

20 October 2026

Trading conduct report 11-17 October 2026

Market monitoring weekly report

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1. Overview

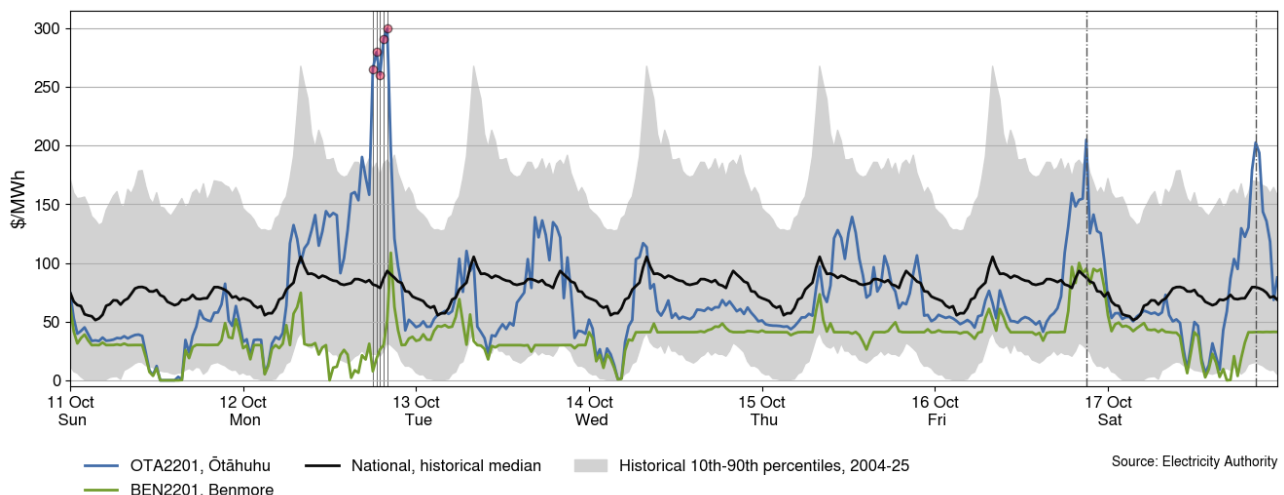
- 1.1. Spot prices have increased this week due to low apparent temperatures increasing demand late in the week, HVDC constraints lowering HVDC capacity, and periods of high Northward HVDC flow leading to North Island price separation. National hydro storage decreased to 74% nominally fully and 119% of the historic average.

2. Spot prices

- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 11-17 October:
 - (a) The average spot price for the week was \$57/MWh, an increase of around \$11/MWh compared to the previous week.
 - (b) 95% of prices fell between \$1/MWh and \$157/MWh.
- 2.3. Spot prices increased this week due to very low apparent temperatures later in the week increasing demand, and lower HVDC capacity due to planned transmission equipment outages near Benmore and Haywards substations increasing the need for thermal and North Island hydro generation. Currently most North Island hydro generation is priced high compared to South Island hydro generation due to low North Island hydro storage levels.
- 2.4. Between 6.00-8.00pm on Monday spot prices at Ōtāhuhu were above \$250/MWh, reaching a maximum of \$299/MWh at 8.00pm. At this time the price at Benmore was \$51/MWh. During this period:
 - Wind generation was very low, below 200MW, and solar generation was falling from ~100MW as the sun was setting, decreasing the availability of cheap energy.
 - The capacity of the HVDC was in the process of decreasing due to the planned transmission equipment outages decreasing flow capacity.
 - Batteries were running low during this period.
 - Additional peaker generation was dispatched.
- 2.5. Between 7.00-11.00pm on Friday spot prices at Ōtāhuhu were above \$100/MWh, reaching a maximum of \$205/MWh at 9.00pm. At this time the price at Benmore was \$95/MWh. During this period:
 - The HVDC was constrained due to the planned transmission equipment outages decreasing flow capacity, along with high North Island demand, and the absence of thermal generation increasing HVDC flows.
 - Intermittent generation was between 8MW and 233MW lower than forecast.

