

6 October 2026

Trading conduct report

27 September-3 October 2026

Market monitoring weekly report

Trading conduct report 27 September-3 October 2026

1. Overview

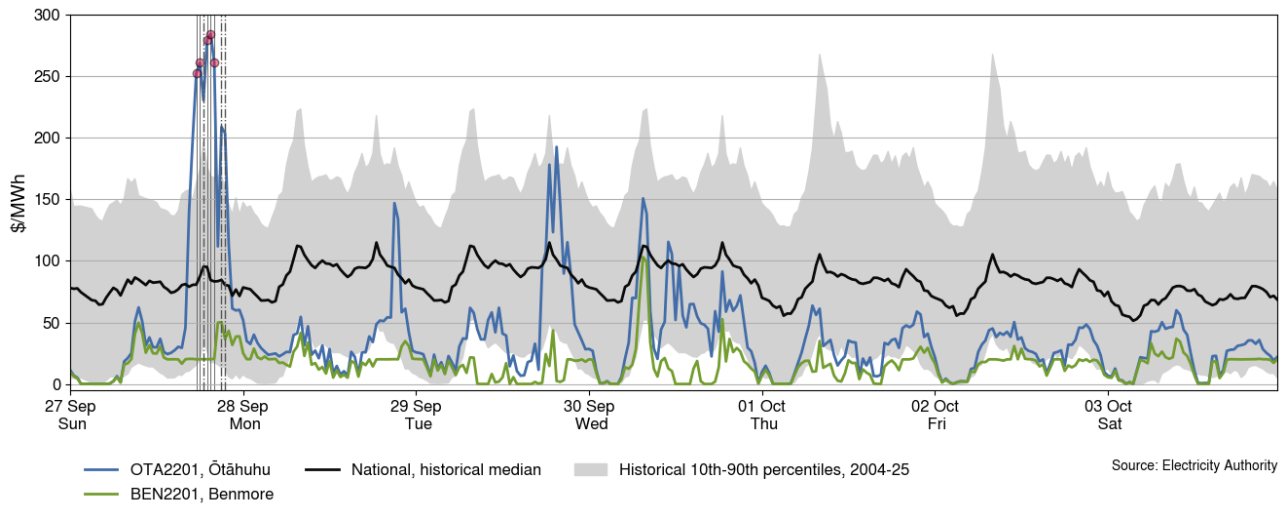
- 1.1. Prices were low this week likely due to overall warmer weather reducing demand and high levels of renewable generation. Hydro and thermal generation have decreased this week, while wind generation has increased. National hydro storage has decreased to 78% nominally full and is 130% of the historic mean for this time of year. Some high prices occurred during periods of high North Island reserve prices.

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 27 September-3 October:
 - (a) The average spot price for the week was \$30/MWh, a decrease of around \$18/MWh compared to the previous week.
 - (b) 95% of prices fell between \$0.02/MWh and \$138/MWh.
- 2.3. Prices were low overall this week due to warmer temperatures reducing demand and high renewable generation increasing the availability of cheap energy.
- 2.4. Between 5.30-9.30pm on Sunday, prices at Ōtāhuhu were mostly above \$200/MWh, peaking at \$284/MWh at 7.30pm. At this time the price at Benmore was \$20/MWh. During this period:
 - Demand was up to 143MW higher than forecast.
 - Intermittent generation was up to 214MW lower than forecast.
 - Some trading periods had little battery energy available to be discharged.
 - There were no Rankine units offered into the market.
 - North Island FIR prices were high, with prices spiking up to \$212/MWh.
- 2.5. At 7.30am on Wednesday the price at Ōtāhuhu spiked up to \$150/MWh. At this time the price at Benmore was \$103/MWh. During this period renewable generation was low reducing the availability of cheap energy to meet rising demand, meaning more expensive units were cleared raising spot prices.
- 2.6. Between 6.00-8.00pm on Tuesday, prices at Ōtāhuhu were mostly above \$100/MWh, peaking at \$192/MWh at 7.30pm. At this time the price at Benmore was \$2/MWh. During this period the HVDC had between 37MW and 66MW remaining and was setting the risk
- 2.7. 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

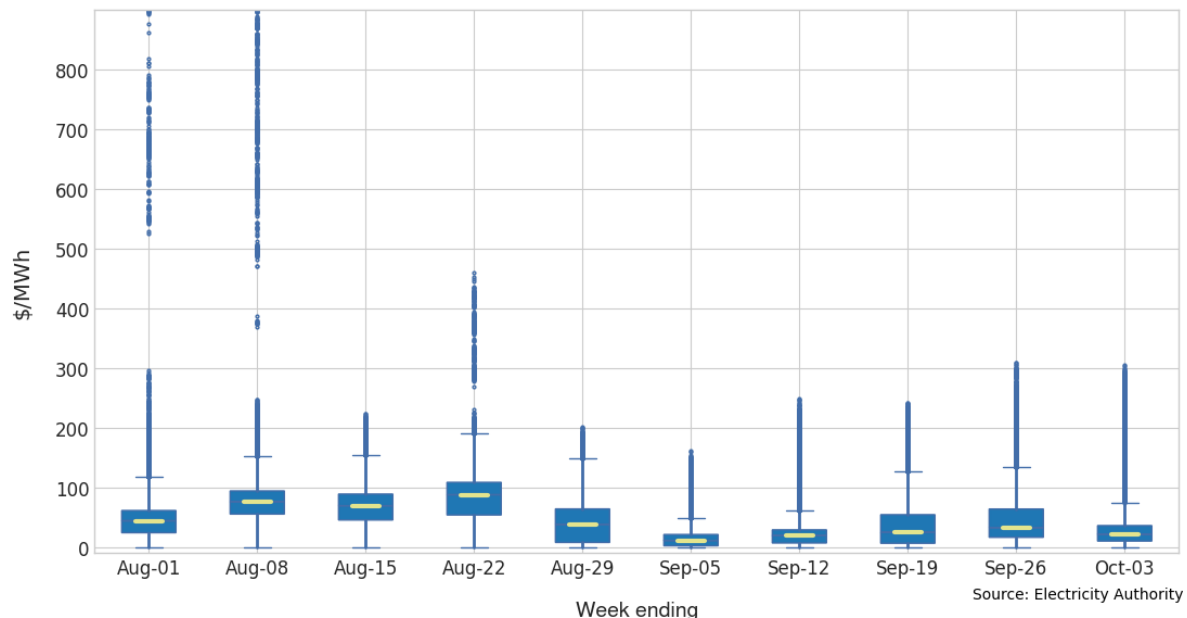
difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 27 September-3 October



- 2.8. 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.
- 2.9. The distribution of spot prices this week was narrower than last week with fewer high price outliers. The median price was \$30/MWh and most prices (middle 50%) fell between \$10/MWh and \$36/MWh.

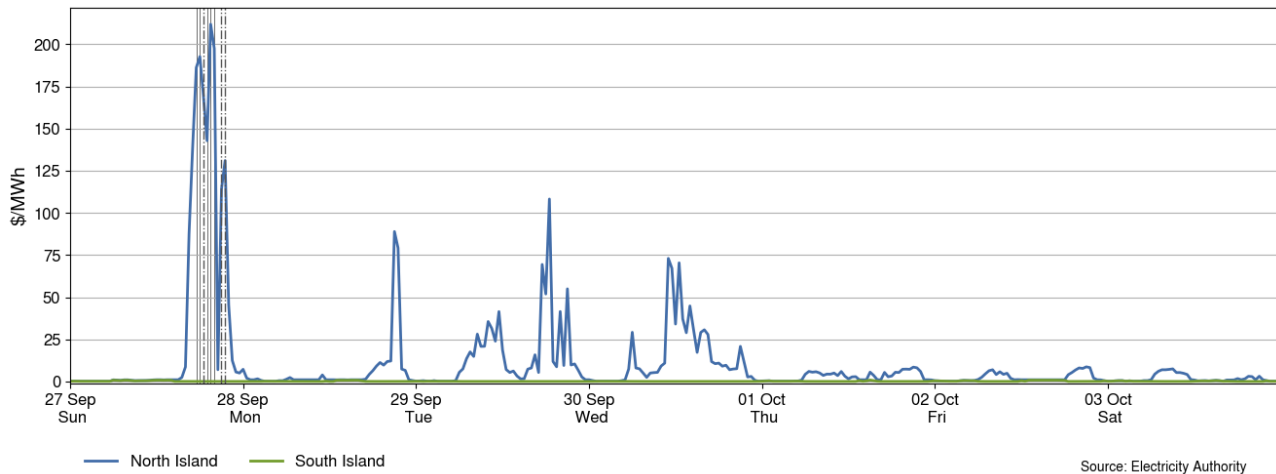
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

