15 September 2025

Trading conduct report 7-13 September 2025

Market monitoring weekly report

Trading conduct report 7-13 September 2025

1. Overview

1.1. The average price decreased by $12/MWh this week to $169/MWh. Demand has decreased over the past three weeks due to warmer spring temperatures. Hydro generation increased slightly, while thermal generation decreased compared to last week. National hydro storage remains stable at 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 7-13 September 2025:

(a) The average spot price for the week was $169/MWh, a decrease of around $12/MWh compared to the previous week.

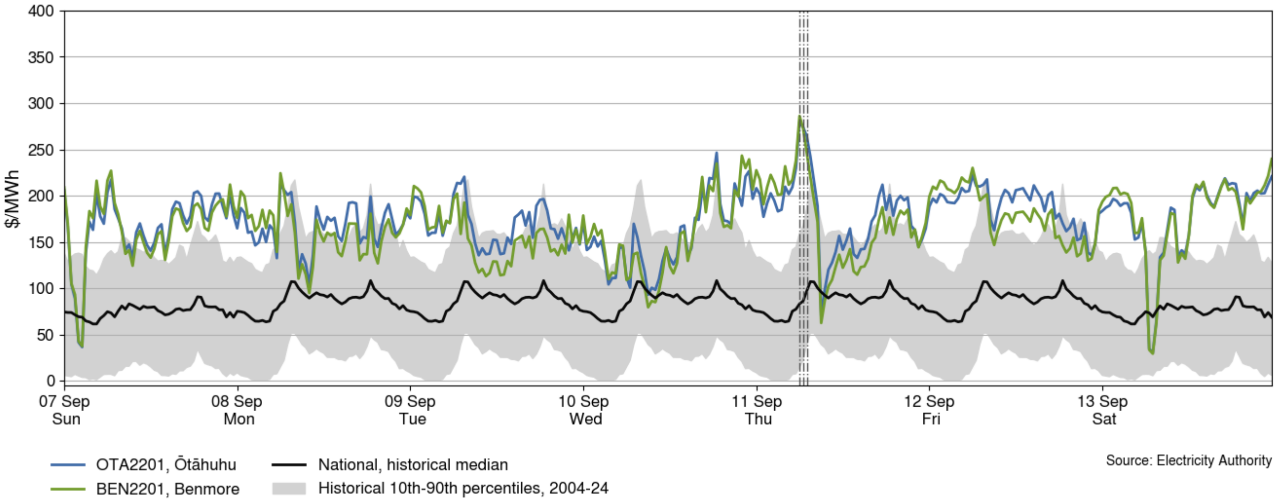
(b) 95% of prices fell between $90/MWh and $235/MWh.

2.3. Spot prices were mostly between $150-$200/MWh. The highest price of the week occurred on Thursday morning at 6.00am, with prices reaching around $280/MWh at Ōtāhuhu and ~$286/MWh at Benmore. During that time, demand was higher than forecast by 45MW, and wind was underestimated by 110MW.

2.4. In contrast, the lowest prices of the week occurred on Saturday (6.30am-7.00am), with prices ranging from $30-35/MWh at Ōtāhuhu and around $29-33/MWh at Benmore. During these times, demand was 37MW-52MW lower than forecast, and wind was 237MW-276MW higher than forecast.

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. Other notable prices above $250/MWh are marked with black dashed lines.

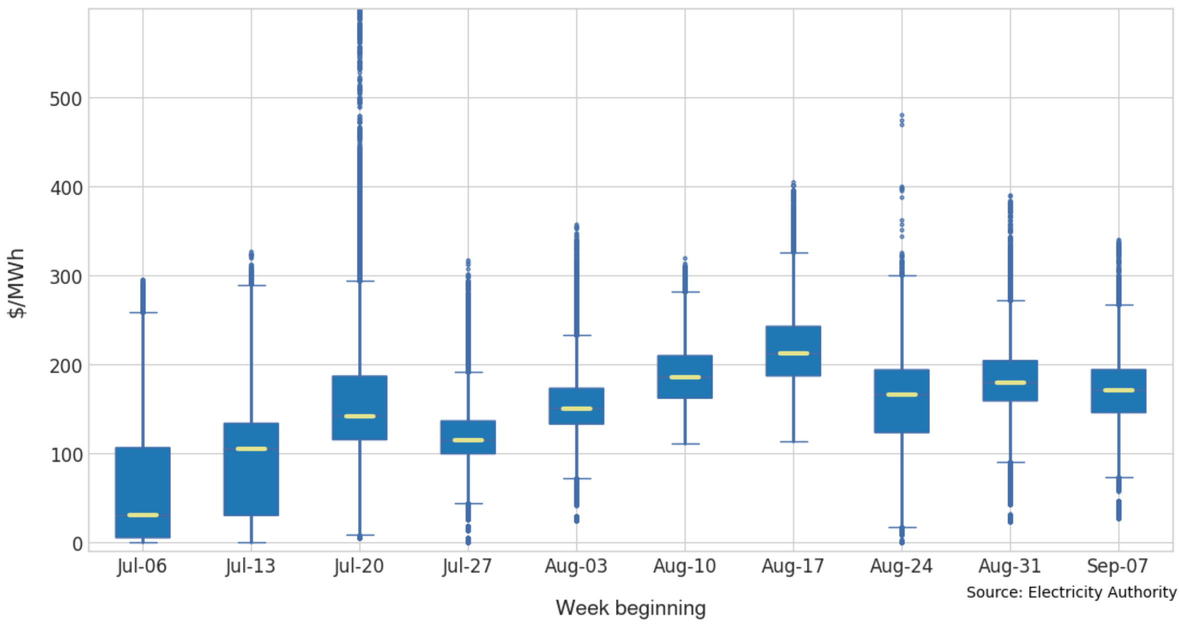
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 7-13 September 2025



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 was similar to last week, with no significant high-priced outliers. The median price was $171/MWh and most prices (middle 50%) fell between $146/MWh and $194/MWh.

