8 September 2025

Trading conduct report
31 August – 6 September 2025

Market monitoring weekly report

Trading conduct report 31 August – 6 September 2025

1. Overview

1.1. The average price increased by $26/MWh this week to $181/MWh. Demand was low due to mild temperatures. Wind generation was high, accounting for around 12.7% of total generation. Southward HVDC flow was high. TCC turned off this week. National hydro storage slightly increased to 48% nominally full and around 83% 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 31 August – 6 September 2025:

(a) The average spot price for the week was $181/MWh, an increase of around $26/MWh compared to the previous week.

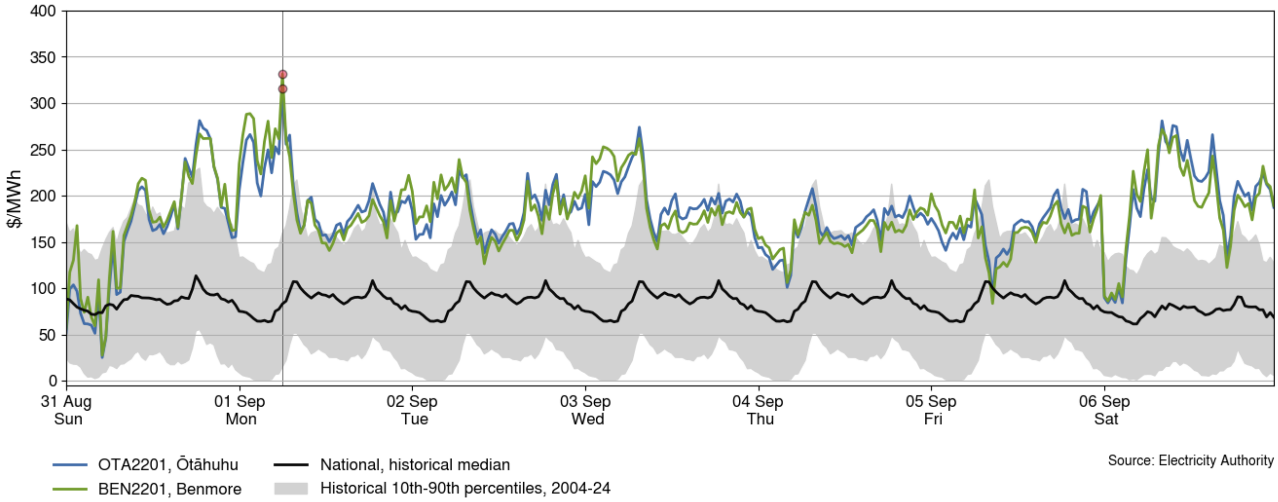
(b) 95% of prices fell between $83/MWh and $274/MWh.

2.3. Spot prices hovered between $150-$200/MWh. The highest price of the week occurred on Monday morning at 6.00am, with prices reaching around $316/MWh at Ōtāhuhu and ~$332/MWh at Benmore. During that time, demand was higher than forecast by 90MW, and wind was underestimated by 124MW.

2.4. Between Sunday and Wednesday prices were generally higher overnight than during the day. During these days, there was high North Island wind generation and high overnight HVDC transfer southwards, which allowed South Island hydro to turn down and further conserve hydro storage. Additionally on Sunday night and early Monday morning, wind generation was lower than forecast, with periods where the 1 hour ahead and real time forecast difference was 197MW.

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, are highlighted with a vertical black line.

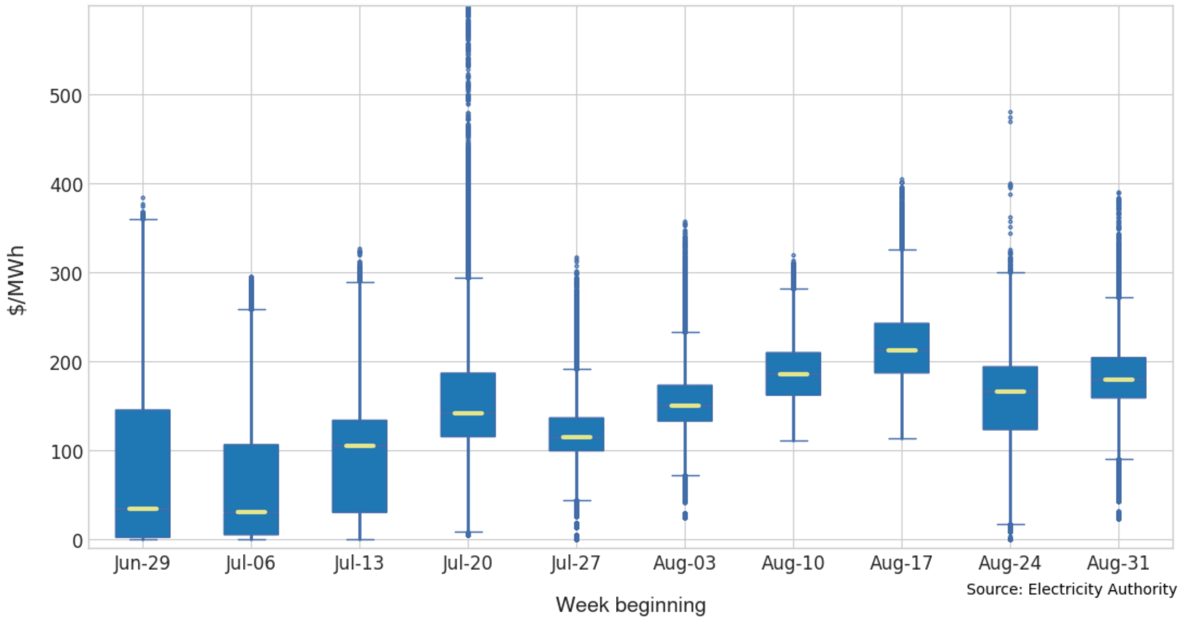
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 31 August – 6 September 2025



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 narrower than last week, with no significant high-priced outliers. The median price was $179/MWh and most prices (middle 50%) fell between $159/MWh and $204/MWh.

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

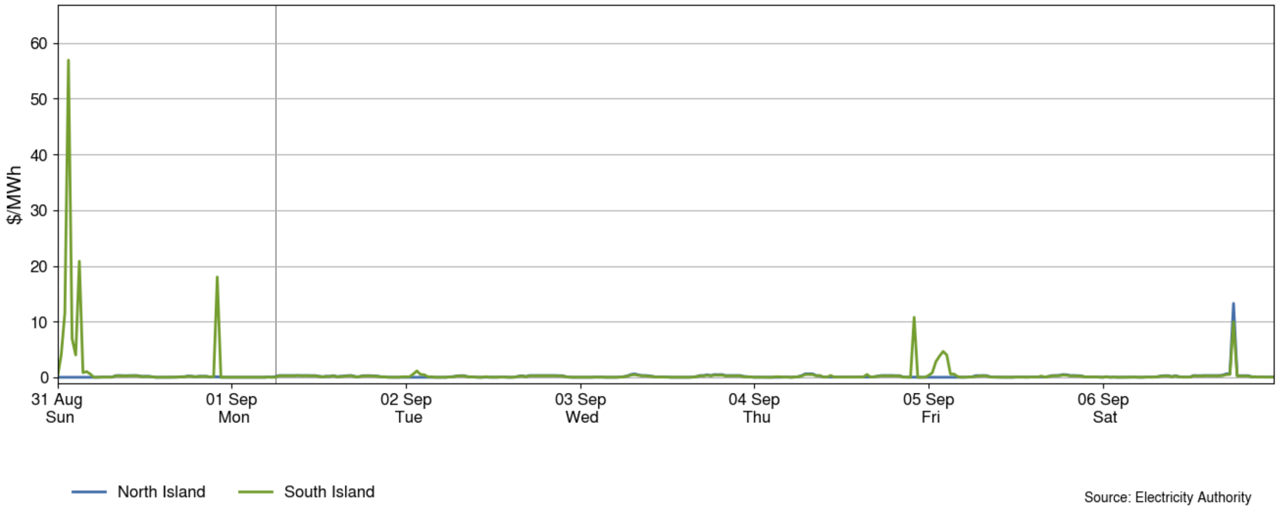


3. Reserve prices

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 price spikes on Sunday for the South Island.