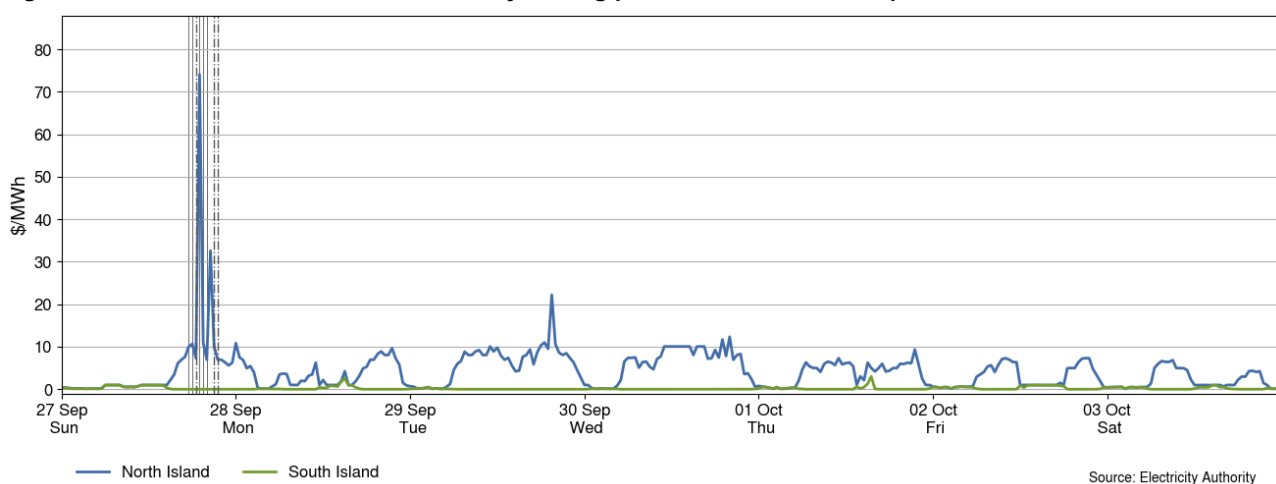
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below \$7/MWh this week.
- 3.2. At 7.30pm on Sunday, North Island FIR prices spiked up to \$212/MWh when the HVDC was setting the risk. At this time demand was 69MW higher than forecast, intermittent generation was 62MW lower than forecast, and the volume of FIR offered during this period was lower, with 28MW of residual FIR.

Figure 3: Fast instantaneous reserve price by trading period and island, 27 September-3 October



- 3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below \$6.8/MWh this week.
- 3.4. At 7.30pm on Sunday, North Island SIR prices spiked up to \$74/MWh when the HVDC was setting the risk. At this time demand was 112MW higher than forecast, intermittent generation was 57MW lower than forecast, and the volume of SIR offered during this period was lower, with 72MW of residual SIR.

Figure 4: Sustained instantaneous reserve by trading period and island, 27 September-3 October



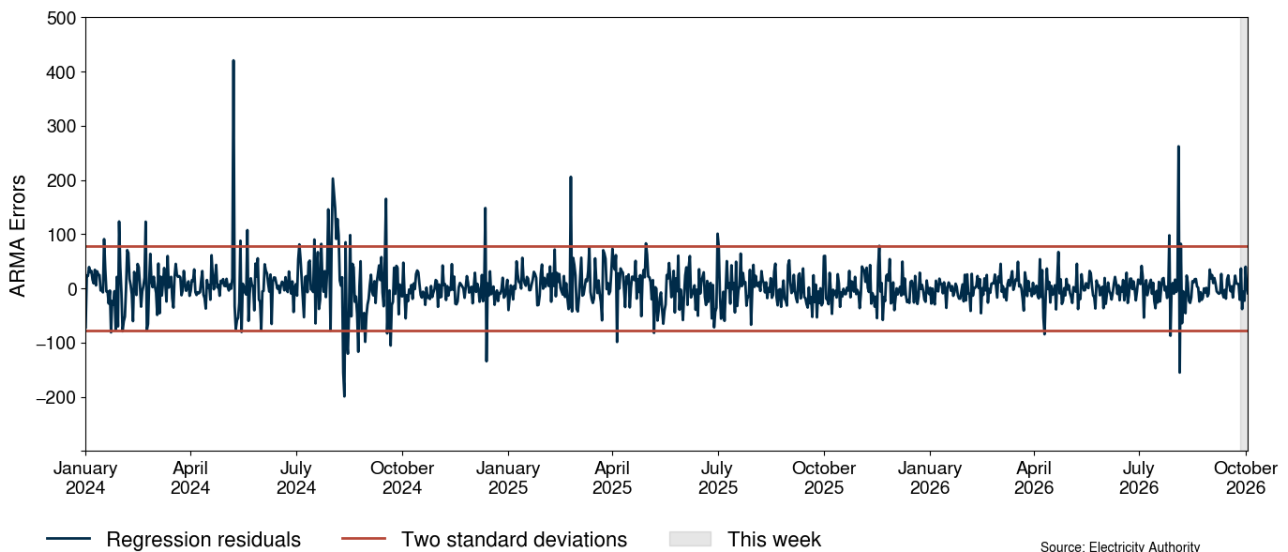
4. Regression residuals

- 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.

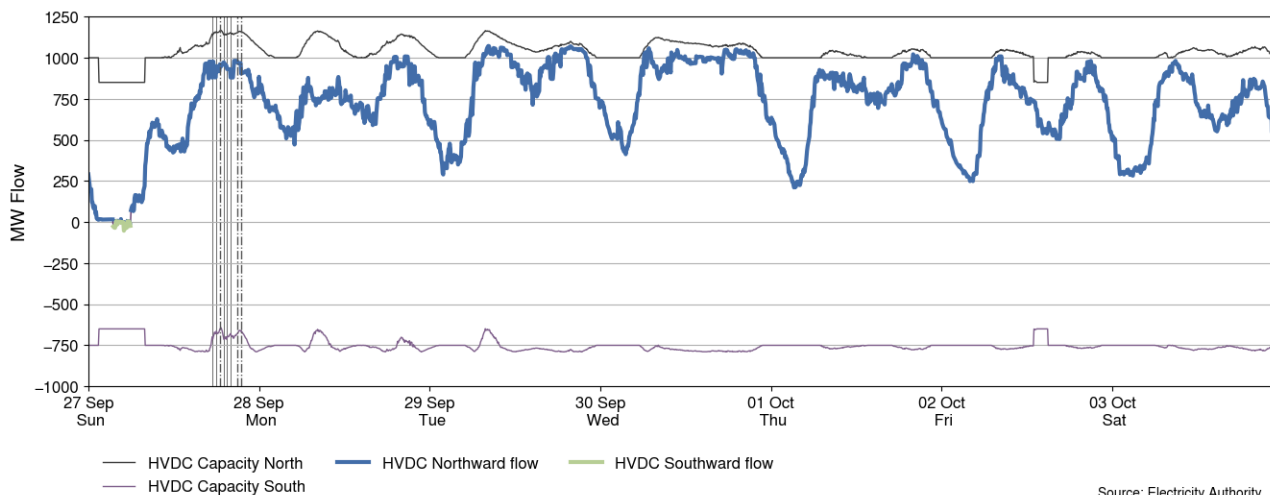
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 3 October 2026



5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 27 September-3 October. HVDC flows were mostly northward this week.
- 5.2. The highest northward HVDC flow this week was 1,071MW which occurred at 8.20am on Tuesday.
- 5.3. The highest southward HVDC flow this week was 53MW which occurred at 5.00am on Sunday.

