22 September 2025

Trading conduct report 14-20 September 2025

Market monitoring weekly report

Trading conduct report 14-20 September 2025

1. Overview

1.1. This week the average price decreased by $47/MWh to $122/MWh. Demand declined compared to last week due to mild temperatures. Wind generation was relatively high this week, while thermal generation decreased. National hydro storage increased to 54% nominally full and around 93% 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 14-20 September 2025:

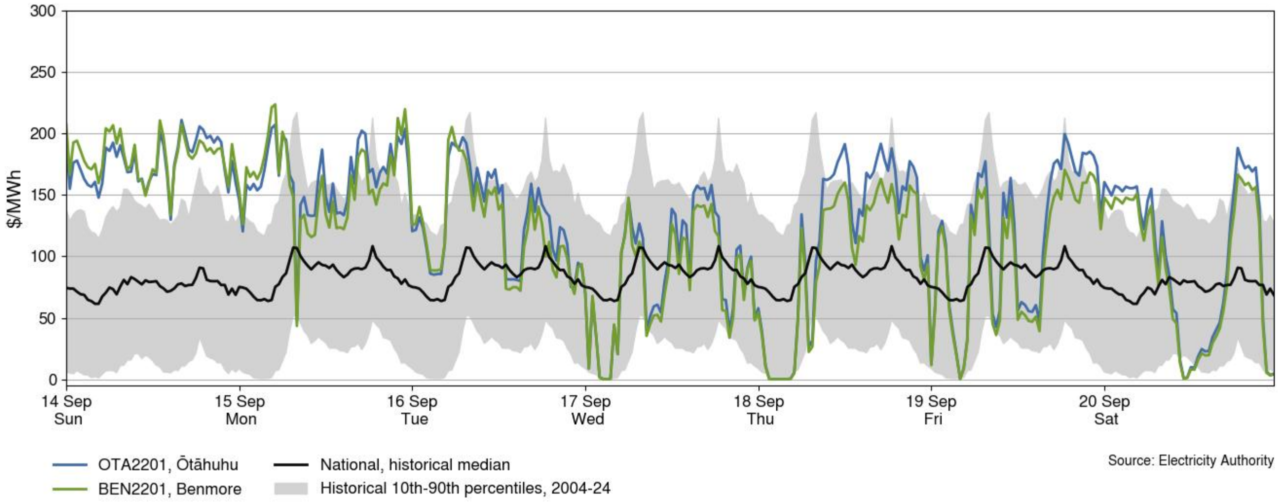
(a) The average spot price for the week was $122/MWh, a decrease of around $47/MWh compared to the previous week.

(b) 95% of prices fell between $0.53/MWh and $205/MWh.

2.3. Spot prices hovered between $150-$200/MWh at the start of the week. From Tuesday, prices began to decline due to high wind generation. Between Wednesday and Friday, overnight prices dropped to near zero.

2.4. 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 (if any).

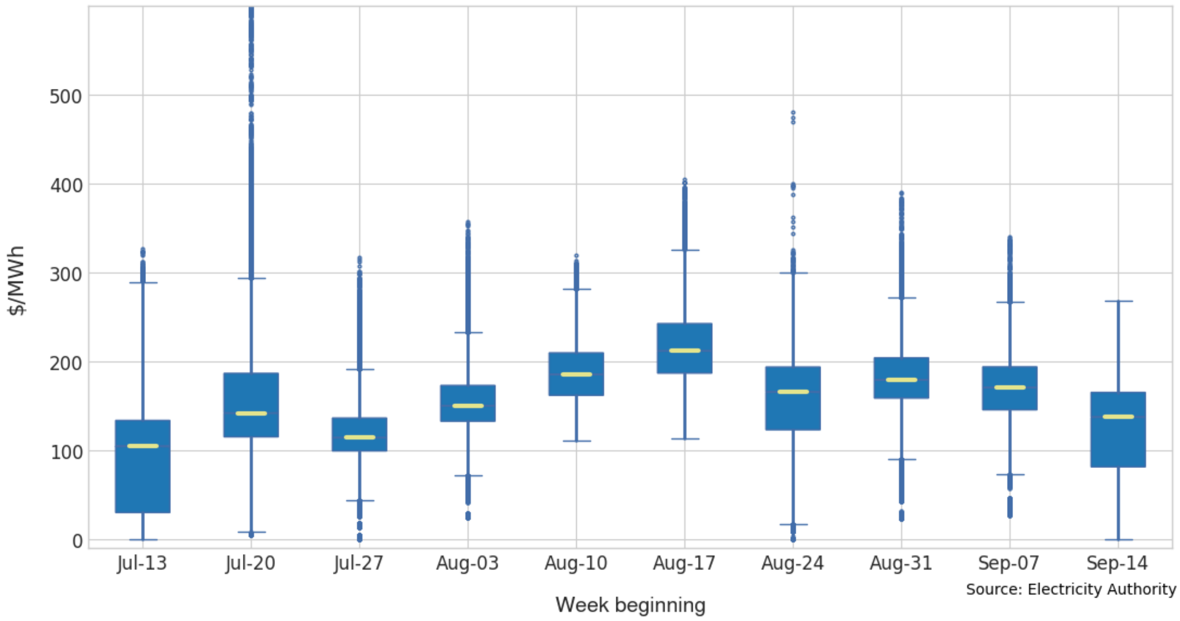
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 14-20 September 2025



2.5. 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.

2.6. The distribution of spot prices this week was wider than last week. The median price was $138/MWh and most prices (middle 50%) fell between $82/MWh and $165/MWh.

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

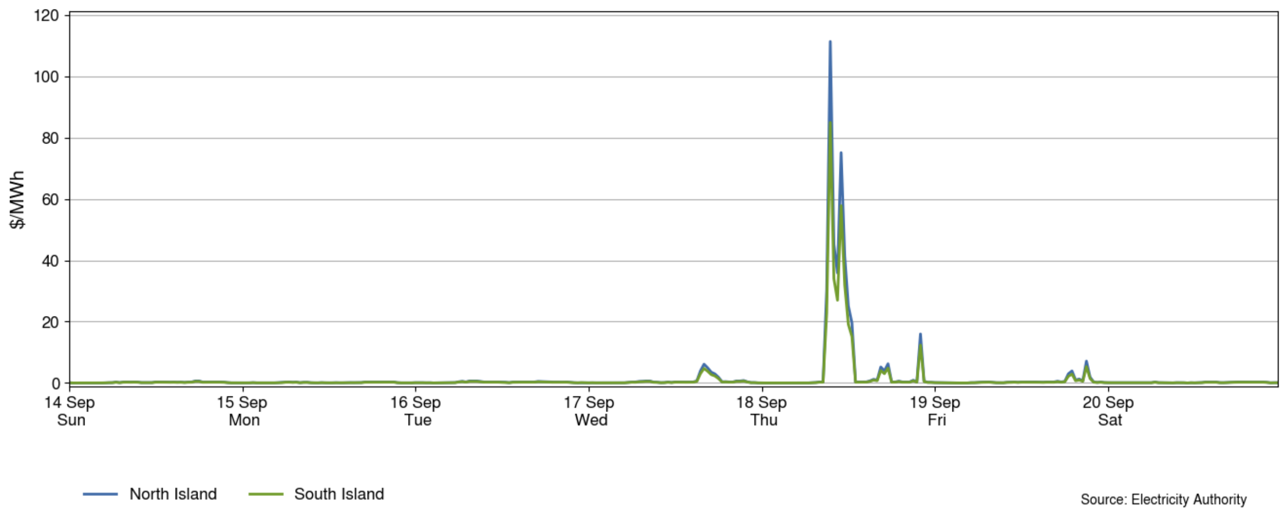


3. Reserve prices

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 on Thursday.

