15 September 2026

Trading conduct report 6-12 September 2026

Market monitoring weekly report

Trading conduct report 6-12 September 2026

1. Overview

1.1. Spot prices have increased compared to the previous week, as wind generation was low at times. However, prices were overall low this week, remaining near or below the historic average for this time of year. Hydro storage has increased to 84% nominally full and ~140% 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 6-12 September:

(a) The average spot price for the week was $29/MWh, an increase of around $12/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $160/MWh.

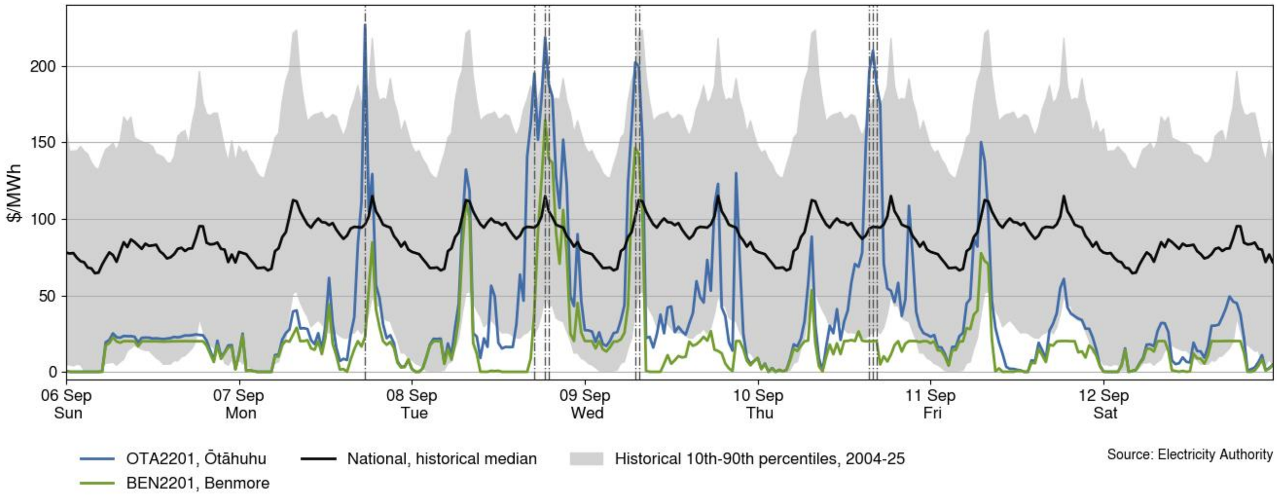
2.3. Prices were low this week but increased compared to last week due to periods of low wind decreasing the availability of cheap energy, and large forecasting errors causing the price of immediate reserves to be high at times.

2.4. On Tuesday evening and Wednesday morning prices were elevated during peak demand as wind generation was very low decreasing the availability of cheap energy.

2.5. On Monday evening at 5.30pm prices spiked to $226/MWh at Ōtāhuhu while prices at Benmore were $23/MWh. At this time demand was 160MW higher than forecast.

2.6. 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.

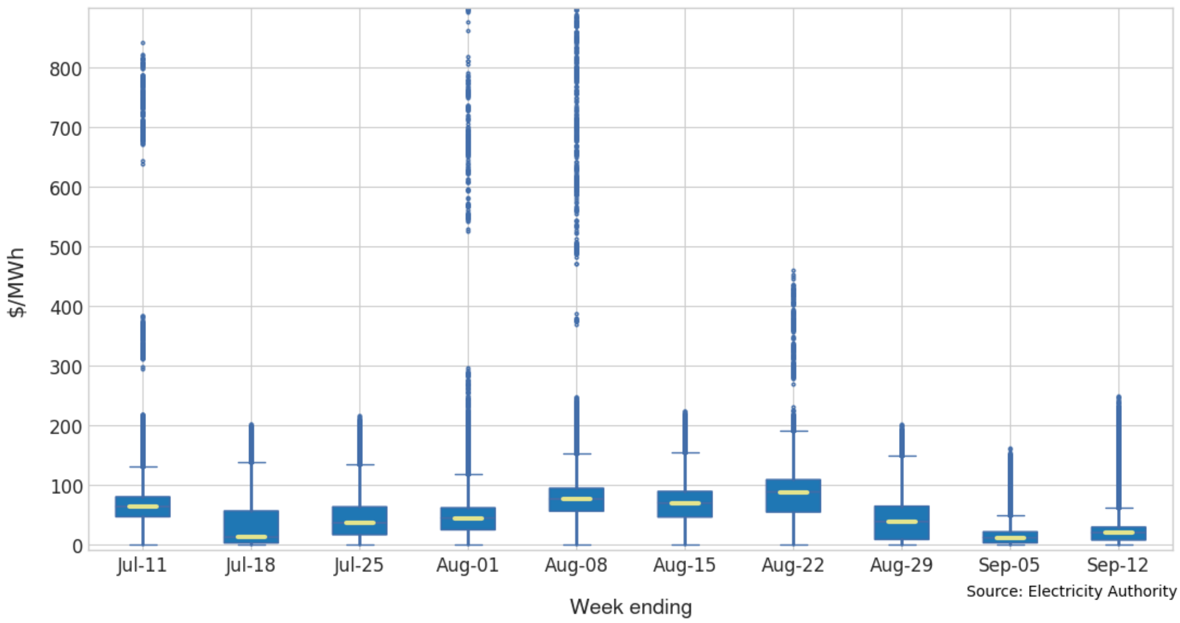
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 6-12 September



2.7. 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.

2.8. The distribution of spot prices this week was wider than last week with more high-priced outliers. The median price was $29/MWh and most prices (middle 50%) fell between $7/MWh and $29/MWh.

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



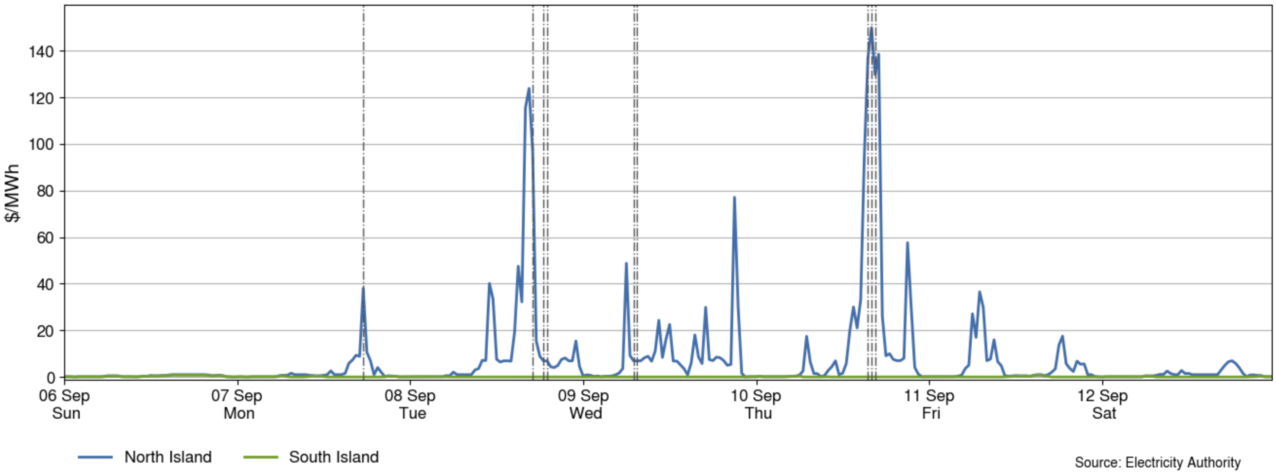
3. Reserve prices

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

3.2. At 4.30pm on Tuesday North Island FIR prices spiked up to $123/MWh. At this time the HVDC was setting the risk, demand was nearing its peak for the evening, wind generation was only 24MW, and the amount of battery FIR offers was low for this trading period.