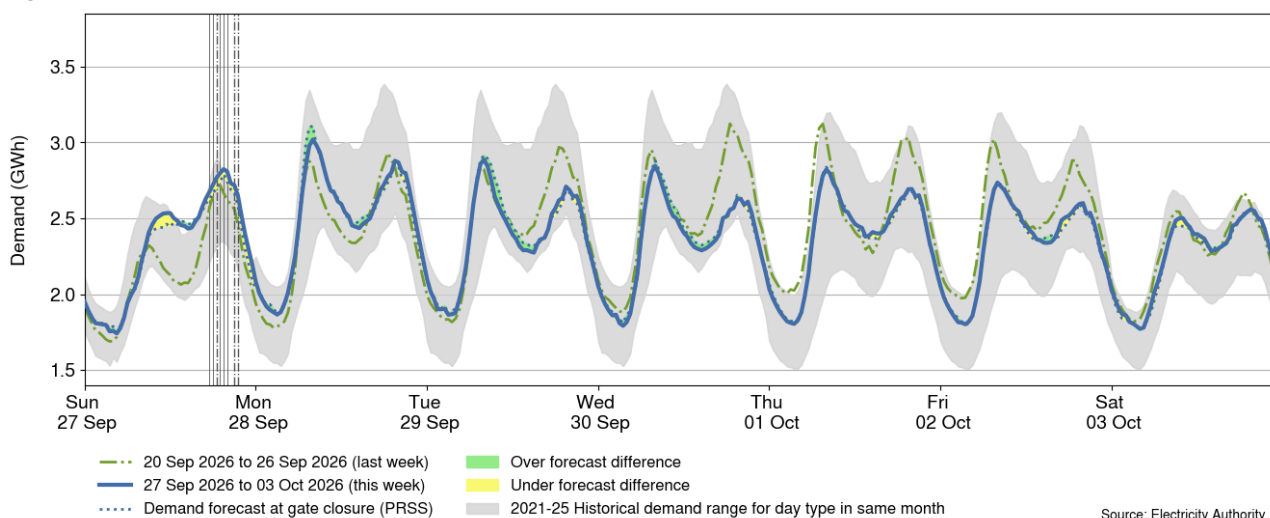
Figure 6: HVDC flow and capacity, 27 September-3 October



6. Demand

- 6.1. Figure 7 shows national demand between 27 September-3 October, compared to the historic range and the demand of the previous week. Demand was higher than last week on Sunday and Monday during colder weather and mostly lower than last week from Tuesday evening onwards.
- 6.2. The maximum demand this week was around 3.02GWh (6.04GW) at 8.00am on Monday.
- 6.3. Demand was:
- (a) Between 85MW and 183MW higher than forecast from 9.30am-12.00pm on Sunday
 - (b) Between 69MW and 203MW higher than forecast from 5.30pm-12.00am on Sunday
 - (c) Between 126MW and 291MW lower than forecast from 6.30-8.00am on Monday.
 - (d) Between 67MW and 234MW lower than forecast from 8.30am-3.00pm on Tuesday.

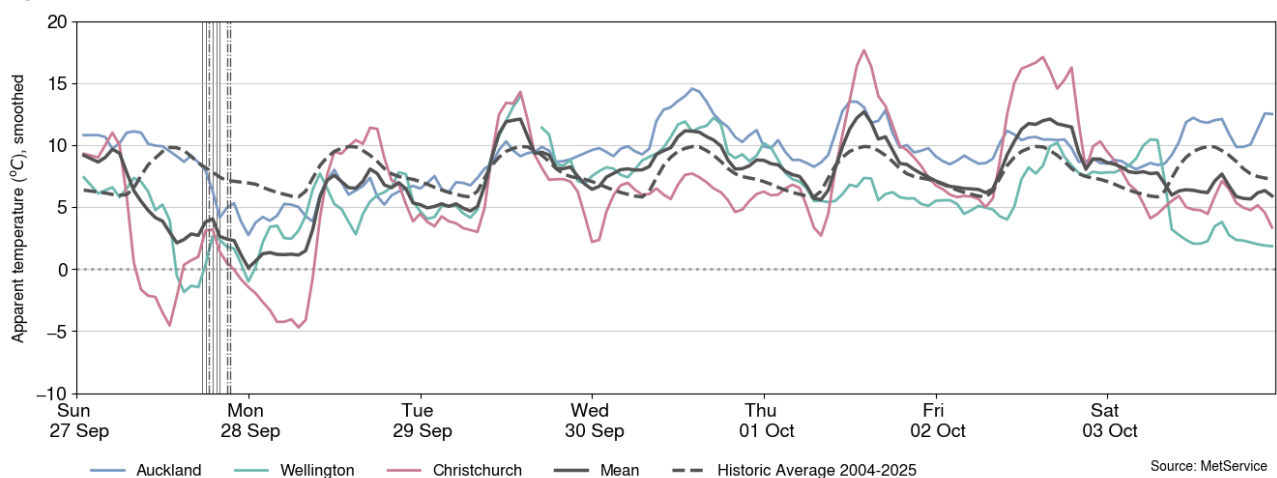
Figure 7: National demand, 27 September-3 October compared to the previous week



6.4.

- 6.5. Apparent temperatures ranged from 3°C to 15°C in Auckland, -2°C to 14°C in Wellington, and -5°C to 18°C in Christchurch. Cold temperatures on Sunday likely contributed to higher than usual demand.
- 6.6. Figure 8 shows the hourly apparent temperature at main population centres from 27 September-3 October. 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.
- 6.7. Apparent temperatures ranged from 3°C to 15°C in Auckland, -2°C to 14°C in Wellington, and -5°C to 18°C in Christchurch. Cold temperatures on Sunday likely contributed to higher than usual demand.

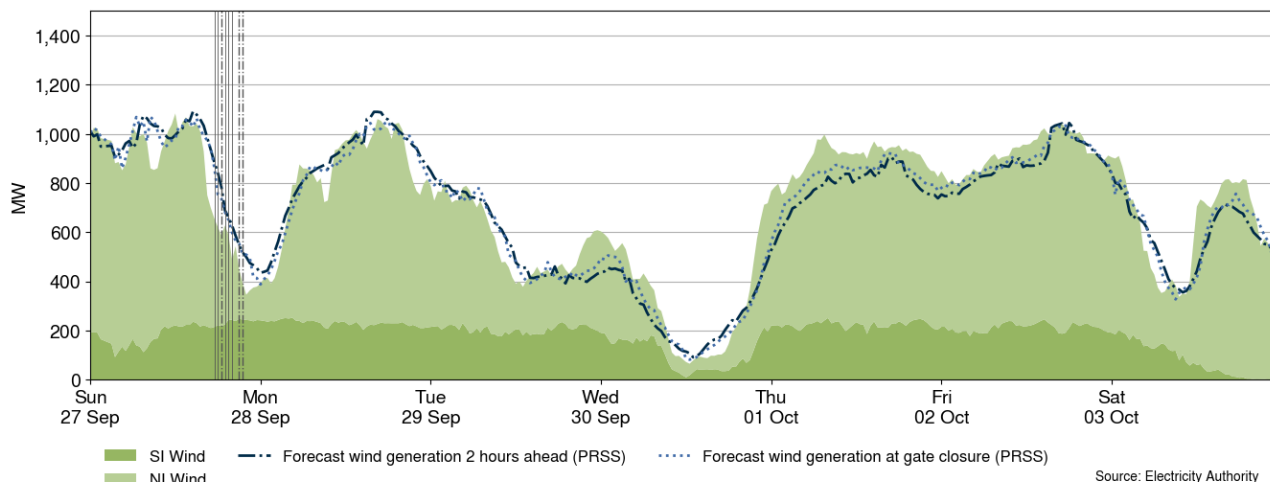
Figure 8: Temperatures across main centres, 27 September-3 October



