8 September 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report
30 August - 5 September 2026

Market monitoring weekly report

Trading conduct report 30 August - 5 September 2026

1. Overview

1.1. Spot prices have decreased compared to the previous week, as intermittent generation was high. Prices remained near or below the historic average for this time of year. Hydro storage has increased to 83% nominally full and ~139% of the historical average for this time of the year.

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 30 August - 5 September:

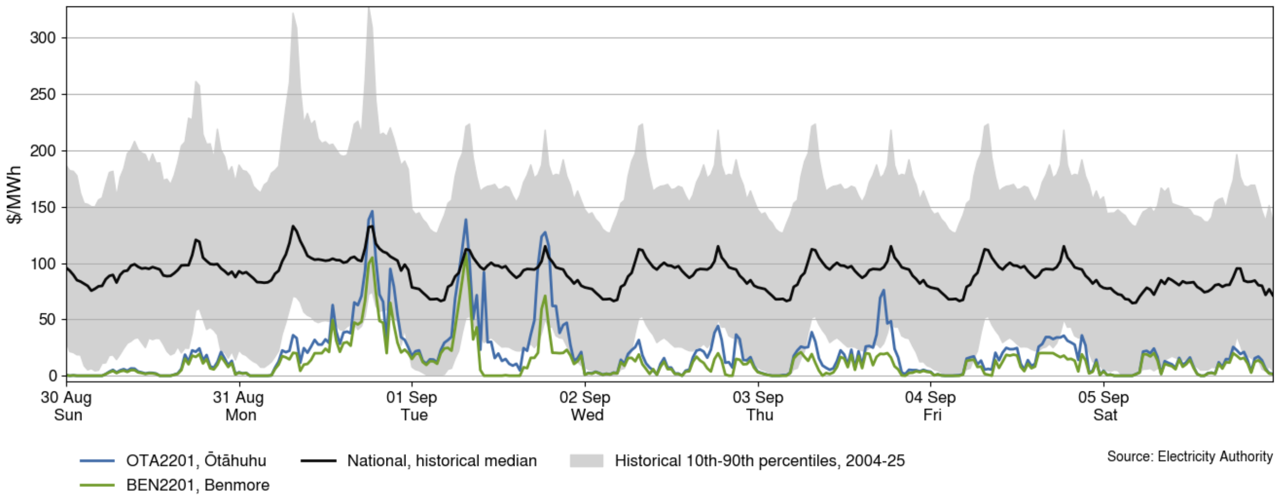
(a) The average spot price for the week was \$17/MWh, a decrease of around \$25/MWh compared to the previous week.

(b) 95% of prices fell between \$0.01/MWh and \$87/MWh.

2.3. Prices were lower this week as wind generation was high increasing the availability of cheap energy. Increased hydro storage also led hydro generators to decrease the price of their hydro generation offers.

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.

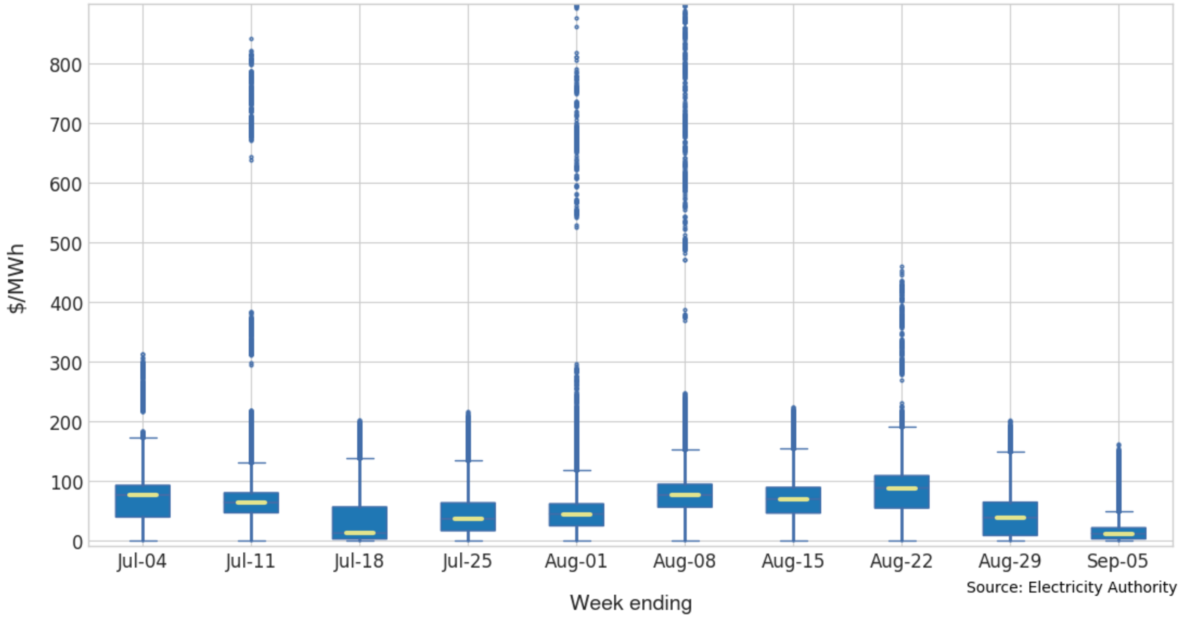
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 30 August - 5 September



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 narrower than last week with lower high-priced outliers. The median price was $17/MWh and most prices (middle 50%) fell between $2/MWh and $21/MWh.

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

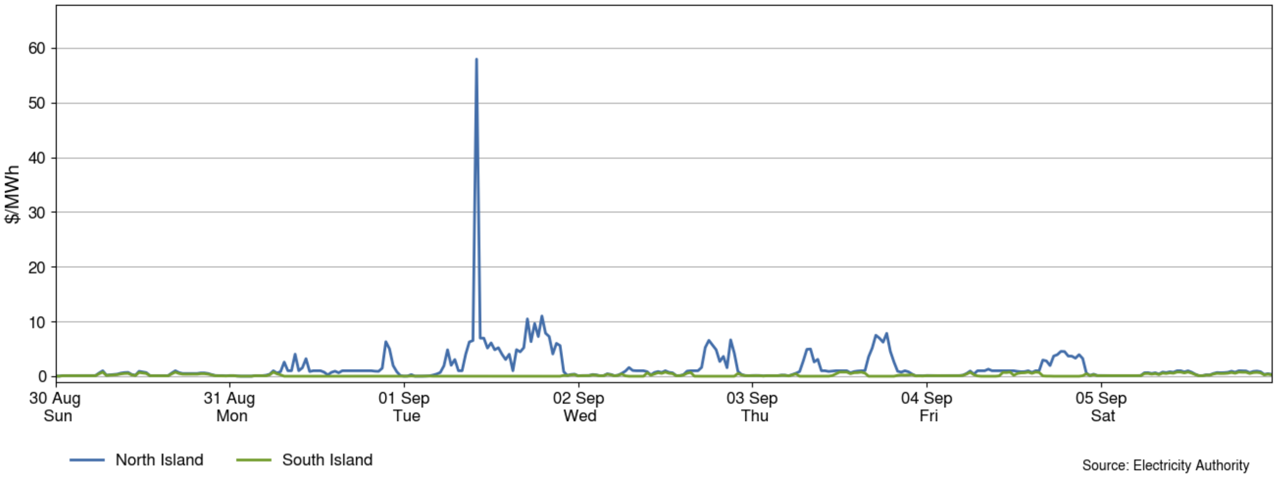


3. Reserve prices

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 this week.

3.2. North Island FIR prices spiked up to ~$58/MWh at 10.00am on Tuesday. At this time the HVDC was setting the risk and there was 30MW of northward HVDC flow capacity remaining. Additionally intermittent generation was 151MW lower than forecast and Huntly BESS was charging at 100MW.