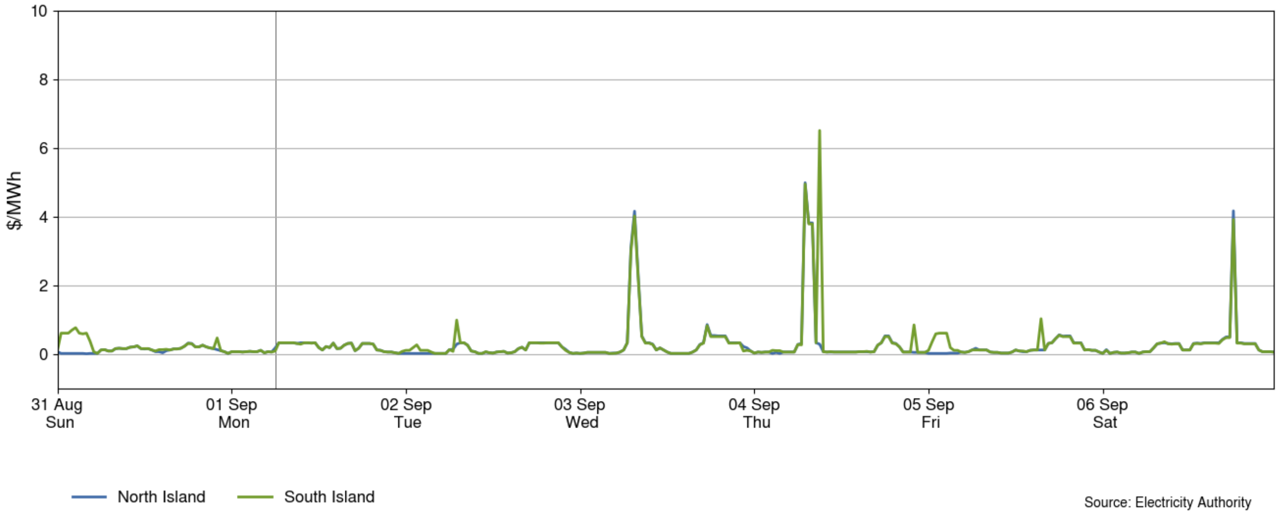
3.2. A significant FIR price spike occurred on Sunday at 1.30am, with prices reaching around $57/MWh in the South Island, while prices in the North Island remained at $0/MWh. During that time, HVDC was setting the South Island risk, with a southward flow of around 570MW.

Figure 3: Fast instantaneous reserve price by trading period and island, 31 August – 6 September 2025



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. This week, SIR prices across both the North and South Island were below $10/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 31 August – 6 September 2025



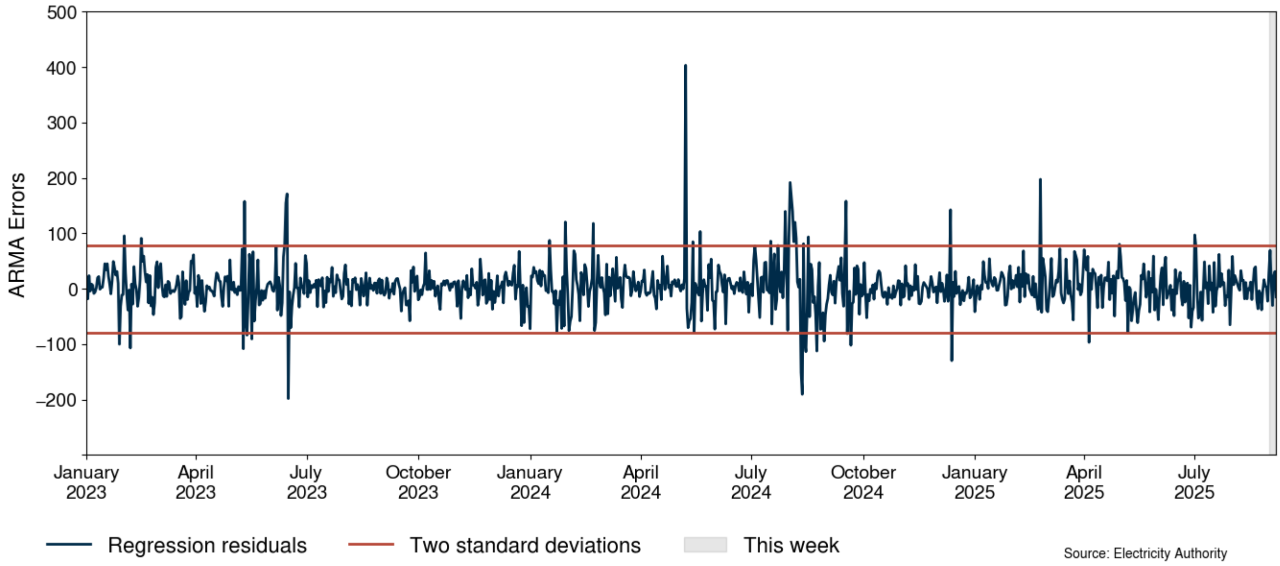
4. Regression residuals

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 – 6 September 2025

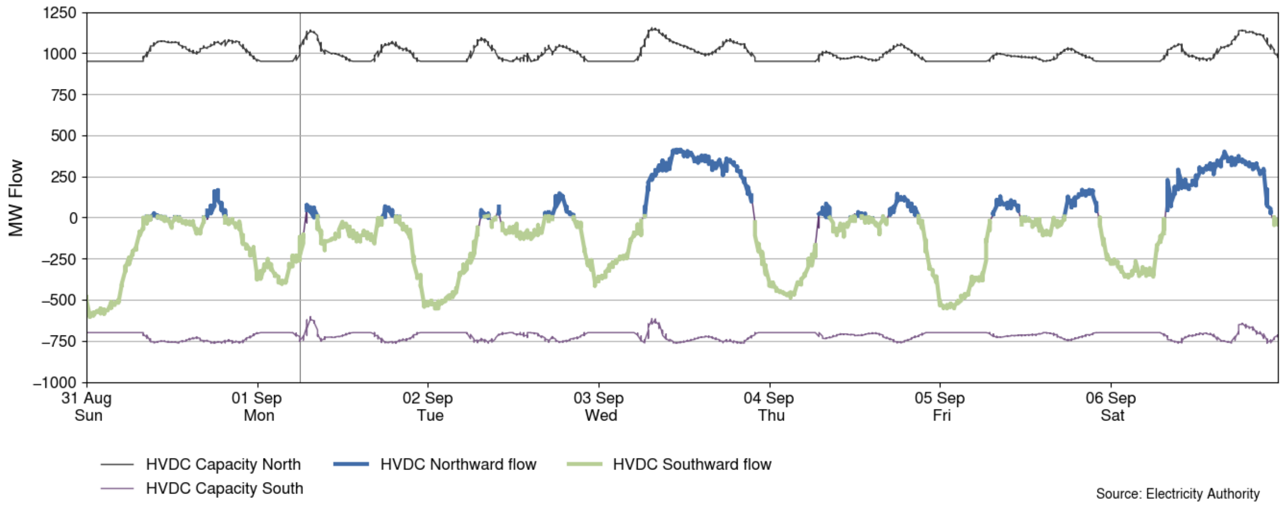


5. HVDC

5.1. Figure 6 shows the HVDC flow between 31 August – 6 September 2025. Northward flow was reduced, likely due to declining hydro storage. On Wednesday, maximum of 413MW northward flow when North Island wind generation was low.