7. Generation

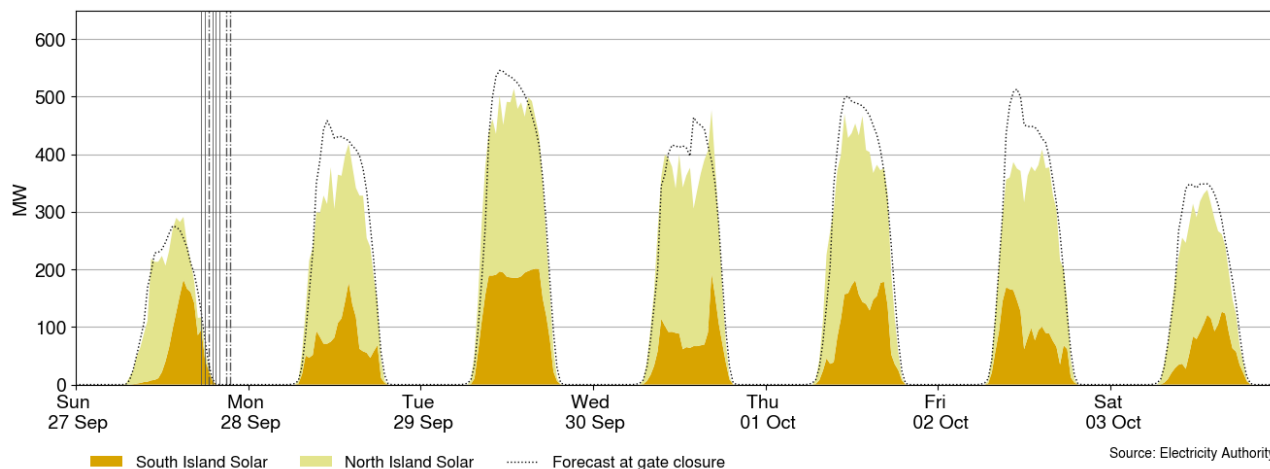
- 7.1. Figure 9 shows wind generation and forecast from 27 September-3 October. This week wind generation varied between 65MW and 1,083MW, with a weekly average of 712MW. Wind generation was high on Sunday and Monday before dropping off on Tuesday evening. Wind generation then picked back up on Thursday, remaining high until Saturday morning.
- 7.2. Wind generation was lower than forecast on Sunday evening. This was mostly due to forecasting differences at Tararua Stage 3, Turitea, Waipipi, and Harapaki wind farms.

Figure 9: Wind generation and forecast, 27 September-3 October



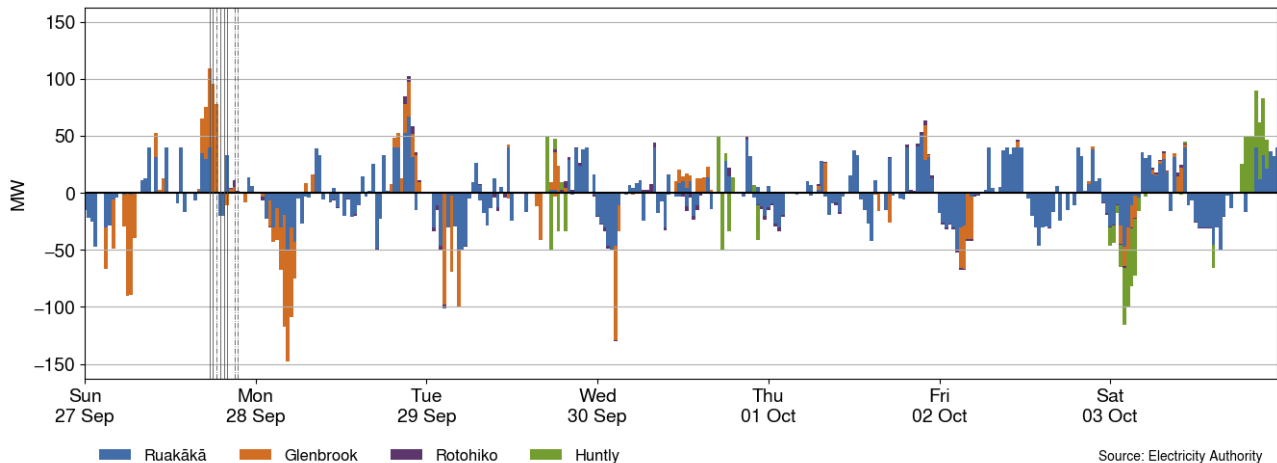
- 7.3. Figure 10 shows utility-scale solar generation from 27 September-3 October. Mean daytime solar generation this week was 258MW, peaking at 514MW on Tuesday at 1:00pm. Solar generation was high this week.
- 7.4. Forecasting differences on Monday and Wednesday are due to the commissioning Kōwhai Park solar farm. Forecasting differences on other days are due to errors accumulated across multiple farms.

Figure 10: Utility-scale solar generation, 27 September-3 October



- 7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) 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.
- 7.6. This week batteries mostly charged at night and during the middle of the day when demand was lower and discharged during morning and evening peak demand.
- 7.7. Meridian's Ruakākā battery charged at 20MW during peak demand and high prices at 7.00pm on Sunday. The monitoring team is looking further into this.

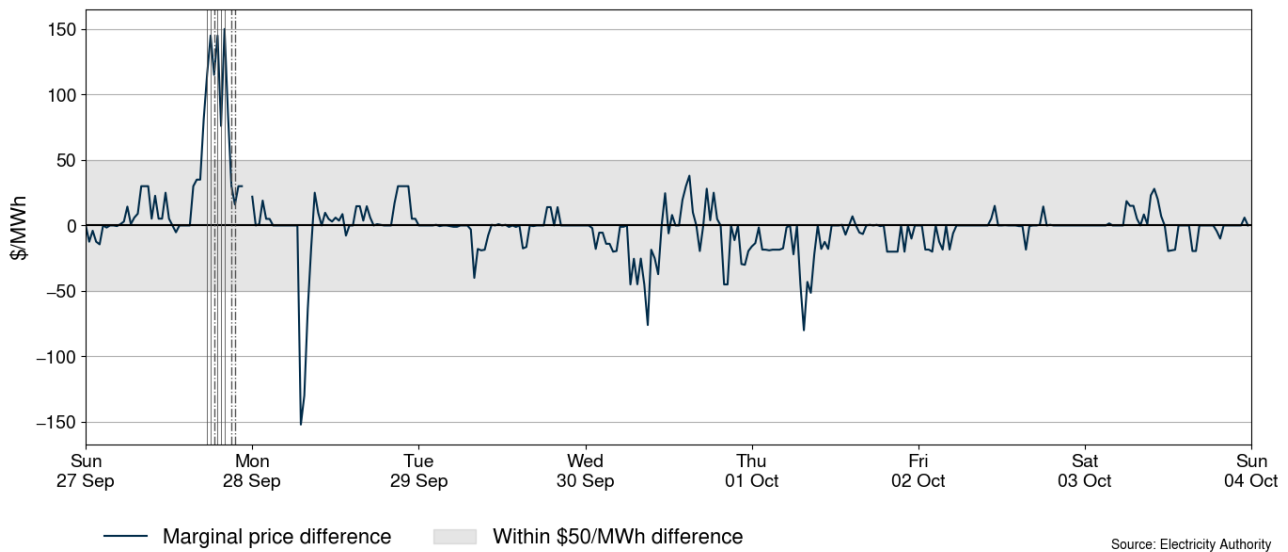
Figure 11: Grid scale battery charge and discharge, 27 September-3 October



- 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 (PRSS¹) 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.
- 7.9. The largest positive difference of \$150/MWh occurred on Sunday at 8.00pm. At this time demand was 130MW higher than forecast and intermittent generation was 109MW lower than forecast.
- 7.10. The largest negative difference of \$152/MWh occurred on Monday at 7.00am. At this time demand was 291MW lower than forecast.