Figure 3: Fast instantaneous reserve price by trading period and island, 30 August - 5 September

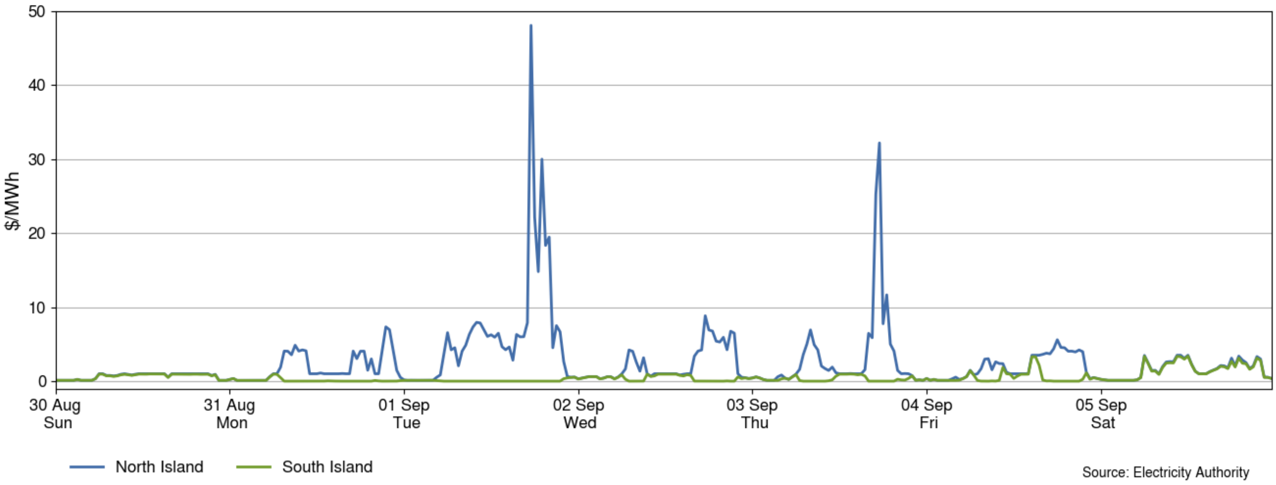


3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh this week.

3.4. North Island SIR prices spiked up to $48/MWh at 5.30pm on Tuesday. At this time the HVDC had 91MW of northward HVDC flow capacity remaining. Intermittent generation was 44MW lower than forecast.

3.5. North Island SIR prices spiked up to $32/MWh at 5.30pm on Thursday. At this time the HVDC had 80MW of northward HVDC flow capacity remaining. Intermittent generation was 60MW lower than forecast.

Figure 4: Sustained instantaneous reserve by trading period and island, 30 August - 5 September