3.3. At 4.00pm on Thursday North Island FIR prices spiked up to $149/MWh. At this time the HVDC was setting the risk, Meridian's battery was on a 60MW outage so could only offer 40MW for reserve, and wind generation was 170MW lower than forecast.

Figure 3: Fast instantaneous reserve price by trading period and island, 6-12 September

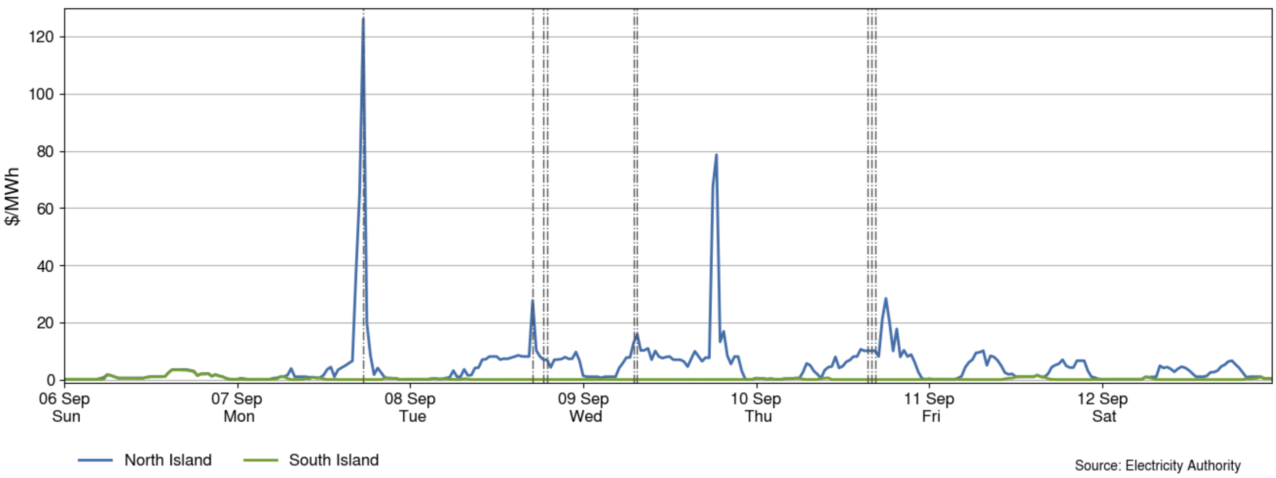


3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh this week.

3.5. At 5.30pm on Monday North Island SIR prices spiked up to $126/MWh. At this time the HVDC was setting the risk, demand was 160MW higher than forecast, and battery SIR offers were low for this trading period.

3.6. At 6.30pm on Wednesday North Island SIR prices spiked up to $78/MWh. At this time the HVDC was setting the risk and had only 156MW of northward flow capacity remaining. Meridian's battery also had 60MW on outage. Of the remaining 40MW, 10MW was dispatched as energy, leaving only 30MW for reserves. This reduced the amount of cheap reserves available to cover the increased HVDC risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 6-12 September



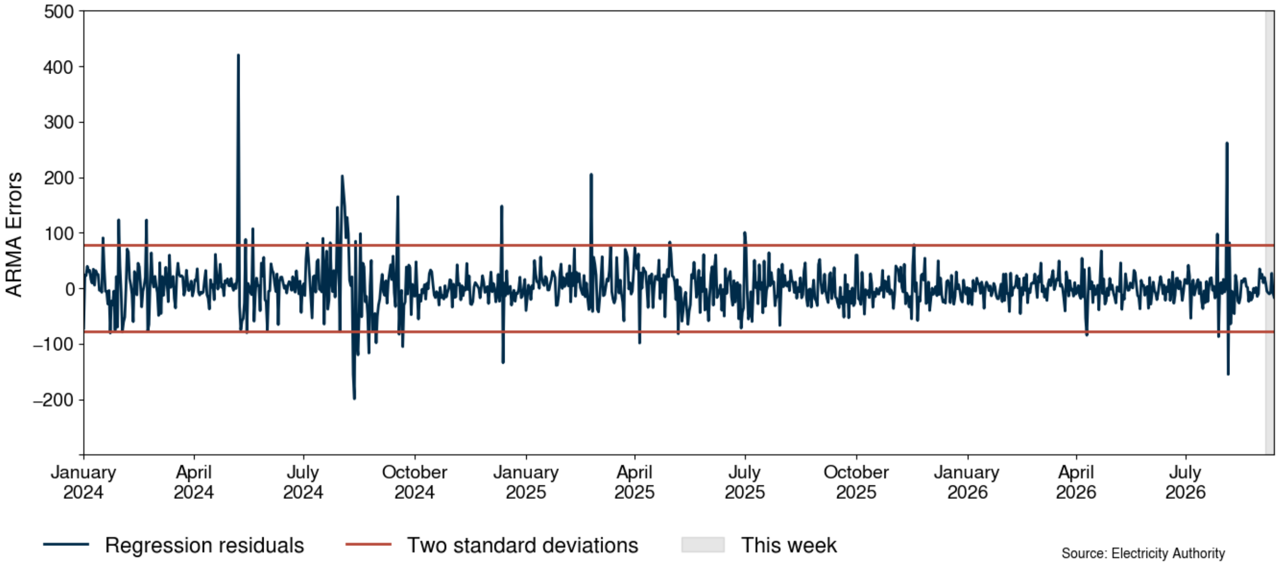
4. Regression residuals

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 - 12 September 2026



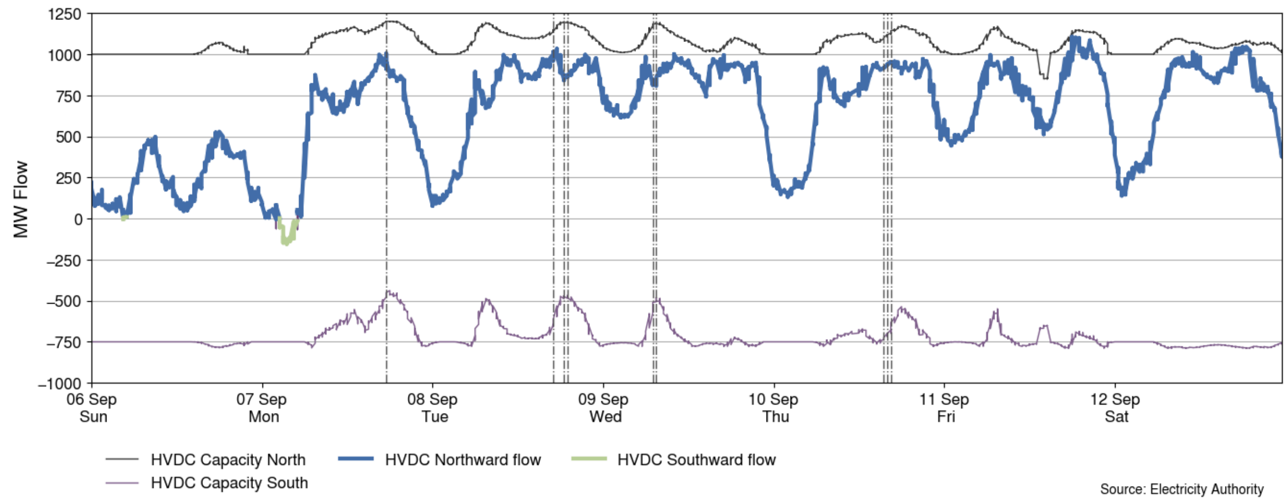
5. HVDC

5.1. Figure 6 shows the HVDC flow between 6-12 September. HVDC flows were mostly northward this week. With some lower HVDC flows occurring overnight during times of higher wind generation.