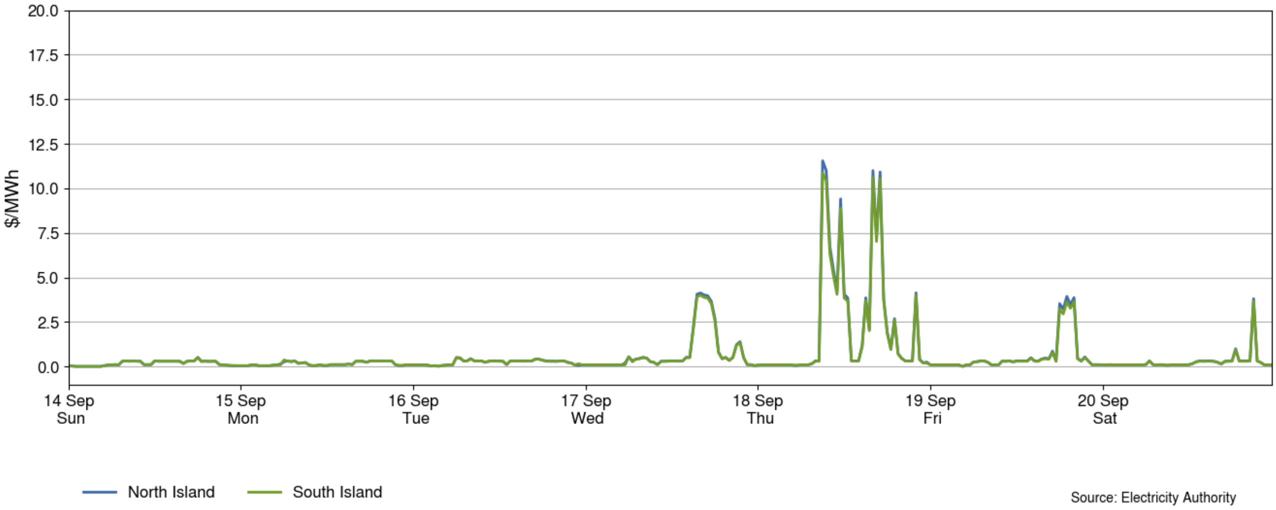
3.2. A significant FIR price spike occurred on Thursday at 9.30am, with prices reaching around $111/MWh in the North Island and $85/MW in the South Island, and reserve prices remained elevated until 1pm. During that time the Ruakākā battery was on outage which removed cheap reserve available to cover the risk setter, which was Huntly 5.

Figure 3: Fast instantaneous reserve price by trading period and island, 14-20 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 $10/MWh. SIR prices were higher on Thursday during the Ruakākā battery outage.

Figure 4: Sustained instantaneous reserve by trading period and island, 14-20 September 2025



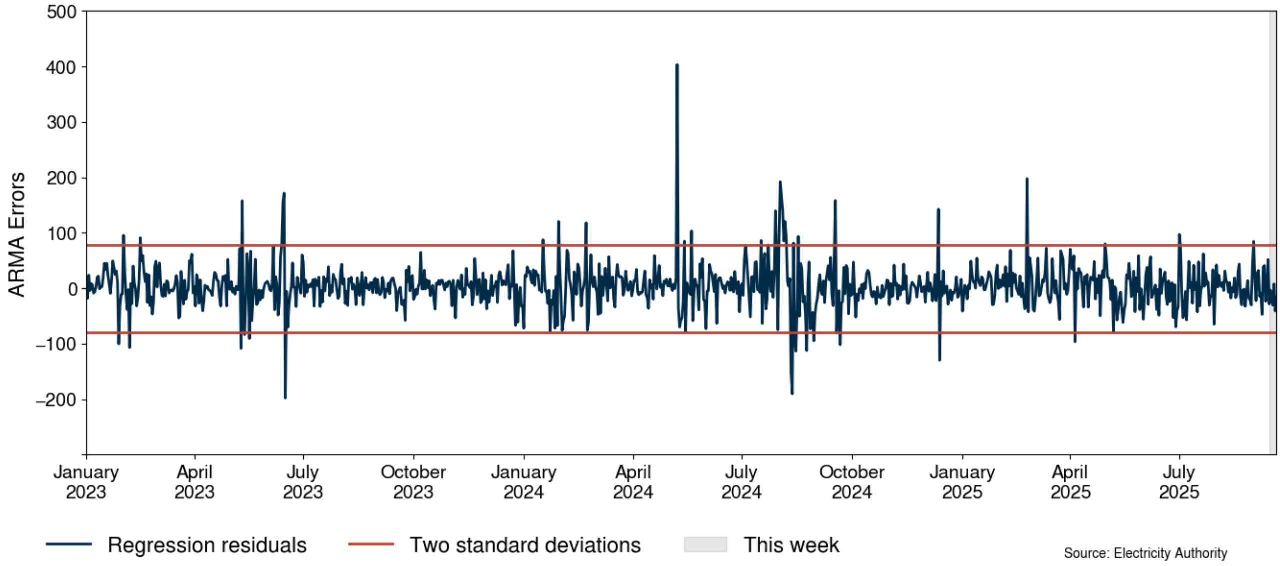
4. Regression residuals

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.

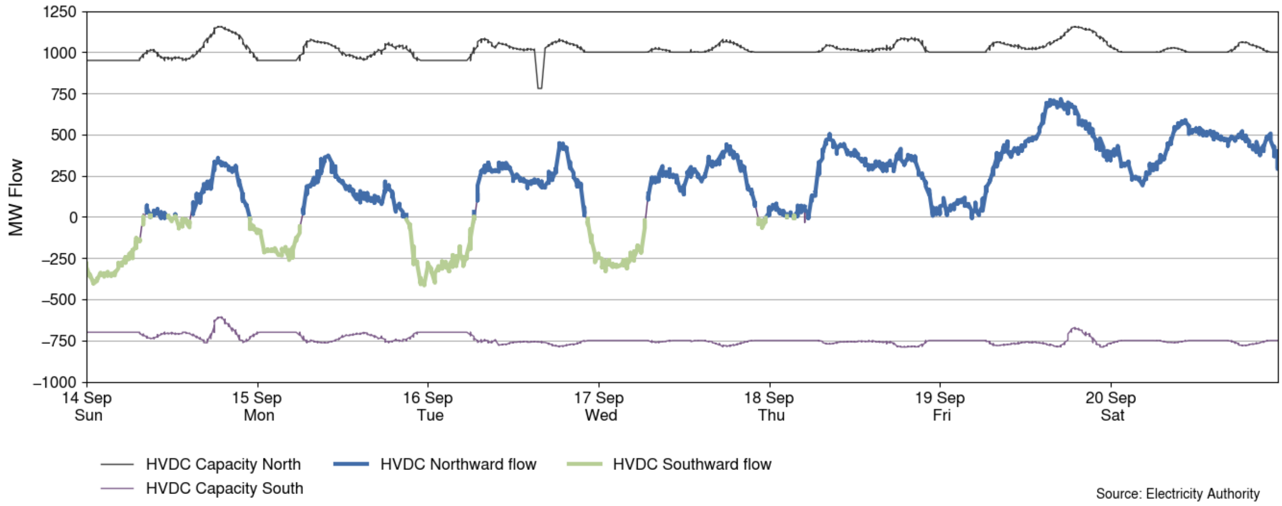
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 20 September 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 14-20 September 2025. From Sunday to Wednesday, HVDC flows were northward during the day and southward overnight. From Thursday, flows were consistently northward. Northward flows reached around 714MW on Friday at 5.00pm.