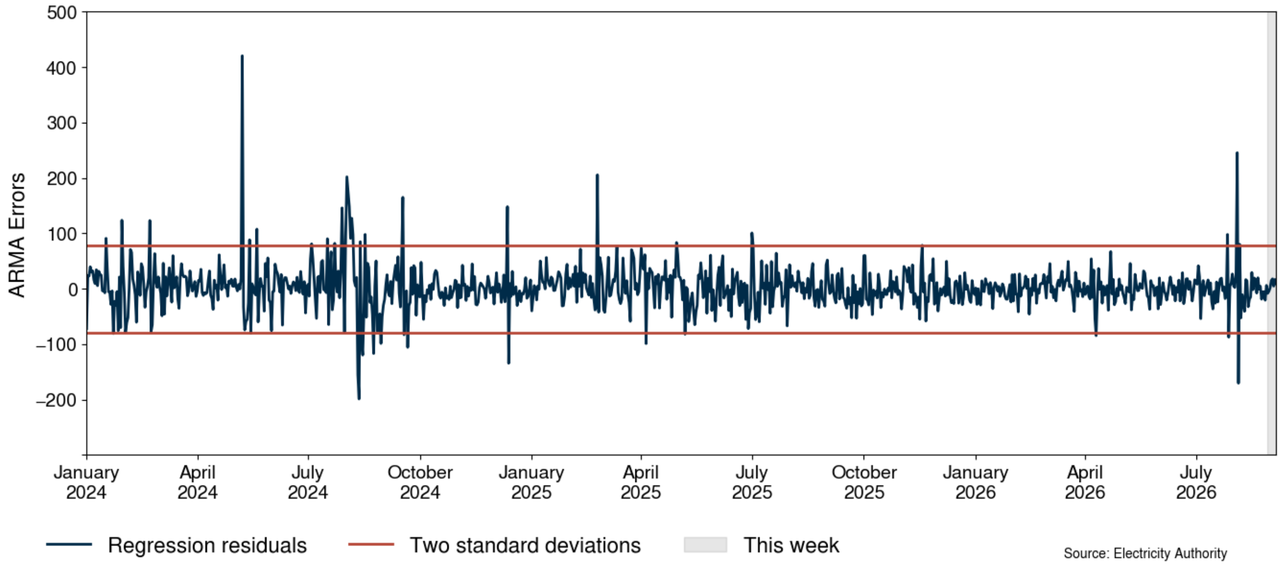
4. Regression residuals

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 2024 - 5 September 2026



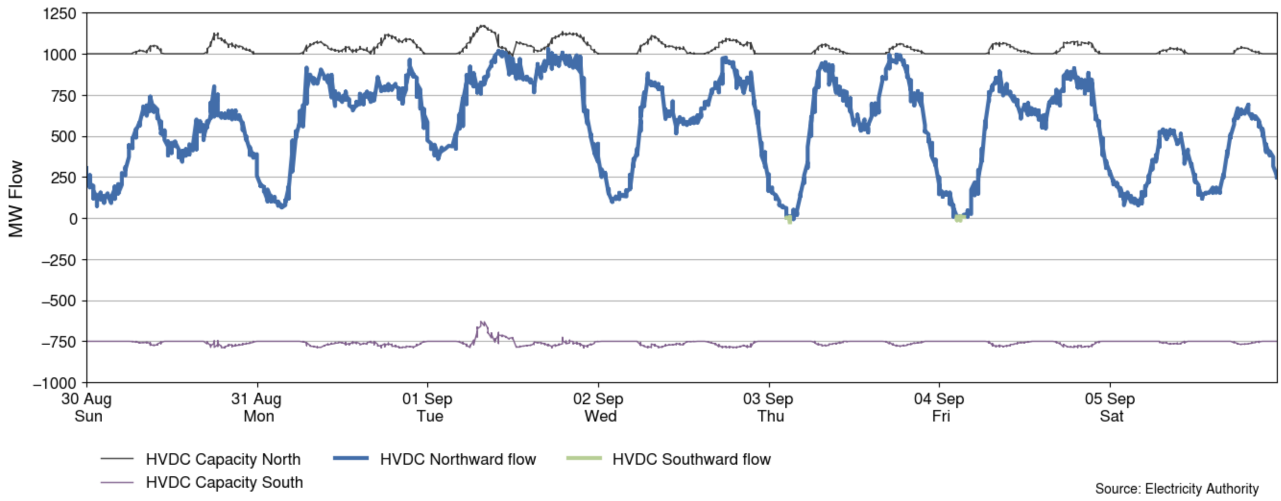
5. HVDC

5.1. Figure 6 shows the HVDC flow between 30 August - 5 September. HVDC flows were mostly northward this week.

5.2. The highest northward HVDC flow this week was 1028MW which occurred at 5.00pm on Tuesday.

5.3. The highest southward HVDC flow this week was -25MW which occurred at 3.00am on Thursday.

Figure 6: HVDC flow and capacity, 30 August - 5 September



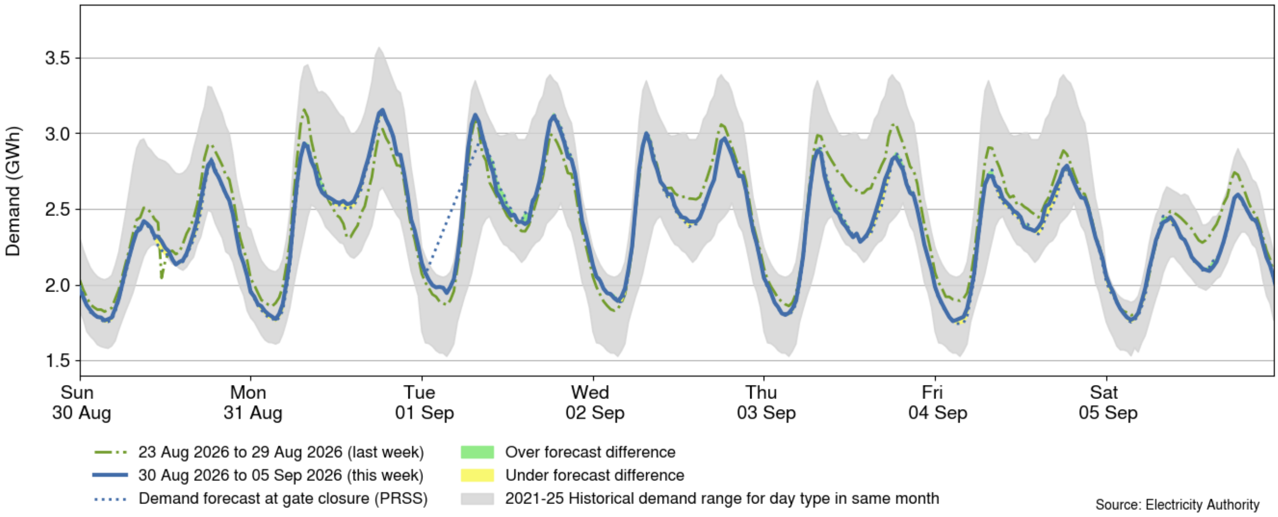
6. Demand

6.1. Figure 7 shows national demand between 30 August - 5 September, compared to the historic range and the demand of the previous week. Demand this week was generally similar or lower than last week.

6.2. The maximum demand this week was around 3.15GWh (6.31GW) at 6:30pm on Monday.

6.3. Demand forecast at gate closure data is missing from 12.00am-8.30am Tuesday due to a data error.

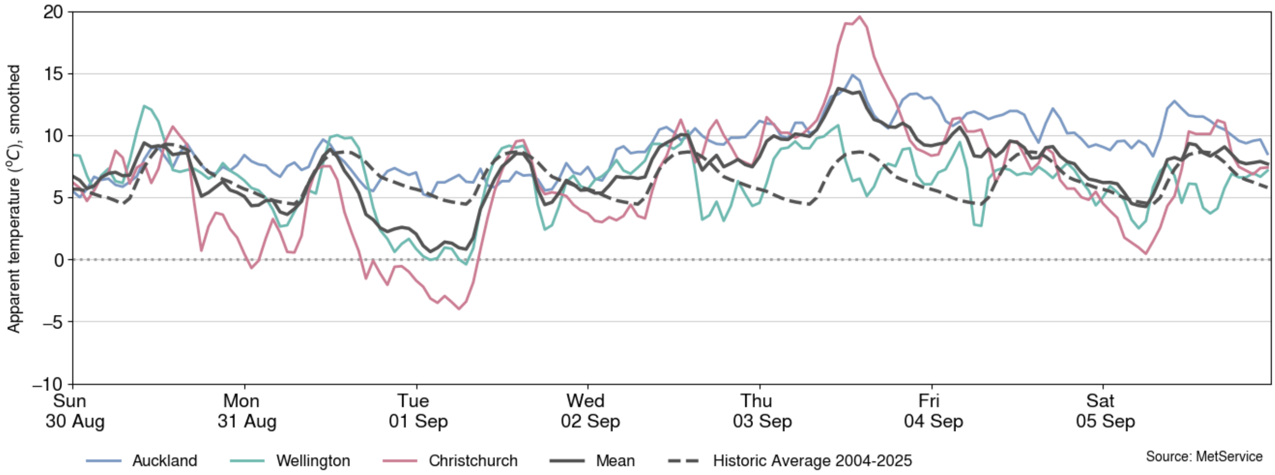
Figure 7: National demand, 30 August - 5 September compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 30 August - 5 September. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how hot or 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.

6.5. Apparent temperatures ranged from 4°C to 15°C in Auckland, 0°C to 13°C in Wellington, and -4°C to 20°C in Christchurch.

Figure 8: Temperatures across main centres, 30 August - 5 September



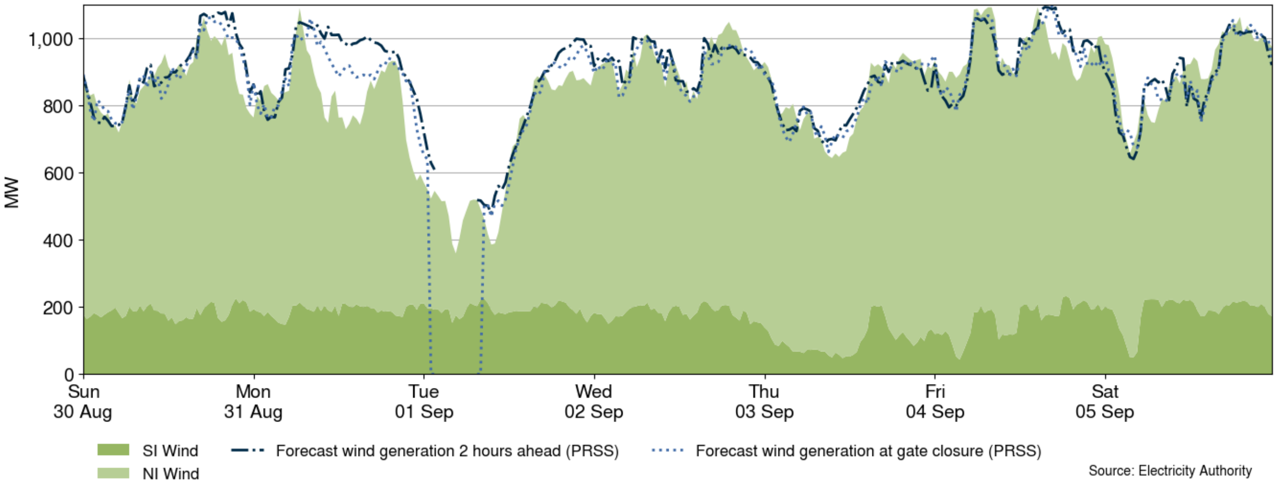
7. Generation

7.1. Figure 9 shows wind generation and forecast from 30 August - 5 September. This week wind generation varied between 359MW and 1093MW, with a weekly average of 854MW. Wind generation was high this week, exceeding 1000MW at times and only dropping below 600MW on Tuesday morning.

7.2. Wind generation forecast data is unavailable from 12.30am-7.30am on Tuesday due to a data error which caused wind generation data to be temporarily unavailable during this period.

7.3. Forecasting errors on Monday where generation was between 42MW and 204MW lower than forecast were due to Harapaki, Waipipi, and Tararua Stage I wind farms.

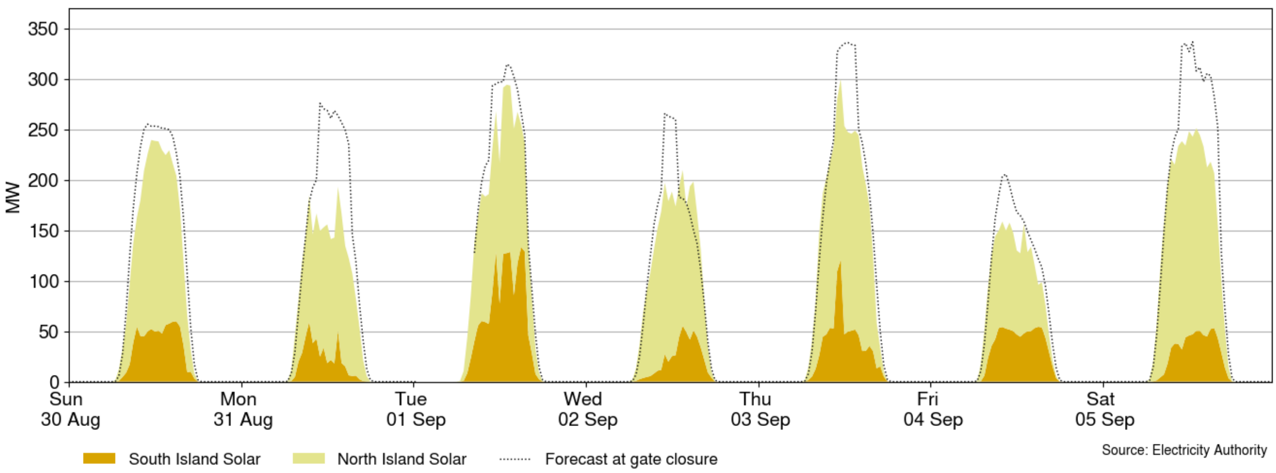
Figure 9: Wind generation and forecast, 30 August - 5 September



7.4. Figure 10 shows grid connected solar generation from 30 August - 5 September. Solar generation was high this week. Mean solar generation this week was 130MW during the day, peaking at 300MW on Thursday at 11:30am.

