22 September 2026

Trading conduct report 13-19 September 2026

Market monitoring weekly report

Trading conduct report 13-19 September 2026

1. Overview

1.1. Spot prices have increased compared to the previous week, as lower wind generation led to higher prices at times. However, spot prices were mostly below average for this time of year, with some high-priced periods early in the week and on Wednesday. Hydro storage has decreased to 82% nominally full and ~136% 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 13-19 September:

(a) The average spot price for the week was $39/MWh, an increase of around $10/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $138/MWh.

2.3. Spot prices have increased compared to the previous week, as lower wind generation led to higher prices at times.

2.4. The highest price at Ōtāhuhu was $230/MWh at 6:30pm on Sunday. At this time the price at Benmore was $23/MWh. At this time the HVDC had 89MW of northward flow capacity remaining, solar and wind generation decreased to ~300MW, and North Island FIR prices were around $160/MWh.

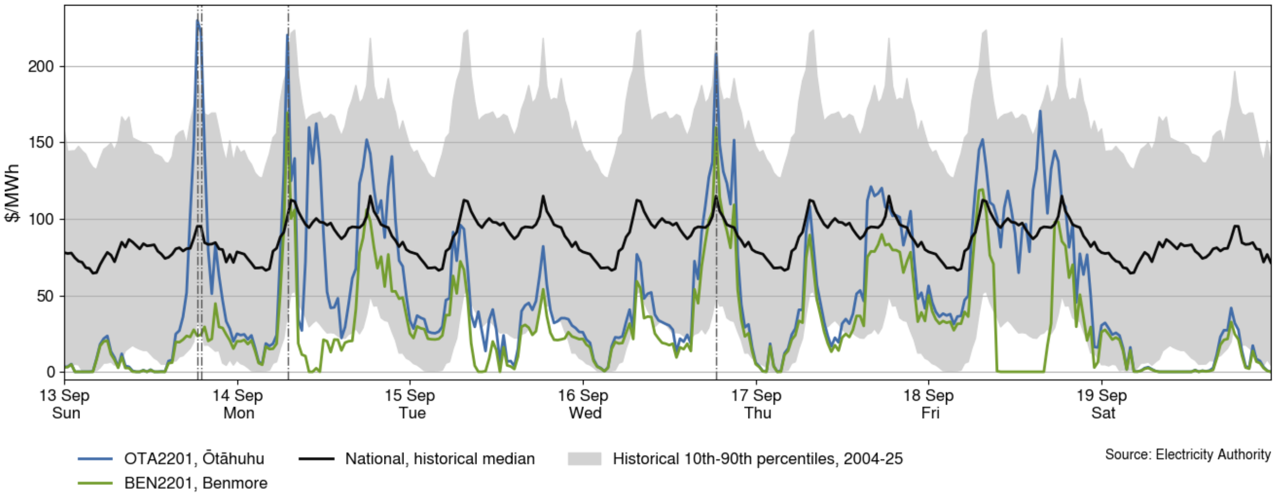
2.5. At 7.00am on Monday the price at Ōtāhuhu spiked up to $220/MWh. At this time the price at Benmore was $169/MWh. During this time national wind generation was below 200MW.

2.6. At 6.30pm on Wednesday the price at Ōtāhuhu spiked up to $207/MWh. At this time the price at Benmore was $159/MWh. During this time demand was 122MW higher than forecast.

2.7. North Island prices also separated from the South Island on Friday when the HVDC was running near capacity for several hours, due to lower North Island wind generation.

2.8. 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 are marked with black dashed lines.

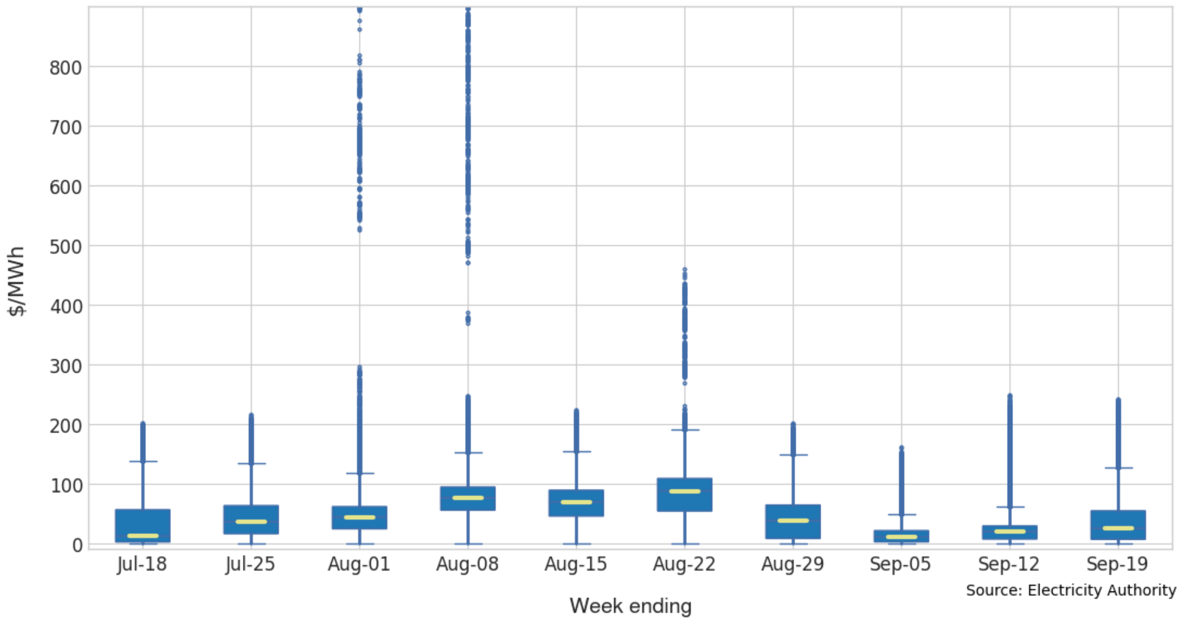
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 13-19 September



2.9. 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.

2.10. The distribution of spot prices this week was wider than last week. The median price was $39/MWh and most prices (middle 50%) fell between $7/MWh and $54/MWh.

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



3. Reserve prices

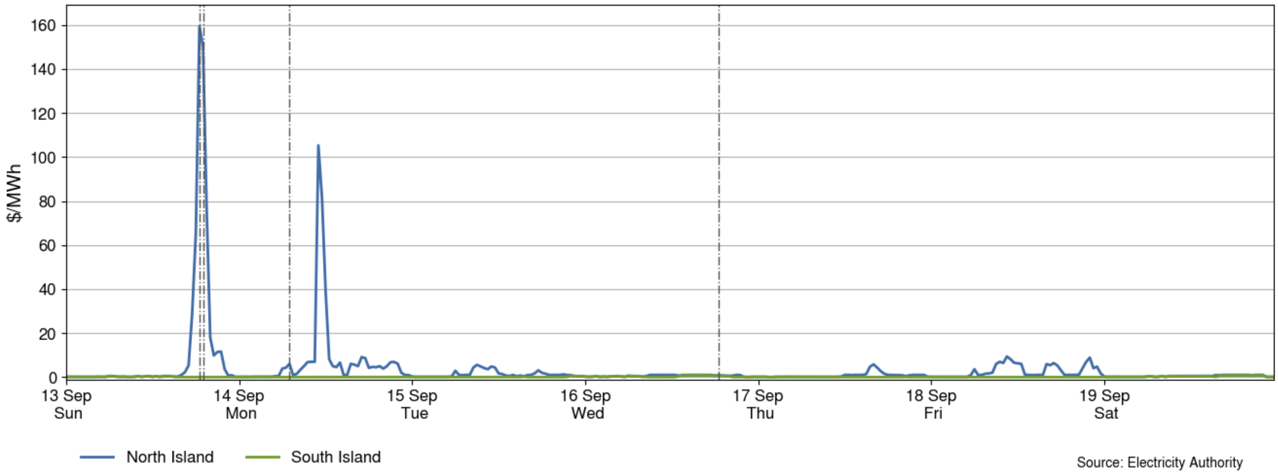
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh this week.