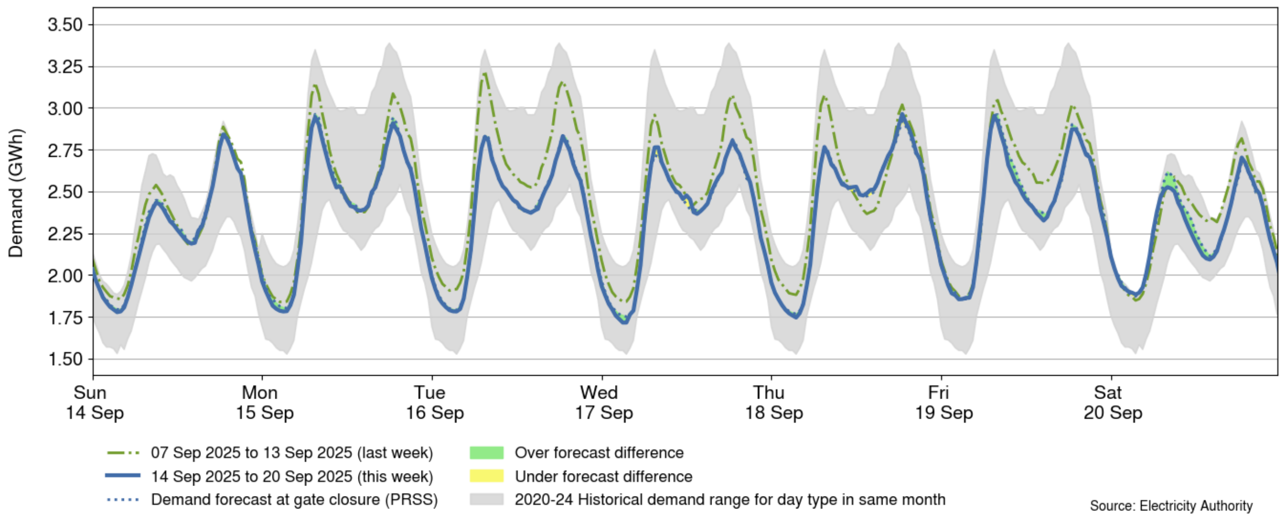
Figure 6: HVDC flow and capacity, 14-20 September 2025



6. Demand

6.1. Figure 7 shows national demand between 14-20 September 2025, compared to the historic range and the demand of the previous week. Overall, demand was lower than last week. The highest demand of the week was around 2.96GWh at 6.30pm on Thursday during the evening peak.

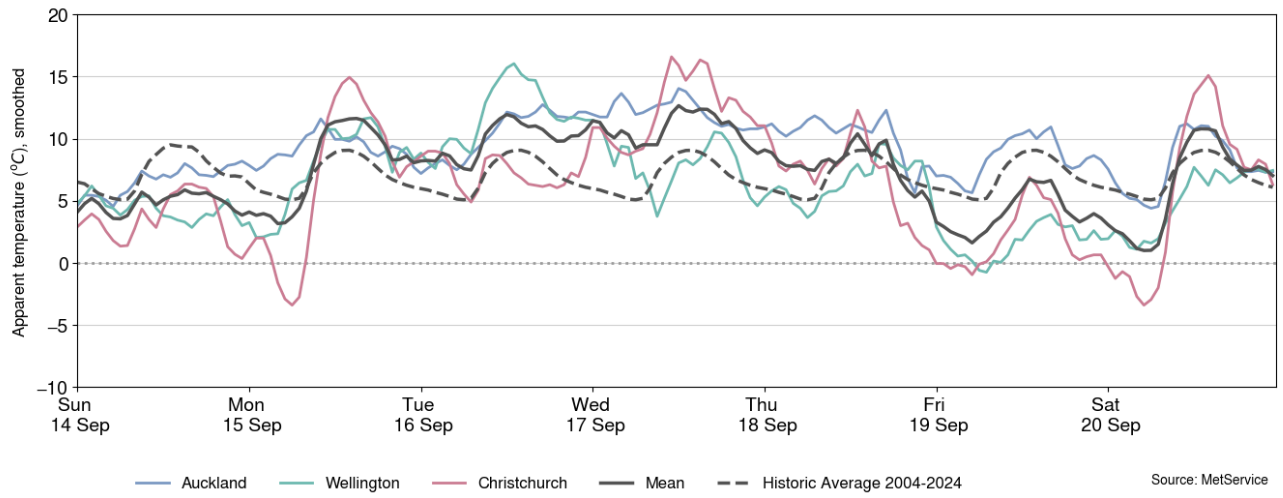
Figure 7: National demand, 14-20 September 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 14-20 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 4°C to 14°C in Auckland, -1°C to 16°C in Wellington, and -4°C to 17°C in Christchurch.

Figure 8: Temperatures across main centres, 14-20 September 2025

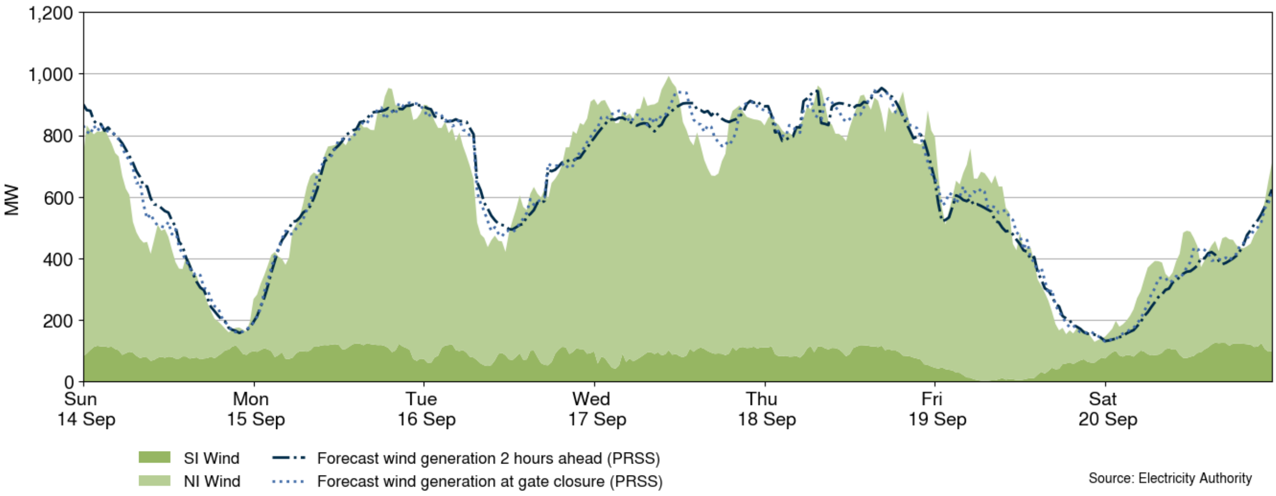


7. Generation

7.1. Figure 9 shows wind generation and forecast from 14-20 September 2025. This week wind generation varied between 129MW and 993MW, with a weekly average of 622MW.