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

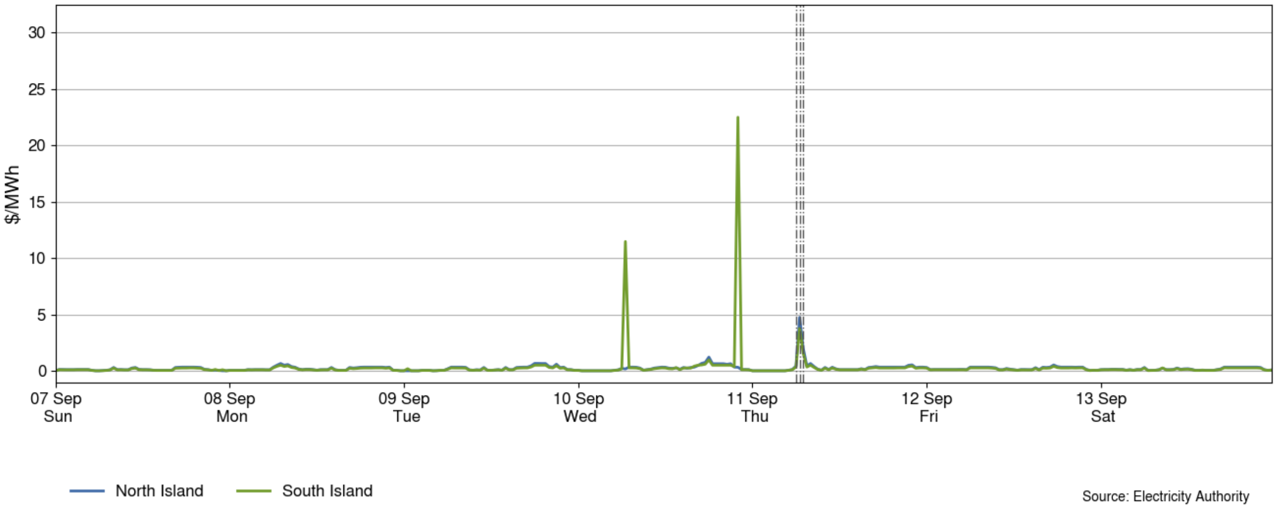


3. Reserve prices

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 two price spikes on Wednesday for the South Island.

3.2. The highest FIR price spike occurred on Wednesday at 10.00pm, with prices reaching around $22/MWh in the South Island, while prices in the North Island remained at $0.32/MWh. During that time, the HVDC was setting the South Island risk for two dispatch intervals within trading period 45.

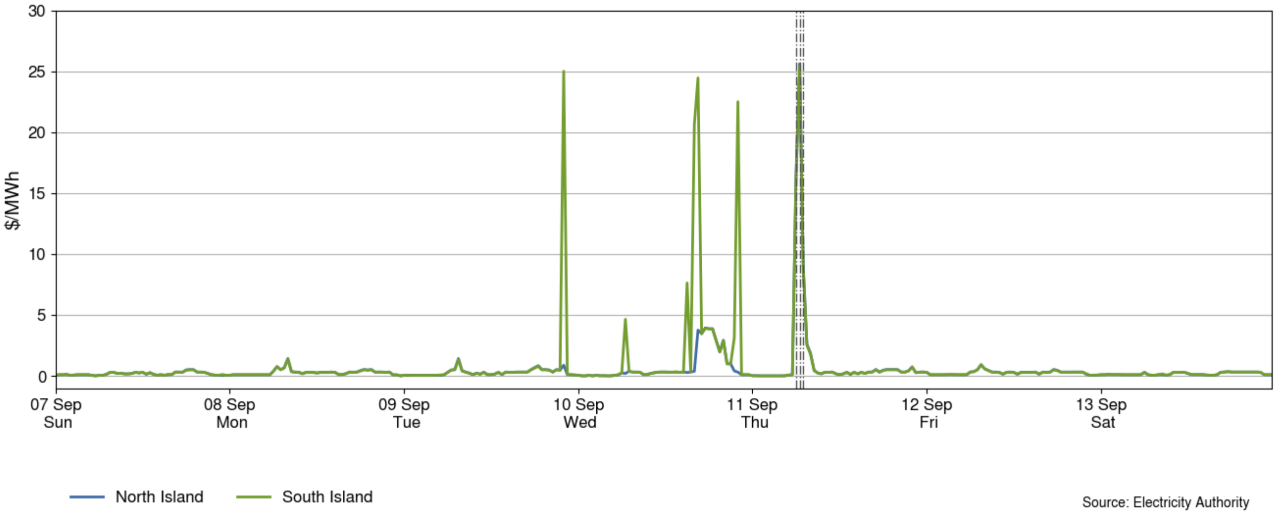
Figure 3: Fast instantaneous reserve price by trading period and island, 7-13 September 2025



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh with a few price spikes between Tuesday and Thursday.

3.4. A significant SIR price spike occurred on Thursday at 6.30am, coinciding with the spot price spike. During that time, prices reached around $25/MWh in both the North Island and the South Island. Other high South Island SIR prices occurred when the HVDC was going south or when the HVDC was switching direction.

Figure 4: Sustained instantaneous reserve by trading period and island, 7-13 September 2025



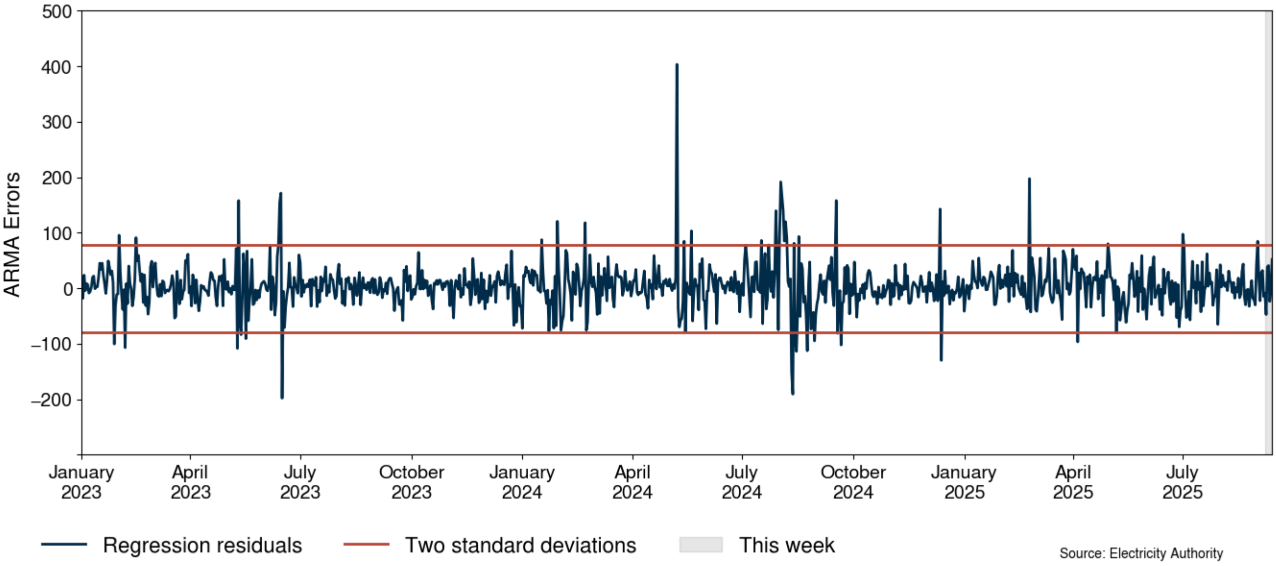
4. Regression residuals

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.