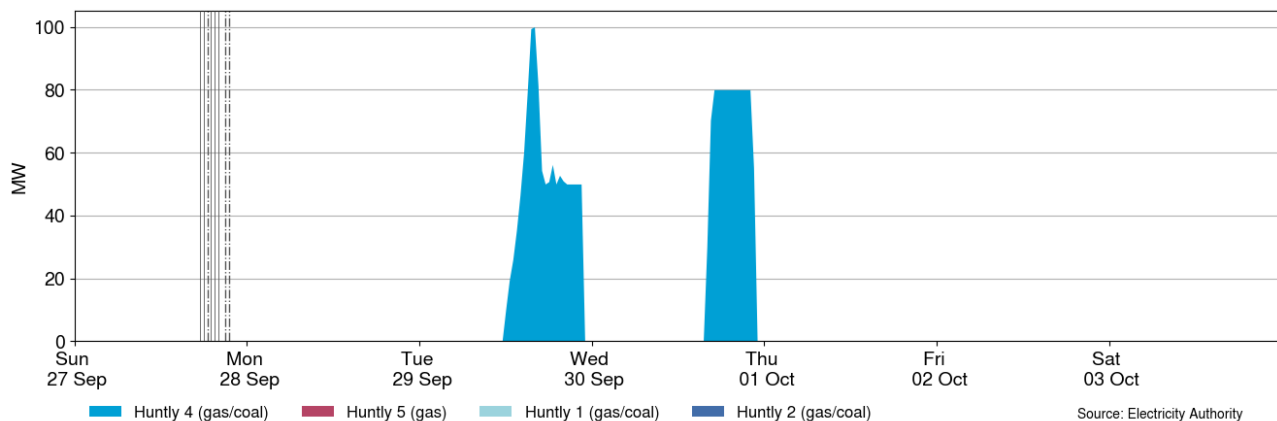
¹ Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 27 September-3 October



7.11. Figure 13 shows the generation of thermal baseload between 27 September-3 October. Huntly 4 provided thermal baseload generation this week only on Tuesday and Wednesday evening.

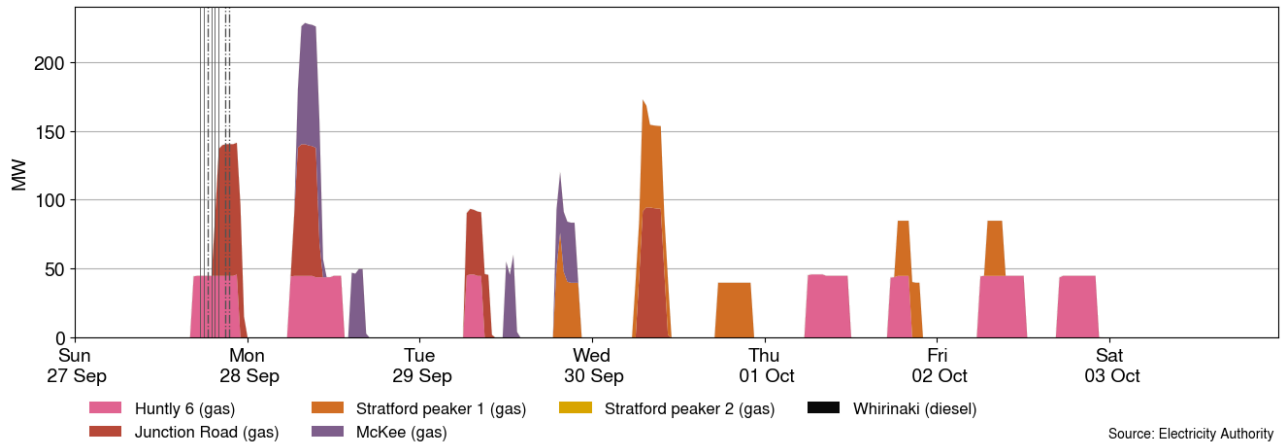
Figure 13: Thermal baseload generation, 27 September-3 October



7.12. Figure 14 shows the generation of thermal peaker plants between 27 September-3 October. Peaker generation was spread throughout the week at times of peak demand.

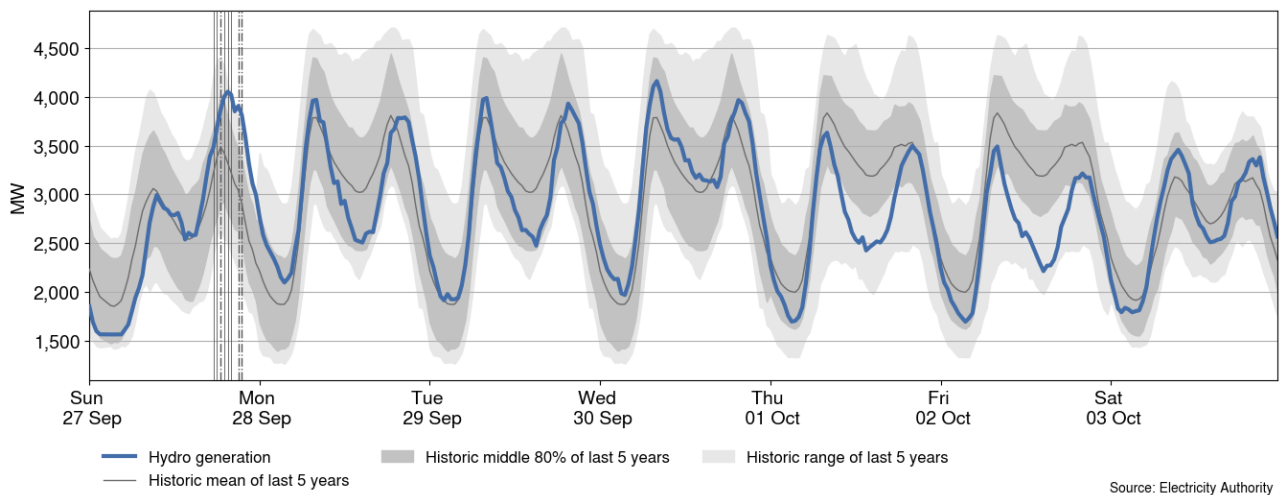
7.13. The Junction Road peaker ran during the Sunday evening high prices once batteries were likely depleted.

Figure 14: Thermal peaker generation, 27 September-3 October



7.14. Figure 15 shows hydro generation between 27 September-3 October. Hydro generation was high on Sunday evening, then similar to mean from Monday to Wednesday. Generation was then lower than mean on Thursday and Friday, before returning to similar to mean on Saturday.

Figure 15: Hydro generation, 27 September-3 October



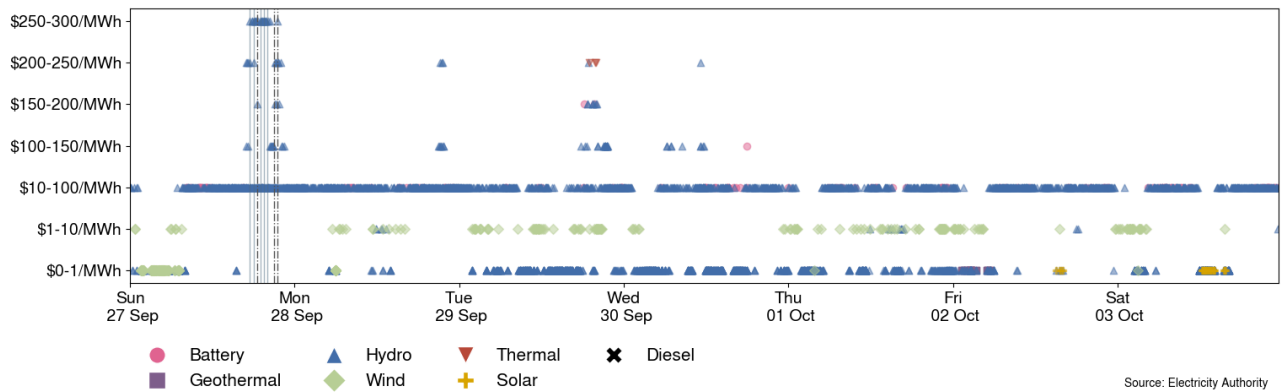
7.15.

7.16. The highest marginal price of \$260/MWh was set by Arapuni at 5:00pm on Sunday. The most common marginal technology was hydro and the second most common technology was wind. Most marginal prices were between \$10-100/MWh.

7.17. 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.