3.2. At 6.30pm on Sunday North Island FIR prices spiked up to $159/MWh. At this time the HVDC was setting the risk. Demand was at its highest for the day (5.44GW), the HVDC had

89MW of northward flow capacity remaining, and the volume of available reserve decreased compared to the previous trading period.

3.3. At 11.00am on Monday North Island FIR prices spiked up to $105/MWh. At this time the HVDC was setting the risk and had 30MW of northward flow capacity remaining.

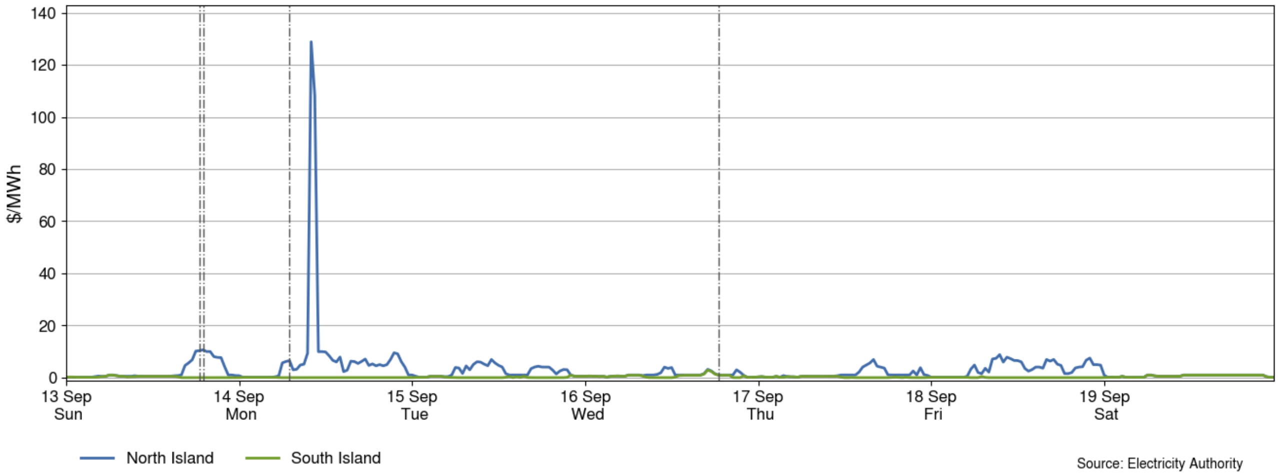
Figure 3: Fast instantaneous reserve price by trading period and island, 13-19 September



3.4. 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.

3.5. At 10.00am on Monday North Island SIR prices spiked up to $128/MWh. At this time the HVDC was setting the risk, and the volume of available reserve decreased compared to previous trading periods, decreasing the availability of cheaper reserve.

Figure 4: Sustained instantaneous reserve by trading period and island, 13-19 September



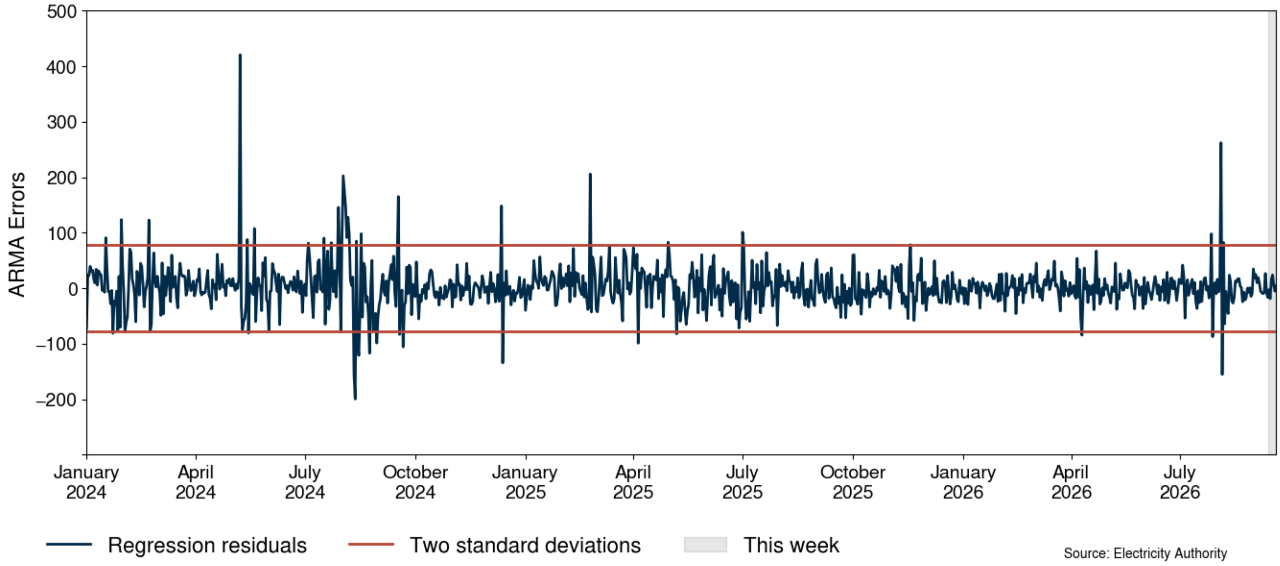
4. Regression residuals

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 - 19 September 2026



5. HVDC

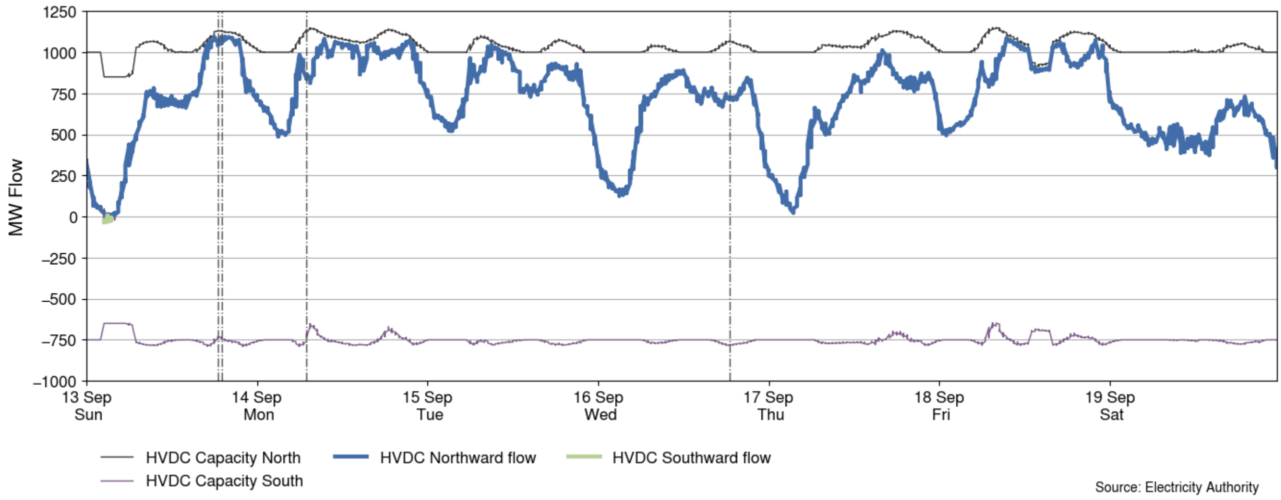
5.1. Figure 6 shows the HVDC flow between 13-19 September. HVDC flows were mostly northward this week.

5.2. The HVDC northward flow increased rapidly on Sunday evening as both solar and North Island wind generation decreased driving up the need for hydro and thermal generation.