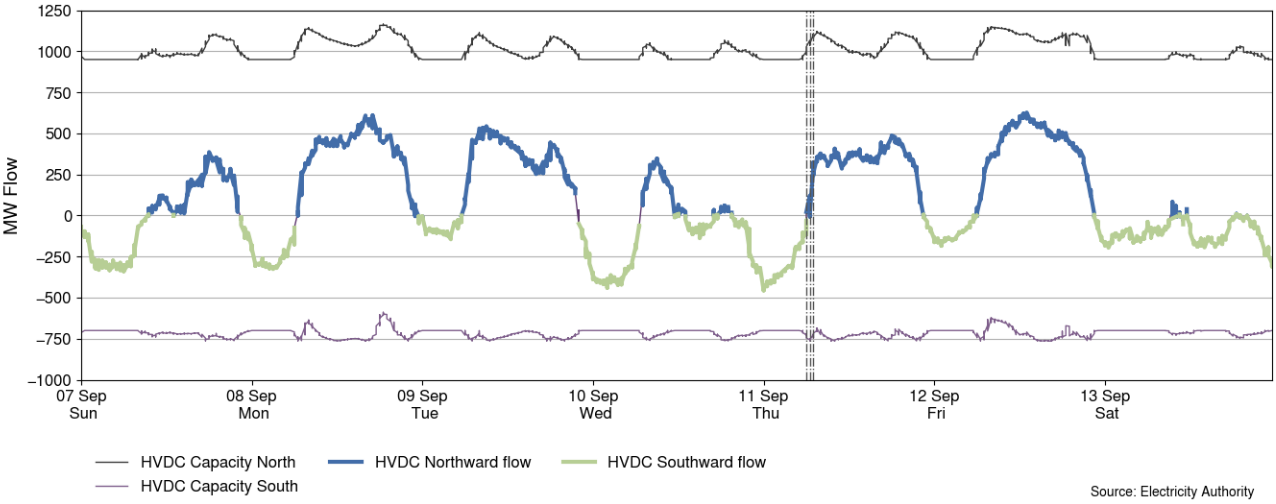
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 13 September 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 7-13 September 2025. HVDC flows were mostly northward during the day and southward overnight. Southward flow was high due to high wind generation on Wednesday. Northward flows reached around 626MW on Friday at 1.00pm.

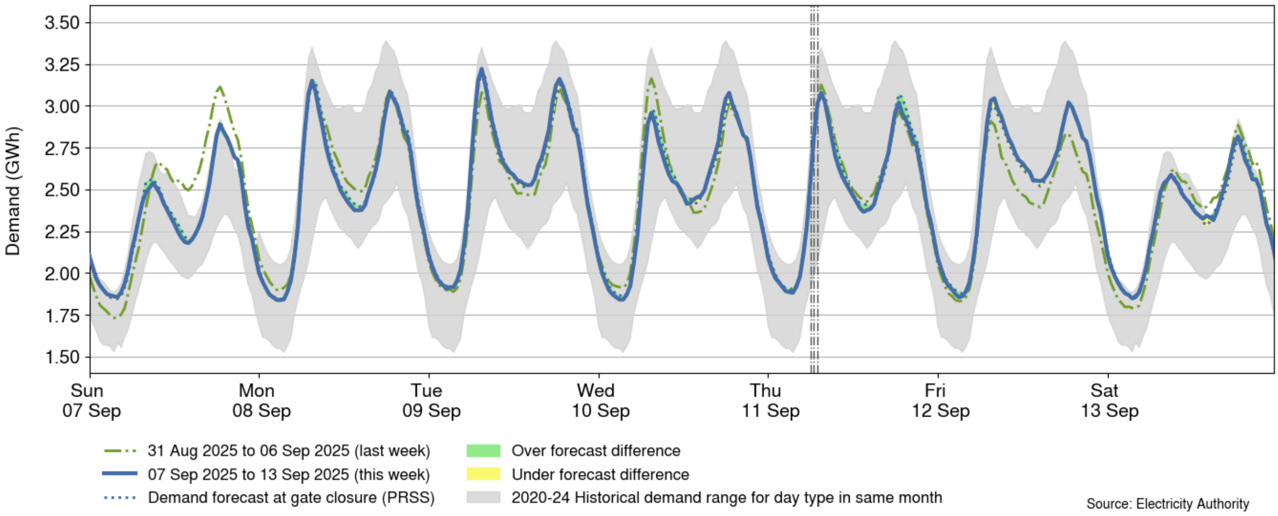
Figure 6: HVDC flow and capacity, 7-13 September 2025



6. Demand

6.1. Figure 7 shows national demand between 7-13 September 2025, compared to the historic range and the demand of the previous week. Demand was lower than last week on Sunday and on Wednesday morning. However, Friday observed higher demand than last week likely due to low temperatures. The highest demand of the week was around 3.22GWh at 7.30am on Tuesday during the morning peak.

Figure 7: National demand, 7-13 September 2025 compared to the previous week

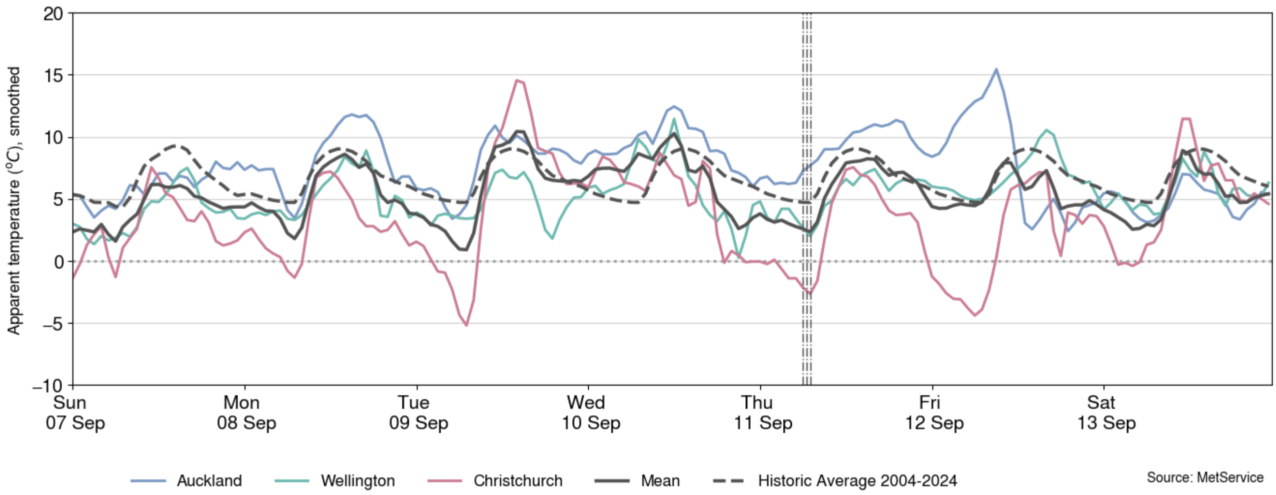


6.2. Apparent temperatures ranged from 2°C to 16°C in Auckland, 0°C to 12°C in Wellington, and -5°C to 15°C in Christchurch.

6.3. Figure 8 shows the hourly apparent temperature at main population centres from 7-13 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.

6.4. Apparent temperatures ranged from 2°C to 16°C in Auckland, 0°C to 12°C in Wellington, and -5°C to 15°C in Christchurch.