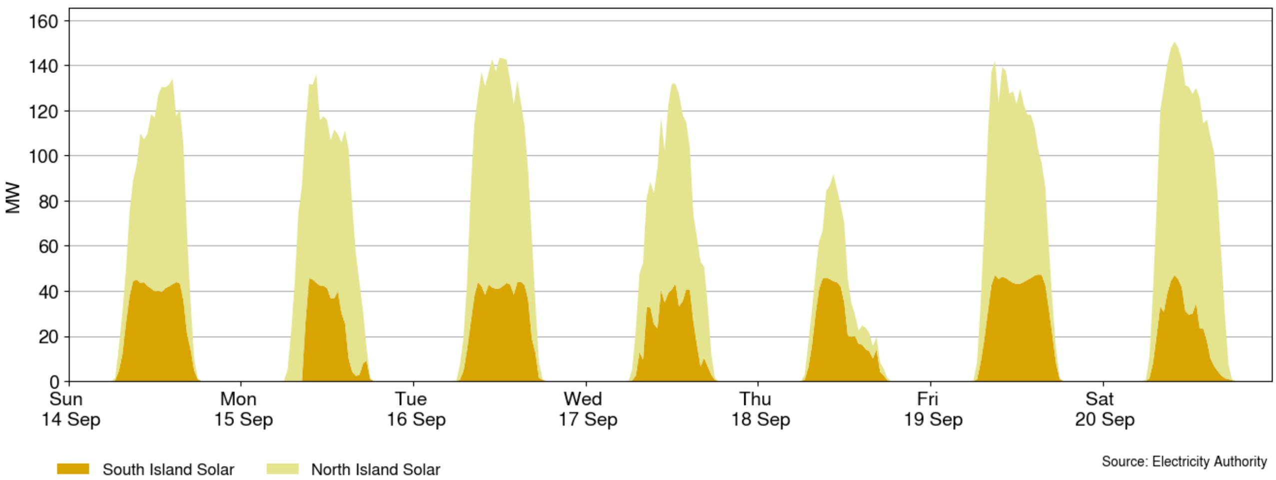
7.2. Wind generation was high on Sunday but dropped sharply by night. It increased again on Monday but began declining on Tuesday night. Wind generation remained mostly high through Wednesday and Thursday, declined on Friday. Wind rose gradually again from Saturday morning. Large forecasting errors occurred on Sunday, Tuesday and Wednesday when several wind farms were overforecast.

Figure 9: Wind generation and forecast, 14-20 September 2025



7.3. Figure 10 shows grid connected solar generation from 14-20 September 2025. Except for Thursday, solar generation typically peaked above 120MW, with a maximum of 150MW at 10.00am on Saturday.

Figure 10: Grid connected solar generation, 14-20 September 2025



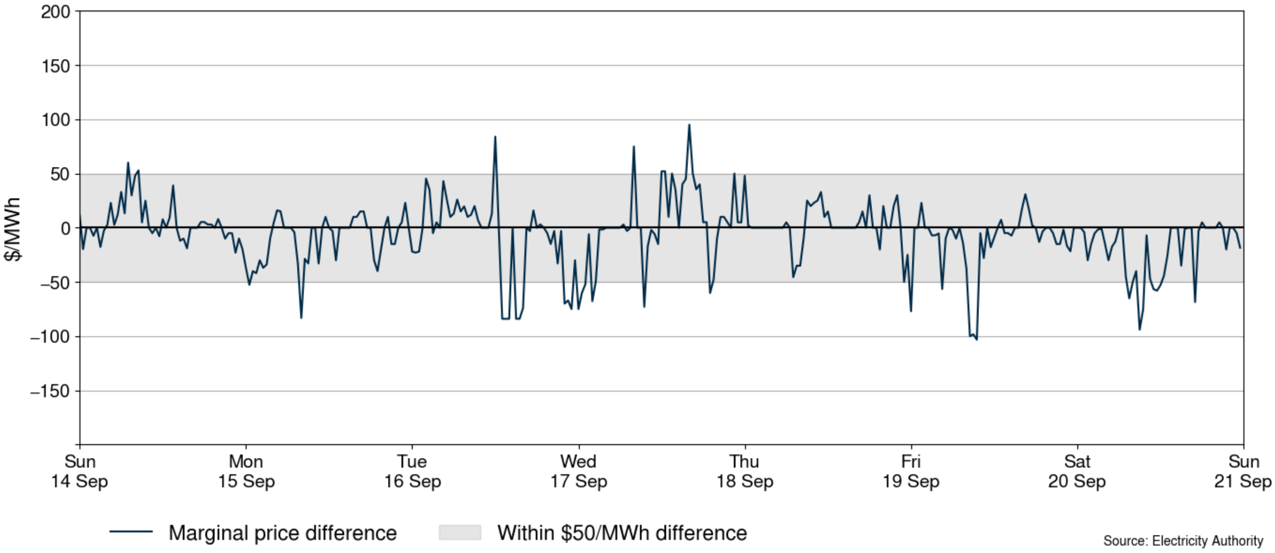
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being 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

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

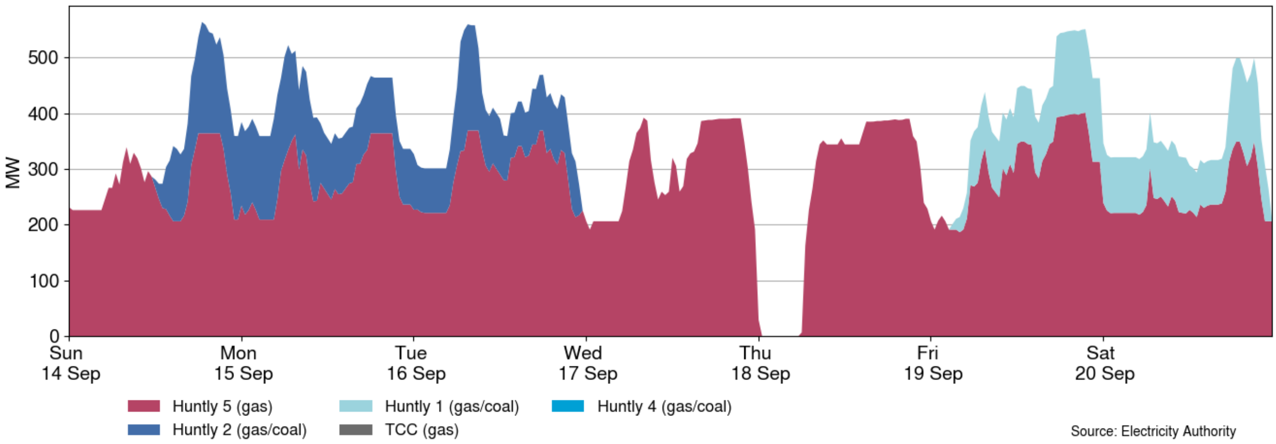
difference of +$95/MWh occurred at 4.00pm on Wednesday, when wind was 140MW lower than forecast. Most price differences were negative this week, meaning wind and demand errors lead to prices being overall lower than the simulated prices.