5.3. The highest northward HVDC flow this week was 1,095MW which occurred at 7.30pm on Sunday.

5.4. The highest southward HVDC flow this week was 35MW which occurred at 2.30am on Sunday.

Figure 6: HVDC flow and capacity, 13-19 September

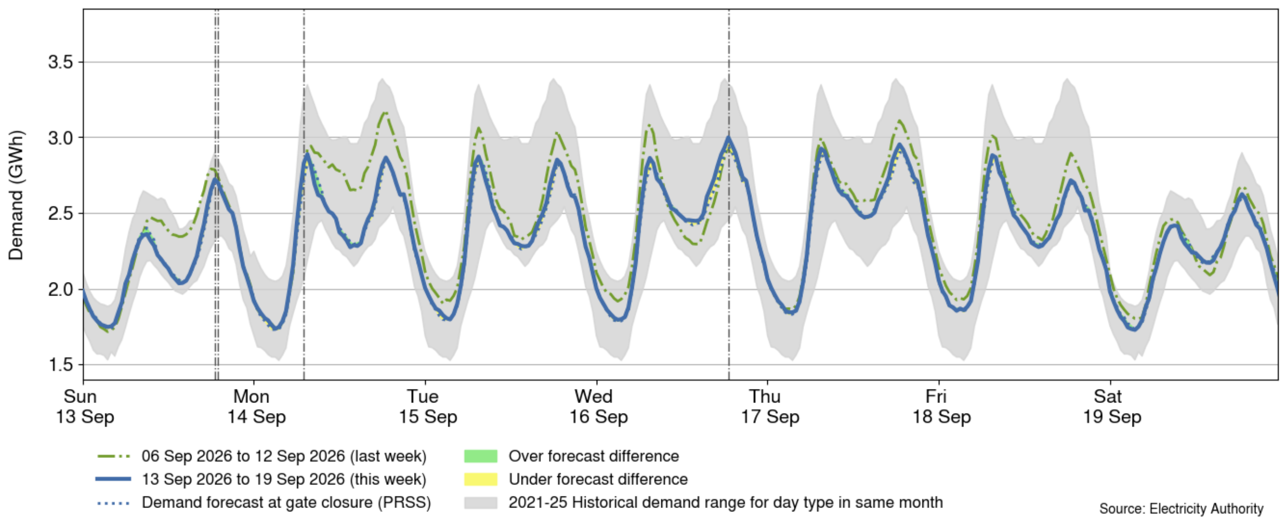


6. Demand

6.1. Figure 7 shows national demand between 13-19 September, compared to the historic range and the demand of the previous week. Demand was mostly lower than last week during peak times, and similar to last week in the middle of the day. Demand on Monday was overall lower than last week.

6.2. The maximum demand this week was around 3.0GWh (6.0GW) at 6:30pm on Wednesday.

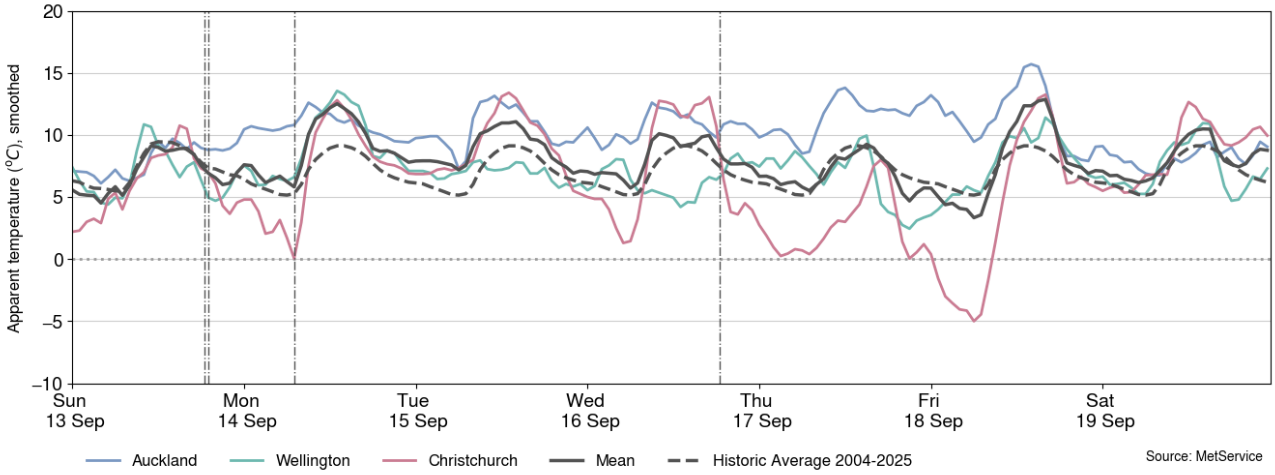
Figure 7: National demand, 13-19 September compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 13-19 September. 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 6°C to 16°C in Auckland, 2°C to 14°C in Wellington, and -6°C to 14°C in Christchurch.

Figure 8: Temperatures across main centres, 13-19 September



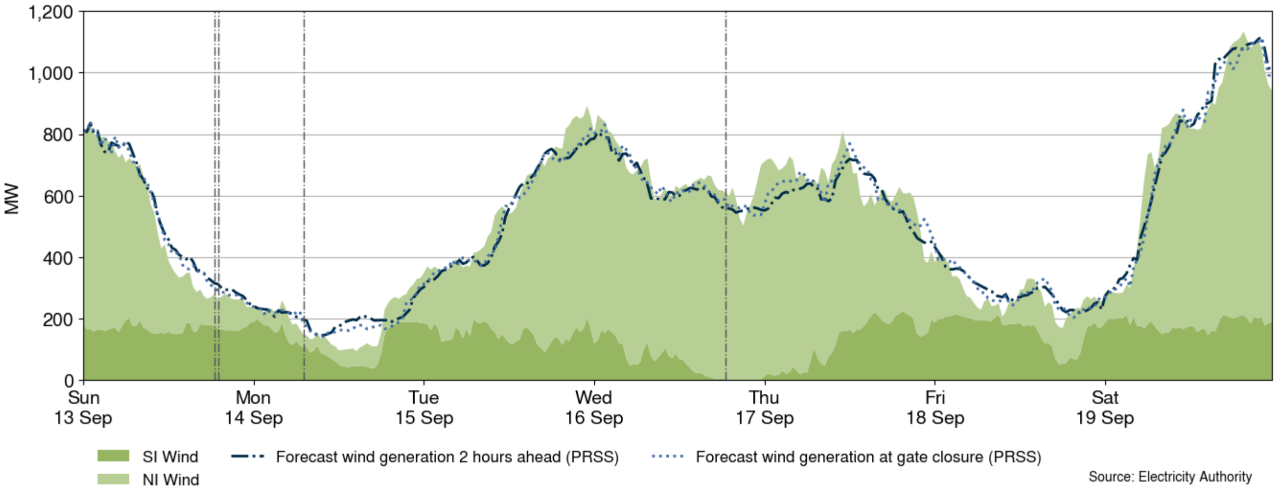
7. Generation

7.1. Figure 9 shows wind generation and forecast from 13-19 September. This week wind generation varied between 94MW and 1,134MW, with a weekly average of 516MW. Wind generation was low from Sunday evening to Tuesday morning and Friday. With higher generation see on Sunday morning, during the middle of the week, and Saturday.

7.2. Generation was lower than forecast on Monday. These forecasting differences were due to Kaiwera Downs Stage 2 wind farm.

7.3. Generation was lower than forecast on Friday. These forecasting differences were due to Harapaki and Kaiwera Downs Stage 2 wind farms.