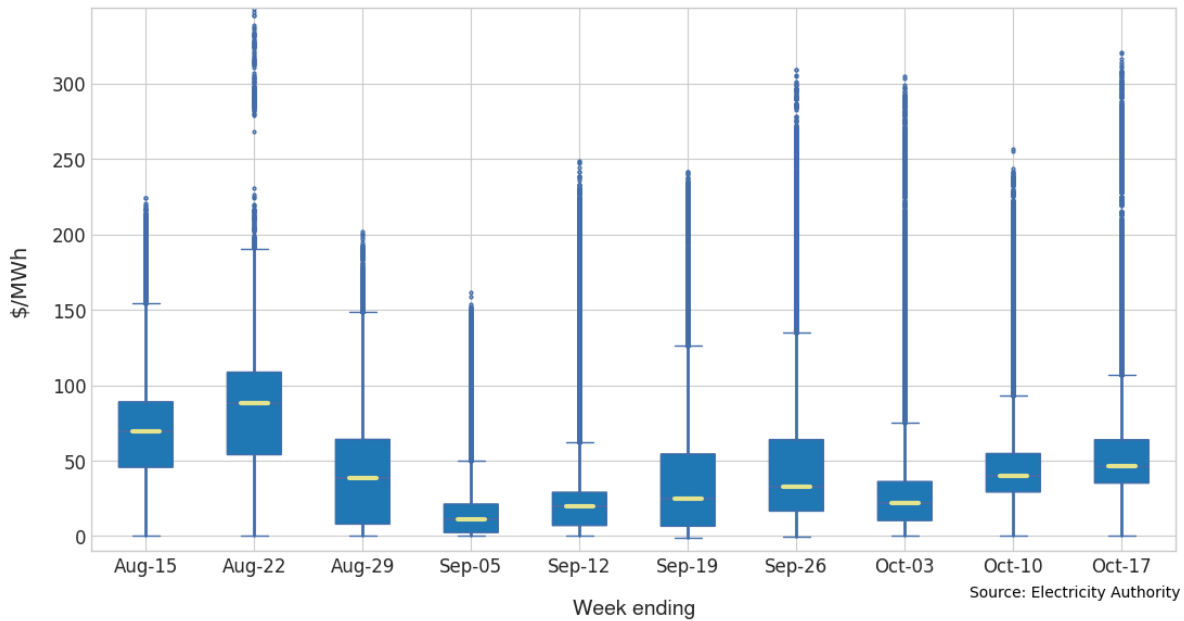
- 2.6. Between 5.30-10.30pm on Saturday spot prices at Ōtāhuhu were above \$100/MWh, reaching a maximum of \$202/MWh at 8.30pm. At this time the price at Benmore was \$41/MWh. During this period:
- North Island fast instantaneous reserve (FIR) prices were high, reaching a maximum of \$94/MWh.
 - The HVDC was constrained due to the planned transmission equipment outages decreasing flow capacity.
 - Intermittent generation was low, below 400MW.
 - Batteries and North Island hydro stations were setting prices.
- 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, 11-17 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 wider than last week with more high-priced outliers. The median price was \$57/MWh and most prices (middle 50%) fell between \$35/MWh and \$64/MWh.

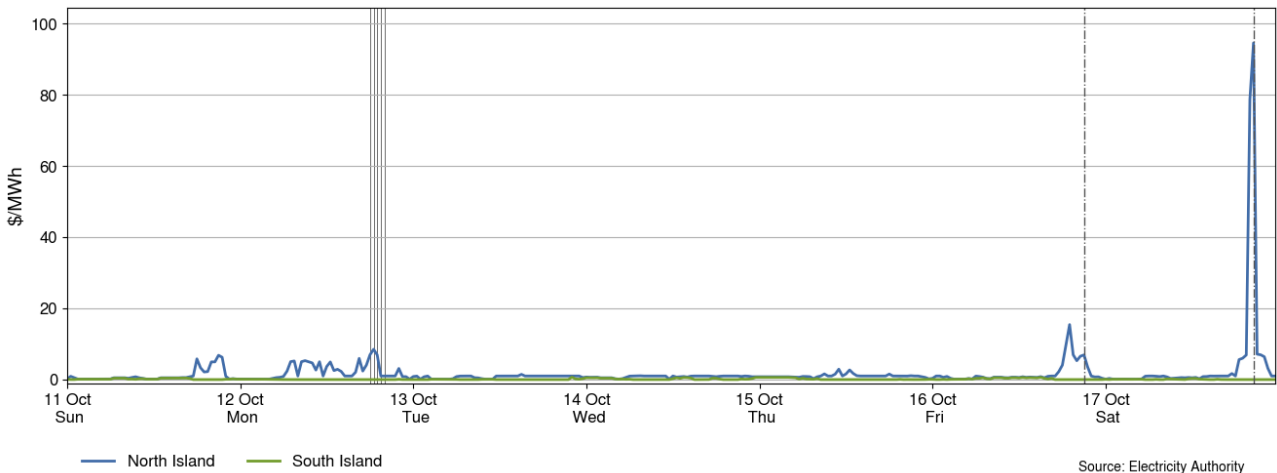
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