5.2. This week, southward flow was high due to high wind generation. Southward flows reached a maximum of 605MW around midnight on Sunday, when North Island wind was high.

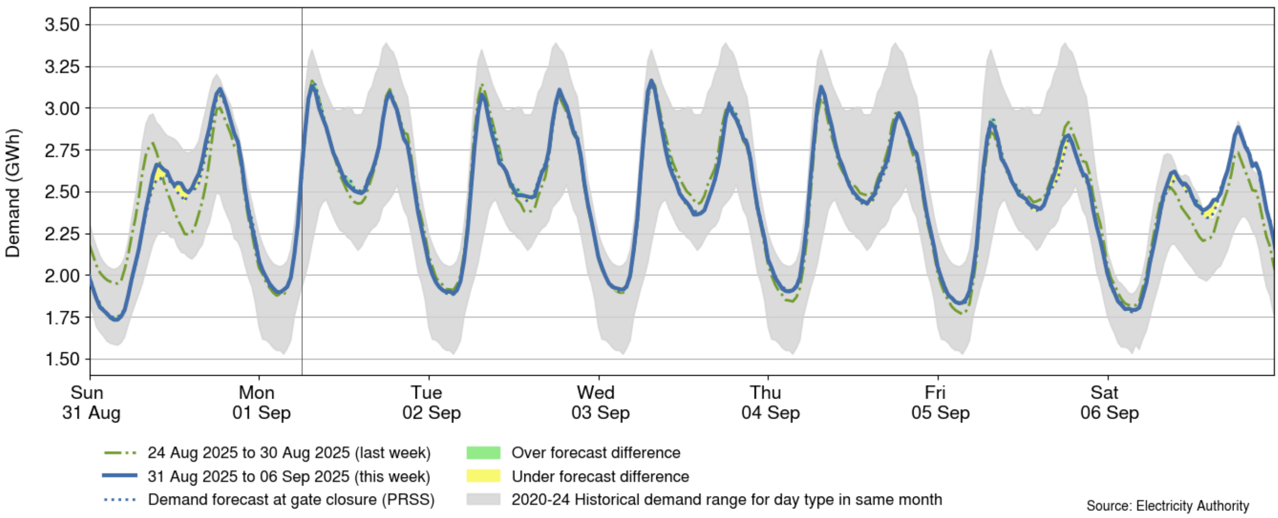
Figure 6: HVDC flow and capacity, 31 August – 6 September 2025



6. Demand

6.1. Figure 7 shows national demand between 31 August – 6 September 2025, compared to the historic range and the demand of the previous week. Demand was low and similar to last week. The highest demand of the week was around 3.16GWh at 7.30am on Wednesday during the morning peak.

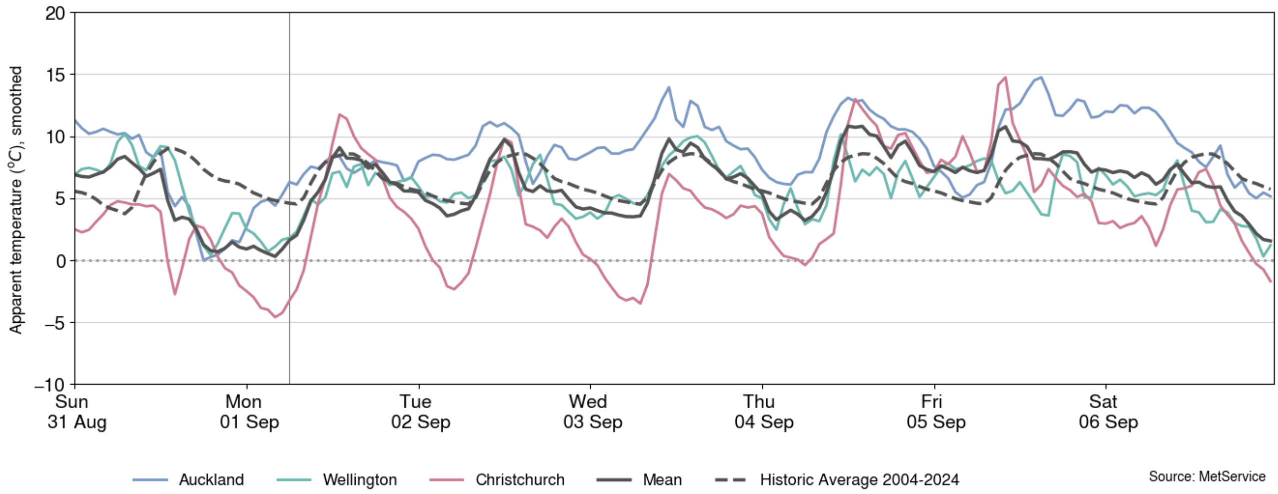
Figure 7: National demand, 31 August – 6 September 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 31 August – 6 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 0°C to 15°C in Auckland, 0°C to 10°C in Wellington, and -5°C to 16°C in Christchurch. Temperatures were mild from Monday, which helped reduce demand. However, Christchurch experienced frosty mornings.

Figure 8: Temperatures across main centres, 31 August – 6 September 2025



7. Generation

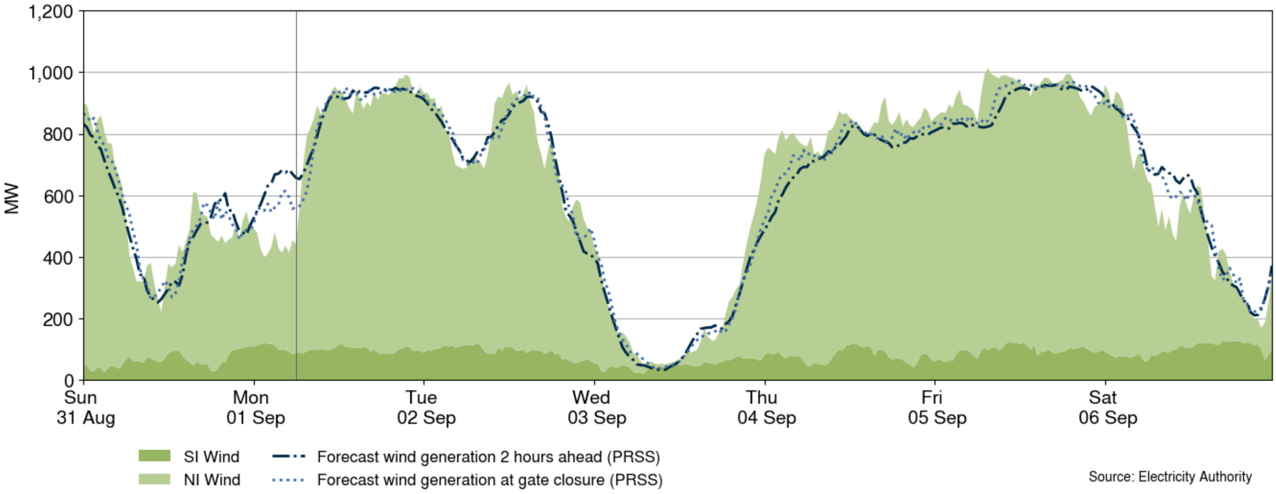
7.1. Figure 9 shows wind generation and forecast from 31 August – 6 September 2025. This week wind generation varied between 48MW and 1,013MW, with a weekly average of 647MW.