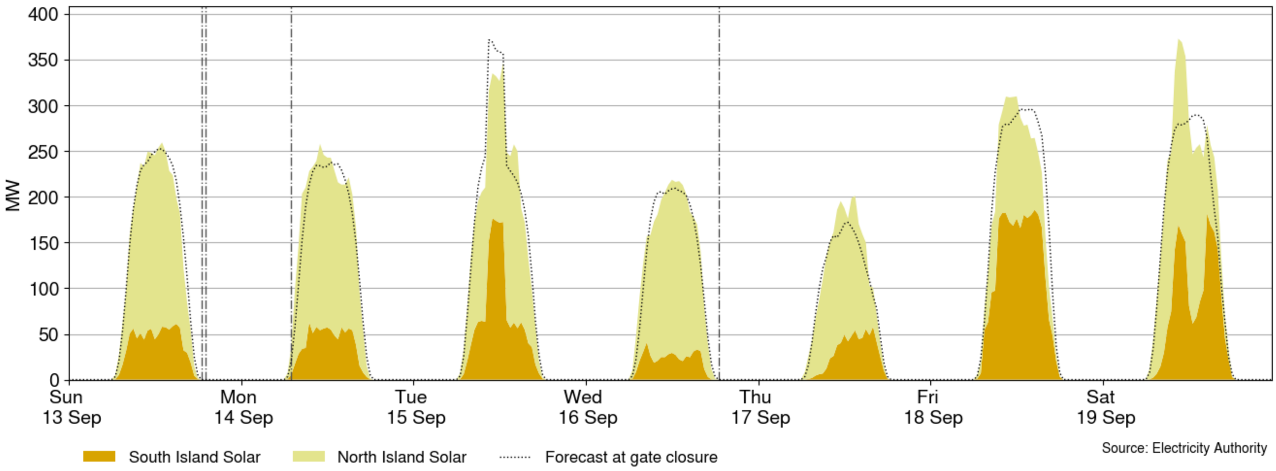
Figure 9: Wind generation and forecast, 13-19 September



7.4. Figure 10 shows grid connected solar generation from 13-19 September. Mean daytime solar generation this week was 166MW, peaking at 373MW on Saturday at 10:30am.

7.5. On Tuesday, Friday, and Saturday large jumps are seen in South Island generation which are inconsistent with typical solar generation patterns. These irregularities are due to the 150MW Kōwhai Park solar farm which is in the process of commissioning. We expect to see the output of this farm vary as it continues to commission.

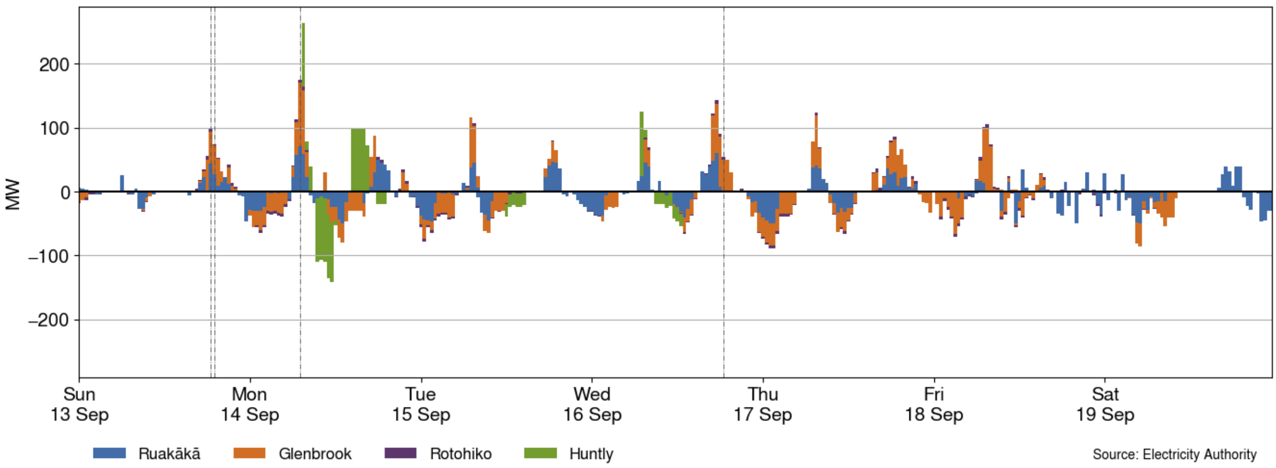
Figure 10: Grid connected solar generation, 13-19 September



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 typically charged overnight and during the middle of the day when demand was lower and discharged during the morning and evening peak demand periods.

Figure 11: Grid scale battery charge and discharge, 13-19 September



7.8. 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.

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

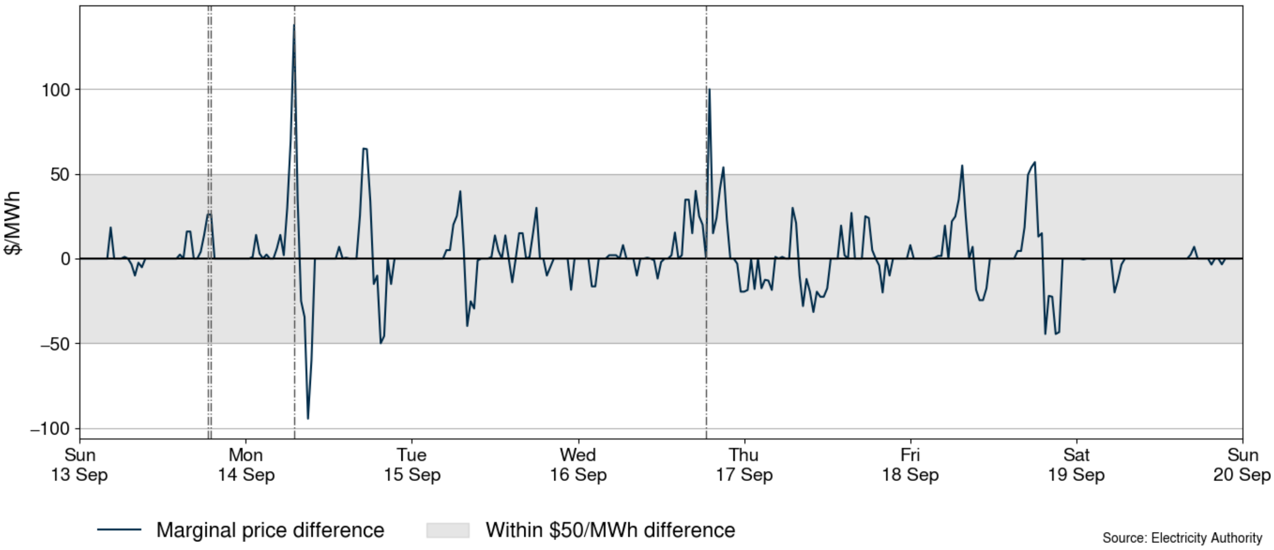
Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.9. This week there were 11 trading periods with a price difference greater than $50/MWh.

7.10. The largest positive difference was $138/MWh at 7.00am on Monday. At this time demand was 219MW higher than forecast, and intermittent generation was 19MW lower than forecast.

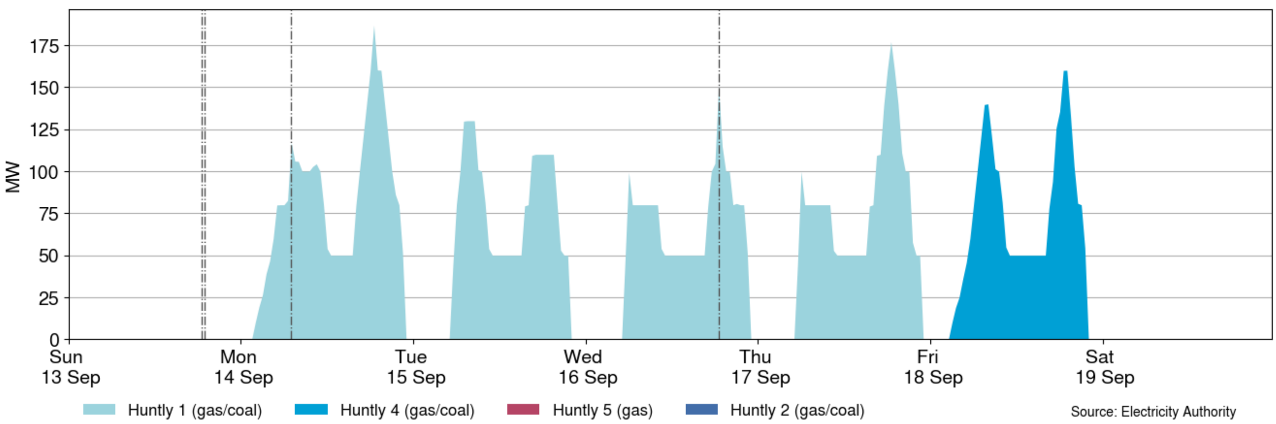
7.11. The largest negative difference was $94/MWh at 9.00am on Monday. At this time demand was 189MW lower than forecast, and intermittent generation was 30MW higher than forecast.