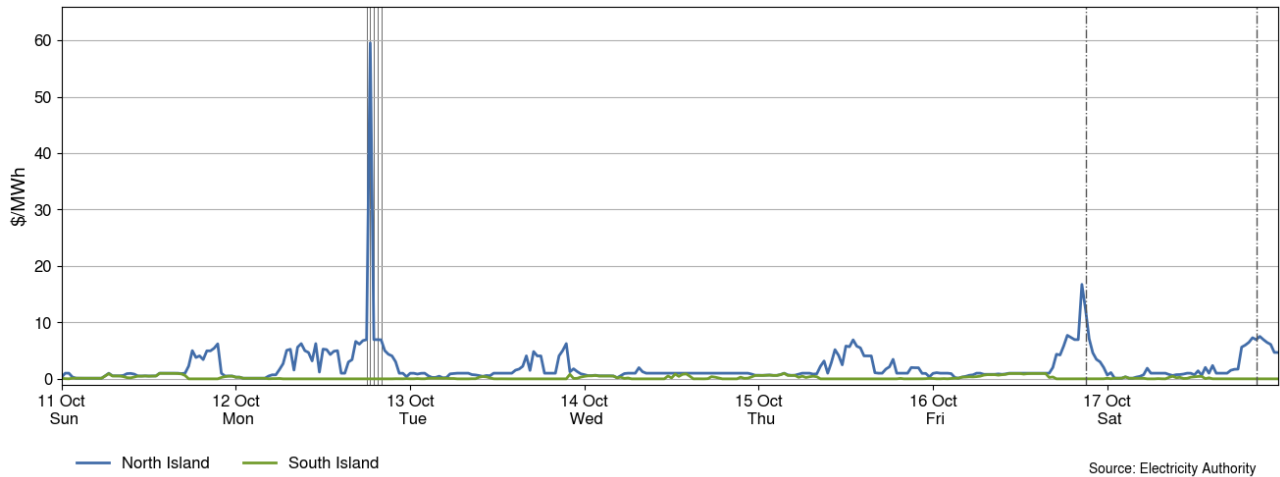
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below \$1/MWh this week.
- 3.2. At 8.30pm on Saturday the North Island FIR price spiked up to \$94/MWh. At this time the HVDC was setting the risk and was binding. The volume of available FIR decreased at the same time required reserve spiked.

Figure 3: Fast instantaneous reserve price by trading period and island, 11-17 October



- 3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below \$1/MWh this week.
- 3.4. At 6.30pm on Monday the North Island SIR price spiked up to \$59/MWh. At this time the HVDC was setting the risk, and its capacity was in the process of decreasing due to planned transmission equipment maintenance near Benmore and Haywards substations. Additionally the quantity of SIR priced between \$0-0.9/MWh decreased during this period.

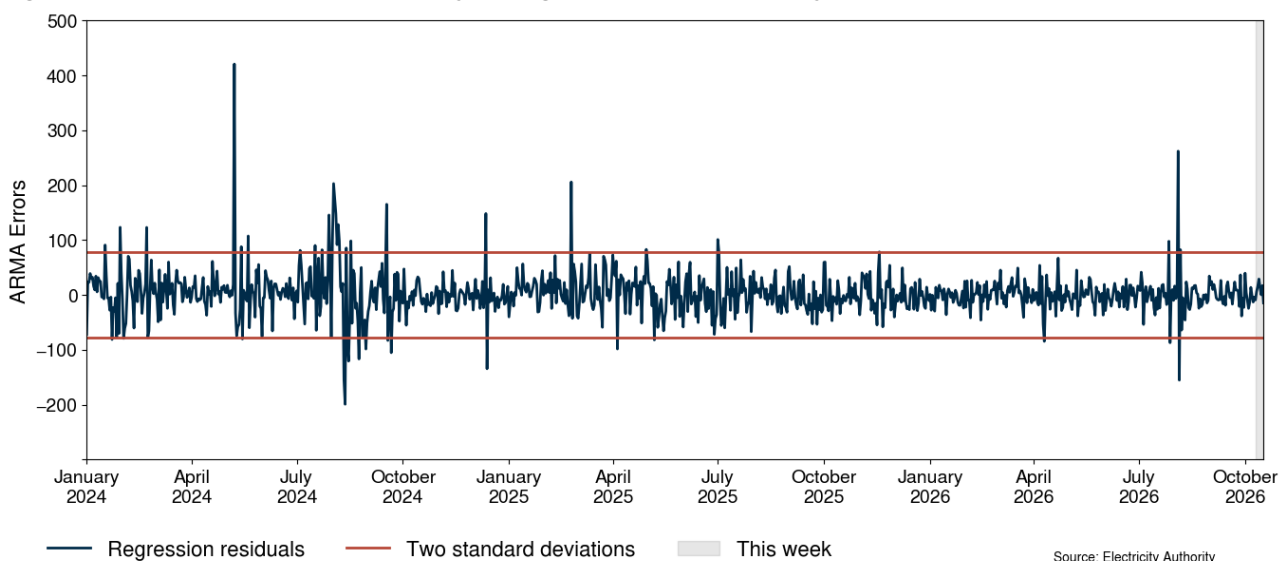
Figure 4: Sustained instantaneous reserve by trading period and island, 11-17 October



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.