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, 14-20 September 2025



7.6. Figure 12 shows the generation of thermal baseload between 14-20 September 2025. Huntly 5 ran as baseload throughout the week, except on Thursday night. Huntly 2 ran from Sunday afternoon through Tuesday. Huntly 1 ran between Friday and Saturday.

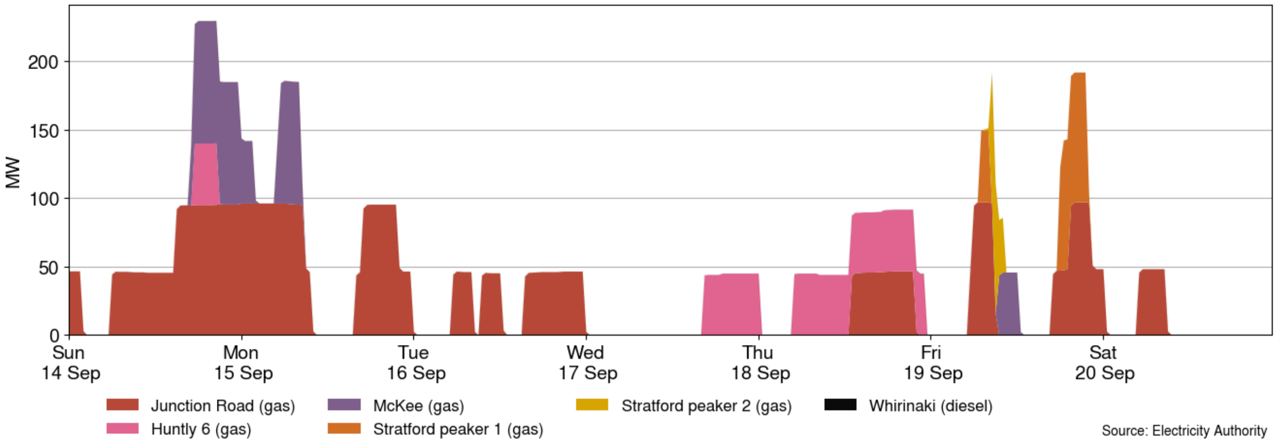
Figure 12: Thermal baseload generation, 14-20 September 2025



7.7. Figure 13 shows the generation of thermal peaker plants between 14-20 September 2025. Junction Road ran daily this week, except on Wednesday when wind was high. McKee ran on Sunday evening, Monday morning, and Friday evening, mostly during the peak demand periods.

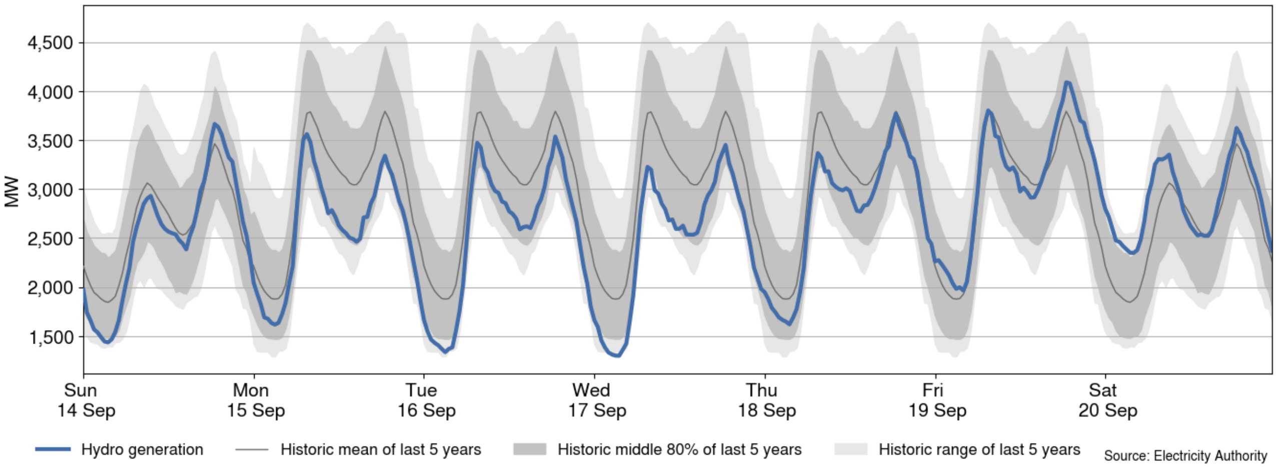
7.8. Stratford peaker 1 and Stratford peaker 2 were also dispatched on Friday. Huntly 6 generated during the evening peak on Sunday and Wednesday, and consistently on Thursday.

Figure 13: Thermal peaker generation, 14-20 September 2025



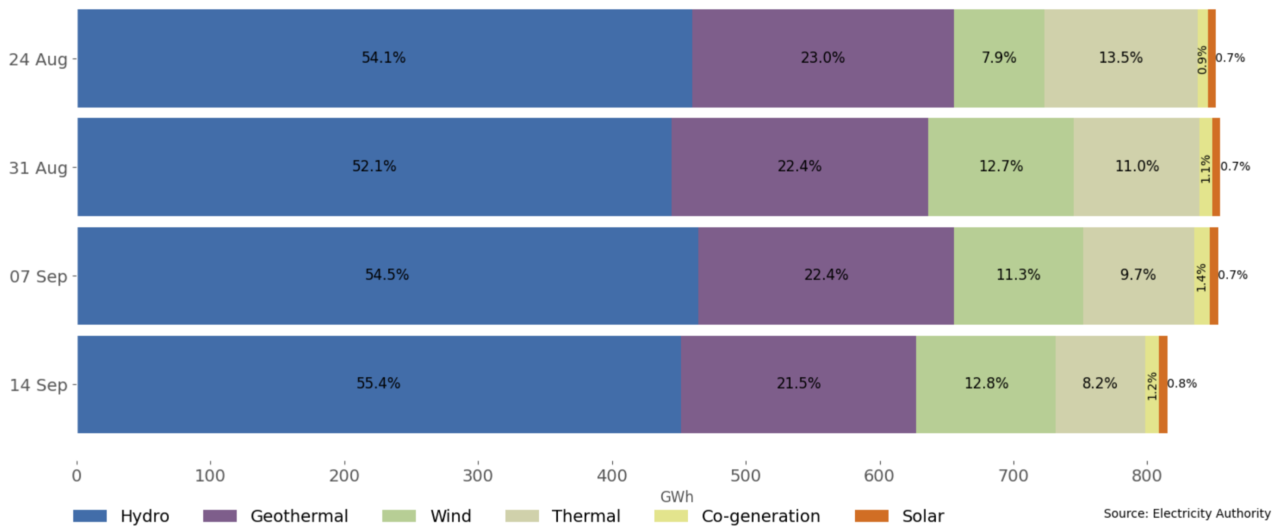
7.9. Figure 14 shows hydro generation between 14-20 September 2025. Hydro generation was below the historic average from Monday to Thursday, as wind was high. However, between Friday and Saturday, hydro generation was around or above the historic average.