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, 13-19 September



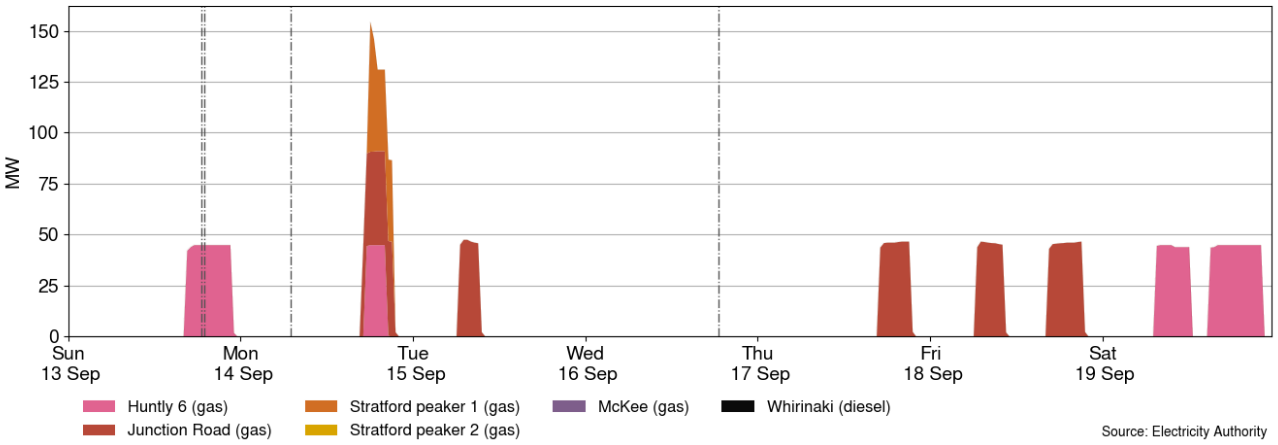
7.12. Figure 13 shows the generation of thermal baseload between 13-19 September. This week thermal baseload generation was provided by Huntly 1 and 4 at 50MW, ramping up to 80MW and above during peak times.

Figure 13: Thermal baseload generation, 13-19 September



7.13. Figure 14 shows the generation of thermal peaker plants between 13-19 September. Peaker generation occurred during at least one peak demand period on all days except Wednesday when wind generation was higher.

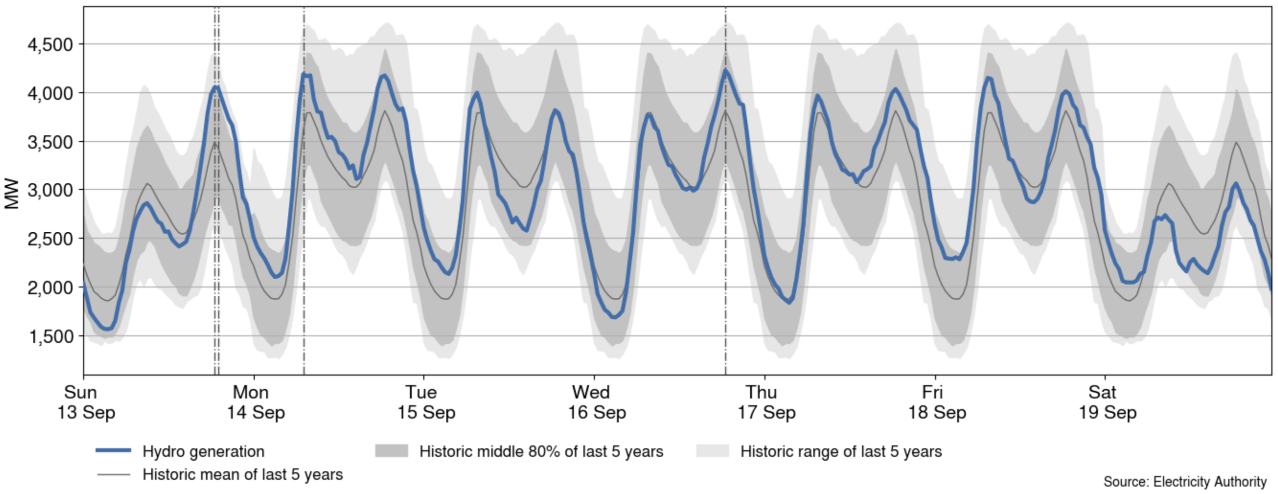
Figure 14: Thermal peaker generation, 13-19 September



7.14. Figure 15 shows hydro generation between 13-19 September. Hydro generation was at or near average for most of this week, except for a couple of peak demand periods on Sunday, Monday, and Wednesday when hydro generation neared the top of the historic 80th percentile.

7.15. On Saturday morning hydro generation dropped off while Kōwhai Park solar farm and Huntly 6 were generating.

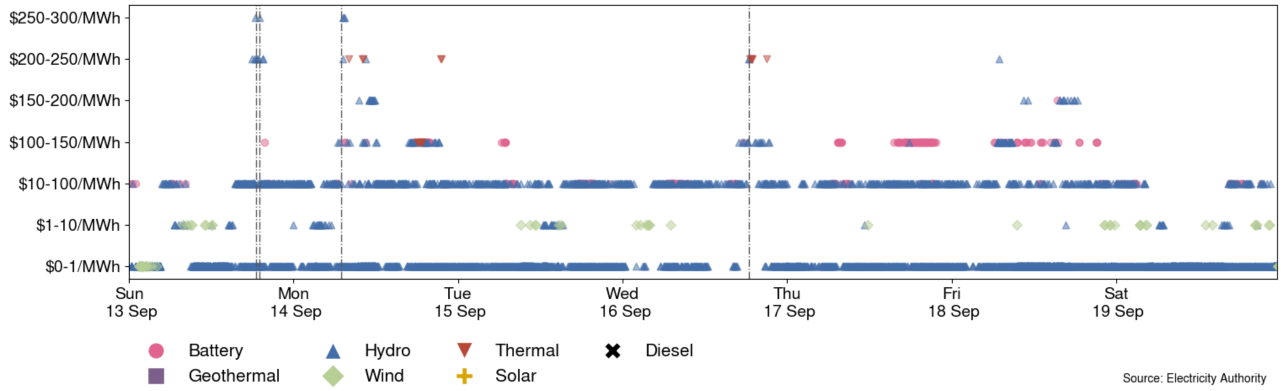
Figure 15: Hydro generation, 13-19 September



7.16. 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.