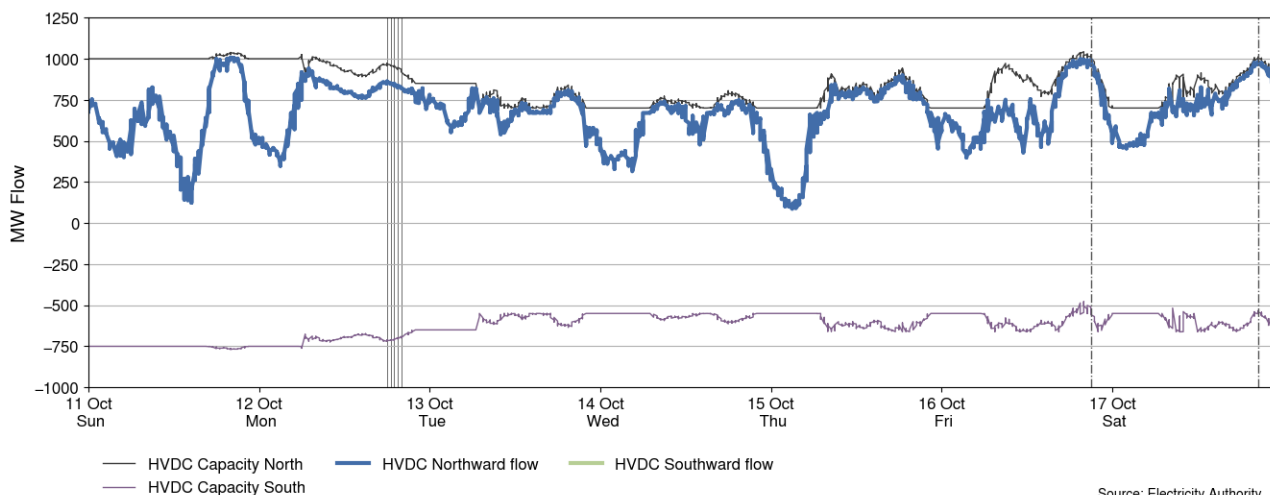
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 17 October 2026



5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 11-17 October. HVDC¹ flows were entirely northward this week.
- 5.2. The HVDC had reduced capacity from Monday morning due to planned transmission equipment outages around Haywards and Benmore substations this week.
- 5.3. The highest northward HVDC flow this week was 1,008MW which occurred at 8.00pm on Sunday. There was no southward HVDC flow this week.

Figure 6: HVDC flow and capacity, 11-17 October

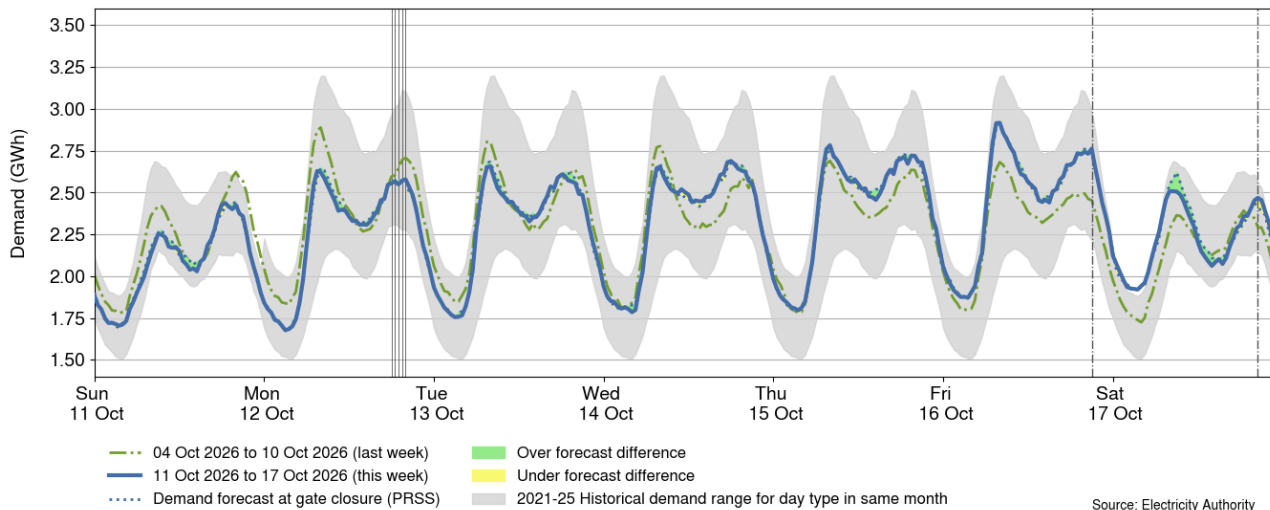


6. Demand

- 6.1. Figure 7 shows national demand between 11-17 October, compared to the historic range and the demand of the previous week. Demand was lower than or similar to last week from Sunday to Tuesday morning, then mostly higher than last week from Tuesday morning onward. The maximum demand this week was around 2.92GWh (5.83GW) at 8.00am on Friday.

¹ Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South Islands. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD (scheduling, pricing and dispatch) co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