5.2. The highest northward HVDC flow this week was 1107MW which occurred at 6.00pm on Friday.

5.3. The highest southward HVDC flow this week was -155MW which occurred at 3.30am on Monday.

Figure 6: HVDC flow and capacity, 6-12 September

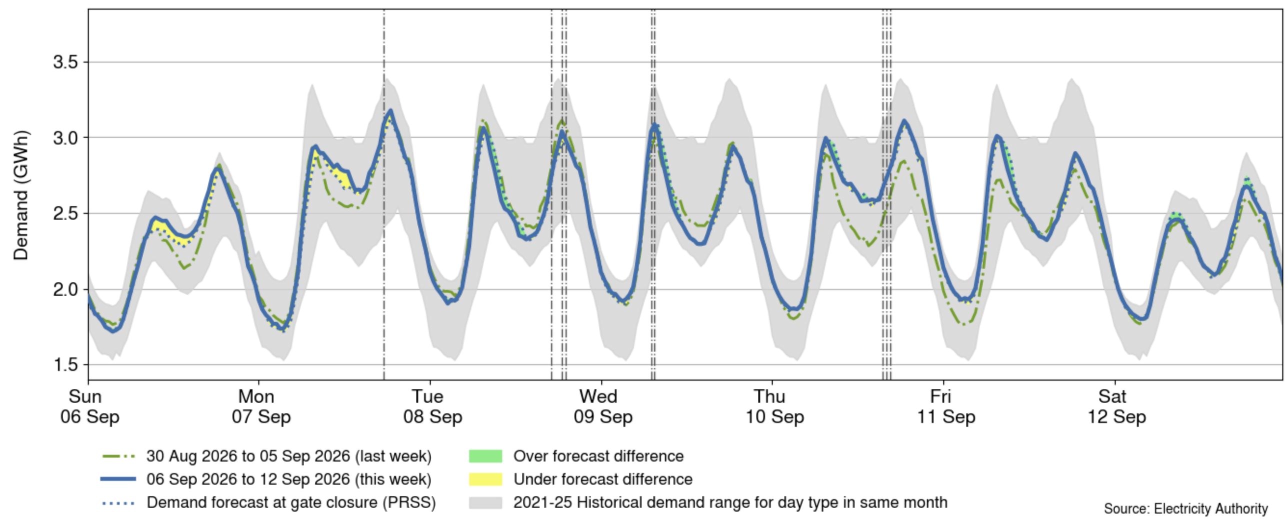


6. Demand

6.1. Figure 7 shows national demand between 6-12 September, compared to the historic range and the demand of the previous week. Demand was similar to last week in all peak periods except for Thursday evening and Friday morning when demand was higher. Demand was overall higher than last week.

6.2. The maximum demand this week was around 3.18GWh (6.36GW) at 6:30pm on Monday.

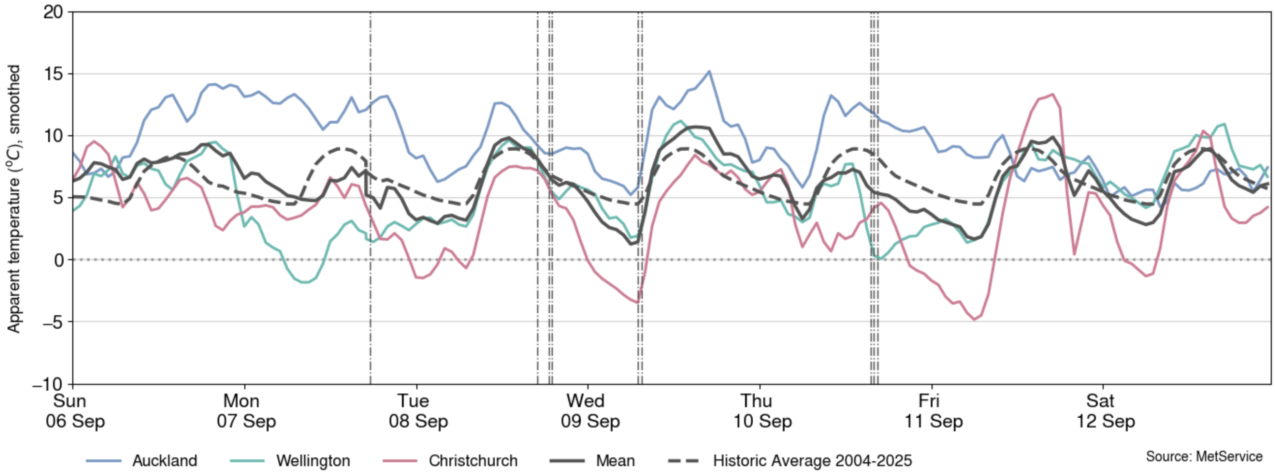
Figure 7: National demand, 6-12 September compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 6-12 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 3°C to 15°C in Auckland, -2°C to 12°C in Wellington, and -5°C to 14°C in Christchurch.

Figure 8: Temperatures across main centres, 6-12 September

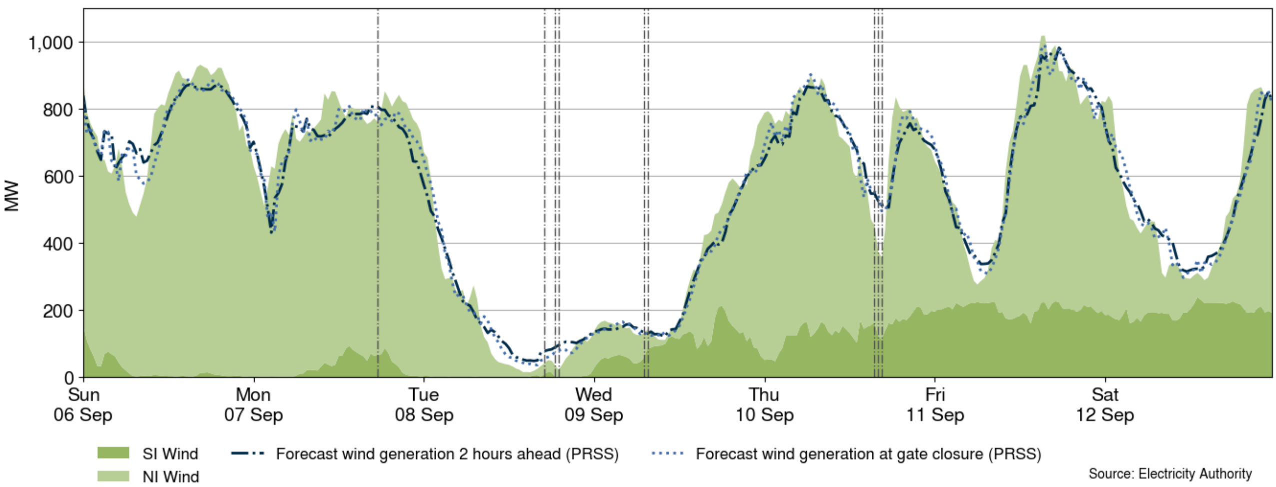


7. Generation

7.1. Figure 9 shows wind generation and forecast from 6-12 September. This week wind generation varied between 15MW and 1019MW, with a weekly average of 560MW. Wind generation was higher in the first two days of the week before dropping to below 150MW on Tuesday afternoon, and Wednesday morning. Wind generation strengthened throughout Wednesday afternoon but remained variable through the rest of the week.

7.2. Wind generation being lower than forecast on Sunday morning between 5.00am and 9.00am was due to forecasting errors Waipipi, Tararua Stage I, and Harapaki wind farms.