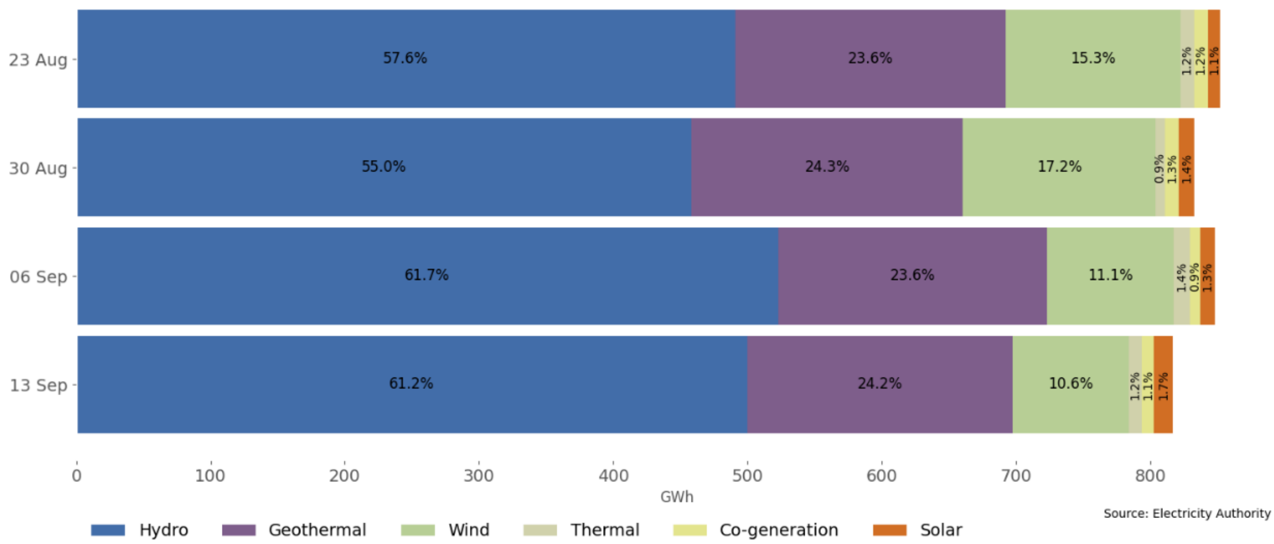
7.17. The highest marginal price of $260/MWh was set by Karāpiro at 6:00pm on Sunday. The most common marginal technology was hydro and the second most common technology was wind. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 13-19 September



7.18. As a percentage of total generation, between 13-19 September, total weekly hydro generation was 61.2%, geothermal 24.2%, wind 10.6%, thermal 1.2%, co-generation 1.1%, and solar (grid connected) 1.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 23 August and 19 September



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 13-19 September ranged between ~963MW and ~1,626MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 13-19 September

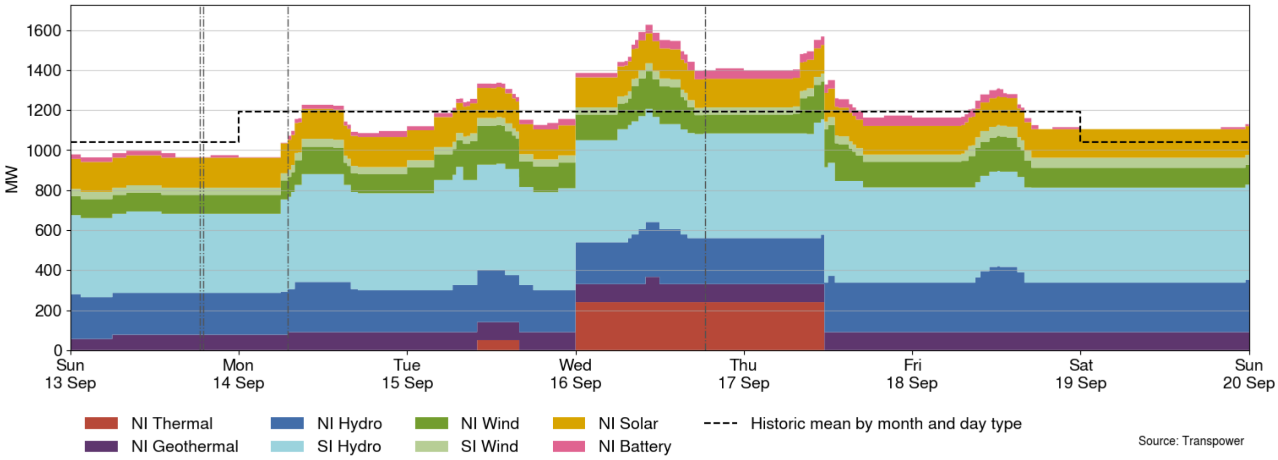
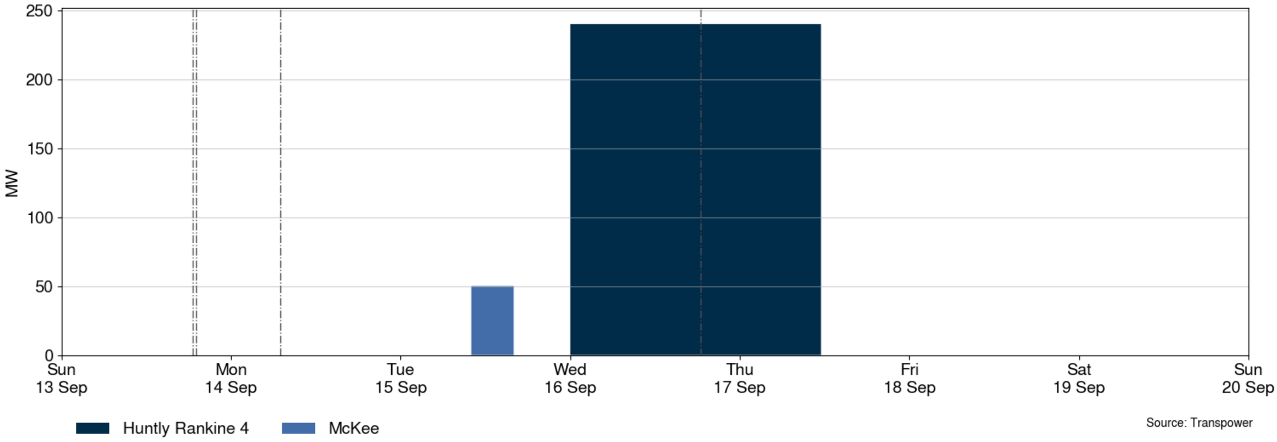


Figure 19: Total MW loss from thermal outages, 13-19 September



8.2. Notable outages include:

Plant	Partial or Full	End Date
Roxburgh unit 8	Full	15 September 2026
Huntly 4	Full	17 September 2026
Tauhei Solar Farm	Partial	21 September 2026
Benmore unit 2	Full	28 September 2026
Kaiwaikawe Wind Farm	Partial	30 November 2026
Takapō B unit 2	Full	6 October 2026
Manapōuri unit 2	Full	2 July 2027

9. Generation balance residuals

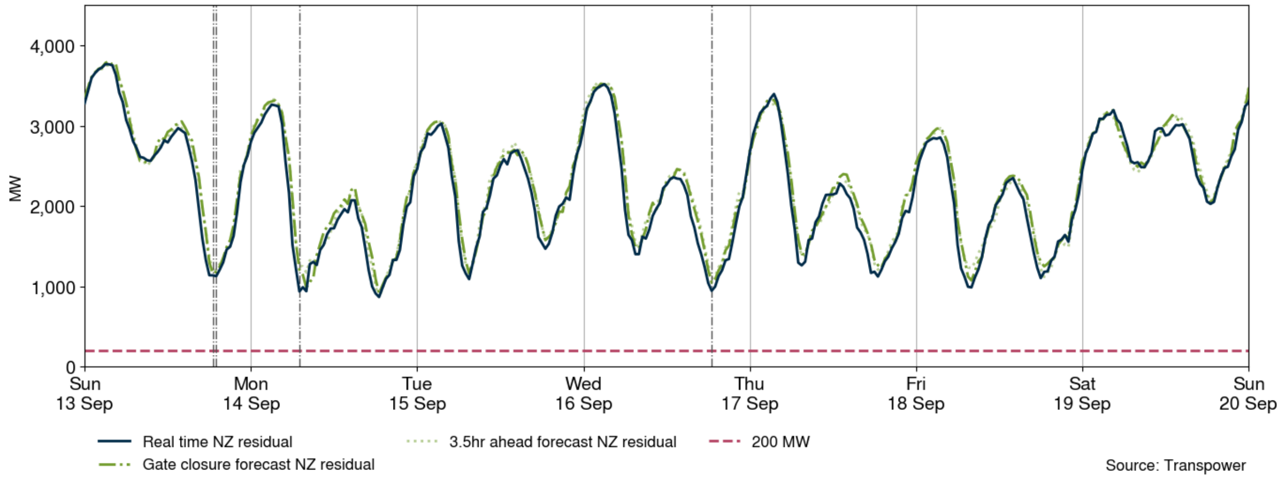
9.1.