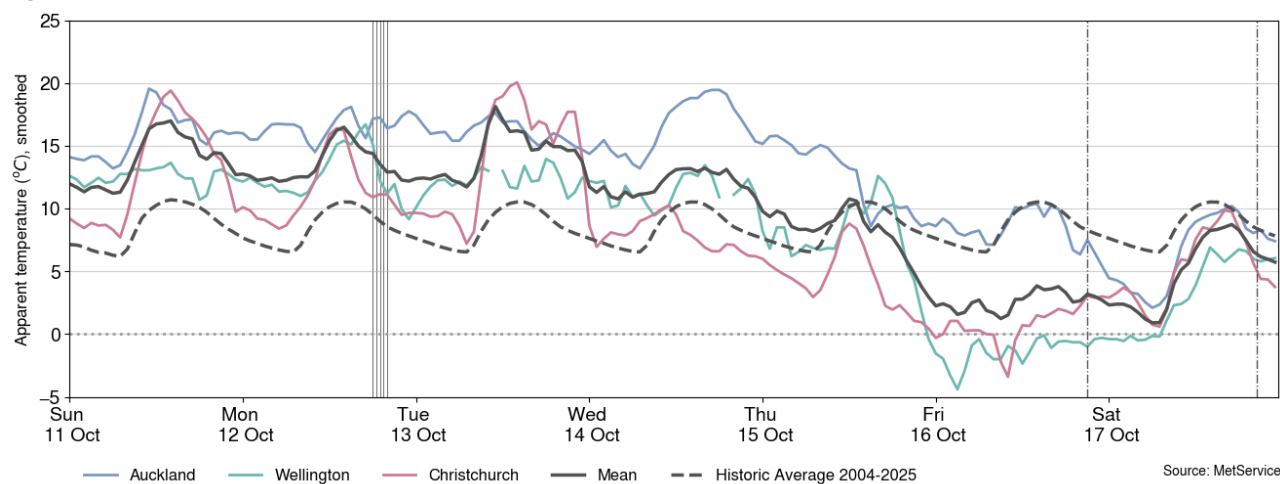
Figure 7: National demand, 11-17 October compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 11-17 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.

6.3. Apparent temperatures ranged from 2°C to 20°C in Auckland, -4°C to 18°C in Wellington, and -4°C to 20°C in Christchurch. Starting higher than average from Sunday to Tuesday then dropping to well below average from Thursday onward.

Figure 8: Temperatures across main centres, 11-17 October



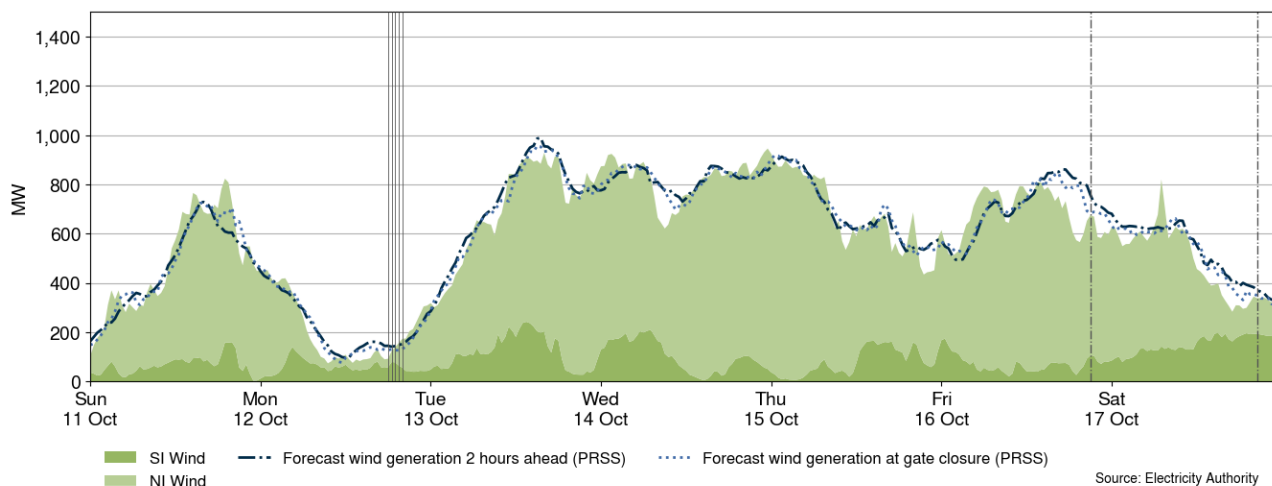
7. Generation

7.1. Figure 9 shows wind generation and forecast from 11-17 October. This week wind generation varied between 73MW and 945MW, with a weekly average of 578MW. Wind generation was reasonably high this week.

7.2. Wind generation was lower than forecast on Monday. This was largely due to forecasting differences at Kaiwera Downs Stage 2 wind farm.