Figure 14: Hydro generation, 14-20 September 2025



7.10. As a percentage of total generation, between 14-20 September 2025, total weekly hydro generation was 55.4%, geothermal 21.5%, wind 12.8%, thermal 8.2%, co-generation 1.2%, and solar (grid connected) 0.8%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 24 August and 20 September 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 14-20 September 2025 ranged between ~1,127MW and ~1,979MW, which is above average for this time of year. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

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

(c) Takapō was on outage from 14-17, and 19 September 2025.

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

(e) Geothermal Te Mihi is on outage until 23 September 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.

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

Figure 16: Total MW loss from generation outages, 14-20 September 2025

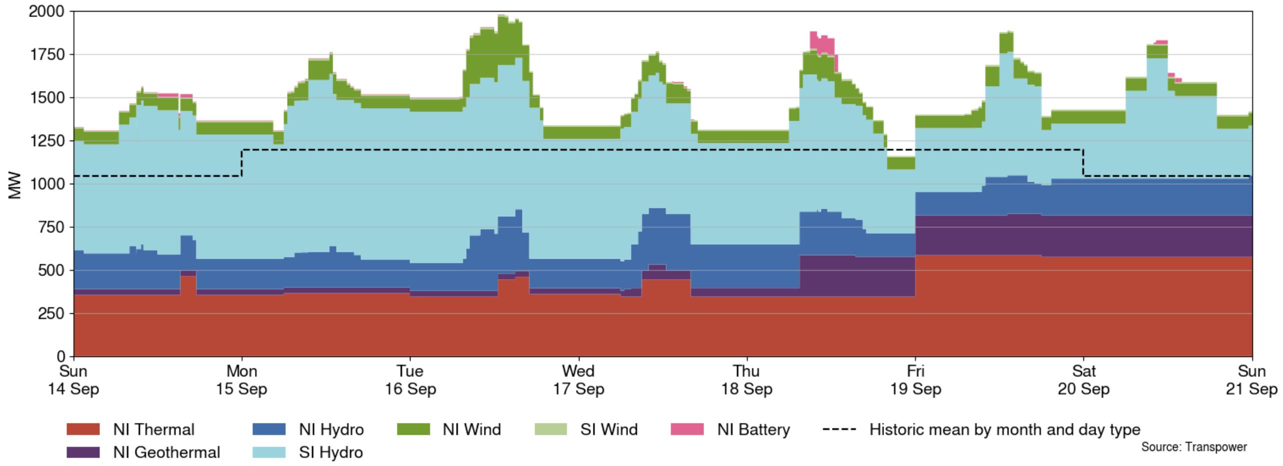
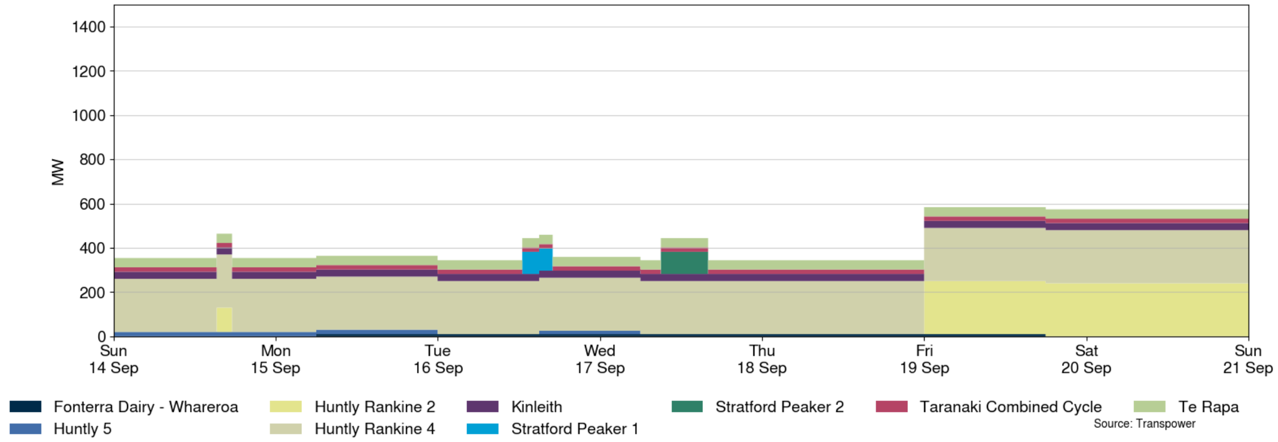


Figure 17: Total MW loss from thermal outages, 14-20 September 2025

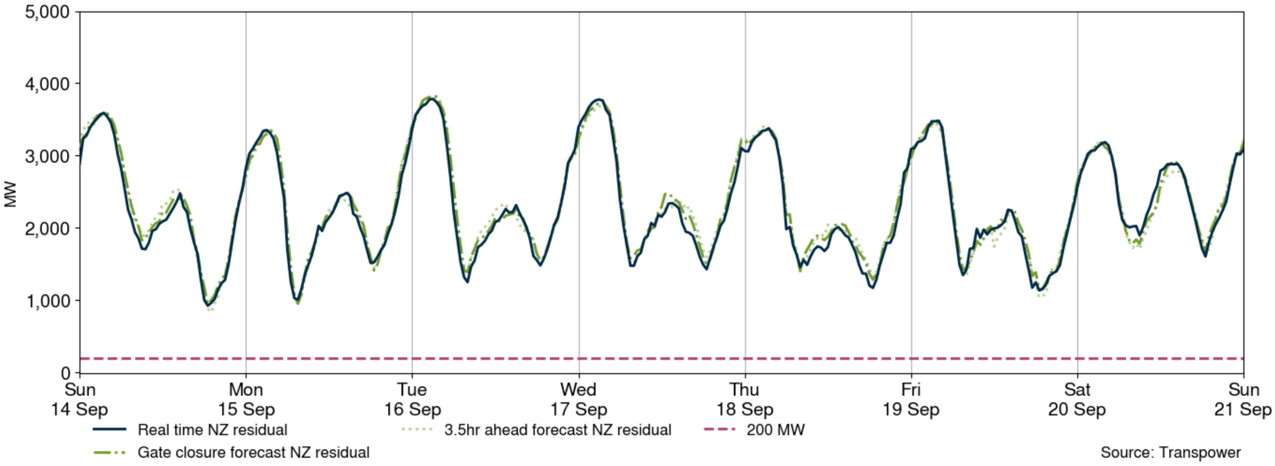


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 14-20 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 925MW on Sunday at 6.30pm.

Figure 18: National generation balance residuals, 14-20 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 20 September 2025, national controlled hydro storage had increased to 54% of nominal full and ~93% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (35% full[2]) and Lake Takapō (34% full) is slightly above their respective historic 10th percentiles.