9.2. There were no residuals lower than 200MW this week.

9.3. Figure 20 shows the national generation balance residuals between 13-19 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.

9.4. There were no residuals lower than 200MW this week.

Figure 20: National generation balance residuals, 13-19 September



10. Storage/fuel supply

10.1. National controlled storage was 82% nominally full and ~136% of the historical average for this time of the year.

10.2. Storage at Lake Pūkaki (89% full) is significantly higher than the historic 90th percentile for this time of year.

10.3. Storage at Lake Tekapō (72% full) is at the historic 90th percentile for this time of year.

10.4. Storage at Lake Taupō is (50% full) is below average for this time of year.

10.5. Storage at Lake Te Anau (129% full) is at the historic 90th percentile for this time of year.

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

10.7. Storage at Lake Hawea (50% full) is slightly below 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 10^{th} to 90^{th} percentiles.

10.9. National controlled storage was 82% nominally full and ~136% of the historical average for this time of the year.

10.10. Storage at Lake Pūkaki (89% full[2]) is significantly higher than the historic 90th percentile for this time of year.

10.11. Storage at Lake Tekapō (72% full) is at the historic 90th percentile for this time of year.

10.12. Storage at Lake Taupō is (50% full) is below average for this time of year.

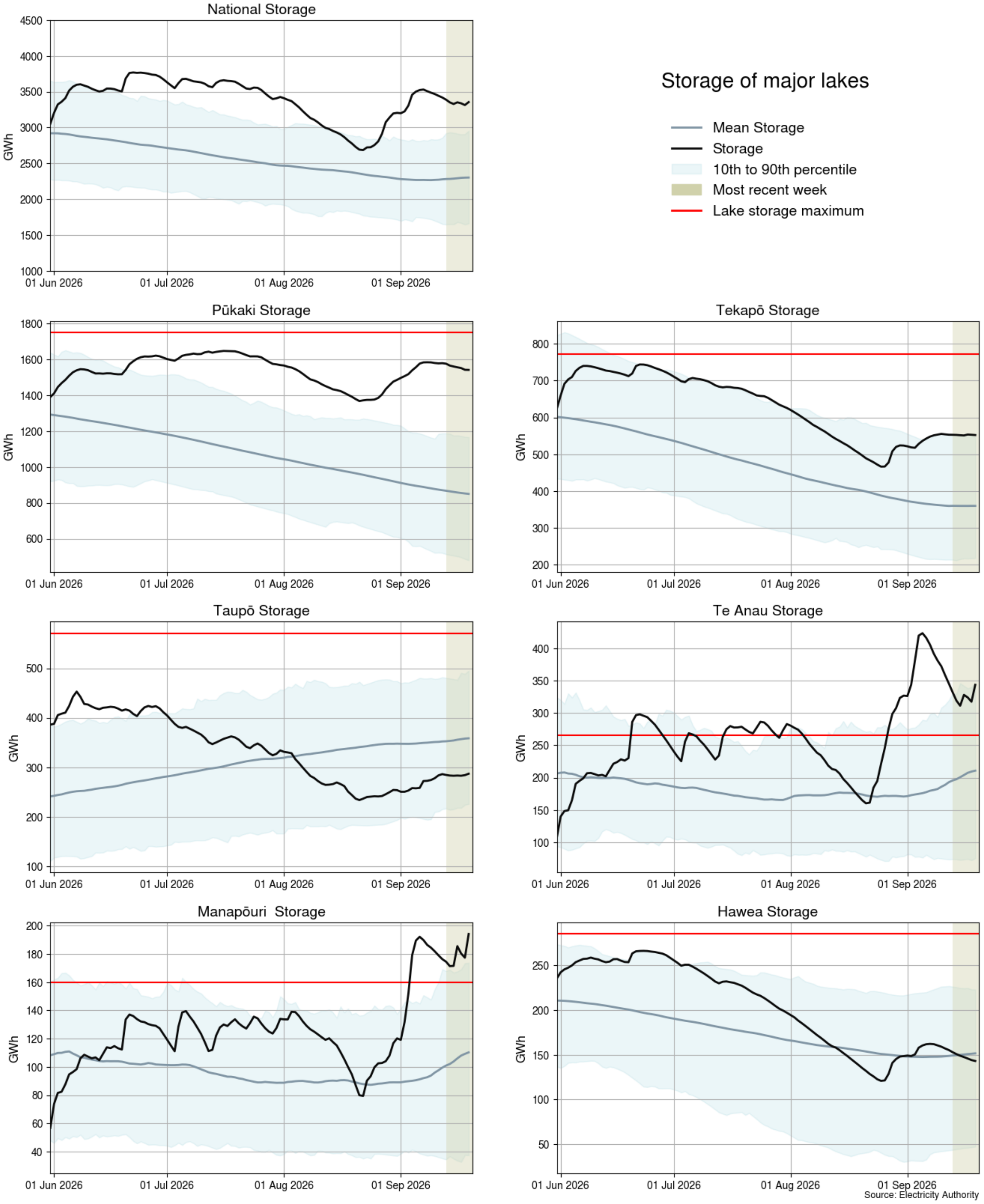
10.13. Storage at Lake Te Anau (129% full) is at the historic 90th percentile for this time of year.

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

10.15. Storage at Lake Hawea (50% full) is slightly below 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.

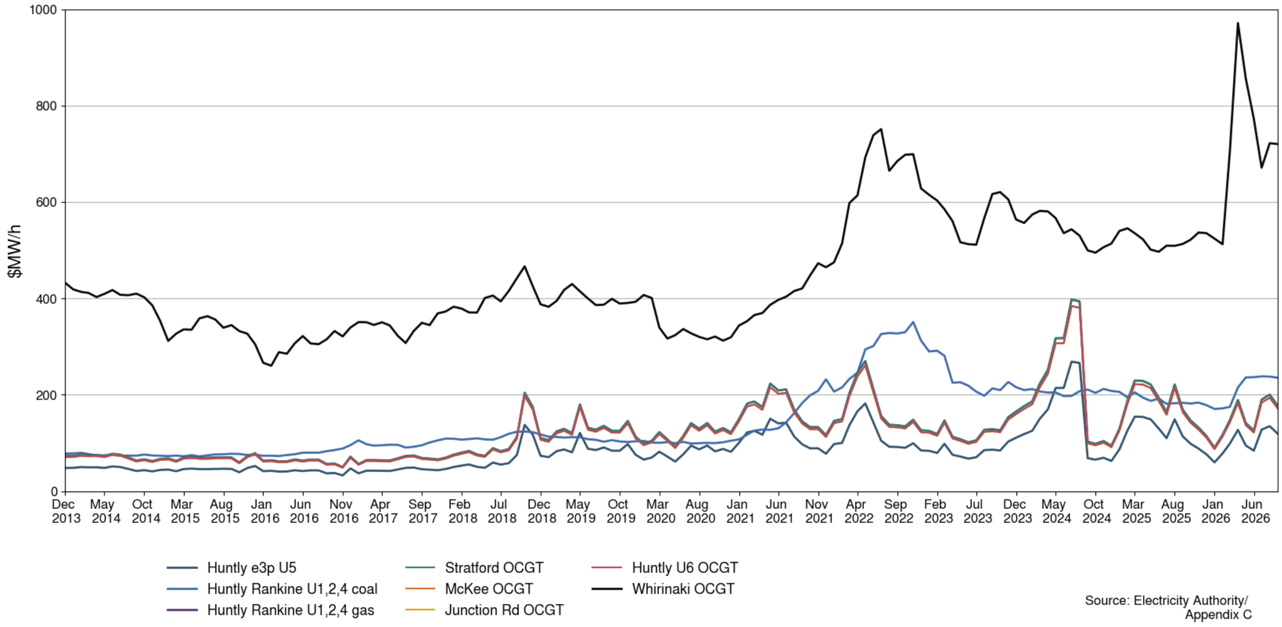
11.5. The SRMC of gas fuelled thermal plants is currently between $118/MWh and $177/MWh.