Figure 9: Wind generation and forecast, 6-12 September

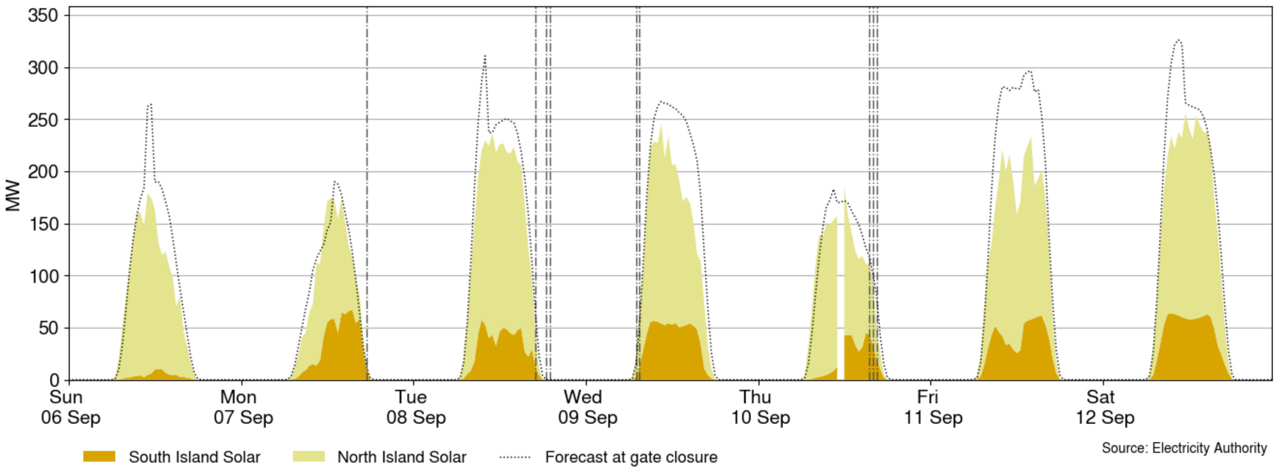


7.3. Figure 10 shows grid connected solar generation from 6-12 September. Solar generation was lower this week. Mean daytime solar generation this week was 123MW, peaking at 255MW on Saturday at 11:30am.

7.4. Forecasting errors from Monday onwards are mainly due to Kōwhai Park solar farm which is in the process of commissioning. All other differences are due to an accumulation of errors at various solar farms.

7.5. Note that due to a data outage one trading period of data is missing at 11.30am on Thursday.

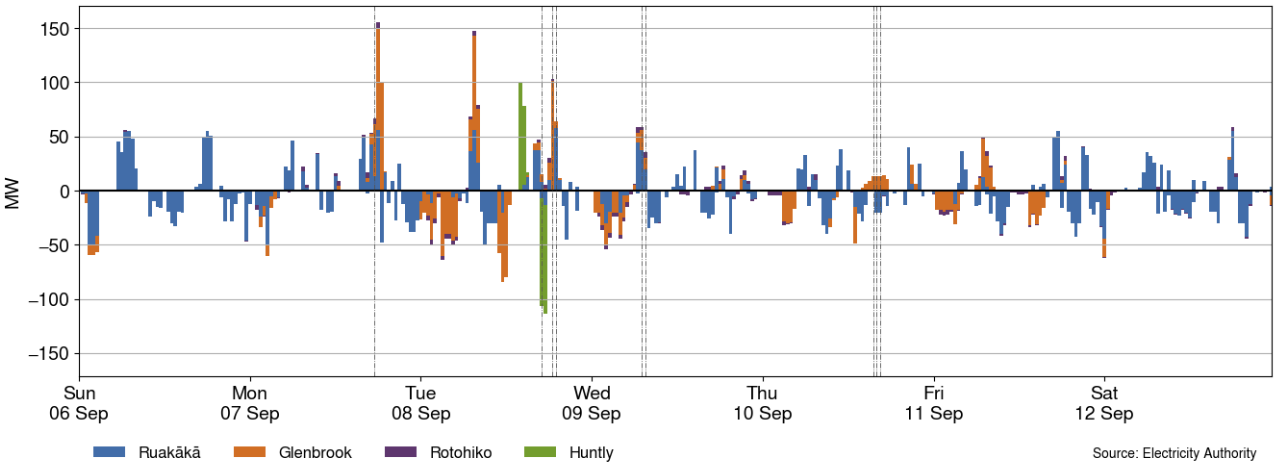
Figure 10: Grid connected solar generation, 6-12 September



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 at night and during the middle of the day when demand was lower and discharged during the morning and evening peaks. Batteries tended to discharge at a higher level when wind generation was lower.

Figure 11: Grid scale battery charge and discharge, 6-12 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.

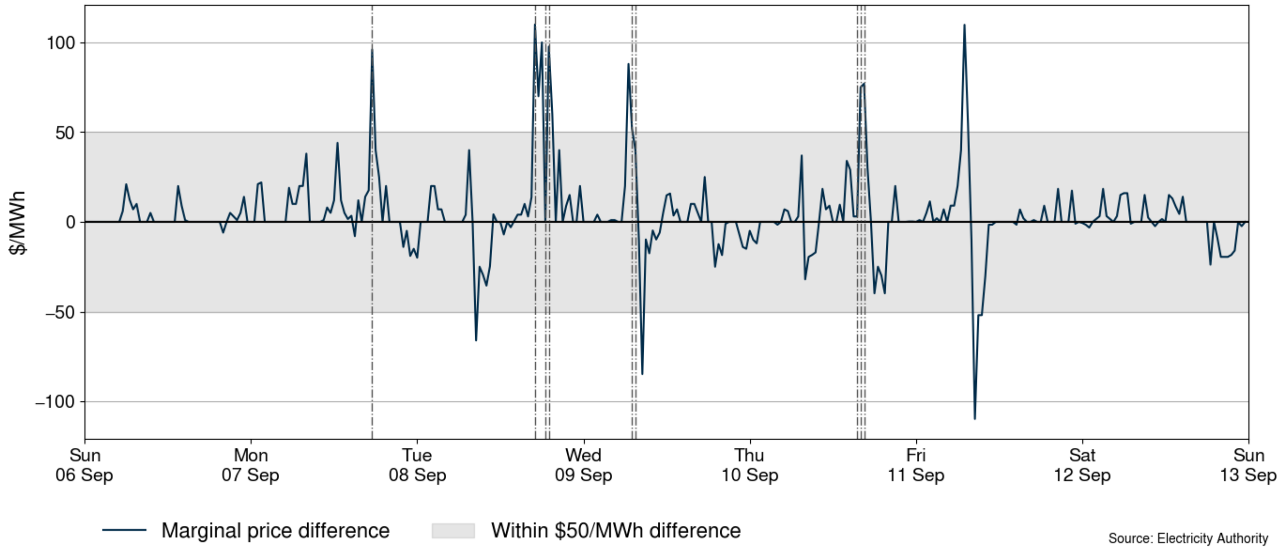
Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.9. This week there are 17 trading periods with marginal price differences greater than $50/MWh.

7.10. The largest positive difference was $110/MWh which occurred at 5.00pm on Tuesday. At this time demand was ~60MW higher than forecast, and intermittent generation 34MW lower than forecast. Additionally, Huntly BESS began charging at 100MW at 5.00pm when demand was 90% of the maximum for the Tuesday evening peak period and climbing.

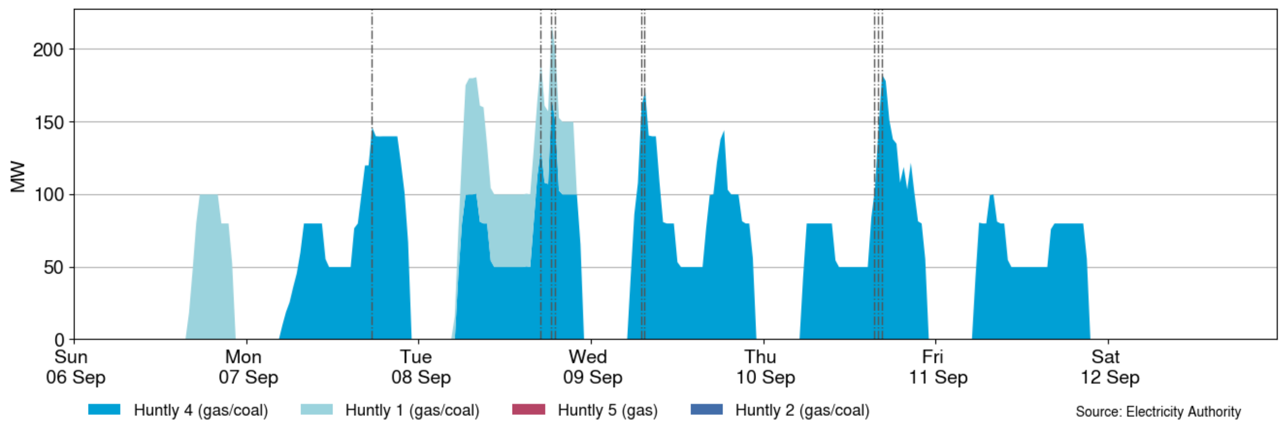
7.11. The largest negative difference was $110/MWh which occurred at 8.30am on Friday. At this time demand was ~158MW lower than forecast.