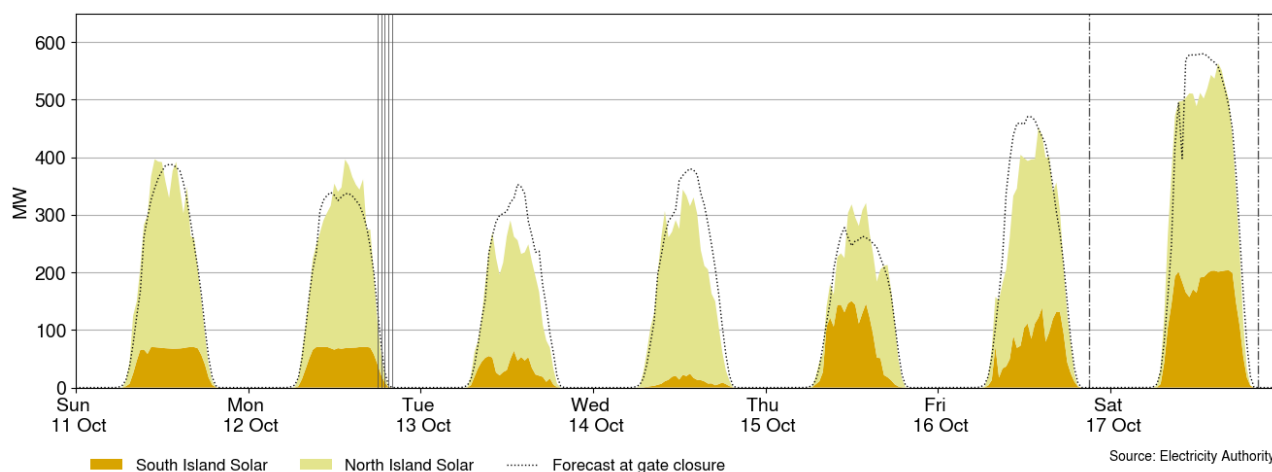
- 7.3. Wind generation was lower than forecast on Wednesday morning. This was largely due to forecasting differences at Turitea and Harapaki wind farms.
- 7.4. Wind generation was lower than forecast on Friday evening. This was due to forecasting differences at Turitea, Kaiwera Downs Stage 2, Tararua Stage 3, Harapaki, Te Āpiti, and an accumulation of differences at other wind farms.

Figure 9: Wind generation and forecast, 11-17 October



- 7.5. Figure 10 shows grid connected solar generation from 11-17 October. This week mean daytime solar generation was 236MW, peaking at 563MW on Saturday at 3:00pm. Solar generation was lower this week compared to last.
- 7.6. Forecasting differences on Friday were due to an accumulation of errors at various solar farms.
- 7.7. Forecasting differences on Saturday were due to Kōwhai Park solar farm.
- 7.8. All other forecasting differences are due to an accumulation of errors at various solar farms.

Figure 10: Grid connected solar generation, 11-17 October

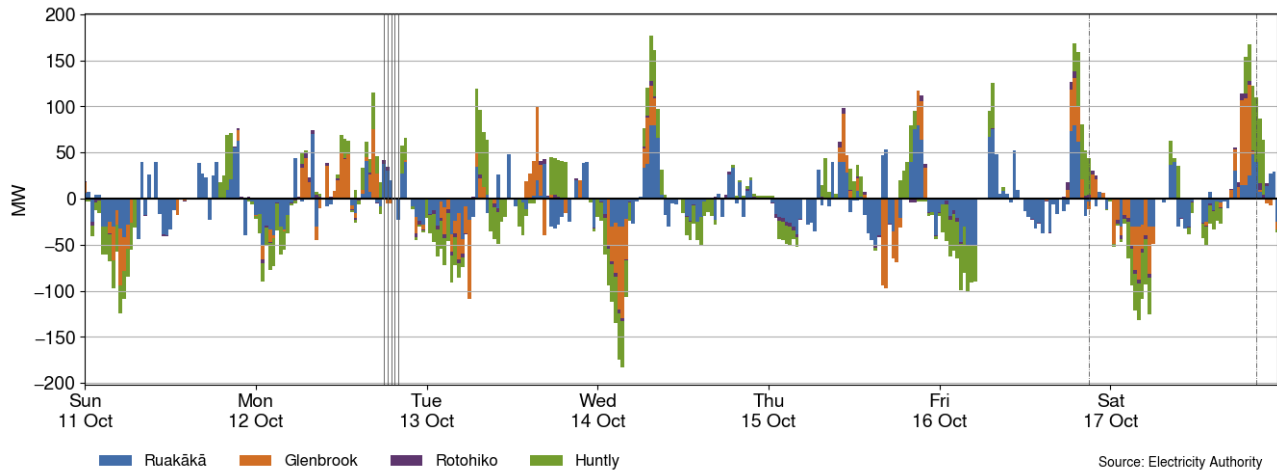


- 7.9. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into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

7.10. This week batteries typically charged at night and during the middle of the day when demand was lower and discharged during morning and evening peak demand.

7.11. Limited dispatch of the batteries was available on Monday evening due to insufficient charge. The monitoring team is looking further into Genesis's battery offers.