Figure 8: Temperatures across main centres, 7-13 September 2025

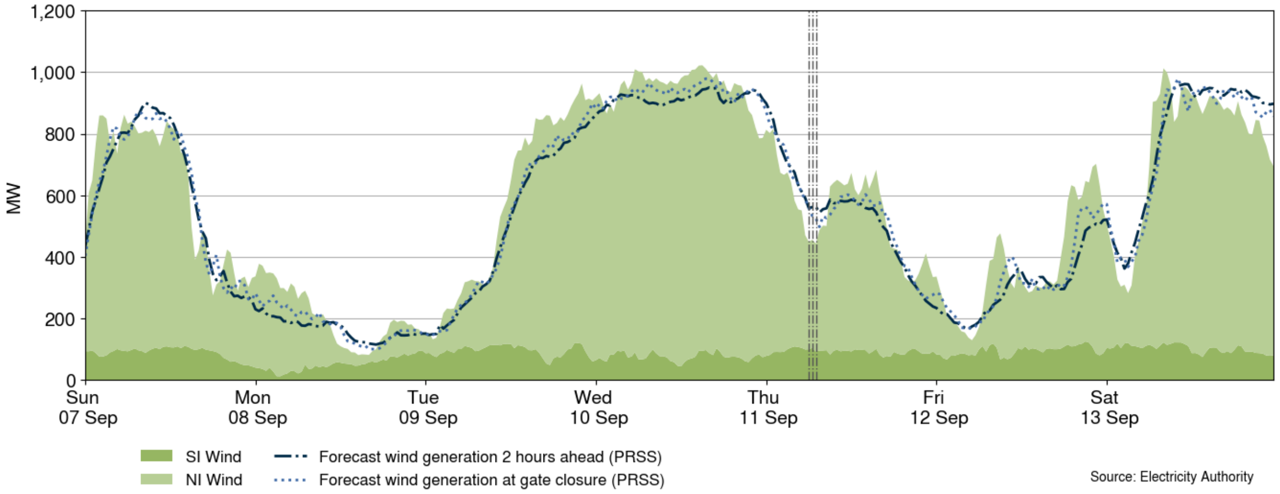


7. Generation

7.1. Figure 9 shows wind generation and forecast from 7-13 September 2025. This week wind generation varied between 81MW and 1,022MW, with a weekly average of 574MW.

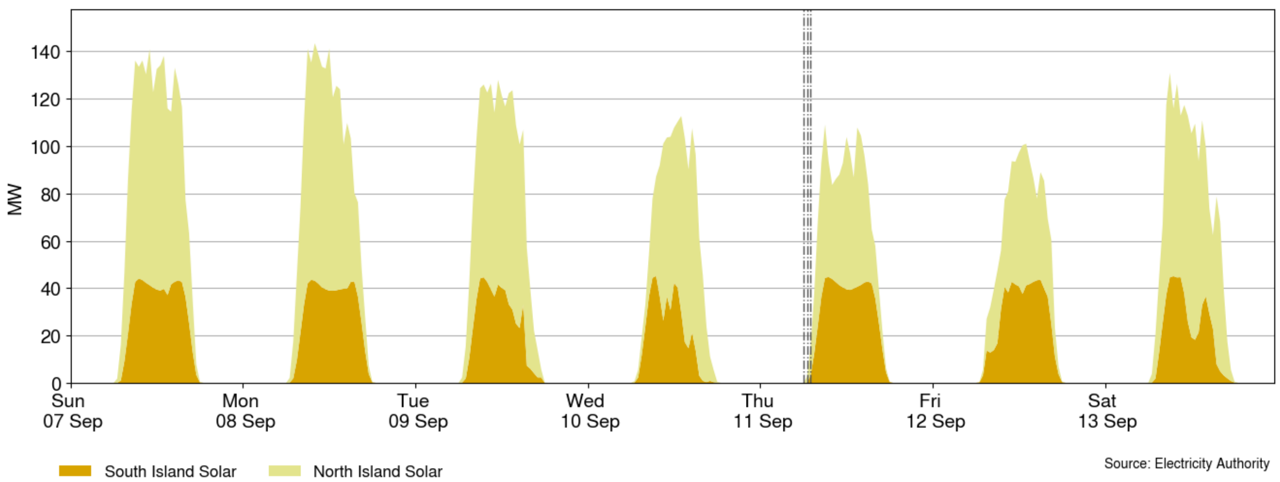
7.2. Wind generation was high on Sunday but dropped sharply to 81 MW by Monday afternoon. It remained mostly high through Tuesday and Wednesday, declined on Thursday. Wind was variable on Friday and then rose steeply again on Saturday morning.

Figure 9: Wind generation and forecast, 7-13 September 2025



7.3. Figure 10 shows grid connected solar generation from 7-13 September 2025. Solar generation typically peaked above 100MW, with a maximum of 143MW at 10.00am on Monday.

Figure 10: Grid connected solar generation, 7-13 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[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

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

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.

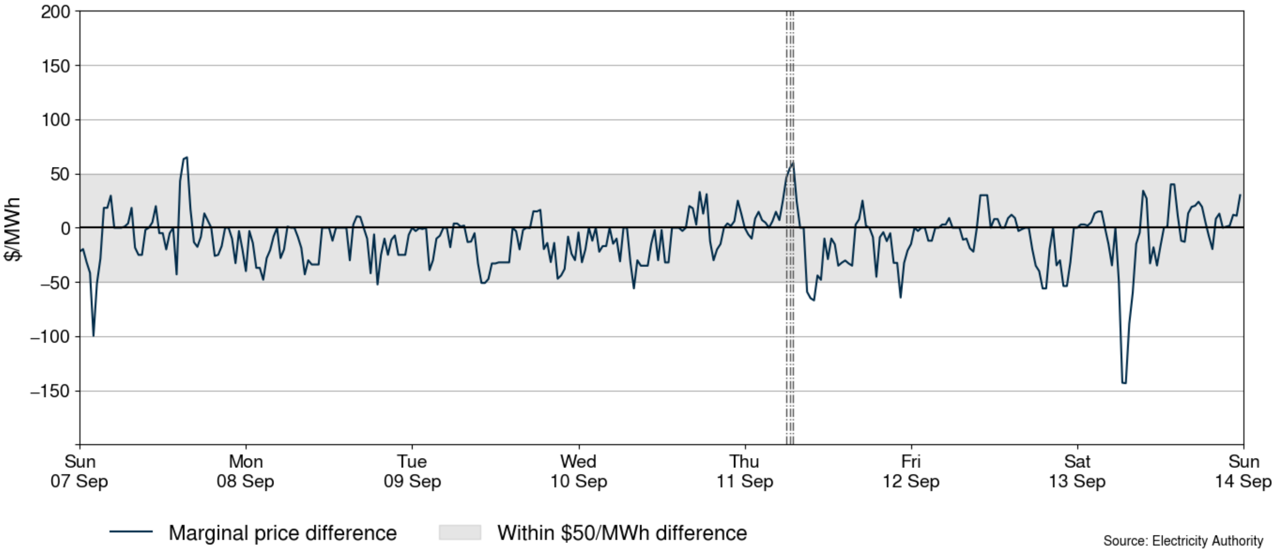
7.5. A few trading periods this week had positive marginal price differences above $50/MWh on Sunday and Thursday, which were driven by wind and demand forecasting errors. The largest positive price difference of +$65/MWh occurred at 3.30pm on Sunday, when wind was 200MW lower than forecast.