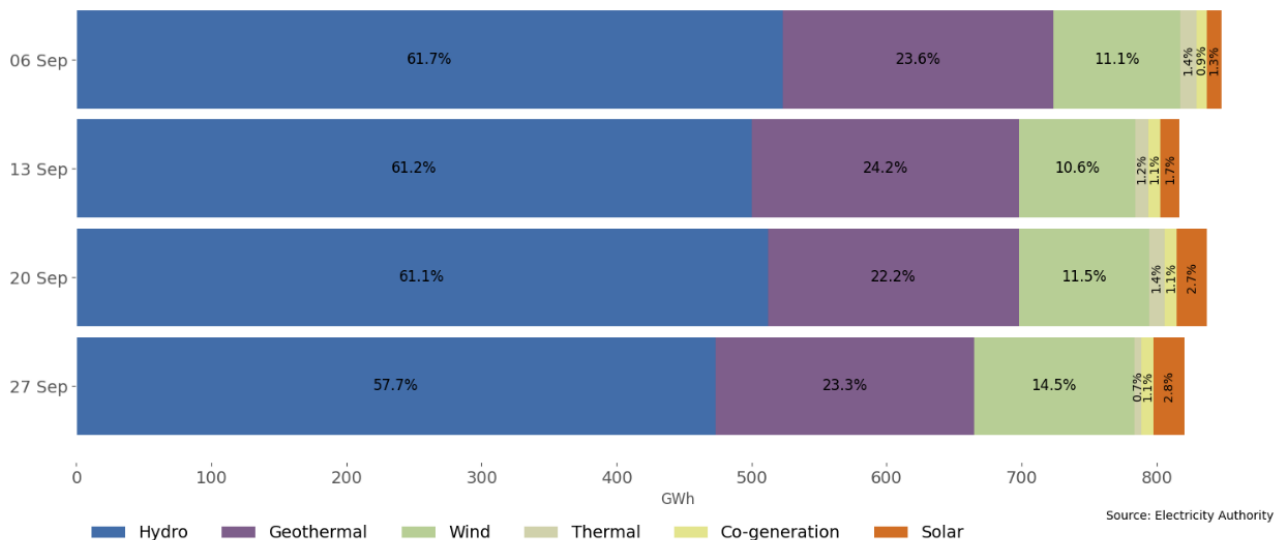
7.18. The highest marginal price of \$260/MWh was set by Arapuni at 5:00pm on Sunday. The most common marginal technology was hydro and the second most common technology was wind. Most marginal prices were between \$10-100/MWh.

Figure 16: Prices of marginal generation, 27 September-3 October



7.19. As a percentage of total generation, between 27 September-3 October, total weekly hydro generation was 57.7%, geothermal 23.3%, wind 14.5%, thermal 0.7%, co-generation 1.1%, and solar (grid connected) 2.8%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 6 September and 3 October



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 27 September-3 October ranged between ~1,094MW and ~1,793MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 27 September-3 October

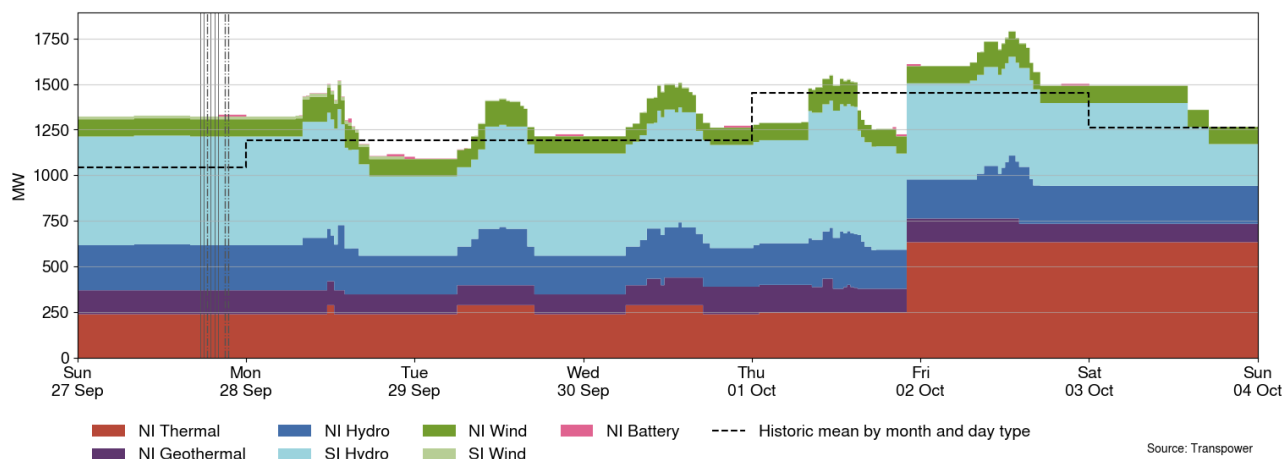
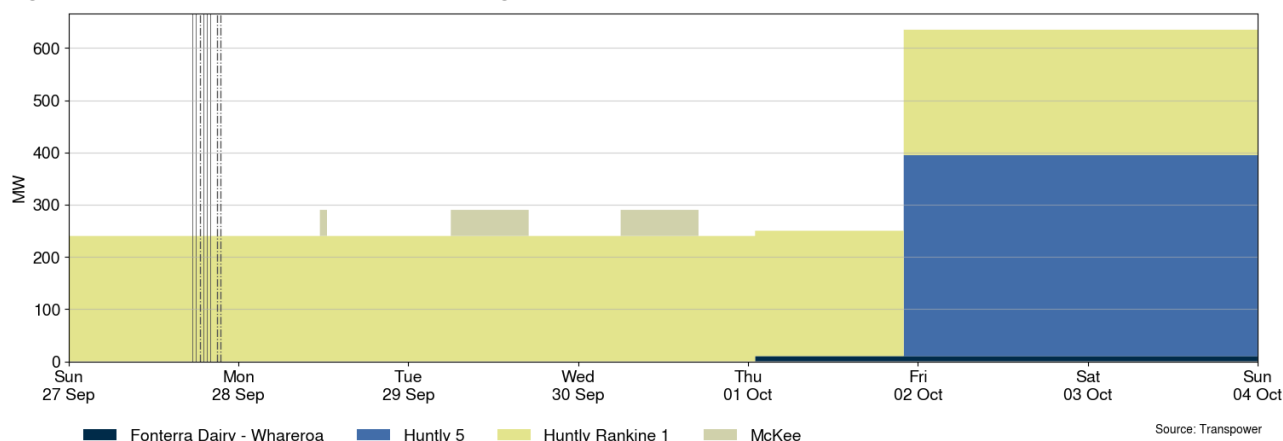


Figure 19: Total MW loss from thermal outages, 27 September-3 October



8.2. Notable outages include:

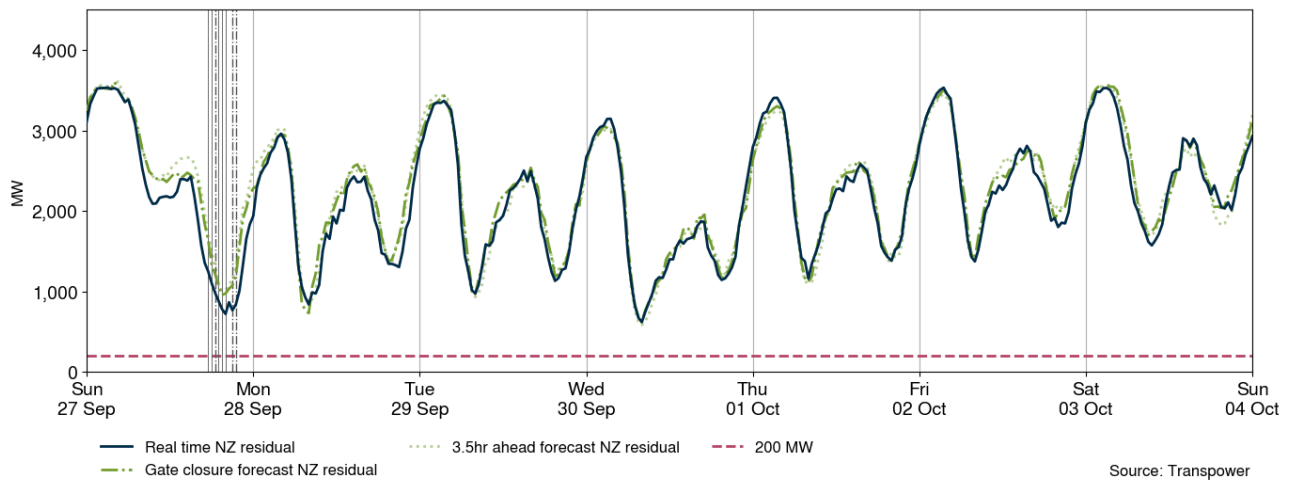
Plant	Partial or Full	End Date
Benmore unit 2	Full	28 September 2026
Te Huka 3	Full	28 September 2026
Manapōuri unit 3	Full	1 October 2026
Ōhau A station	Full	3 October 2026
Takapō B unit 2	Full	3 October 2026
Huntly 5	Full	28 October 2026
Huntly 1	Full	11 October 2026
Kaiwaikawe wind farm	Partial	30 November 2026
Manapōuri unit 2	Full	2 July 2027