7.2. Wind generation was high on Sunday night but dropped in the morning. It stayed mostly high through Monday and Tuesday, before falling sharply to 48MW on Wednesday morning. Wind picked up again steeply on Wednesday evening.

7.3. Wind remained mostly high and above 800MW on Thursday and Friday. On Saturday, it steadily declined.

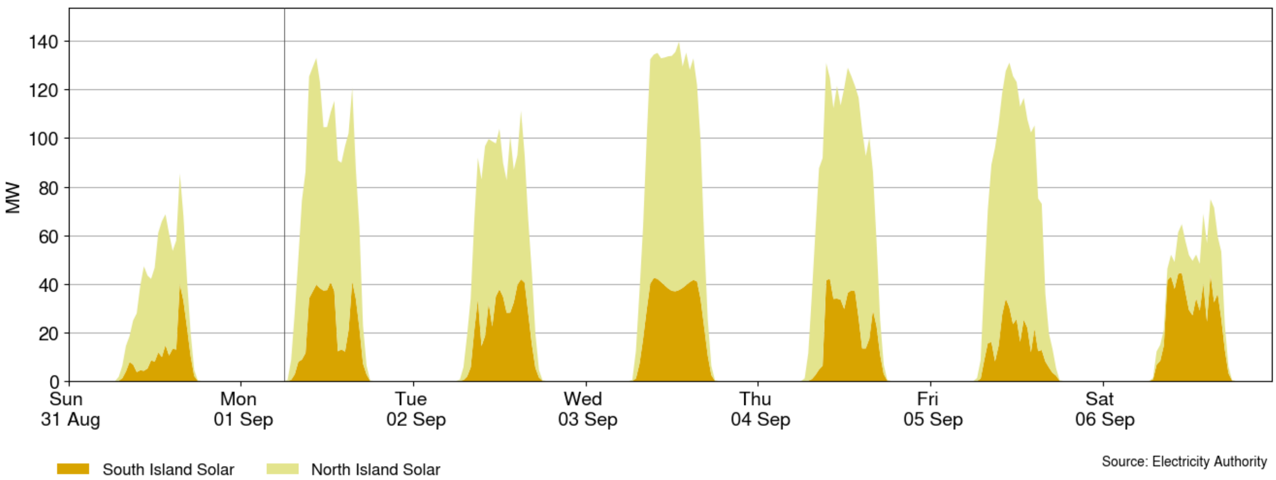
7.4. Wind was notably under forecast on Sunday and Monday, with a maximum of 197MW lower than forecast on Monday at 4.00am.

Figure 9: Wind generation and forecast, 31 August – 6 September 2025



7.5. Figure 10 shows grid connected solar generation from 31 August – 6 September 2025. Solar generation remained low over the weekend, mostly below 60 MW on both Saturday and Sunday. However, weekday output was relatively higher, with a peak of 140MW at 1.00pm on Wednesday.

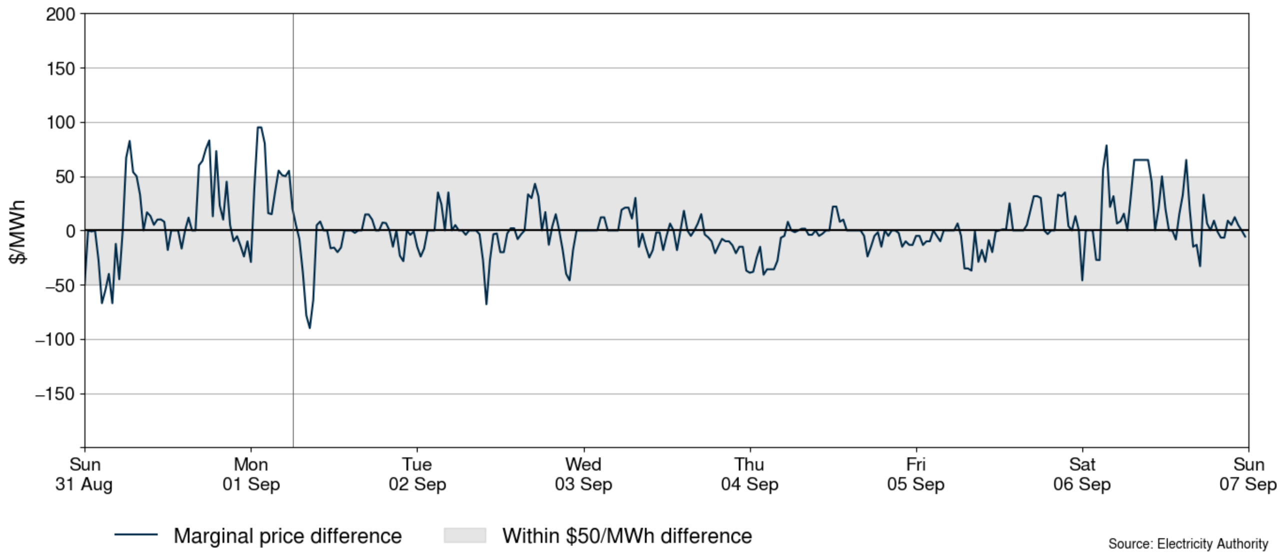
Figure 10: Grid connected solar generation, 31 August – 6 September 2025



7.6. 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.

7.7. A few trading periods this week had positive marginal price differences above $50/MWh on Sunday and Saturday, which were driven by wind and demand forecasting errors. The largest positive price difference of +$95/MWh occurred at 1.00am on Monday, when wind was 134MW lower than forecast.