7.6. On Thursday, a positive price difference of +$60/MWh occurred at 6.00am during the price spike, when wind was 110MW lower than forecast and demand was 45MW higher than forecast.

7.7. The largest negative price difference of -$143/MWh occurred at 6.30am and 7.00am on Saturday, when demand was 37MW-52MW lower than forecast, and wind was 237MW-276MW higher than forecast.

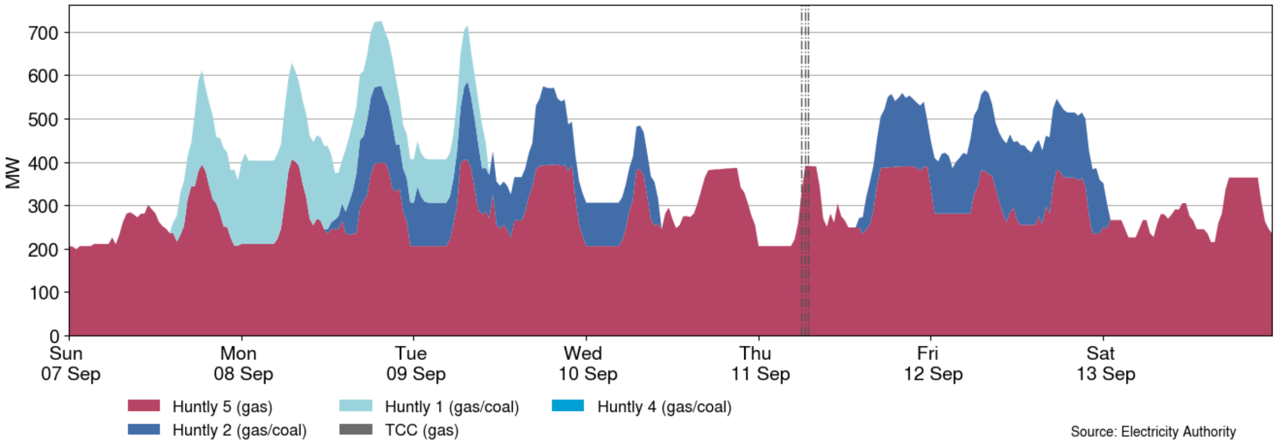
7.8. The lowest prices of the week occurred during those periods, with prices ranging from ~$30-35/MWh at Ōtāhuhu and ~$29-33/MWh at Benmore. If demand and wind had matched the forecast, prices at that time would likely have been much higher.

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, 7-13 September 2025



7.9. Figure 12 shows the generation of thermal baseload between 7-13 September 2025. Huntly 5 ran as baseload throughout the week. Huntly 1 ran from Sunday afternoon to Tuesday morning. Huntly 2 ran from Monday through Friday, except from Wednesday afternoon to Thursday evening, when it was offline due to high wind generation during that period.

Figure 12: Thermal baseload generation, 7-13 September 2025

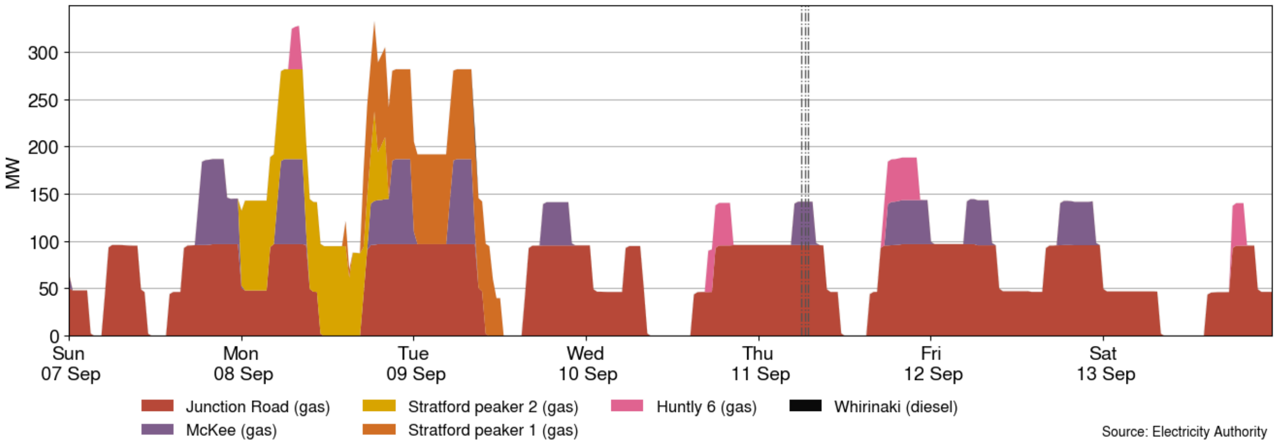


7.10. Figure 13 shows the generation of thermal peaker plants between 7-13 September 2025. Junction Road ran daily this week. McKee ran from Sunday to Tuesday, and on Thursday and Friday during peak periods.

7.11. Due to low wind generation between Monday and Tuesday, Stratford peaker 1 and Stratford peaker 2 were also dispatched to meet demand.

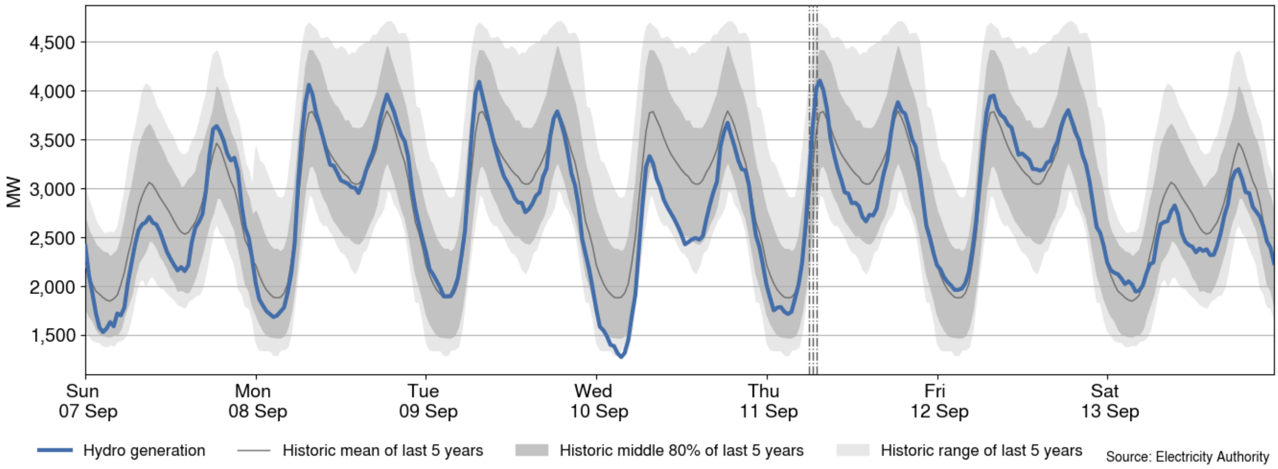
7.12. Huntly 6 also generated during the morning peak on Monday, and evening peaks on Wednesday, Thursday, and Saturday.