Figure 11: Grid scale battery charge and discharge, 11-17 October

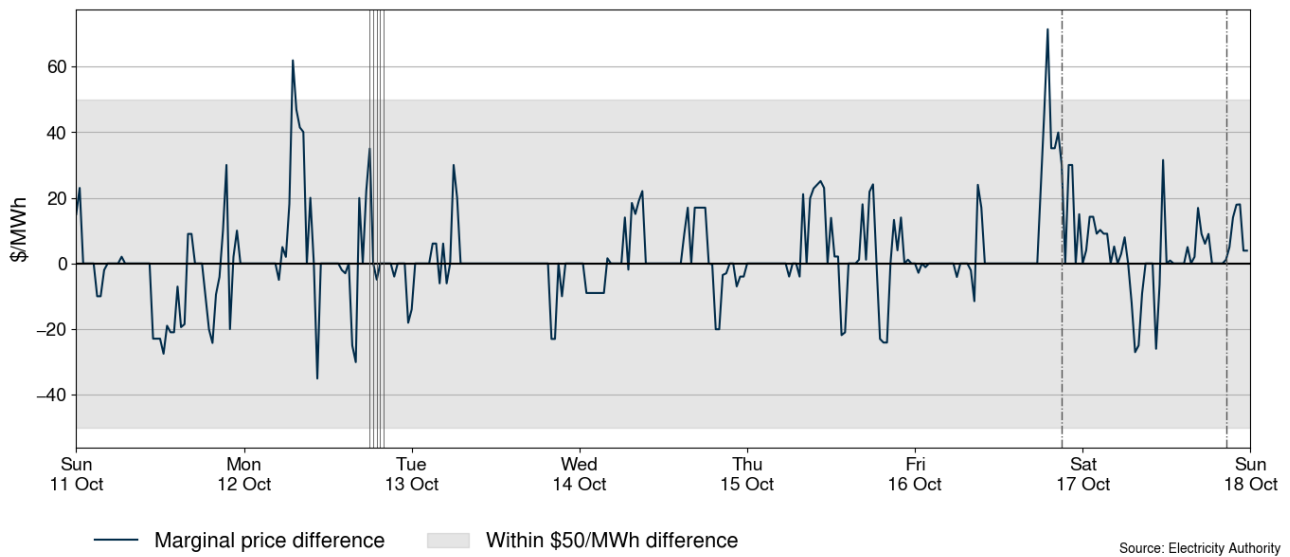


7.12. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS²) projections. The figure highlights when forecasting inaccuracies are causing 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.

7.13. The highest positive forecast difference occurred of \$71/MWh occurred at 7.00pm on Friday when demand was 47MW higher than forecast and intermittent generation was 230MW lower than forecast.

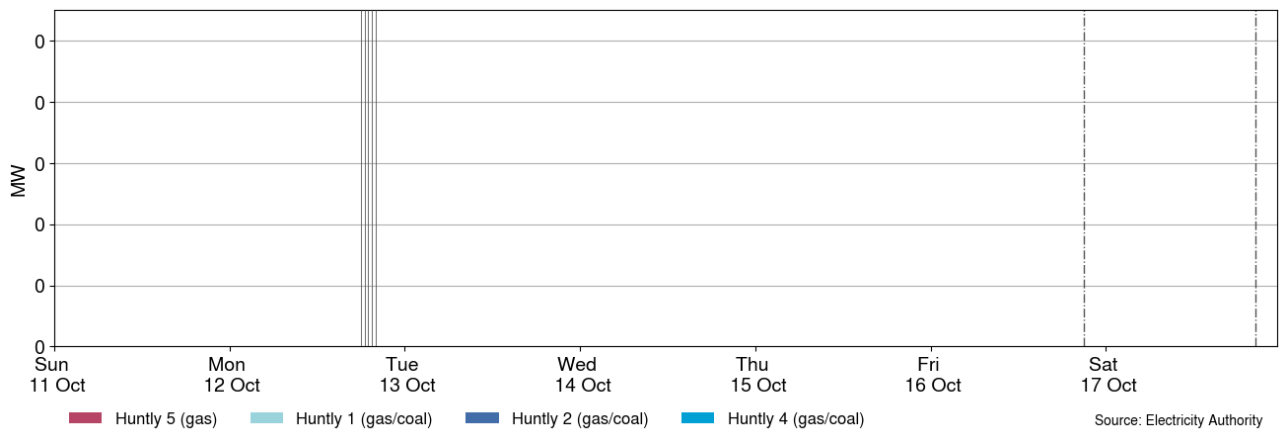
² Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 11-17 October



7.14. Figure 13 shows the generation of thermal baseload between 11-17 October. There has been no thermal baseload generation this week.

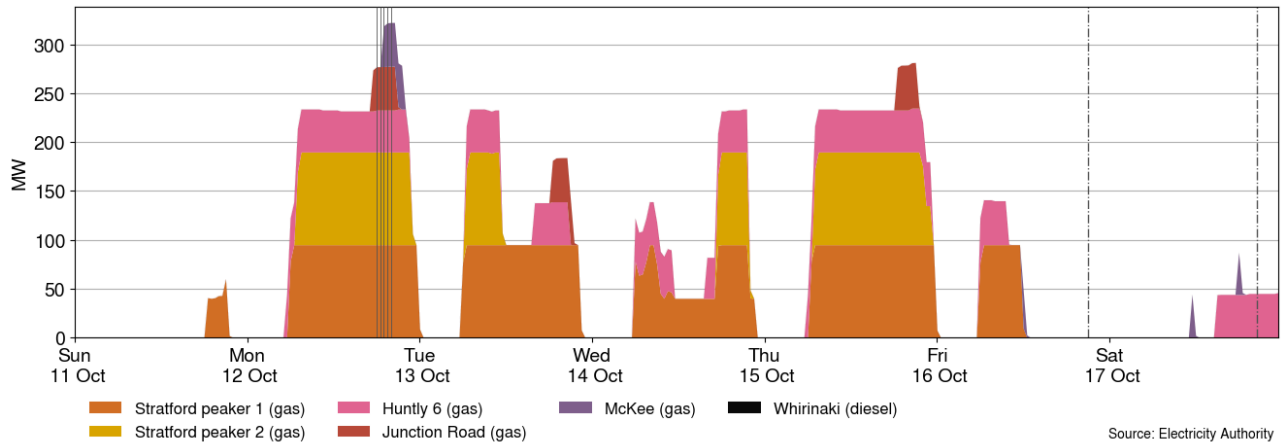
Figure 13: Thermal baseload generation, 11-17 October