7.5. Forecasting errors throughout the week are mainly due to Kōwhai Park solar farm.

Figure 10: Grid connected solar generation, 30 August - 5 September

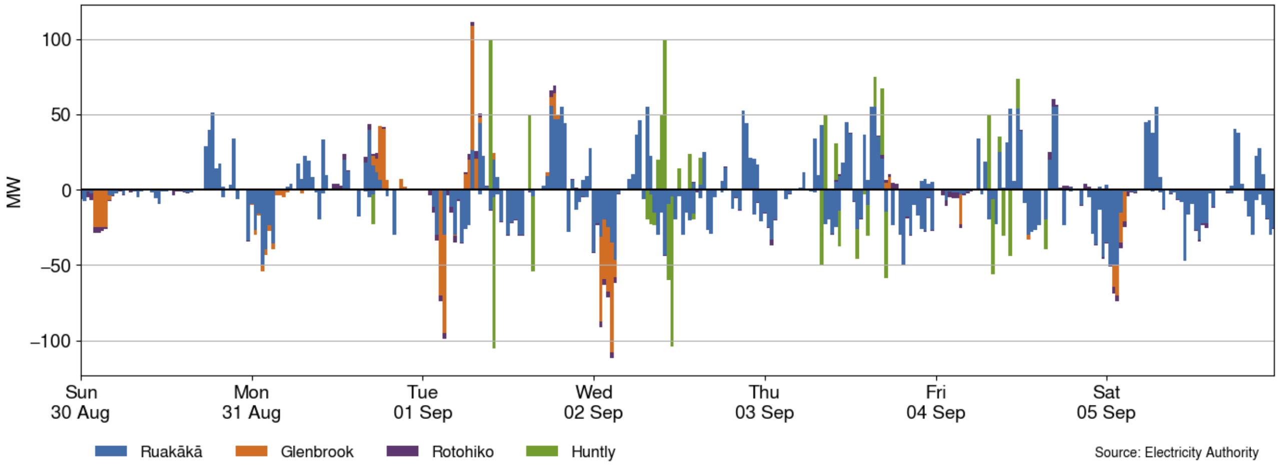


7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh, commissioning) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.7. This week batteries generally charged overnight and during the middle of the day when demand was lower and discharged during morning and evening peak demand.

7.8. Genesis' Huntly BESS appears to be conducting testing as part of its commissioning process.

Figure 11: Grid scale battery charge and discharge, 30 August - 5 September



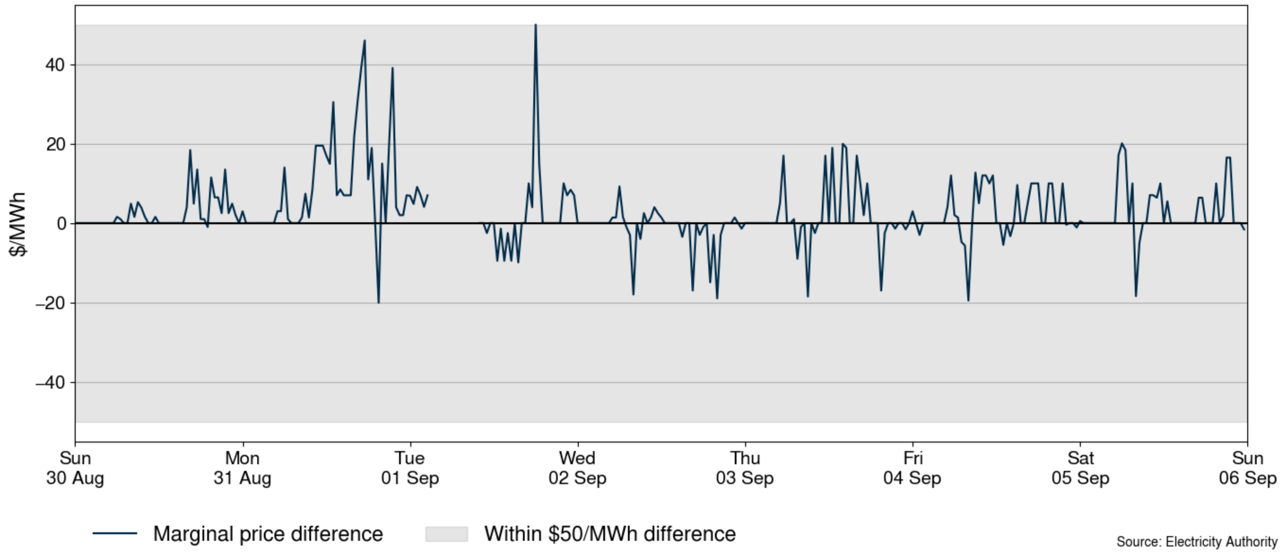
7.9. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing 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 intermittent generation is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and intermittent generation forecasting, the 1-hour ahead and the RTD intermittent generation 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.

7.10. This week there were no periods with a price forecast difference greater than $50/MWh.

7.11. Marginal price forecast data is missing on Tuesday morning due to multiple sources of forecast data being disrupted due to the data error.

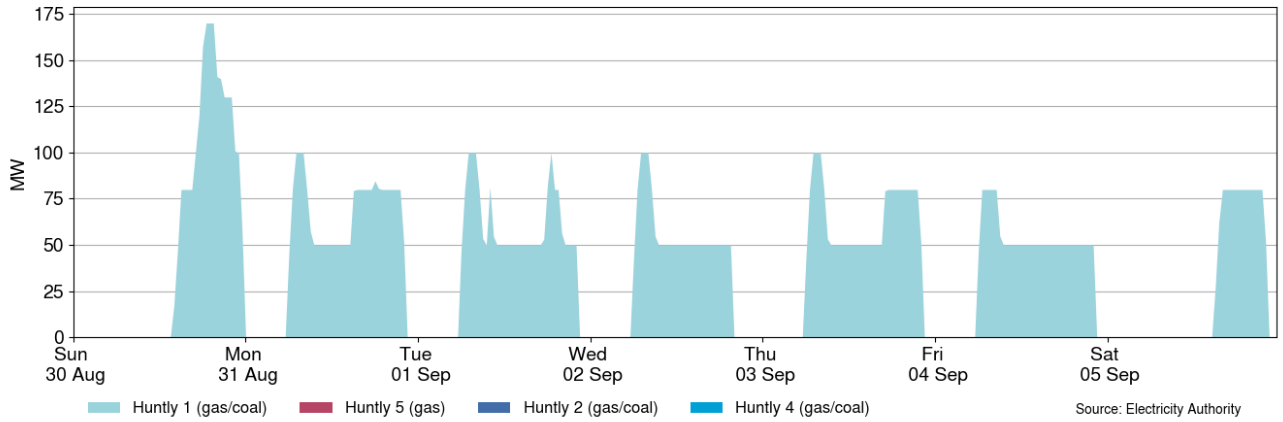
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 30 August - 5 September