Figure 13: Thermal peaker generation, 7-13 September 2025



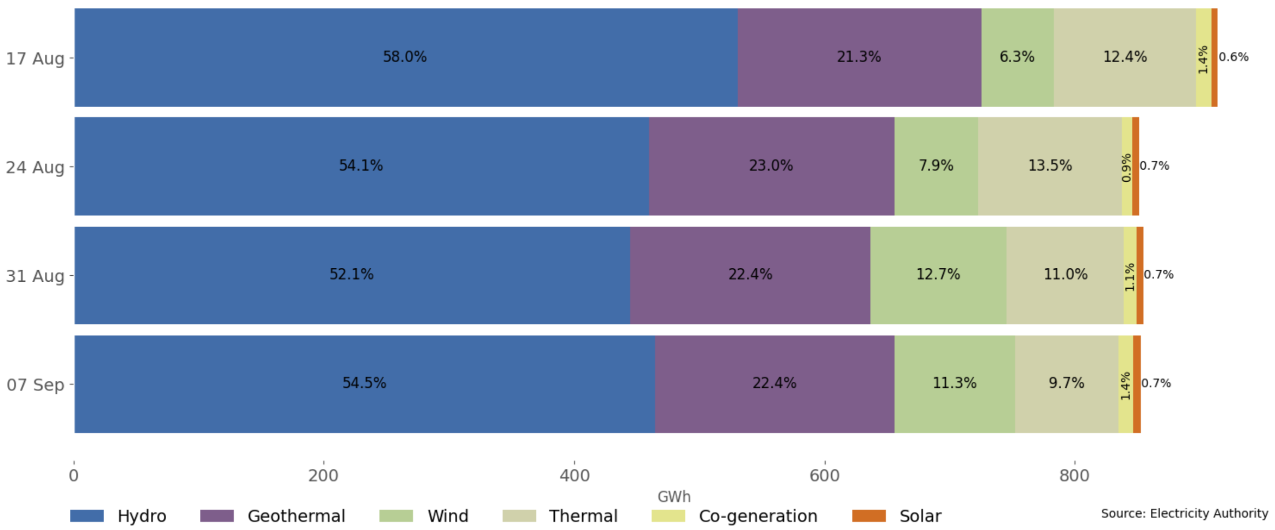
7.13. Figure 14 shows hydro generation between 7-13 September 2025. Hydro generation was around the historic mean for this time of year. On Wednesday, hydro generation was below the historic mean when wind was high.

Figure 14: Hydro generation, 7-13 September 2025



7.14. As a percentage of total generation, between 7-13 September 2025, total weekly hydro generation was 54.5%, geothermal 22.4%, wind 11.3%, thermal 9.7%, co-generation 1.4%, and solar (grid connected) 0.7%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 17 August and 13 September 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 7-13 September 2025 ranged between ~684MW and ~1,797MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC was on outage between 8-11 September 2025.

(b) Huntly 4 was on outage between 10-11 September 2025.

(c) Huntly 5 was on outage on 11 September 2025.

(d) Tekapo unit 3 was on outage from 1 September to 14 September 2025.

(e) West wind farm is on partial outage until 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, 7-13 September 2025

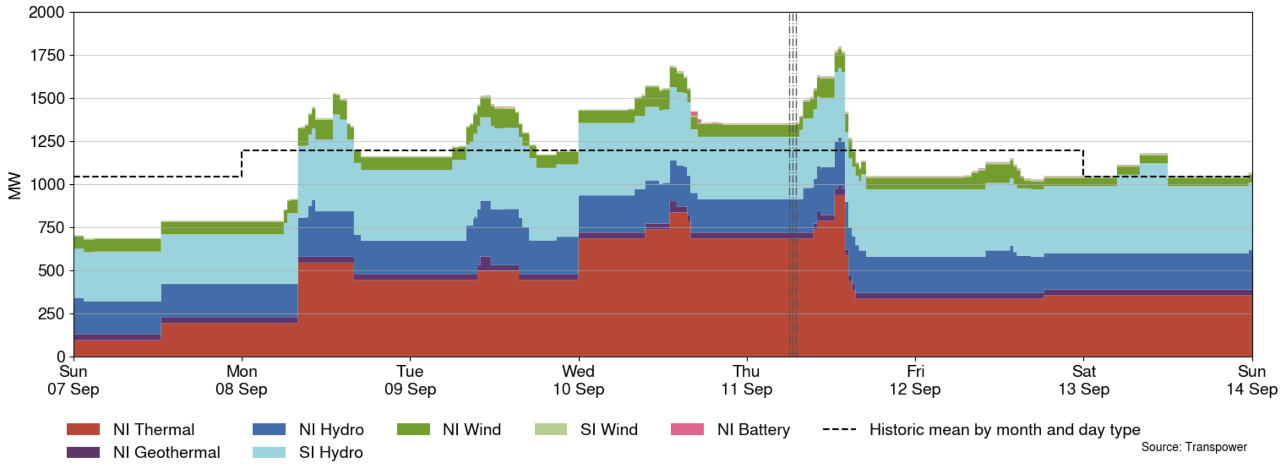
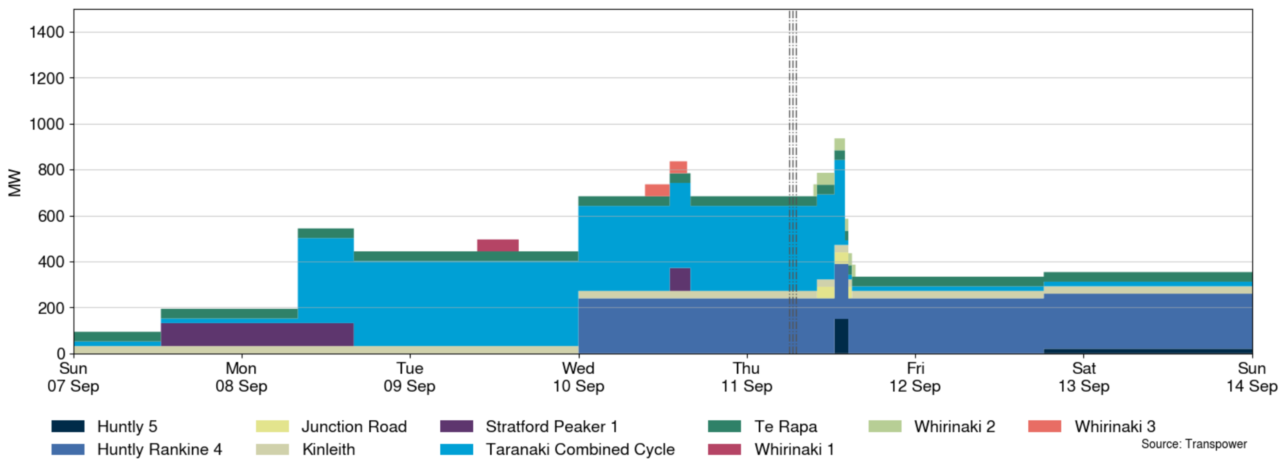