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, 6-12 September



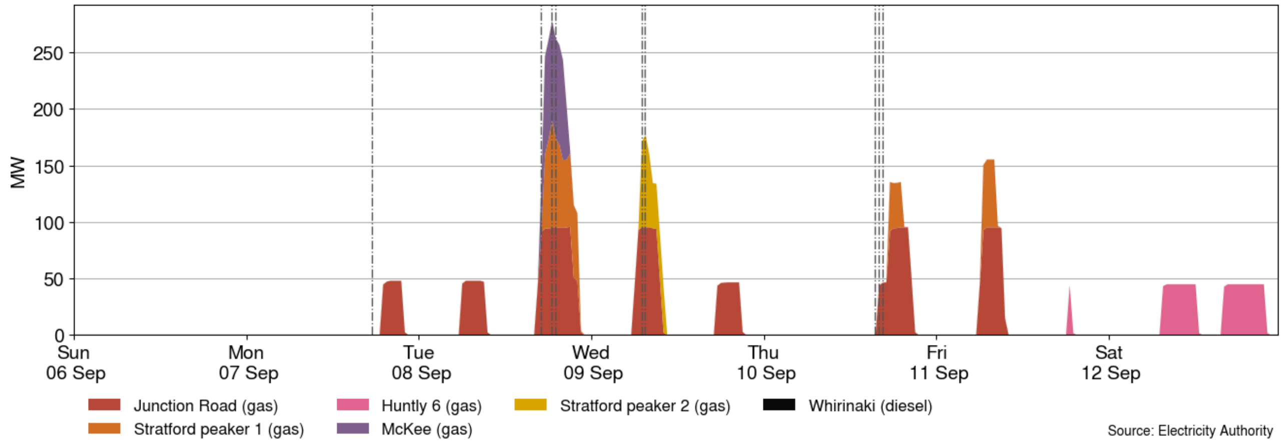
7.12. Figure 13 shows the generation of thermal baseload between 6-12 September. This week the majority of thermal baseload generation was provided by Huntly 4 at 50MW, increasing to 80MW and above during peak demand. Huntly 1 provided additional baseload on Tuesday when wind generation was low, and during the Sunday evening peak when demand was higher due to colder weather

Figure 13: Thermal baseload generation, 6-12 September



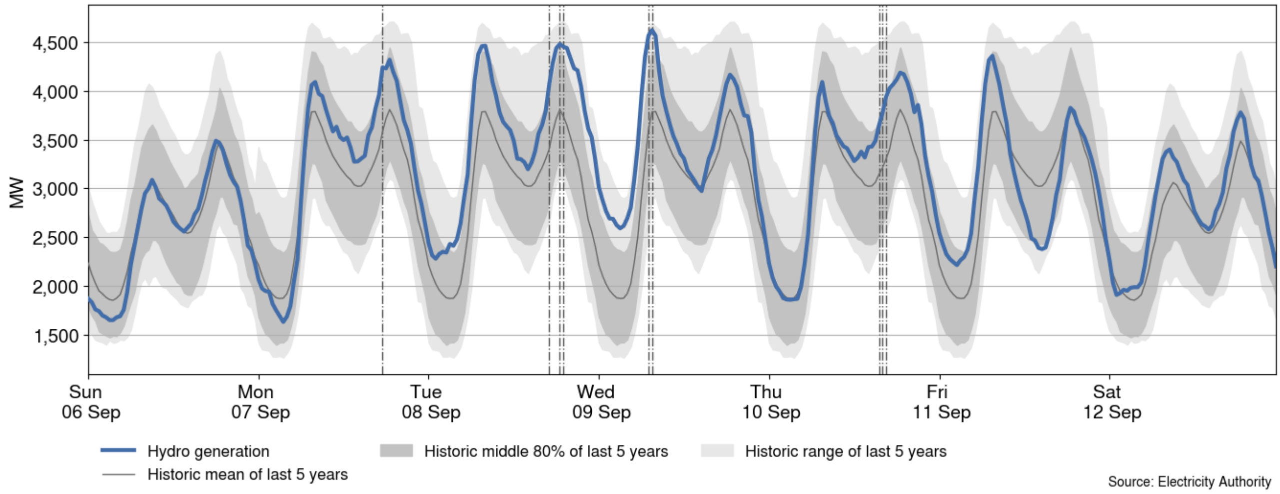
7.13. Figure 14 shows the generation of thermal peaker plants between 6-12 September. Peaker generation was low throughout the week with more peakers turning on during the Tuesday evening demand peak as wind generation was low and HVDC flows were high.

Figure 14: Thermal peaker generation, 6-12 September



7.14. Figure 15 shows hydro generation between 6-12 September. Hydro generation was mostly above average this week. With hydro generation coming within 250MW of the top of the historic range for the last 5 years during the Wednesday morning peak.

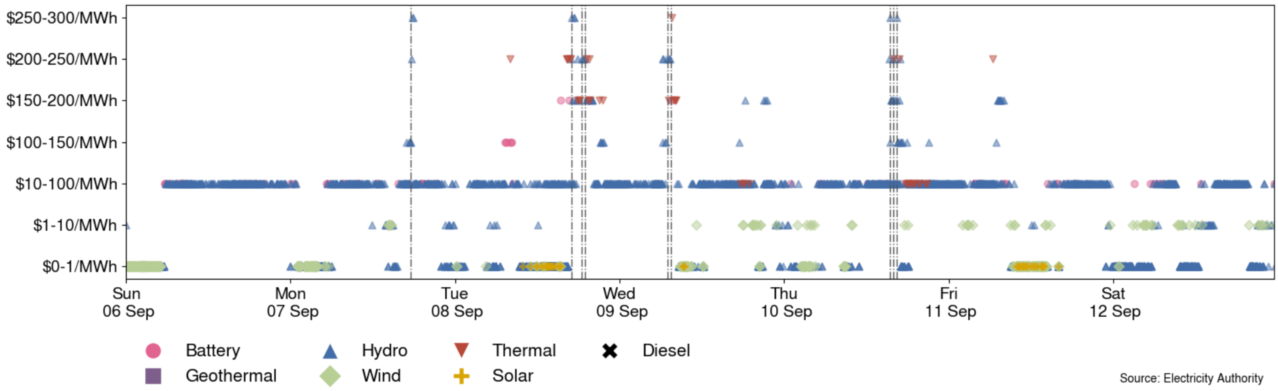
Figure 15: Hydro generation, 6-12 September



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.