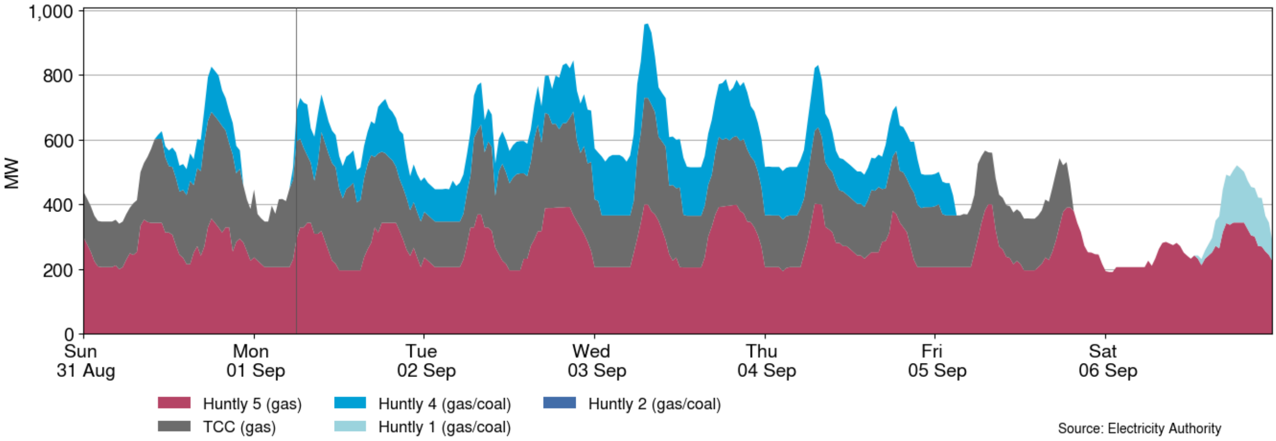
Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 31 August – 6 September 2025



7.8. Figure 12 shows the generation of thermal baseload between 31 August – 6 September 2025. Huntly 5 ran as baseload throughout the week. TCC remained online until Friday. Huntly 4 ran from Sunday to Thursday. Huntly 1 ran from Saturday afternoon when wind generation was low.

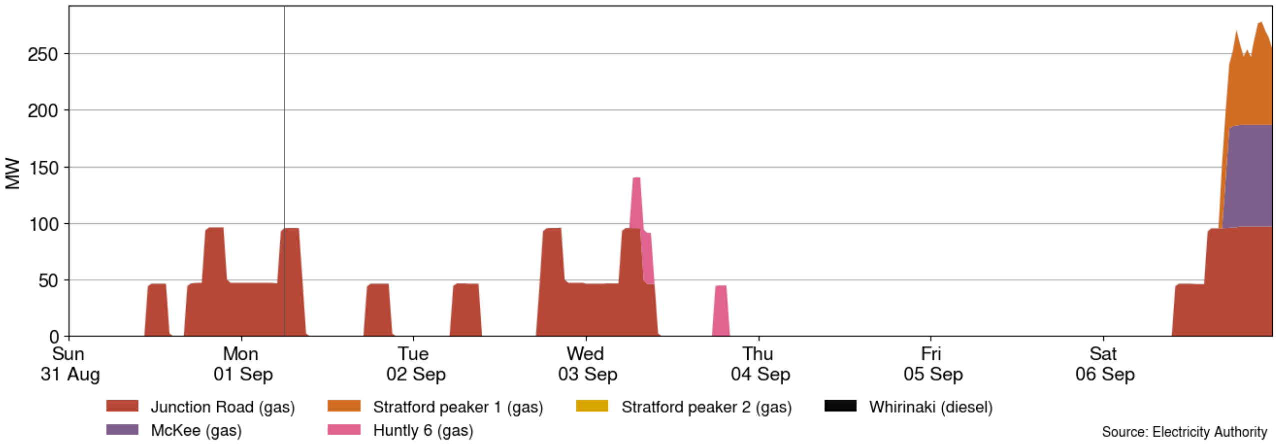
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Thermal baseload generation, 31 August – 6 September 2025



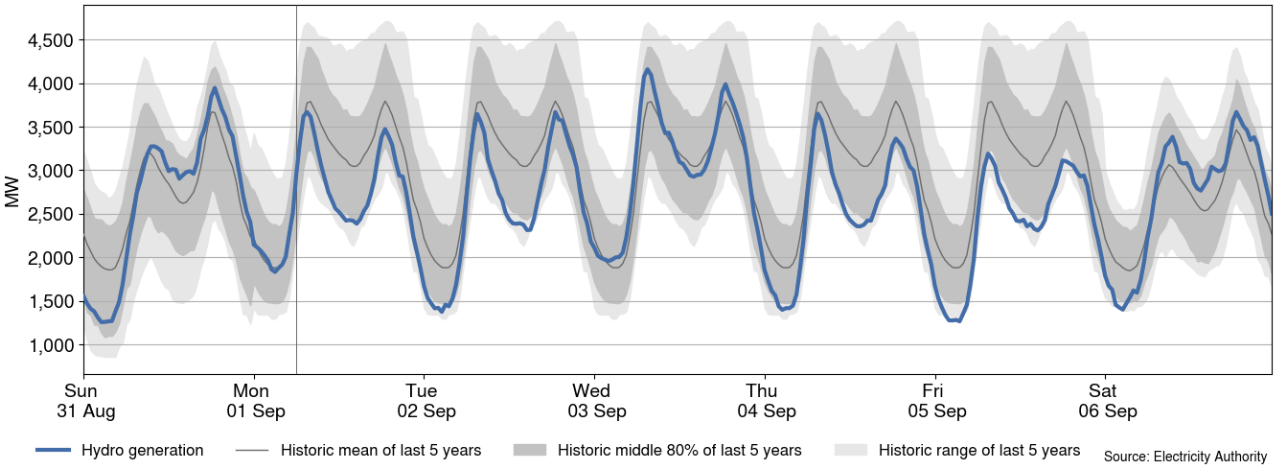
7.9. Figure 13 shows the generation of thermal peaker plants between 31 August – 6 September 2025. Junction Road ran from Sunday to Wednesday, and on Saturday. Huntly Unit 6 generated during both the morning and evening peak periods on Wednesday. On Saturday, due to low wind conditions, Junction Road, McKee, and Stratford peaker 1 were dispatched to meet demand.

Figure 13: Thermal peaker generation, 31 August – 6 September 2025



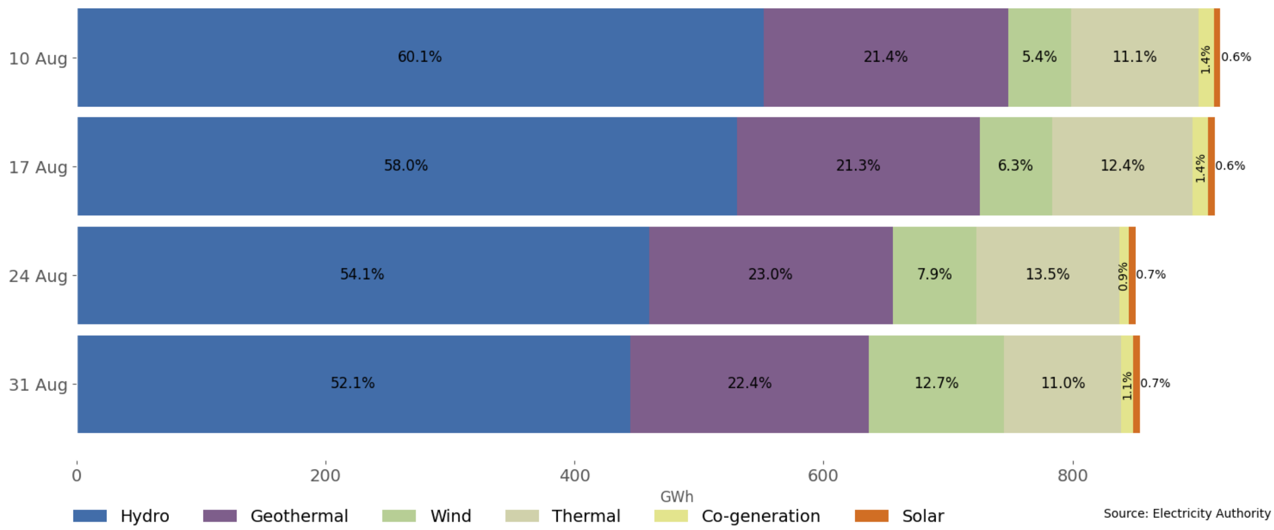
7.10. Figure 14 shows hydro generation between 31 August – 6 September 2025. Hydro generation was low compared to the previous week due to relatively high wind generation. On Wednesday, hydro generation was above the historic mean when wind was low.