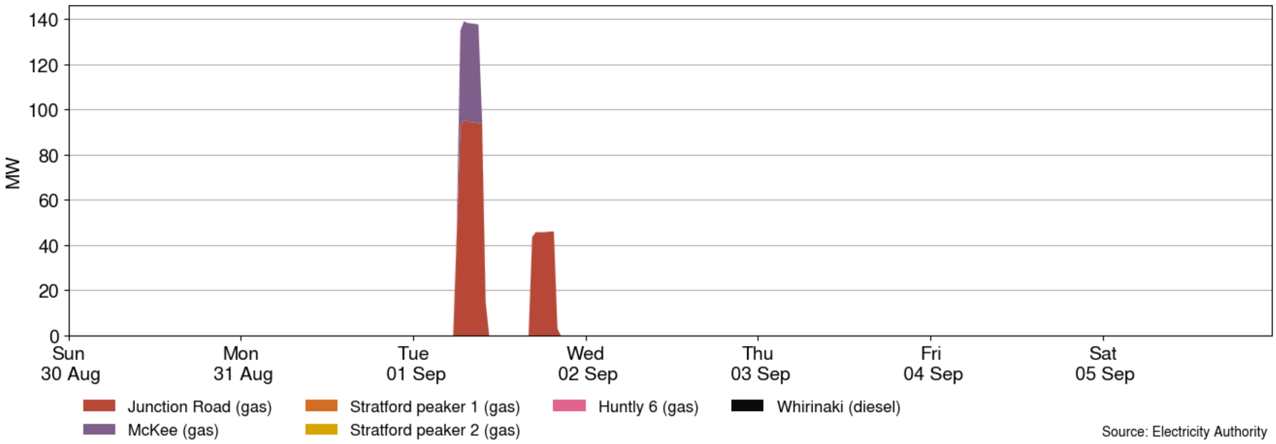
7.12. Figure 13 shows the generation of thermal baseload between 30 August - 5 September. 50MW of thermal baseload generation was provided by Huntly 1 this week. Ramping up to 100MW or more at peak times.

Figure 13: Thermal baseload generation, 30 August - 5 September



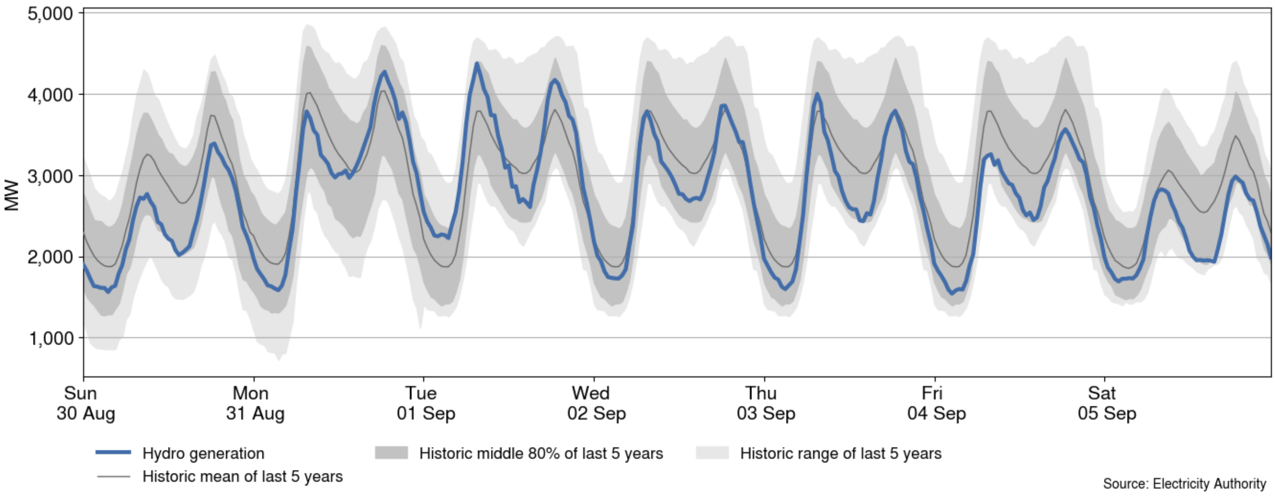
7.13. Figure 14 shows the generation of thermal peaker plants between 30 August - 5 September. Peaker generation this week was isolated to peak demand periods on Tuesday when HVDC flows were close to the northward flow capacity.

Figure 14: Thermal peaker generation, 30 August - 5 September



7.14. Figure 15 shows hydro generation between 30 August - 5 September. Hydro generation was near or below the historic mean every day this week except Tuesday.

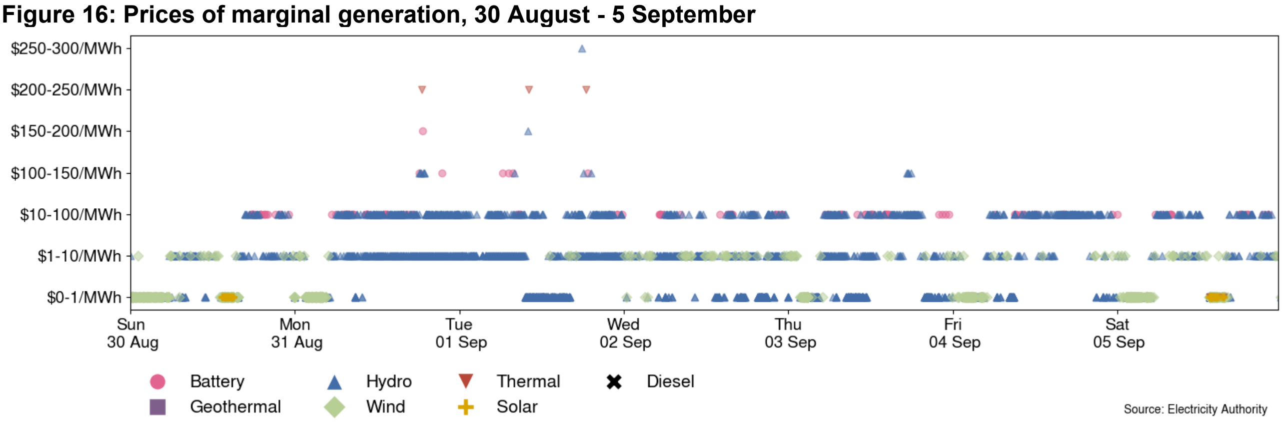
Figure 15: Hydro generation, 30 August - 5 September



7.15. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.

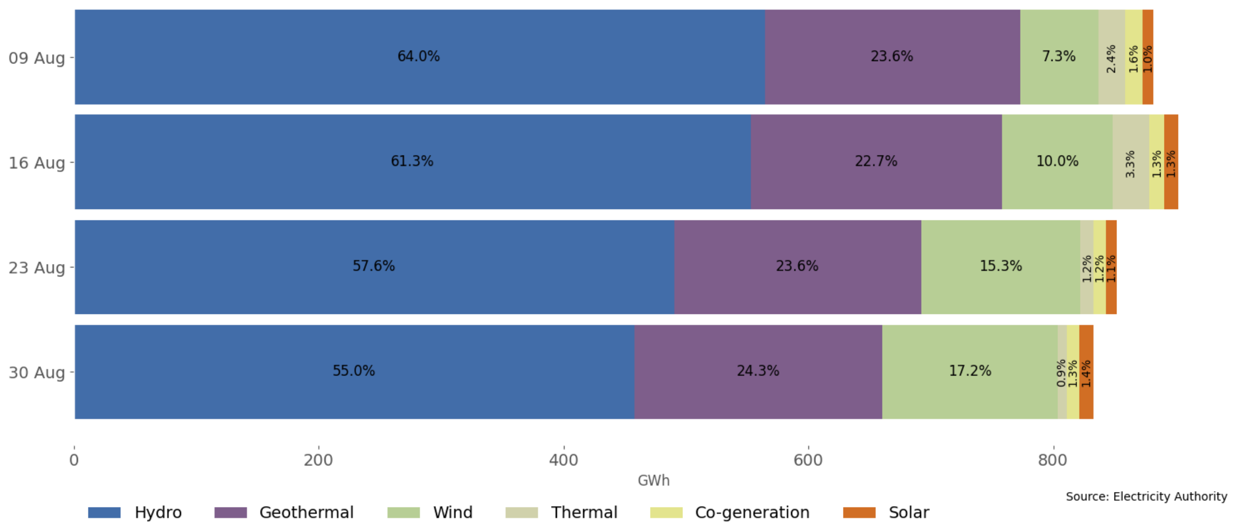
7.16. The highest marginal price of $260/MWh was set by Karāpiro at 5:30pm on Tuesday. The most common marginal technology was hydro and the second most common was wind. Most marginal prices were between $1-10/MWh.