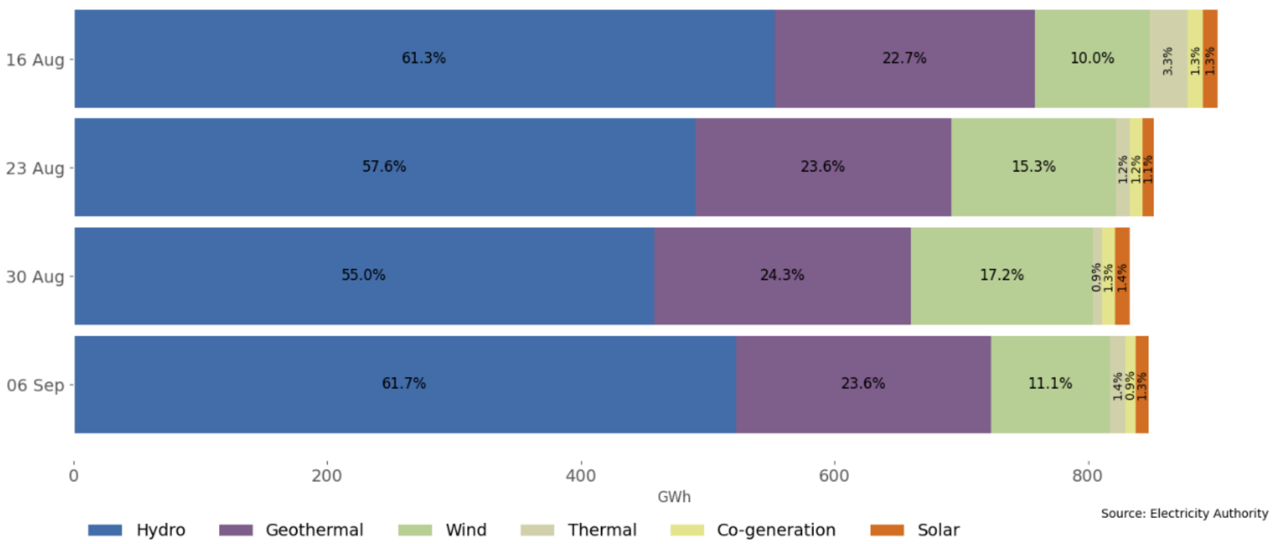
7.16. The highest marginal price of $260/MWh was set by Karāpiro at 5:30pm on Monday. The most common marginal technology was hydro and the second most common technology was wind. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 6-12 September



7.17. As a percentage of total generation, between 6-12 September, total weekly hydro generation was 61.7%, geothermal 23.6%, wind 11.1%, thermal 1.4%, co-generation 0.9%, and solar (grid connected) 1.3%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 16 August and 12 September



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 6-12 September ranged between ~702MW and ~1706MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 6-12 September

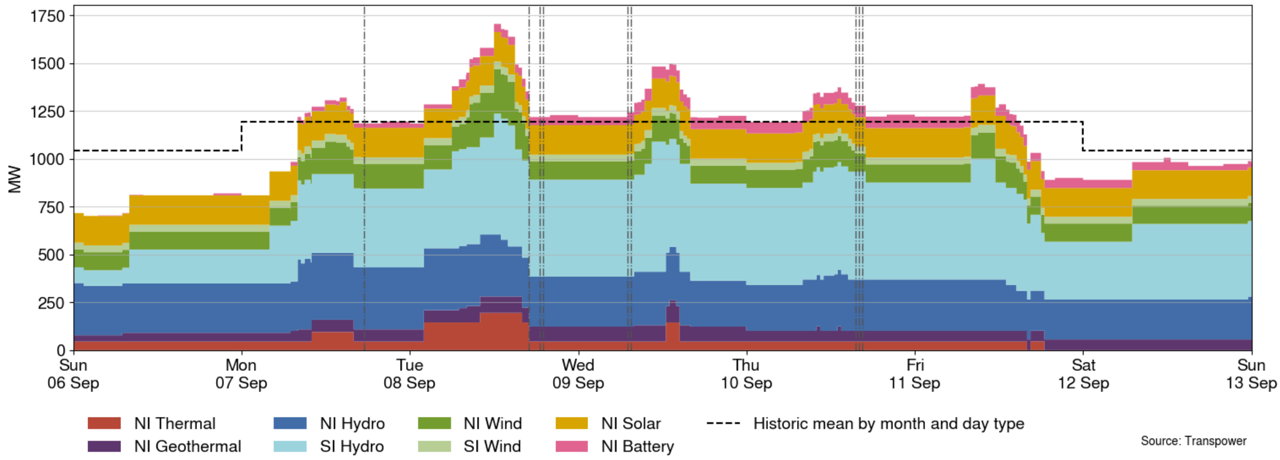
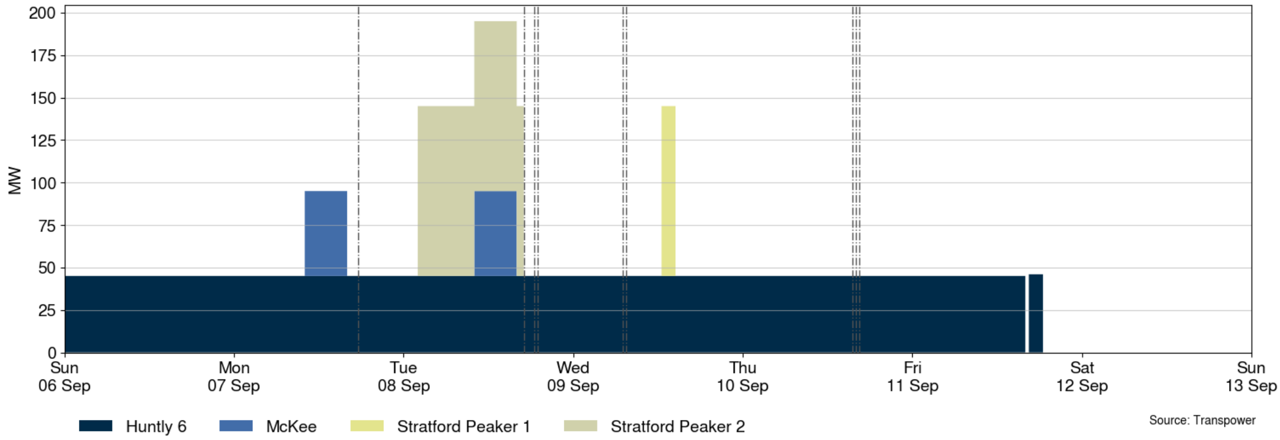


Figure 19: Total MW loss from thermal outages, 6-12 September



8.2. Notable outages include:

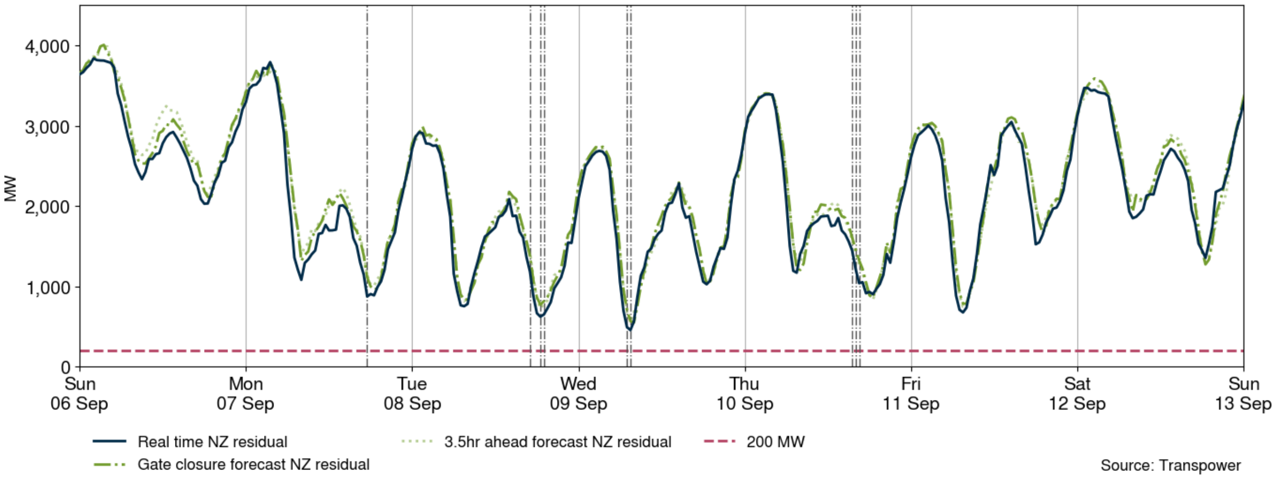
Plant	Partial or Full	End Date
Manapōuri unit 7	Full	8 September 2026
Stratford Peaker 2	Full	8 September 2026
Clyde unit 4	Full	9 September 2026
Stratford Peaker 1	Full	9 September 2026
Manapōuri unit 1	Full	11 September 2026
Tauhei Solar Farm	Full	14 September 2026
Roxburgh unit 8	Full	15 September 2026
Kaiwaikawe Wind Farm	Partial	30 November 2026
Manapōuri unit 2	Full	2 July 2027

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 6-12 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. There were no residuals below 200MW this week.