Figure 14: Hydro generation, 31 August – 6 September 2025



7.11. As a percentage of total generation, between 31 August – 6 September 2025, total weekly hydro generation was 52.1%, geothermal 22.4%, wind 12.7%, thermal 11%, co-generation 1.1%, and solar (grid connected) 0.7%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 10 August and 6 September 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 31 August – 6 September 2025 ranged between ~605MW and ~1,471MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 was on outage until 6 September 2025.

(b) Manapōuri unit 2 was on outage between 2-4 June 2025.

(c) Clyde unit 2 was on outage between 5-6 June 2025.

(d) Benmore unit 2 is on outage between 4-19 September 2025.

(e) West wind farm is on partial outage from 1 September to 9 October 2025.

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

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

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

Figure 16: Total MW loss from generation outages, 31 August – 6 September 2025

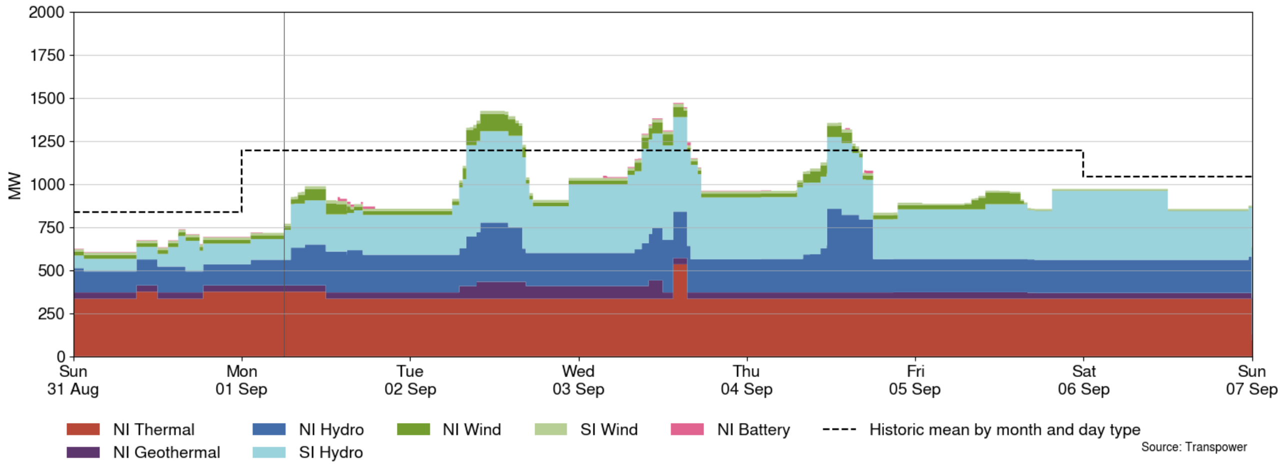
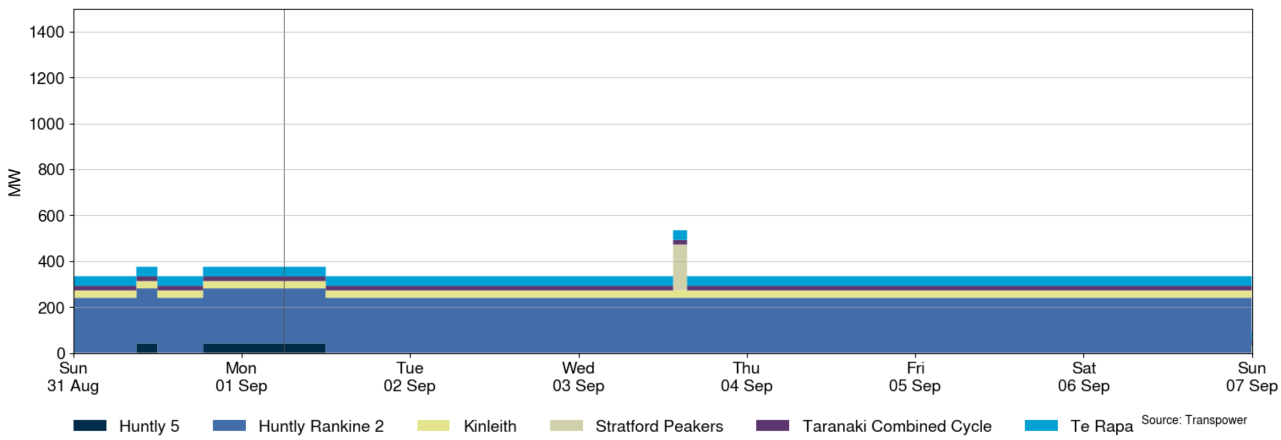


Figure 17: Total MW loss from thermal outages, 31 August – 6 September 2025

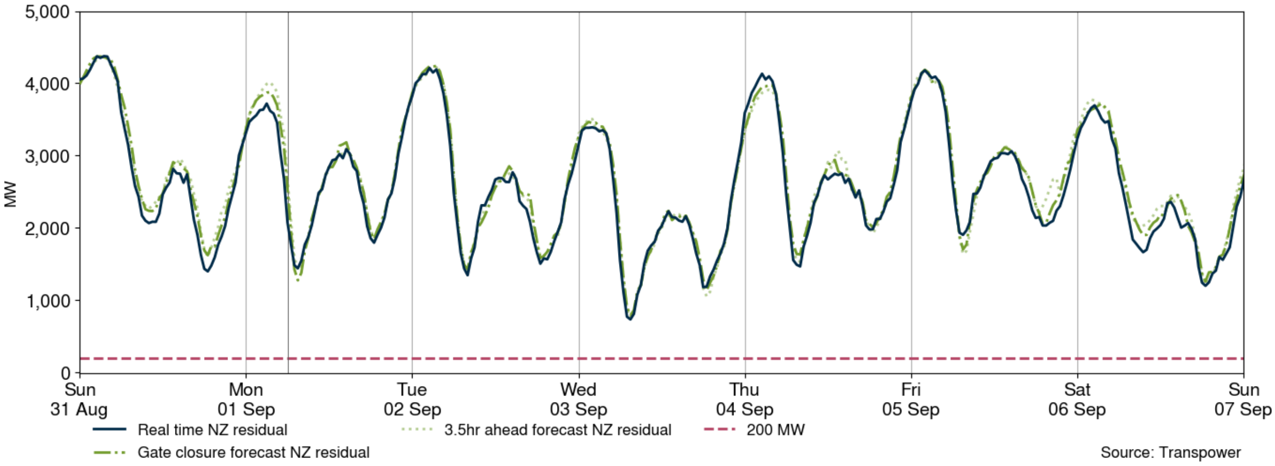


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 31 August – 6 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 735MW on Wednesday at 7.30am.

Figure 18: National generation balance residuals, 31 August – 6 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 6 September 2025, national controlled hydro storage had slightly increased to 48% of nominal full and ~83% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (32% full[2]) is touching its historic 10th percentile, while storage at Lake Takapō (28% full) is below its historic 10th percentile.