Figure 16: Prices of marginal generation, 30 August - 5 September



7.17. As a percentage of total generation, between 30 August - 5 September, total weekly hydro generation was 55%, geothermal 24.3%, wind 17.2%, thermal 0.9%, co-generation 1.3%, and solar (grid connected) 1.4%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 9 August and 5 September



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 30 August - 5 September ranged between ~453MW and ~1306MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 30 August - 5 September

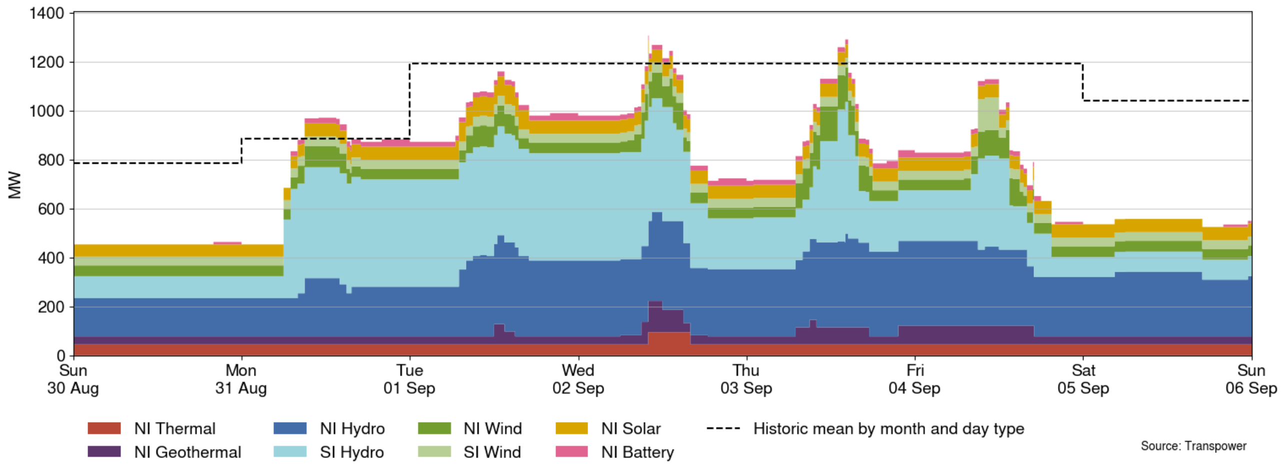
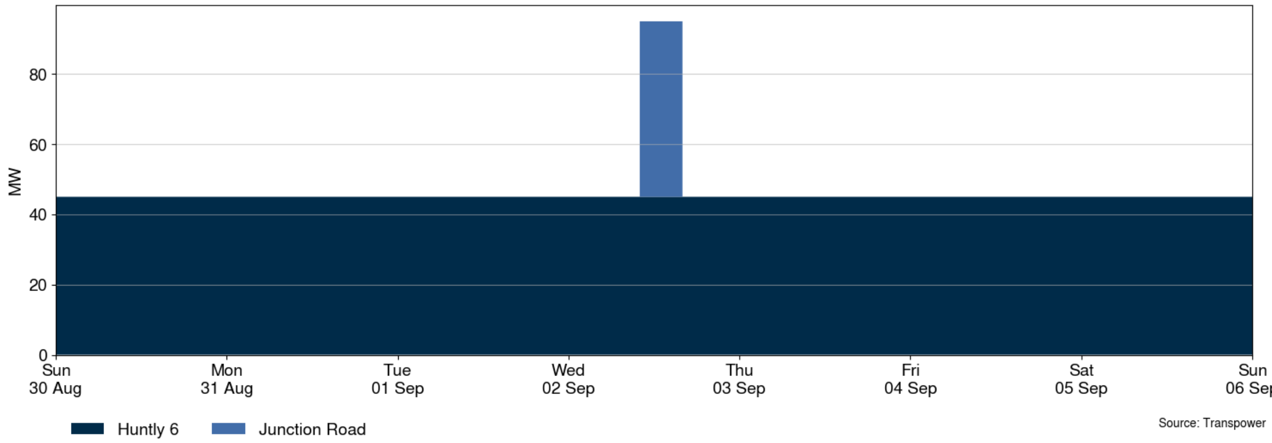


Figure 19: Total MW loss from thermal outages, 30 August - 5 September



8.2. Notable outages include:

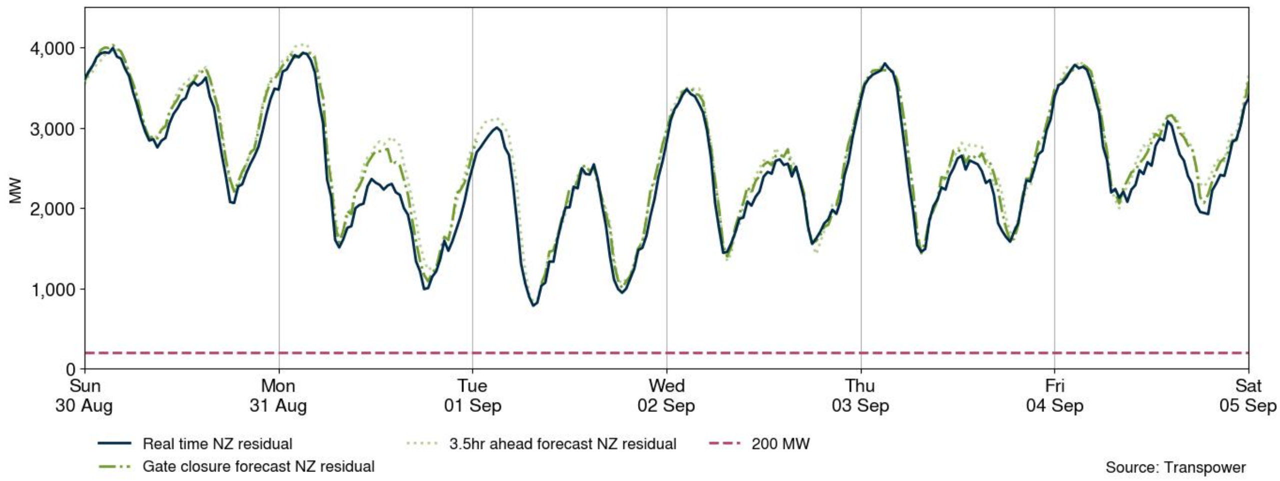
Plant	Partial or Full	End Date
Kaiwaikawe Wind Farm	Partial	1 September 2026
Manapōuri unit 7	Full	3 September 2026
Clyde unit 2	Full	3 September 2026
Manapōuri unit 0	Full	4 September 2026
Kaiwera Downs 2	Partial	4 September 2026
Tauhei Solar Farm	Full	11 September 2026
Roxburgh unit 8	Full	21 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 30 August - 5 September. 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 forecast low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. The minimum residual generation this week was 782MW on Tuesday at 7.30pm.

Figure 20: National generation balance residuals, 30 August - 5 September



10. Storage/fuel supply

10.1. National controlled storage was 83% nominally full and ~139% of the historical average for this time of the year.

10.2. Storage at Lake Pūkaki (91% full) is significantly higher than the historic 90th percentile for this time of year.

10.3. Storage at Lake Tekapō (71% full) is at the historic 90th percentile for this time of year.

10.4. Storage at Lake Taupō is (45% full) is below average for this time of year.

10.5. Storage at Lake Te Anau (156% full) is higher than the historic 90th percentile for this time of year.

10.6. Storage at Lake Manapōuri (122% full) is higher than the historic 90th percentile for this time of year.

10.7. Storage at Lake Hawea (57% full) is slightly above average for this time of year.

10.8. Figure 21 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. The red line represents a lake's upper consent limit. Storage may be allowed to be above this limit temporarily, depending on the specific consent.