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

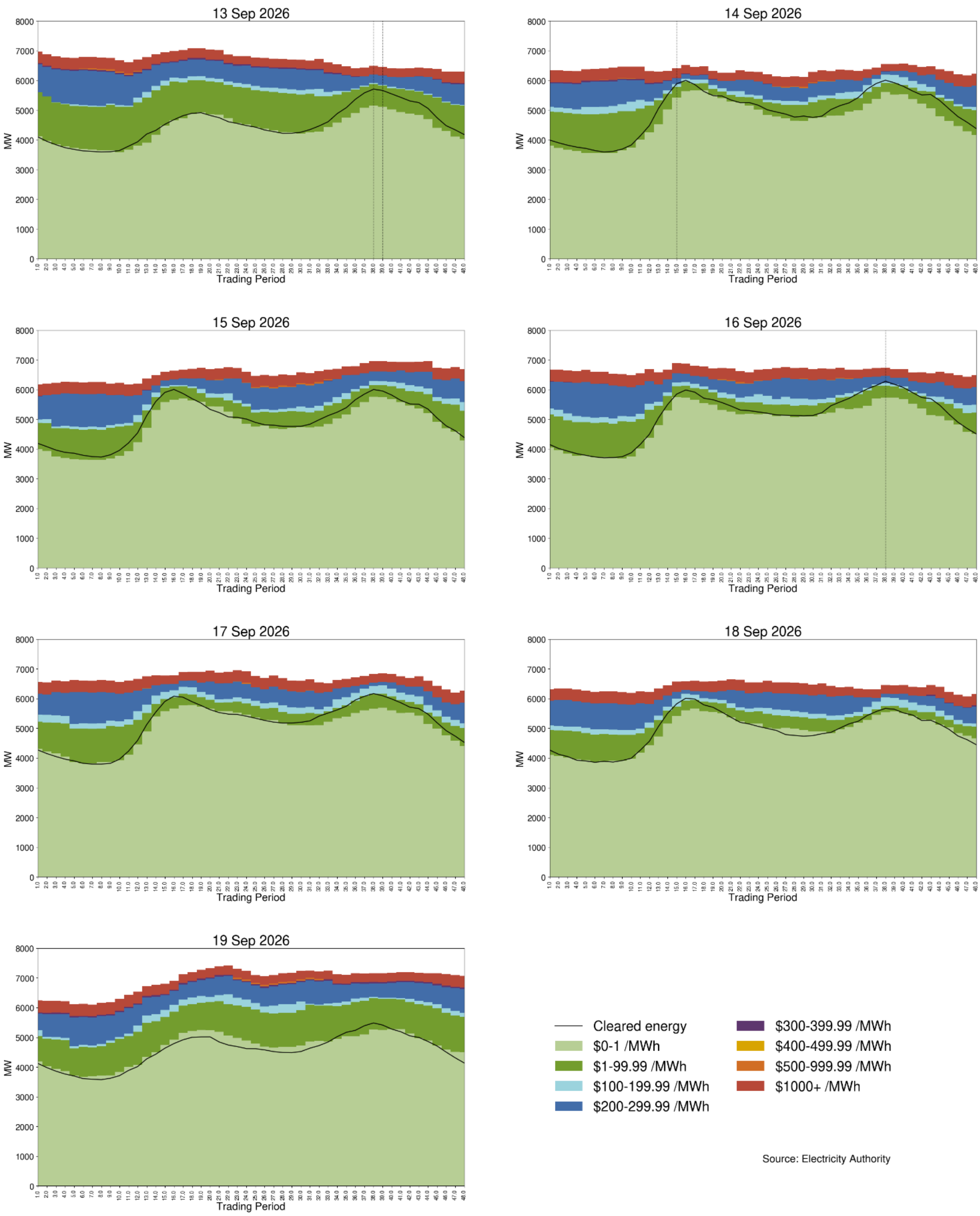


12. Offer behaviour

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.

12.2. This week energy mostly cleared between $1-99/MWh, though peak periods on Monday morning and Wednesday evening saw energy clearing between $200-299/MWh.

Figure 23: Daily offer stacks



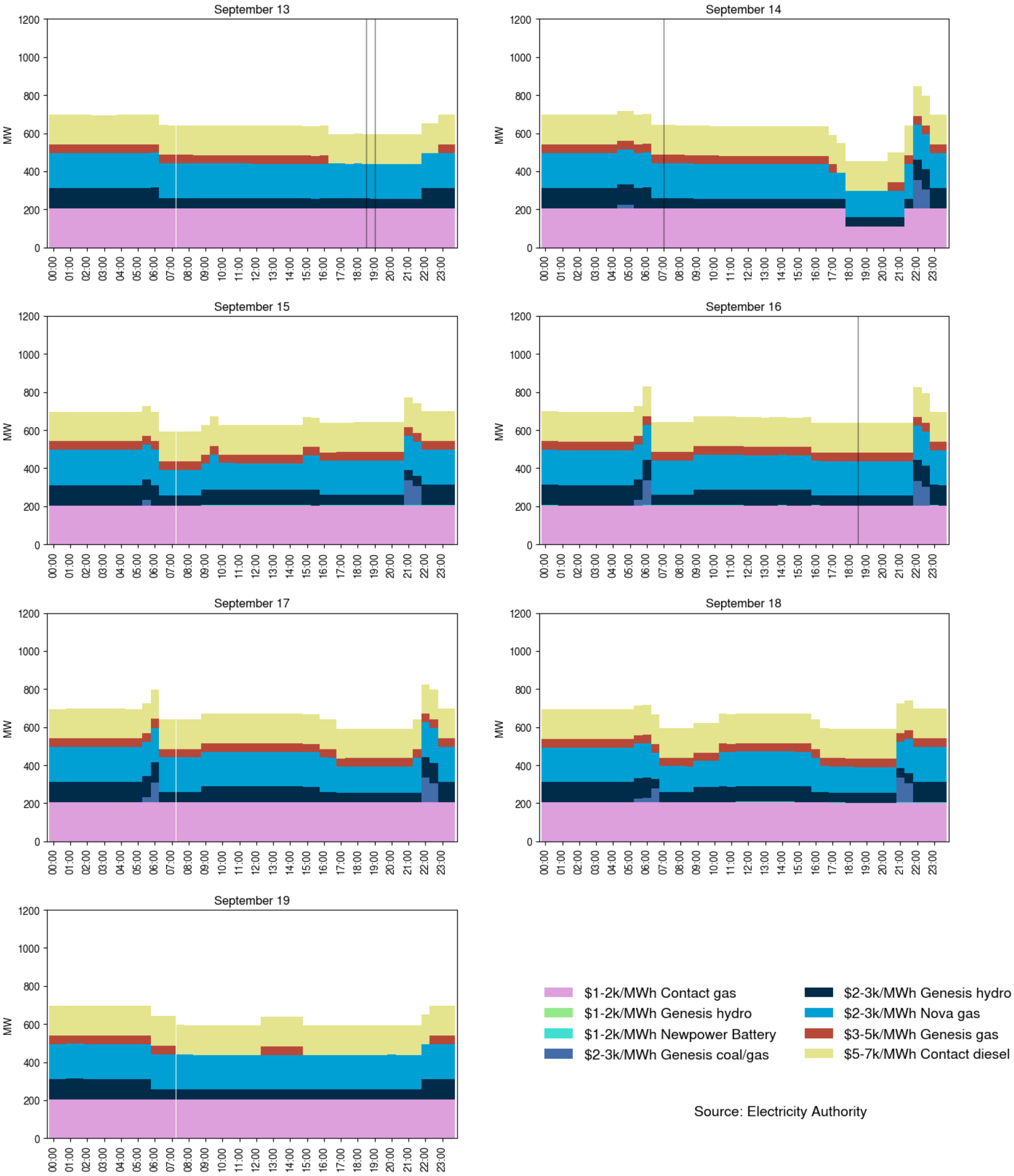
Source: Electricity Authority

12.3. 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.

12.4. 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, intermittent 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 654MW per trading period was priced above $1,000/MWh this week, which is roughly 12% 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