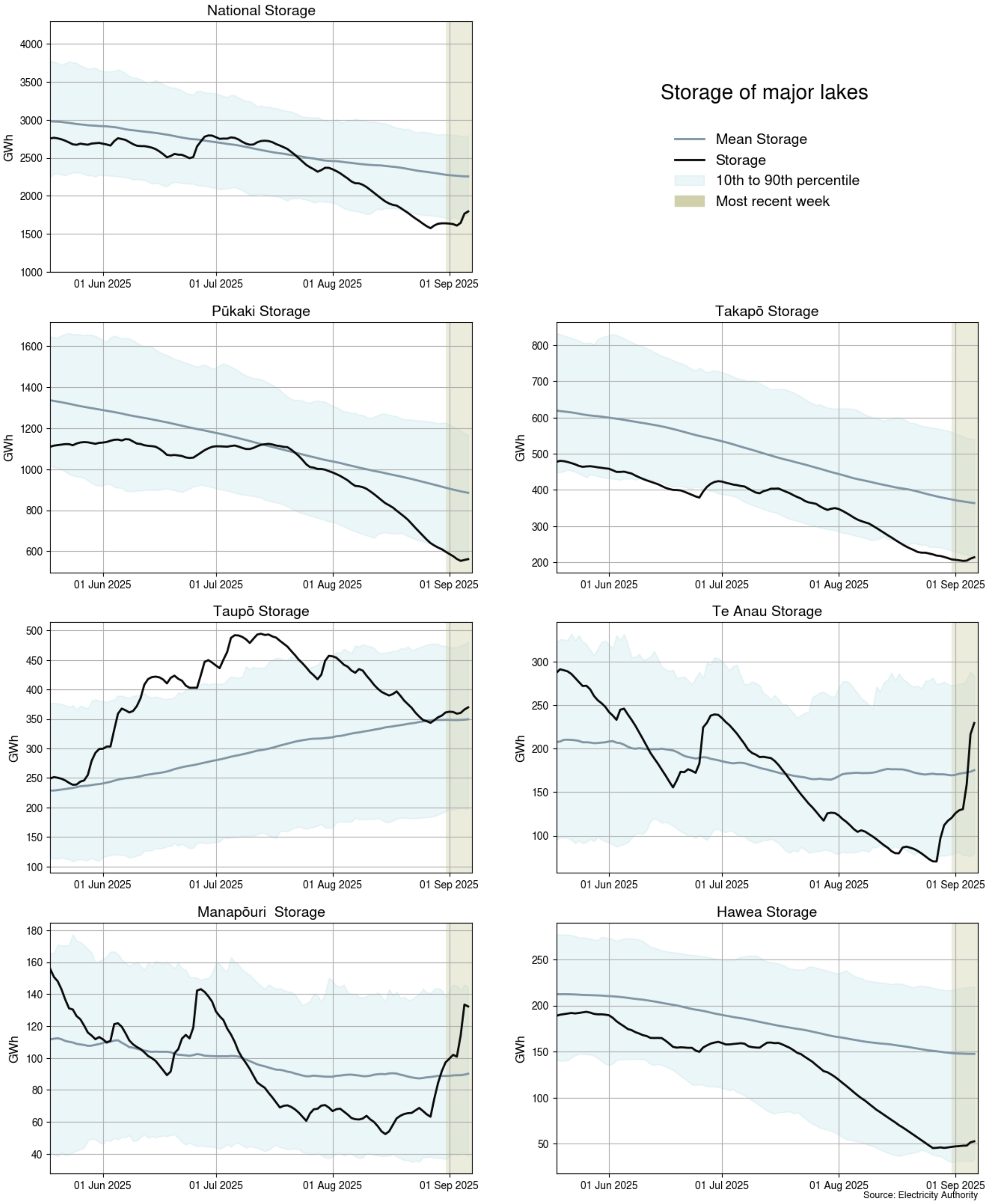
10.4. Storage at Lake Te Anau (88% full) and Lake Manapōuri (82% full) is above their respective historic means.

10.5. Storage at Lake Taupō (63% full) is slightly above its historic mean for this time of year.

10.6. Storage at Lake Hawea (19% full) remains close to its historic 10th percentile.

[2] Percentage full values sourced from NZX hydrological summary 7 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.

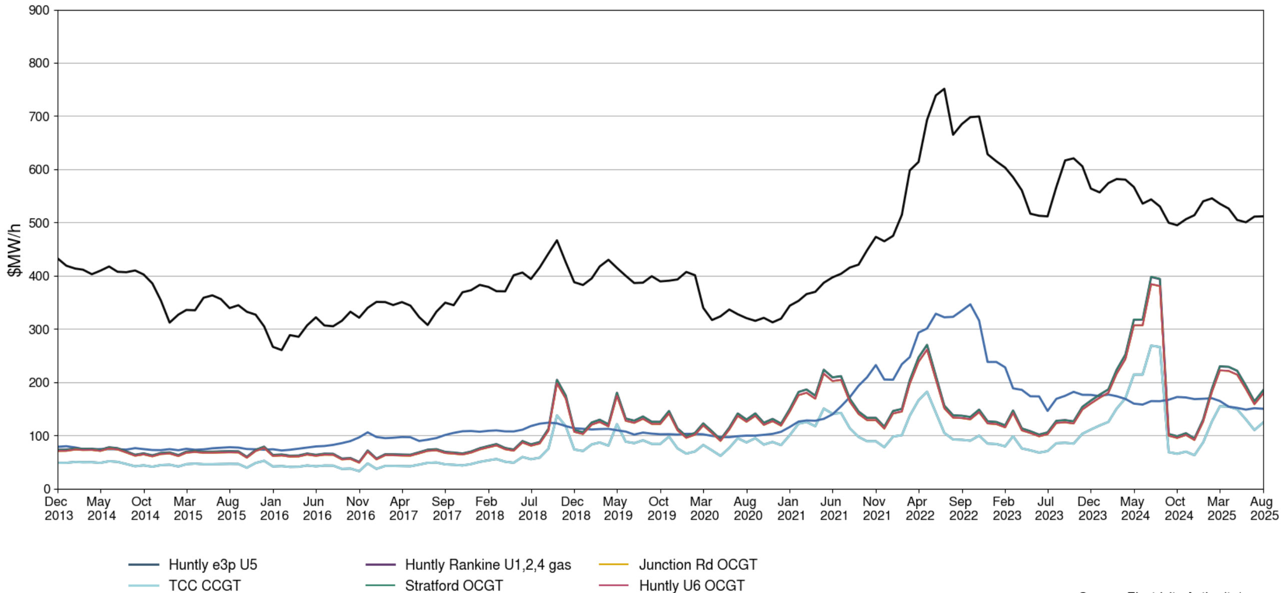
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

