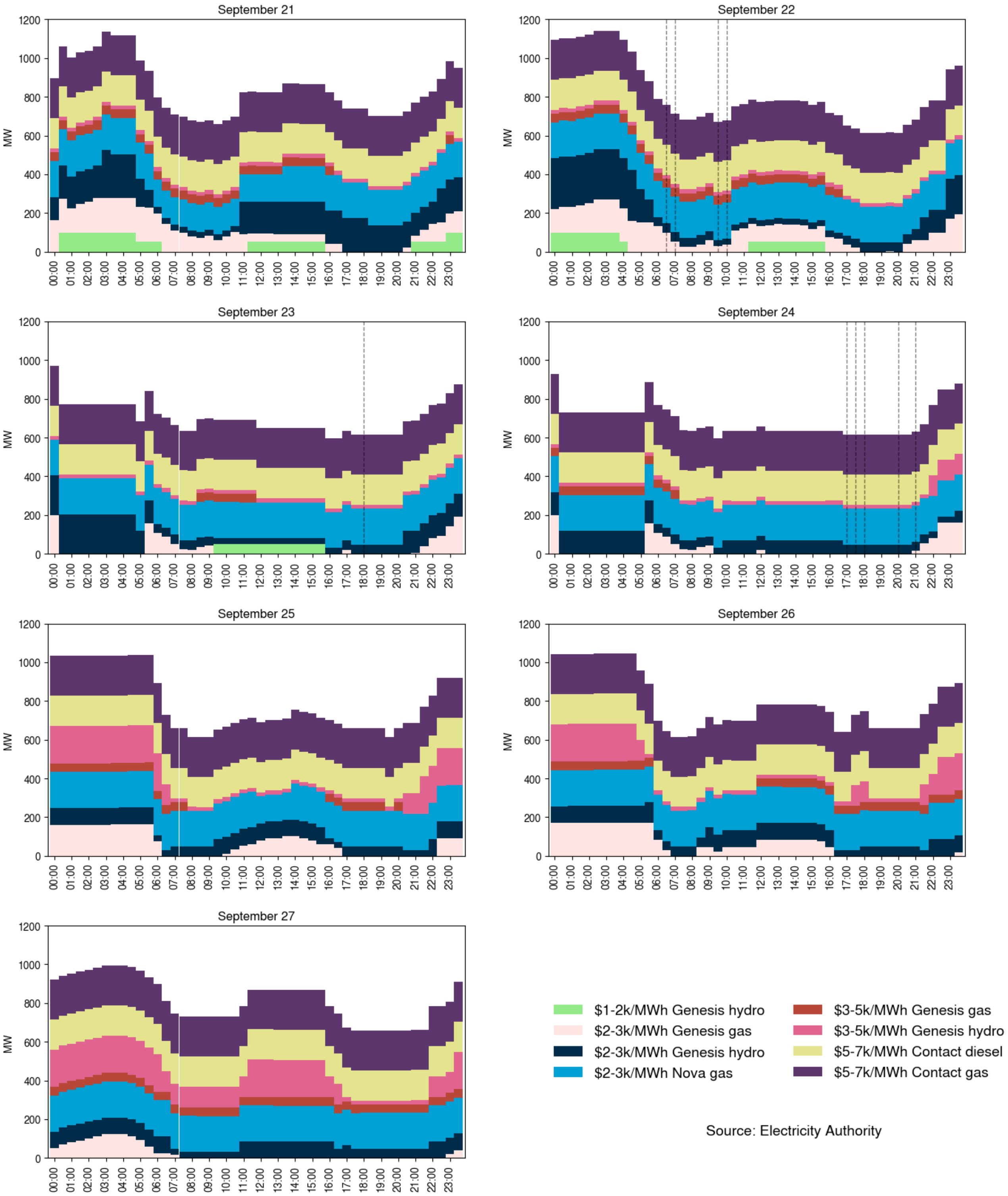


12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 the 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 779MW per trading period was priced above $1,000/MWh this week, which is roughly 14% 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. We are looking further into offers at Takapō from 21-26 September.

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