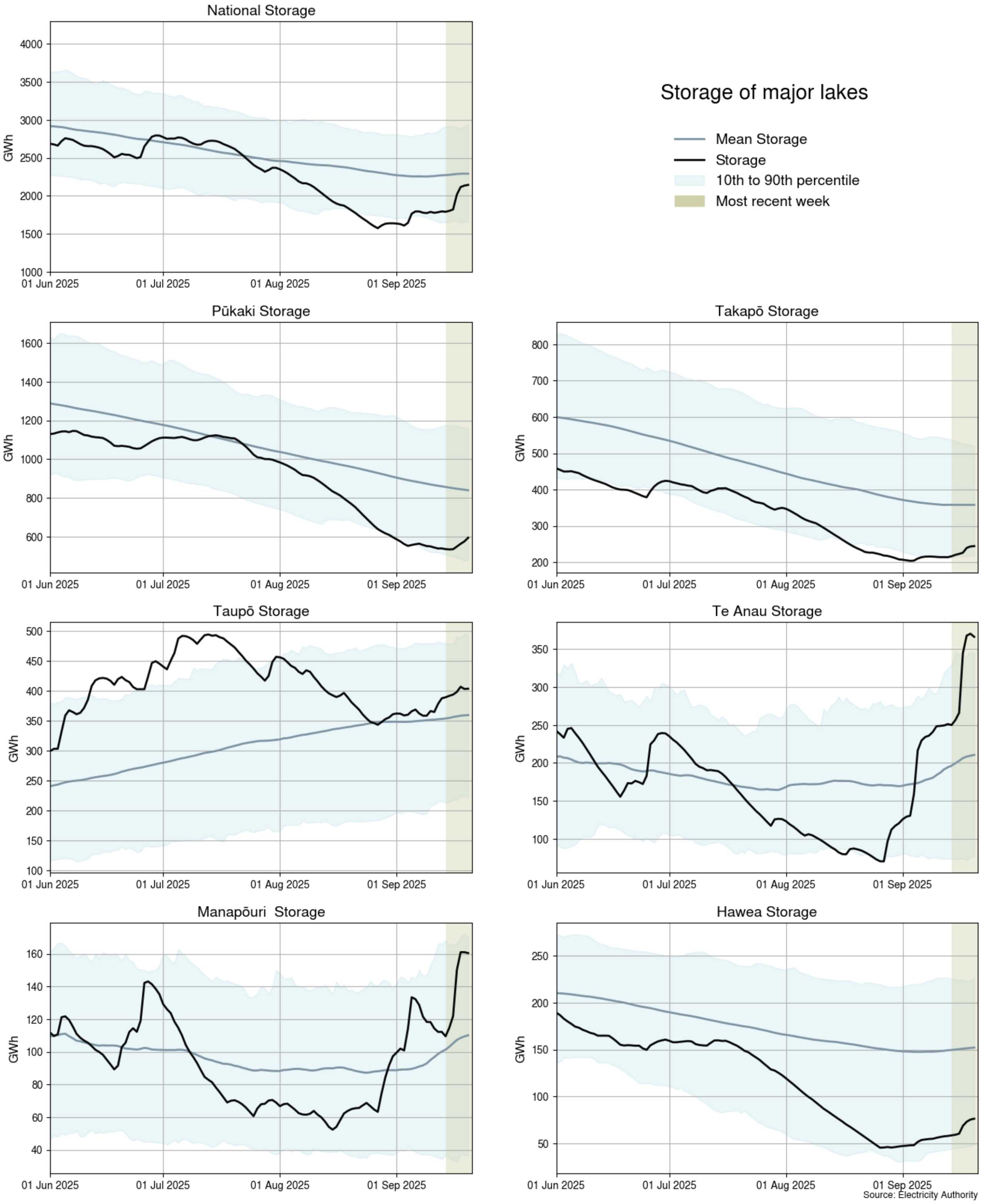
10.4. Storage at Lake Te Anau (146% full) is above its historic 90th percentile, while Lake Manapōuri (109% full) is slightly below its historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (71% full) is above its historic mean for this time of year.

10.6. Storage at Lake Hawea (28% full) is slightly above its historic 10th percentile.

[2] Percentage full values sourced from NZX hydrological summary 21 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.

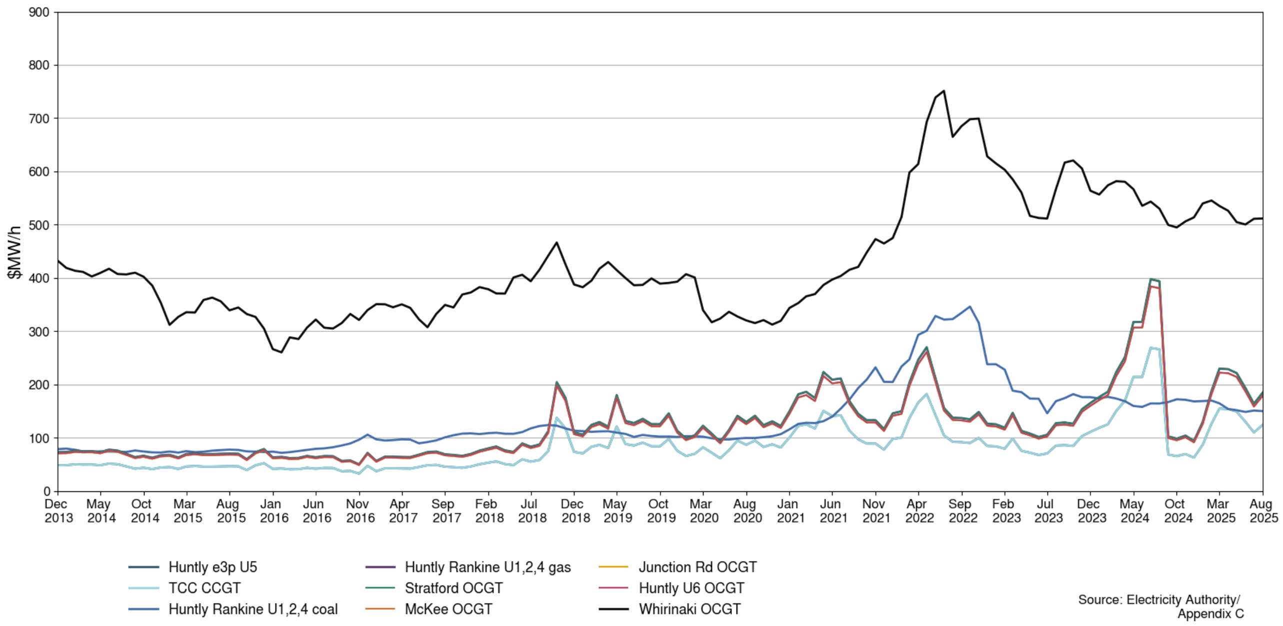
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