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



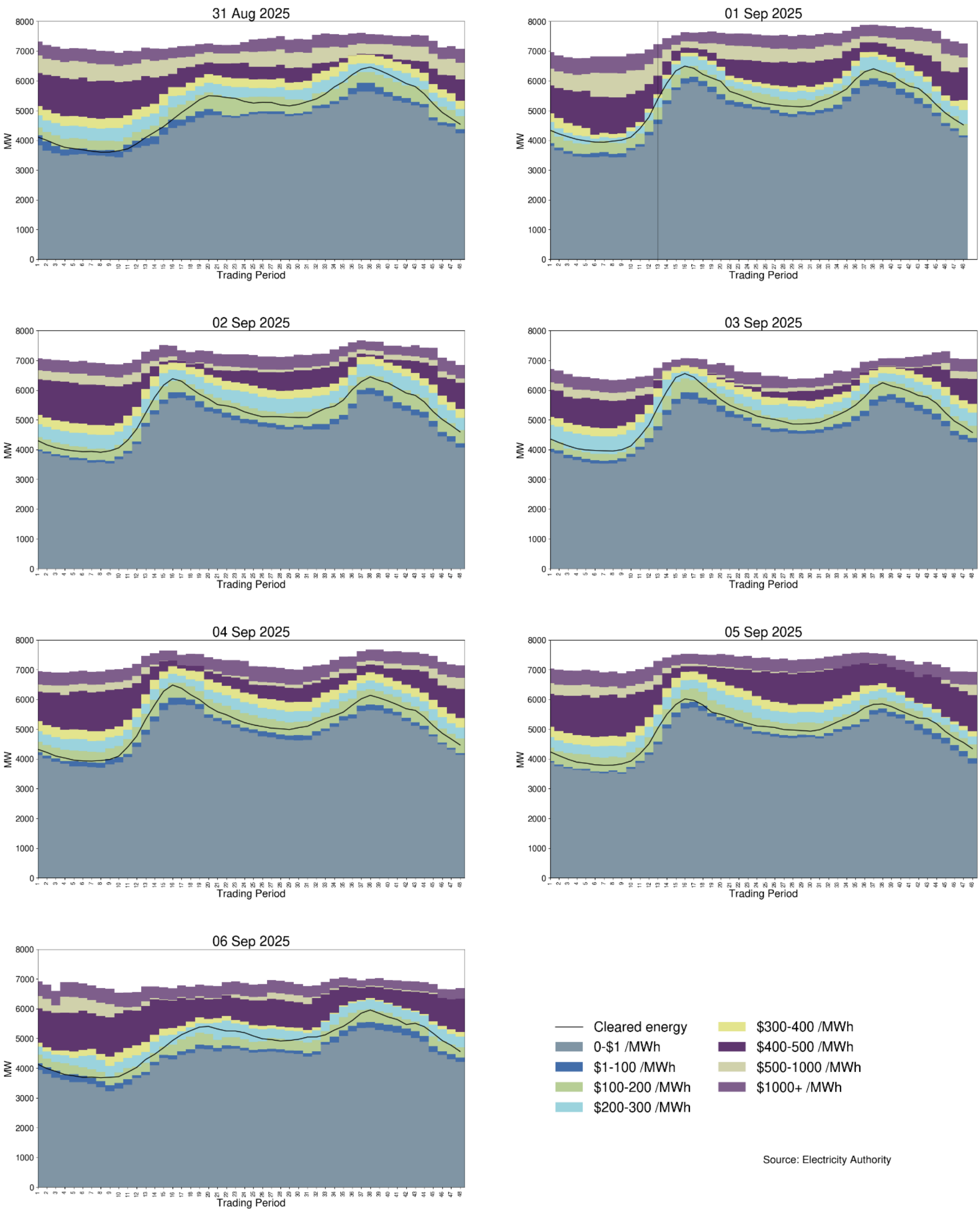
Source: Electricity Authority/ Appendix C

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 $100-$300/MWh range. Hydro generation continued to be offered into higher priced tranches to signal the increasing value of stored water.

Figure 21: Daily offer stacks[3]



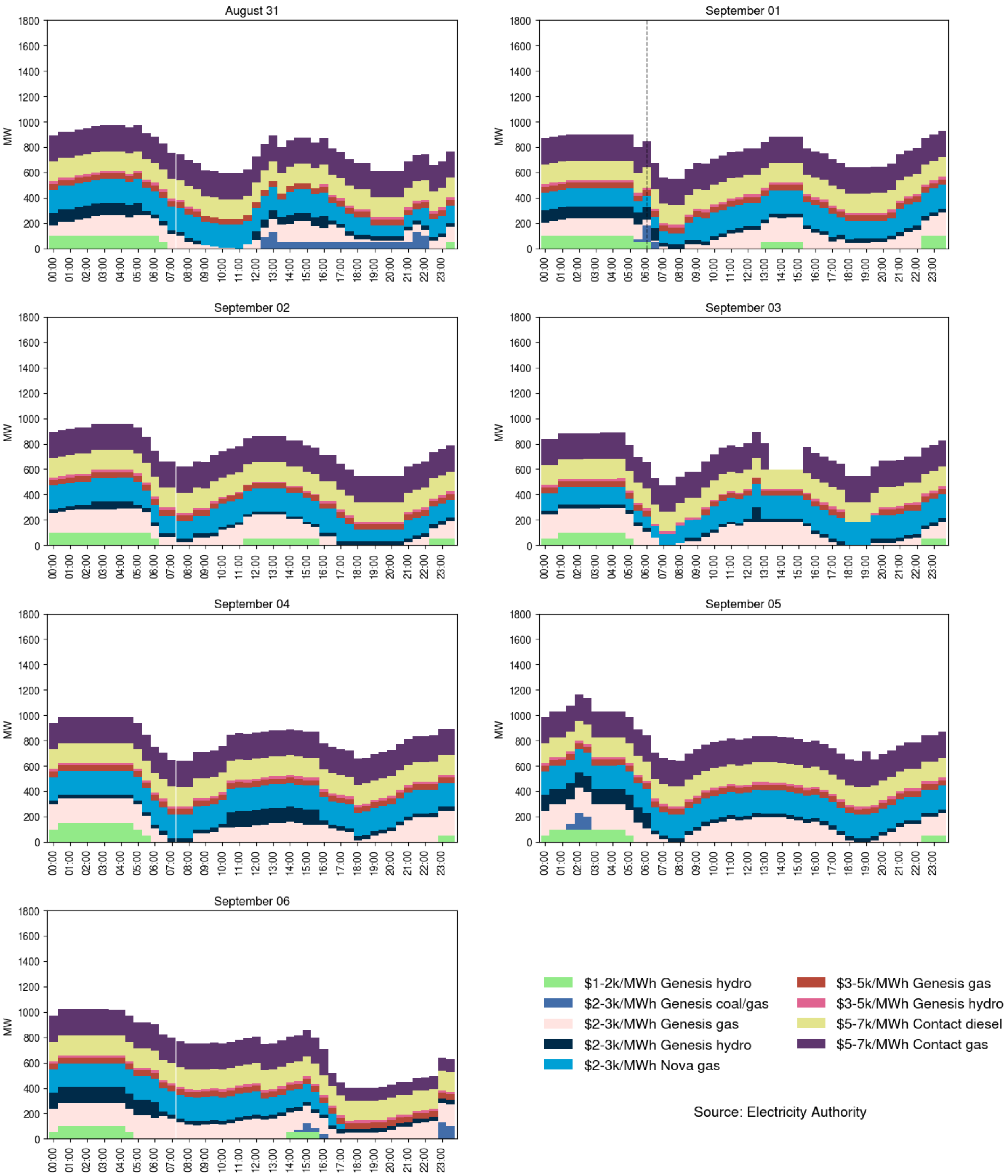
12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

[3] The RTD data for TP21 on 1 September 2025 is missing.

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 775MW 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



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
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