Figure 17: Total MW loss from thermal outages, 7-13 September 2025

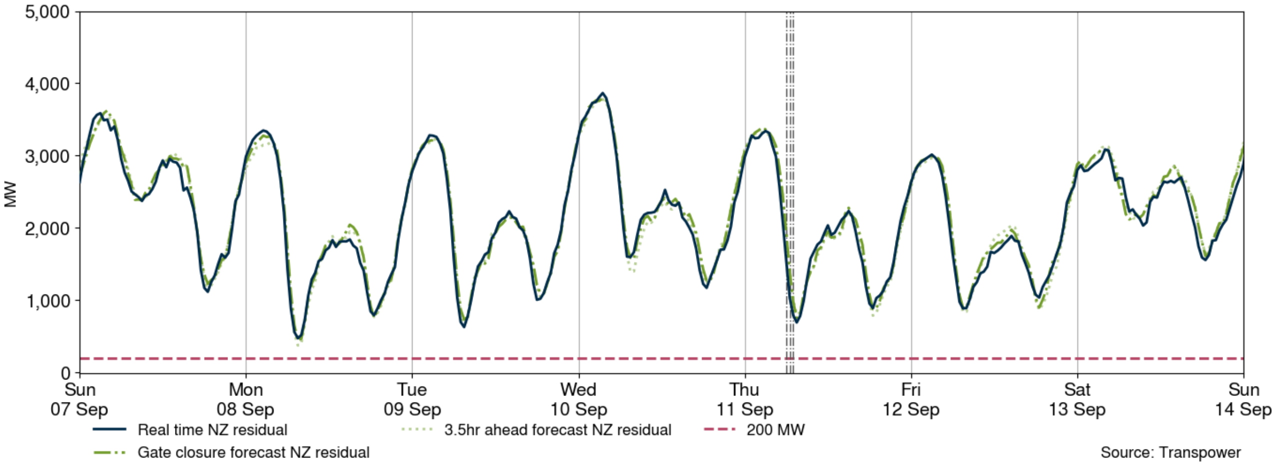


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 7-13 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 474MW on Monday at 7.30am.

Figure 18: National generation balance residuals, 7-13 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 13 September 2025, national controlled hydro storage remains stable at 48% of nominal full and ~83% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (31% full[2]) and Lake Takapō (28% full) have reached their respective historic 10th percentiles.

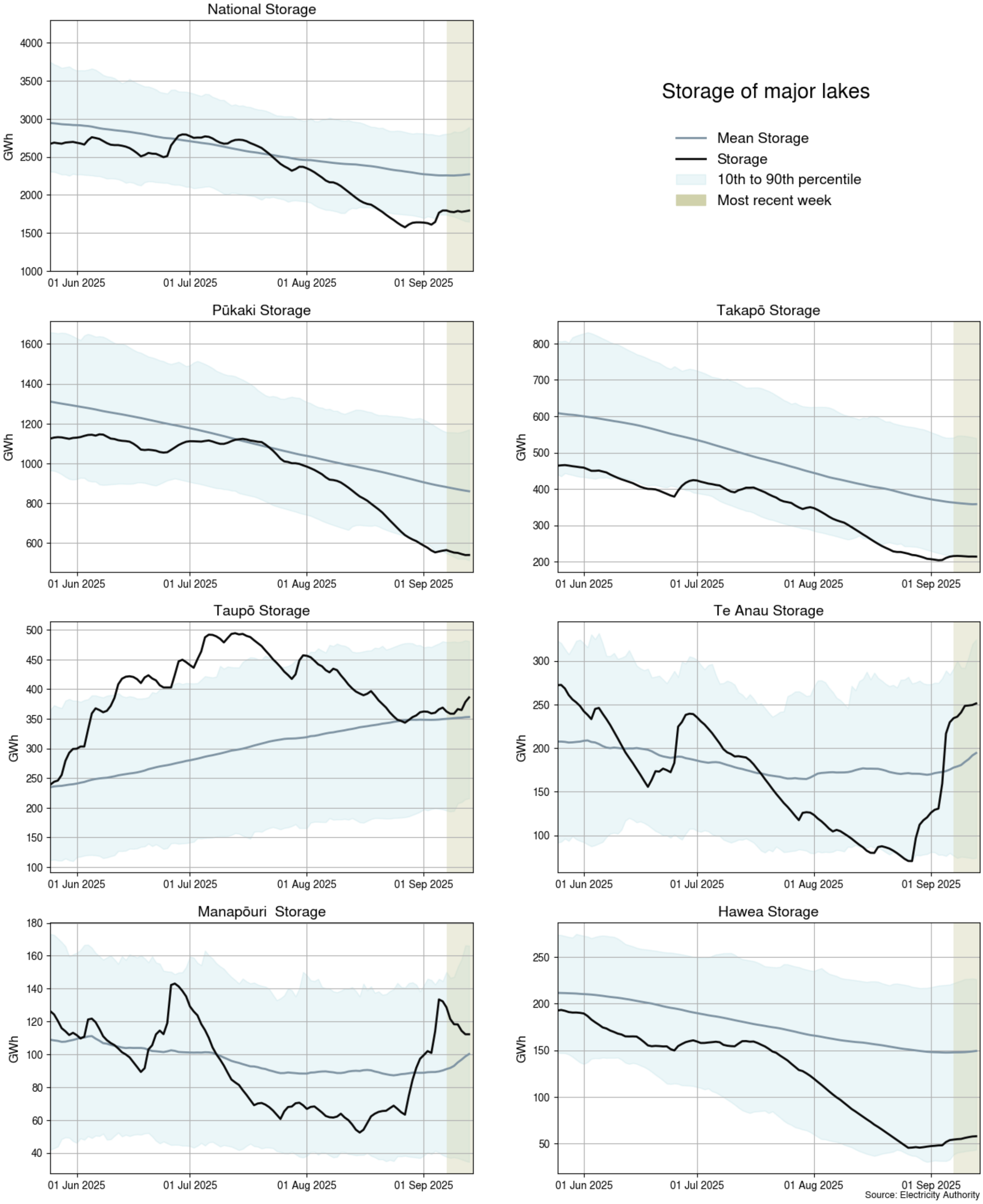
10.4. Storage at Lake Te Anau (94% full) and Lake Manapōuri (70% full) is above their respective historic means.