10.9. National controlled storage was 83% nominally full and ~139% of the historical average for this time of the year.

10.10. Storage at Lake Pūkaki (91% full[2]) is significantly higher than the historic 90th percentile for this time of year.

10.11. Storage at Lake Tekapō (71% full) is at the historic 90th percentile for this time of year.

10.12. Storage at Lake Taupō is (45% full) is below average for this time of year.

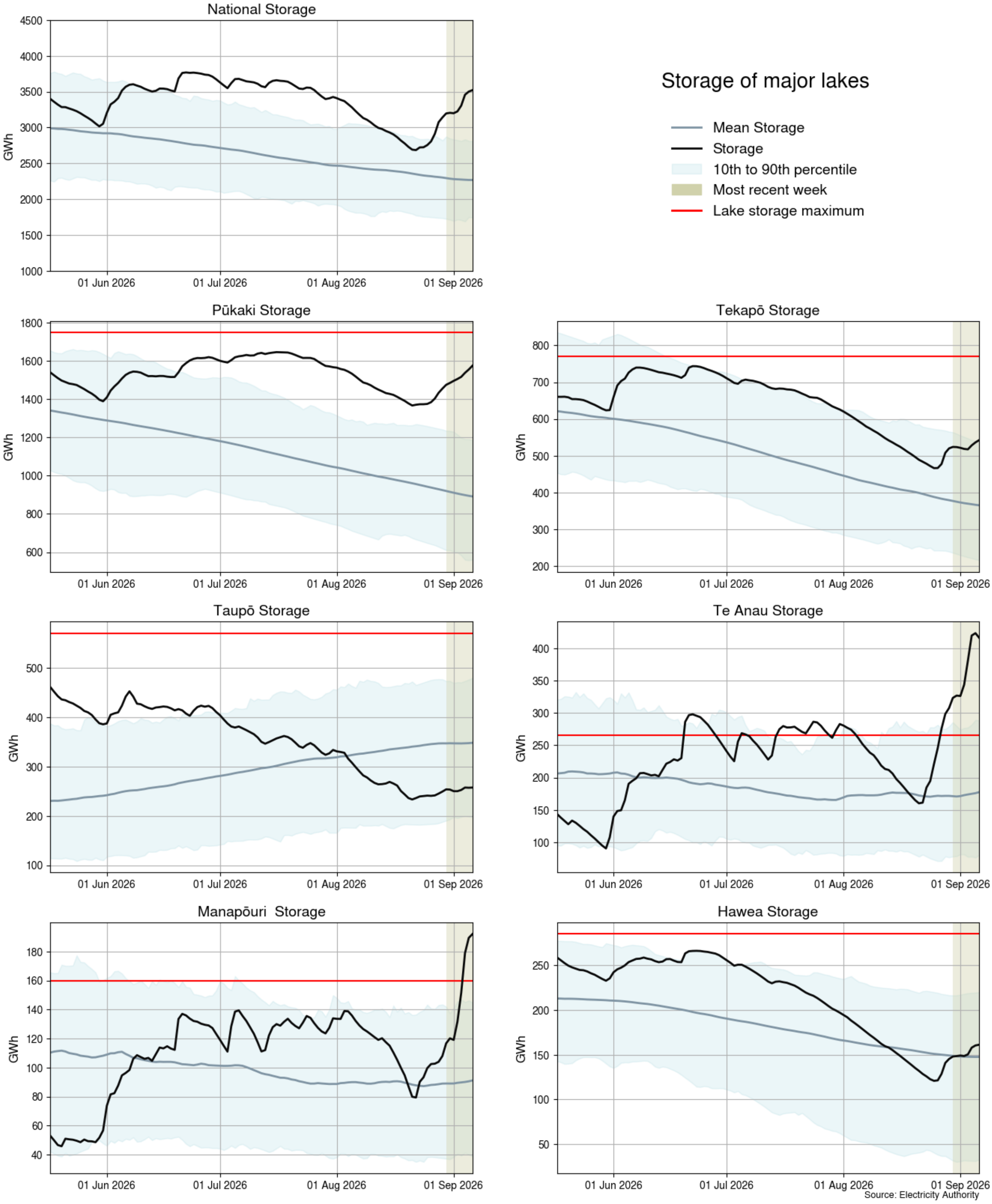
10.13. Storage at Lake Te Anau (156% full) is higher than the historic 90th percentile for this time of year.

10.14. Storage at Lake Manapōuri (122% full) is higher than the historic 90th percentile for this time of year.

10.15. Storage at Lake Hawea (57% full) is slightly above average for this time of year.

[2] Percentage full values sourced from NZX Hydro.

Figure 21: 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 23 shows an estimate of thermal SRMCs as a monthly average up to 1 September 2026. The SRMCs for gas generation have decreased, with SRMCs for coal and diesel fuelled generation remaining steady.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$235/MWh, while the cost of running the Rankines on gas is ~$177/MWh.

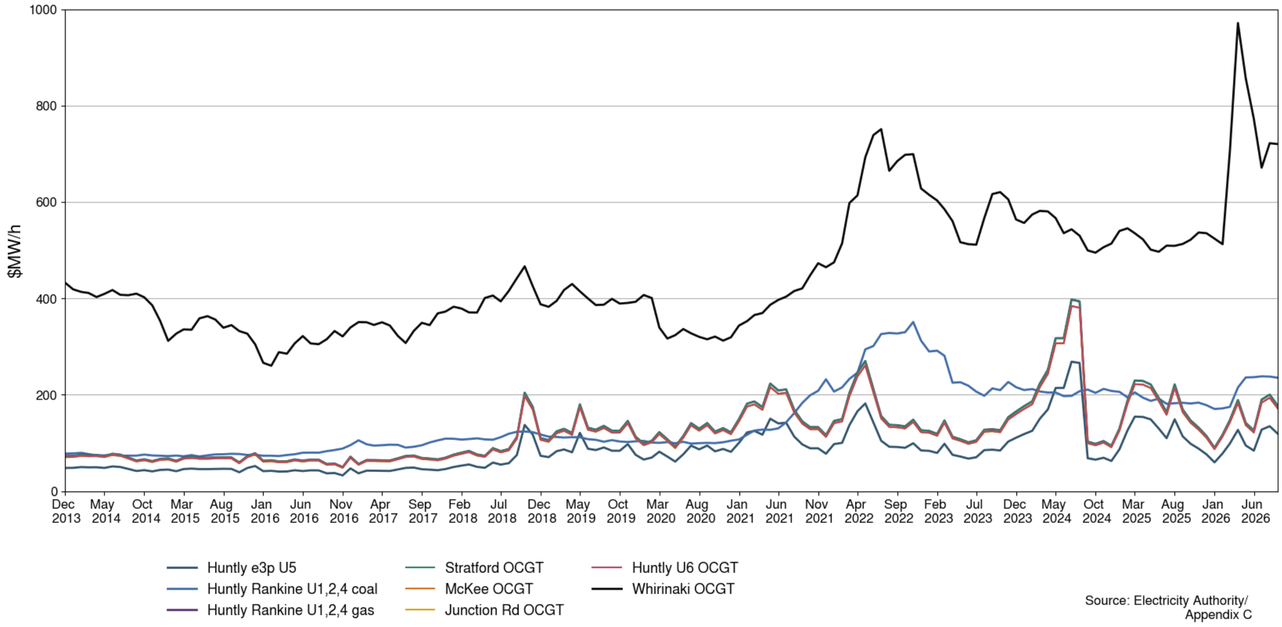
11.5. The SRMC of gas fuelled thermal plants is currently between $118/MWh and $177/MWh.