9. Generation balance residuals

- 9.1. Figure 20 shows the national generation balance residuals between 27 September-3 October. 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, 27 September-3 October

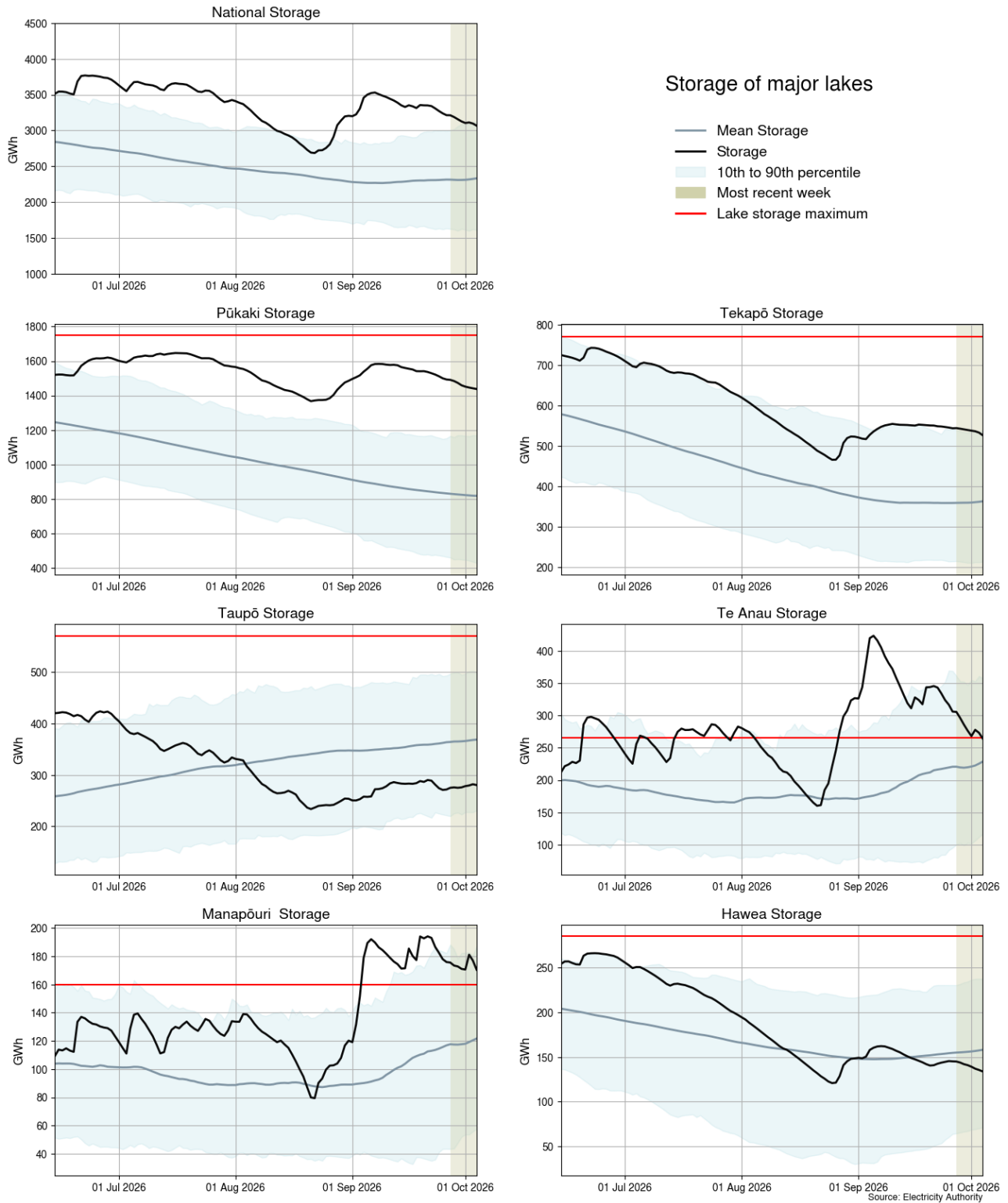


10. Storage/fuel supply

- 10.1. 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.
- 10.2. National controlled storage was 78% nominally full and ~130% of the historical average for this time of the year.
- 10.3. Storage at Lake Pūkaki (83% full²) is significantly higher than the historic 90th percentile for this time of year.
- 10.4. Storage at Lake Tekapō (69% full) is at the historic 90th percentile for this time of year.
- 10.5. Storage at Lake Taupō is (49% full) is below average for this time of year.
- 10.6. Storage at Lake Te Anau (100% full) is well above average for this time of year and remains above nominal full level.
- 10.7. Storage at Lake Manapōuri (108% full) is at the historic 90th percentile for this time of year and remains above nominal full level.
- 10.8. Storage at Lake Hawea (48% full) is below average for this time of year.

² Percentage full values sourced from NZX Hydro.

Figure 21: Hydro storage

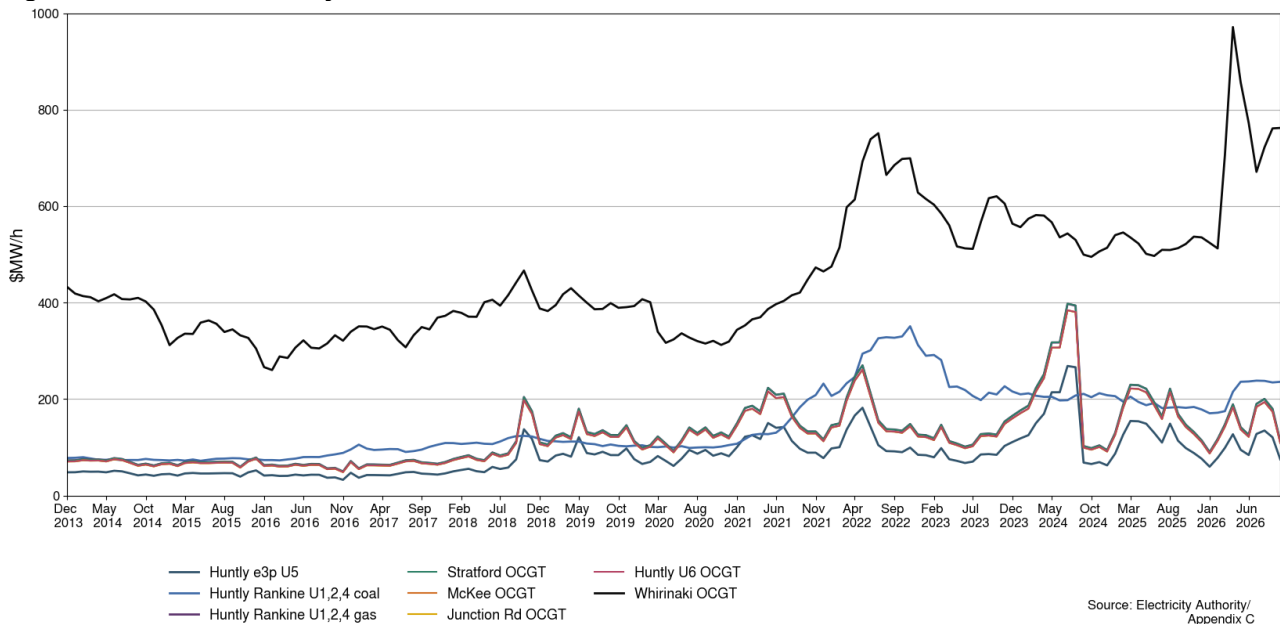


11. Prices versus estimated costs

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 October 2026. The SRMCs for gas generation have decreased, the SRMC for diesel generation has increased, with the SRMC for coal 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 ~\$112/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$74/MWh and \$112/MWh.
- 11.6. The SRMC of Whirinaki is ~\$762/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](#).