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

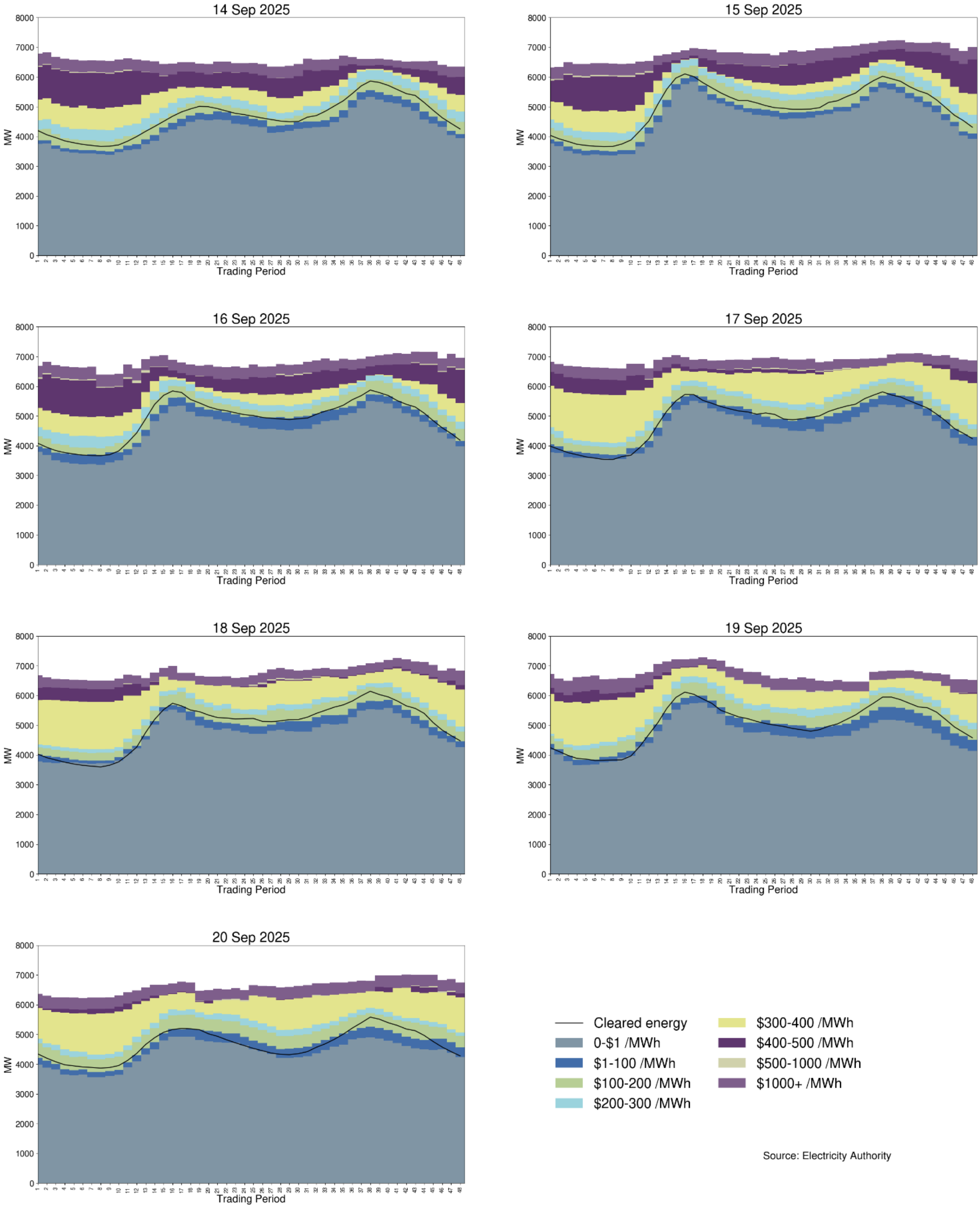


12. Offer behaviour

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. A few hydro generation offers were down in the next lower tranches, as hydro storage increased slightly.

Figure 21: Daily offer stacks

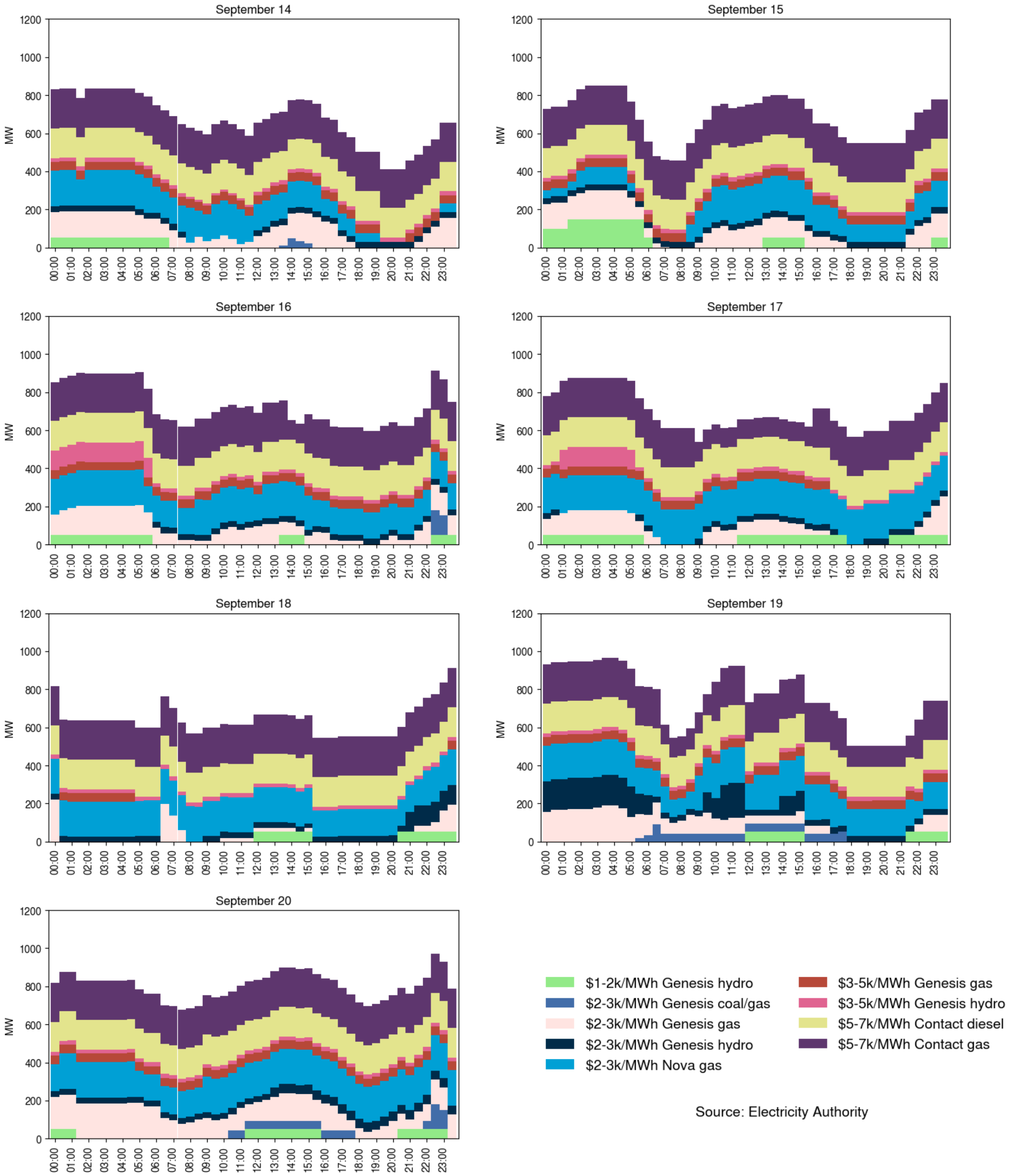


12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 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 712MW per trading period was priced above $1,000/MWh this week, which is roughly 12.6% 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