11.6. The SRMC of Whirinaki is ~$720/MWh.

11.7. Note that coal prices have been rolled forward from May.

11.8. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

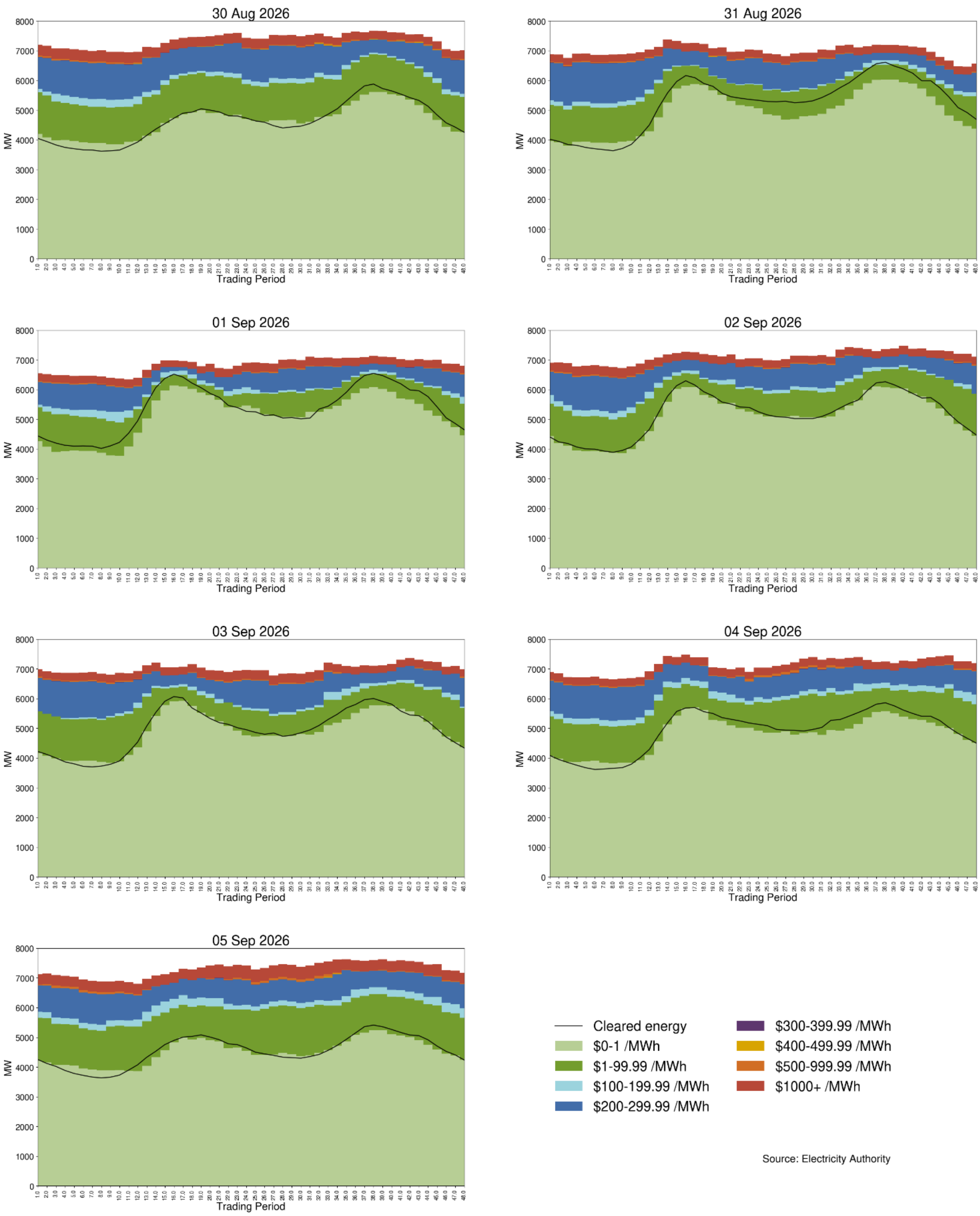
Figure 22: Estimated monthly SRMC for thermal fuels



12. Offer behaviour

12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

Figure 23: Daily offer stacks



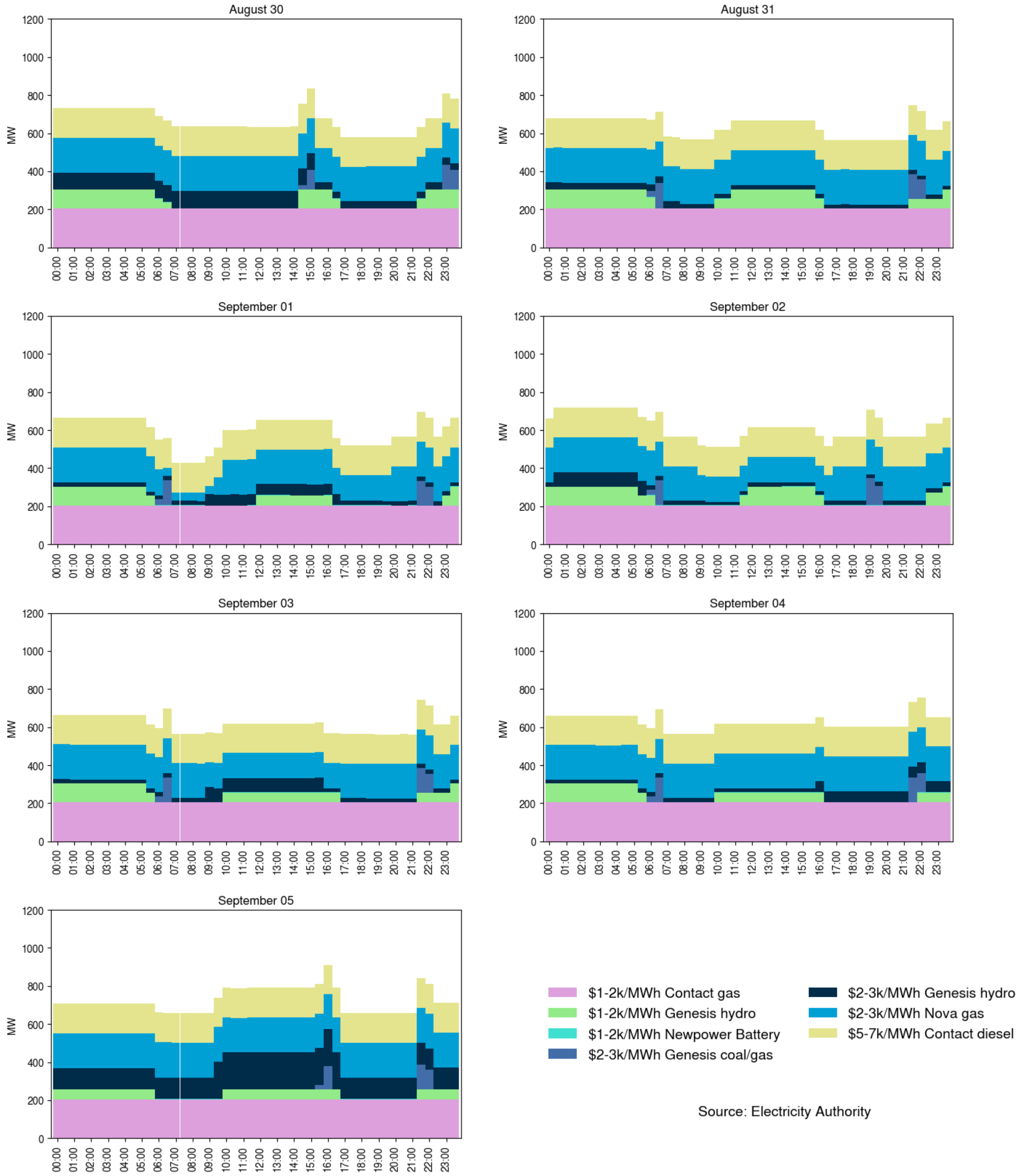
Source: Electricity Authority

12.2. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.3. 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, intermittent generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.4. On average 642MW per trading period was priced above $1,000/MWh this week, which is roughly 11% of the total energy available.

Figure 24: 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
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers
07/05/2026-08/05/2026	Several	Further analysis	Genesis	Tekapō	Offers
27/05/2026	Several	Further analysis	Genesis	Huntly 5	Offers
02/08/2026-08/08/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers
26/08/2026-29/08/2026	Several	Further analysis	Meridian	Ruakākā	Reserve offers