Figure 20: National generation balance residuals, 6-12 September



10. Storage/fuel supply

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

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

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

10.4. Storage at Lake Te Anau (125% full) is at the historic 90th percentile for this time of year.

10.5. Storage at Lake Manapōuri (111% full) is slightly above the historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (55% full) is slightly above average for this time of year.

10.7. 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.

10.8. National controlled storage was 84% nominally full and ~140% of the historical average for this time of the year.

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

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

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

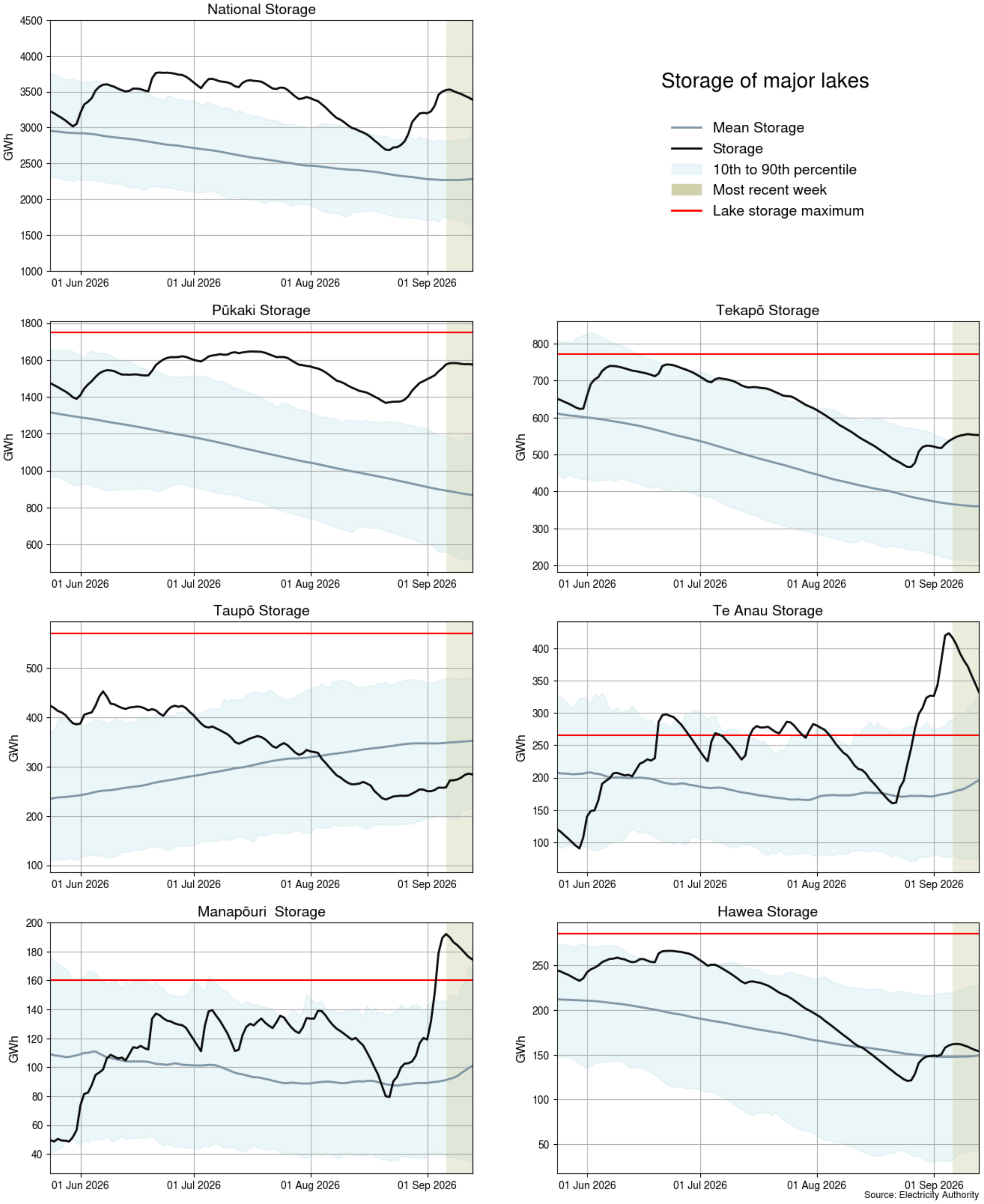
10.12. Storage at Lake Te Anau (125% full) is at the historic 90th percentile for this time of year.

10.13. Storage at Lake Manapōuri (111% full) is slightly above the historic 90th percentile for this time of year.

10.14. Storage at Lake Hawea (55% 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.

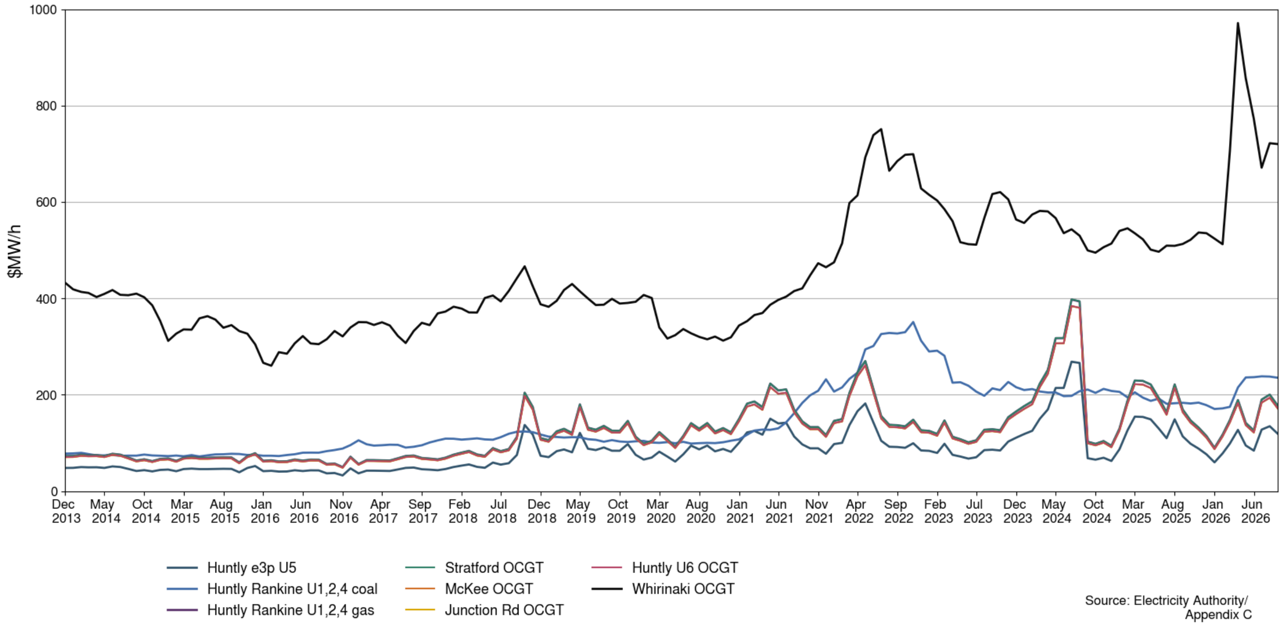
11.5. The SRMC of gas fuelled thermal plants is currently between $118/MWh and $177/MWh.