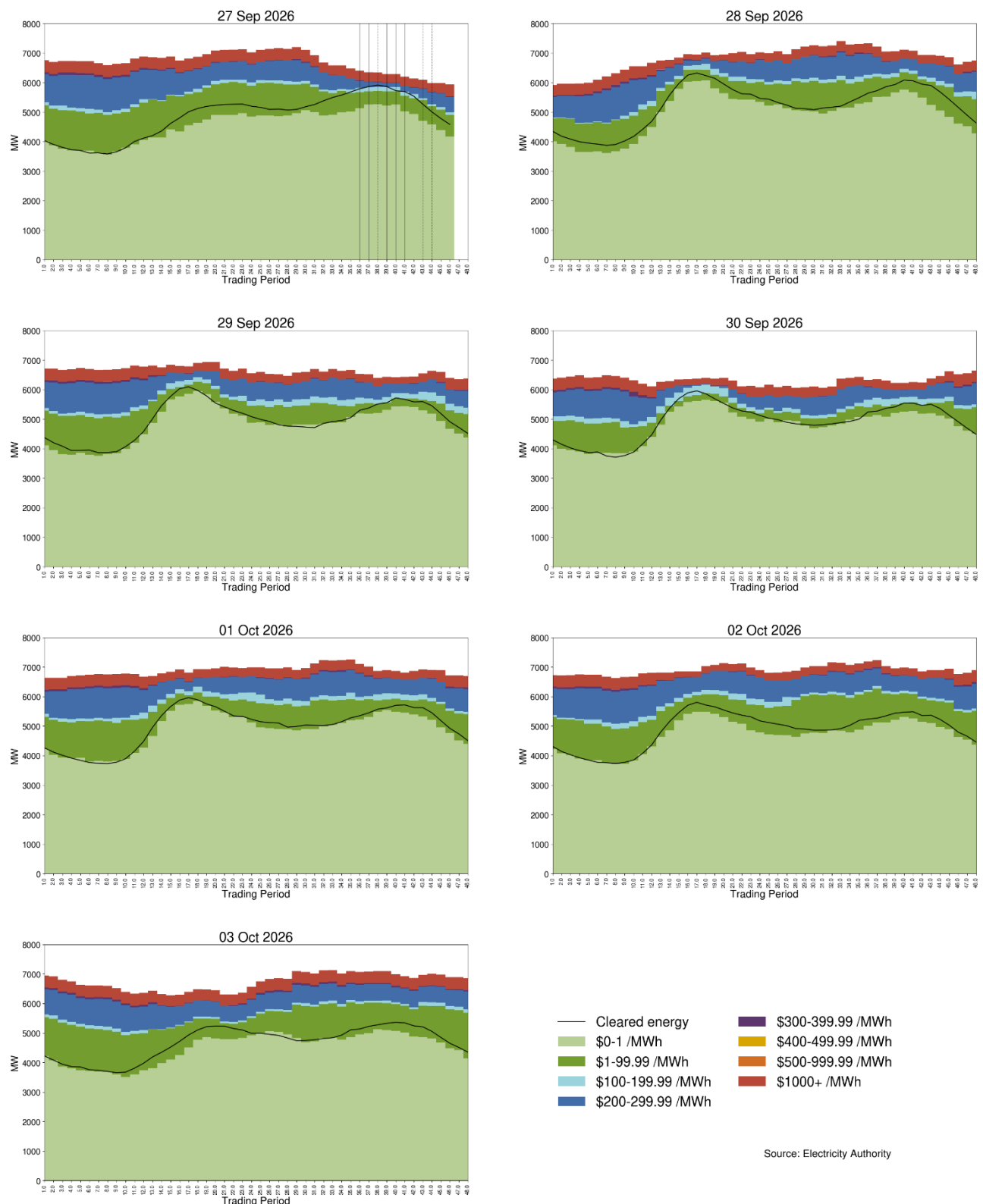
Figure 22: Estimated monthly SRMC for thermal fuels



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. Most energy cleared between \$1-99/MWh this week, except for times on Sunday evening and Wednesday morning when energy cleared between \$200-299/MWh and \$100-199/MWh respectively.

Figure 23: Daily offer stacks³

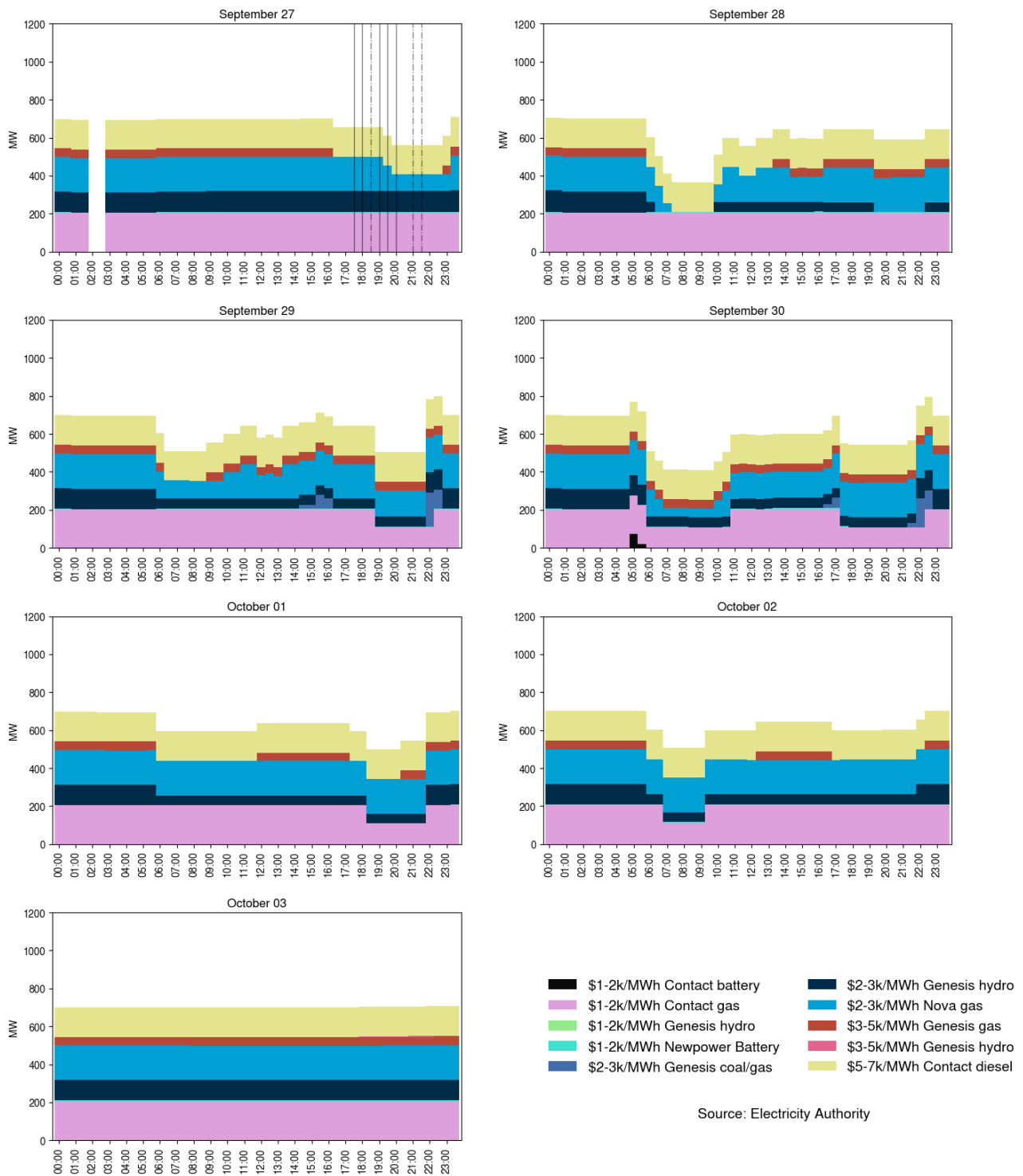


12.3. Figure 24 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

³ Trading periods 47 and 48 on Sunday 27 September have no data due to the daylight-saving transition.

- 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 641MW per trading period was priced above \$1,000/MWh this week, which is roughly 12% of the total energy available.

Figure 24: High priced offers⁴



13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. The monitoring team is looking into Ruakākā battery charging bids further this week.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

⁴ Trading periods starting at 2.00am and 2.30am on Sunday 27 September have no data due to the daylight-saving transition.

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
27/09/2026	Several	Further analysis	Meridian	Ruakākā BESS	Bids