10.5. Storage at Lake Taupō (68% full) is slightly above its historic mean for this time of year.

10.6. Storage at Lake Hawea (20% 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.

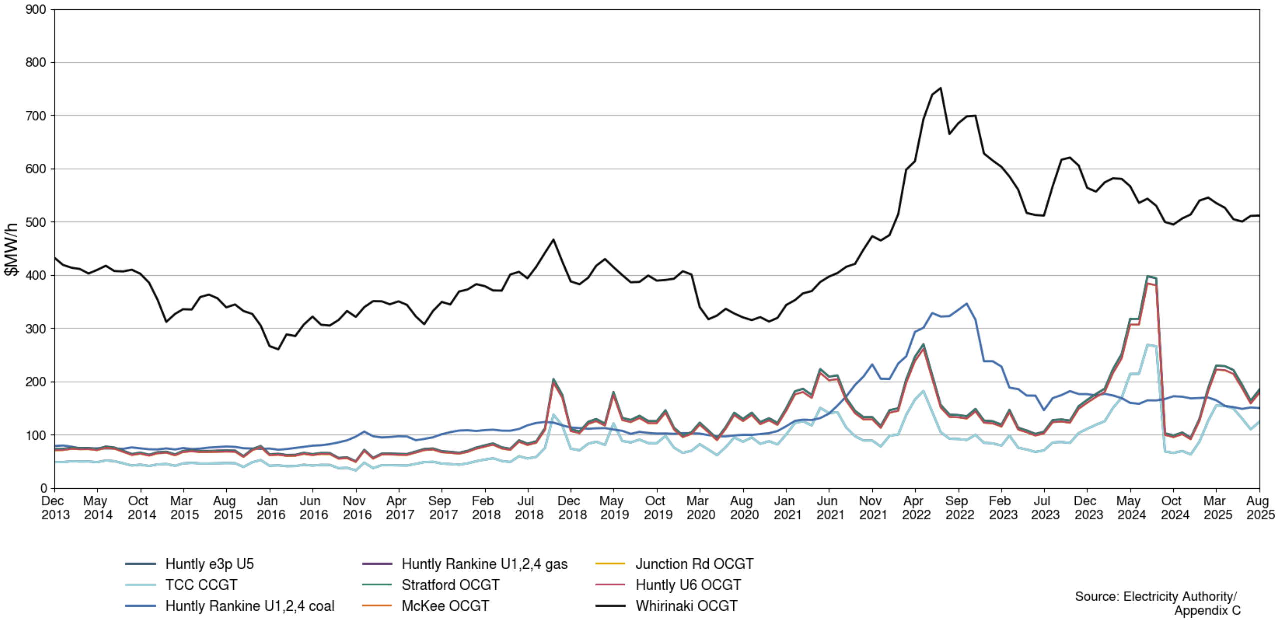
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

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

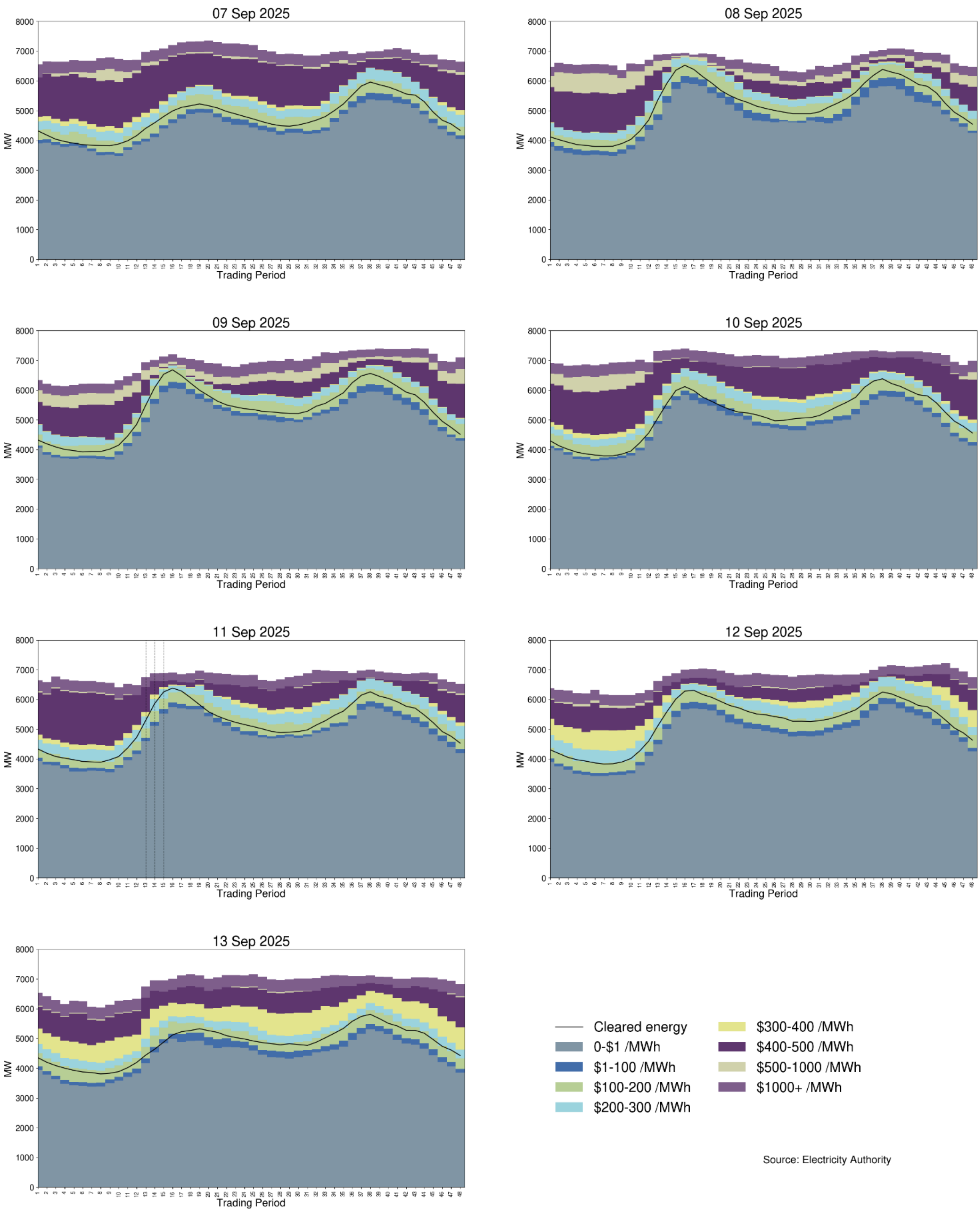


12. Offer behaviour

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-$200/MWh range. Some hydro generation continues to be offered into higher priced tranches to signal the increasing value of stored water, however, some hydro generation was priced down from the $400-500/MWh band to the $300-400/MWh band.

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 637MW per trading period was priced above $1,000/MWh this week, which is roughly 11% 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