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

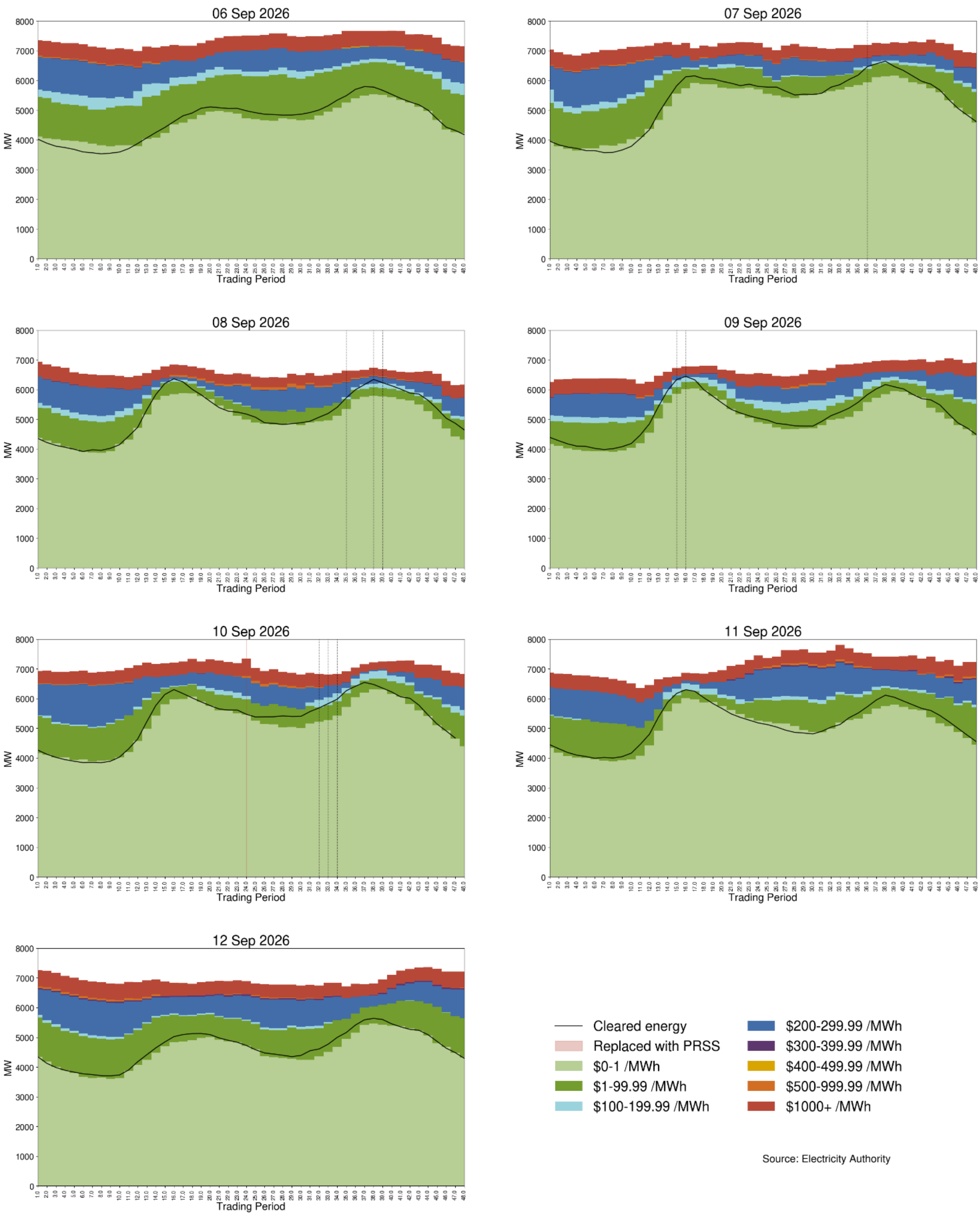


12. Offer behaviour

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.

12.2. This week energy mostly cleared between $1-100/MWh, though Monday evening, Tuesday, and Wednesday morning peak demand periods saw prices clearing between $200-299/MWh

Figure 23: Daily offer stacks[3]



Source: Electricity Authority

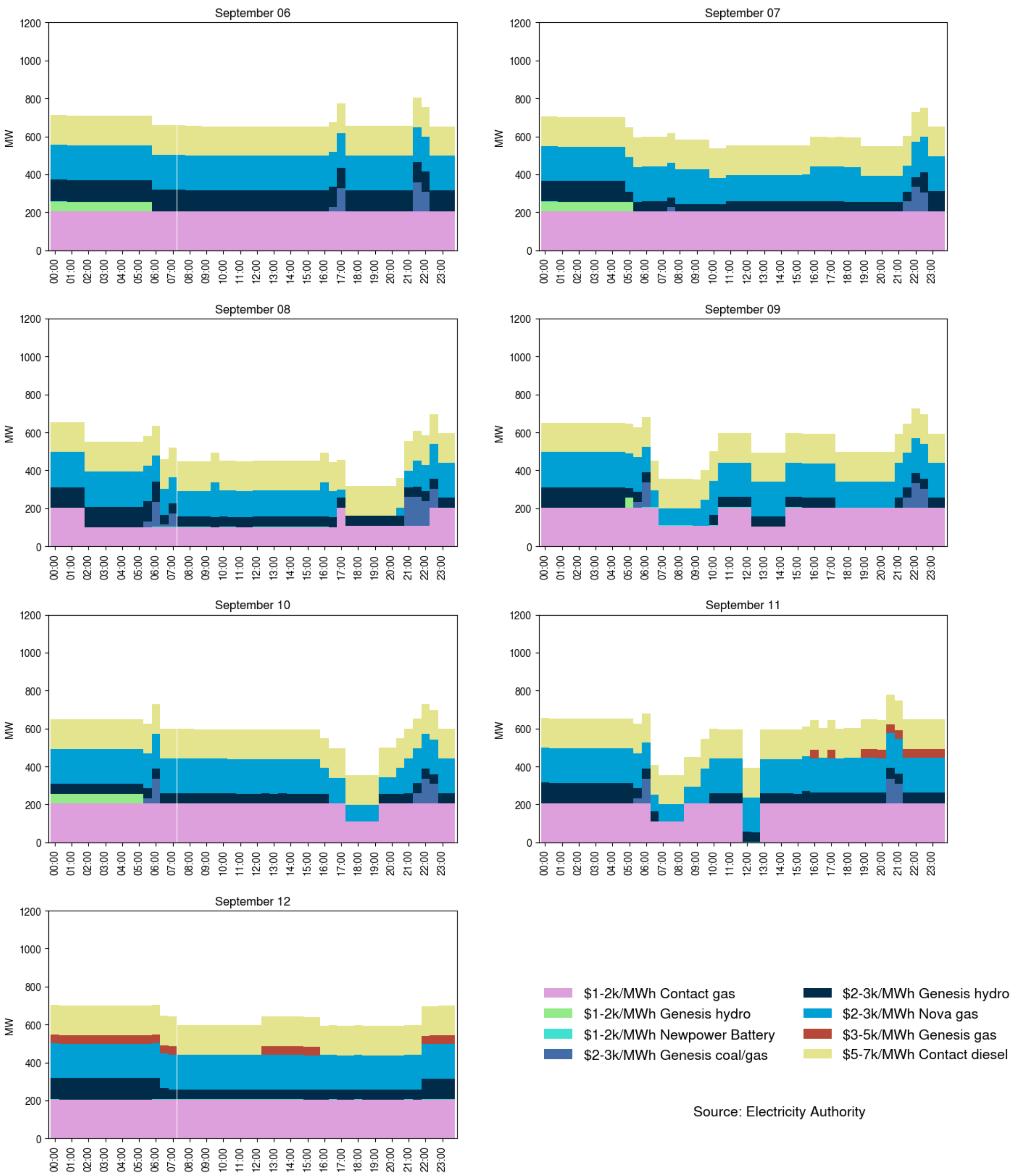
12.3. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

[3] PRSS data has been used for trading period 24 where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

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 601MW 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
8/09/2026	Several	Further analysis	Genesis	Huntly battery	Charging and discharging times