7.15. Figure 14 shows the generation of thermal peaker plants between 11-17 October. Peaker generation this week has been high. This was likely influenced by the HVDC having reduced capacity this week.

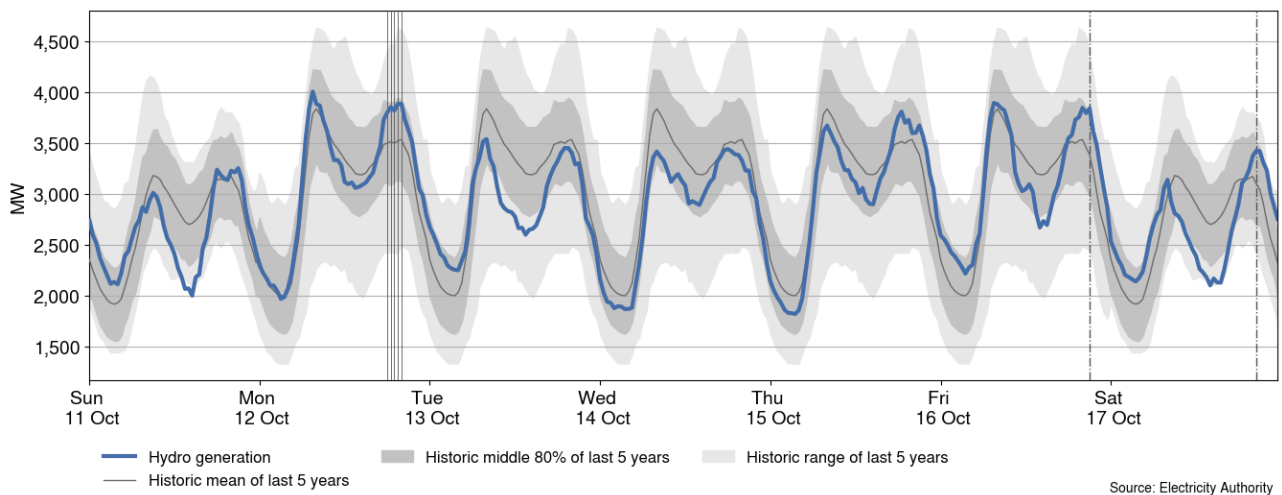
7.16. McKee attempted to run at 12.00pm on Friday and tripped off at 12:17pm.

Figure 14: Thermal peaker generation, 11-17 October



7.17. Figure 15 shows hydro generation between 11-17 October. Hydro generation has been mostly near mean this week. Hydro generation was significantly lower than average at midday on Sunday and Saturday, and generally lower than average at midday throughout the week. Peak times were variable being both above and below average at times.

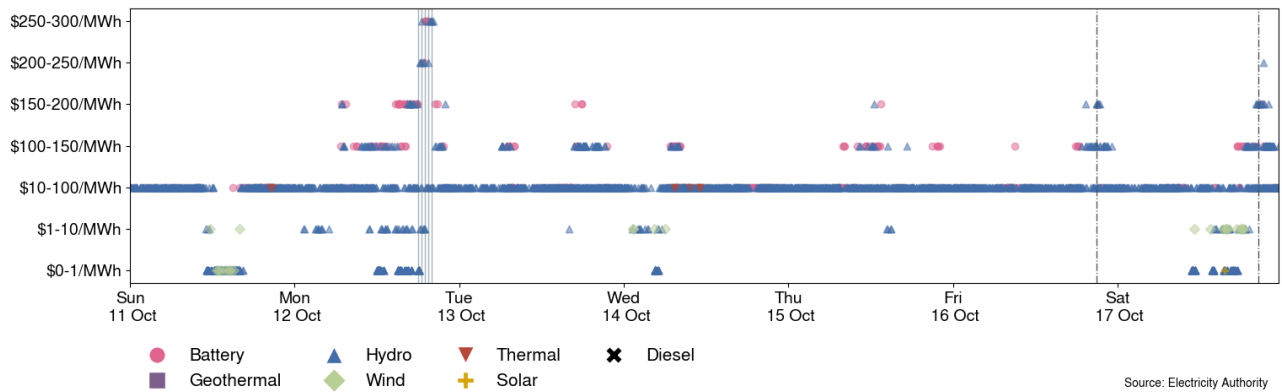
Figure 15: Hydro generation, 11-17 October



7.18. 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.

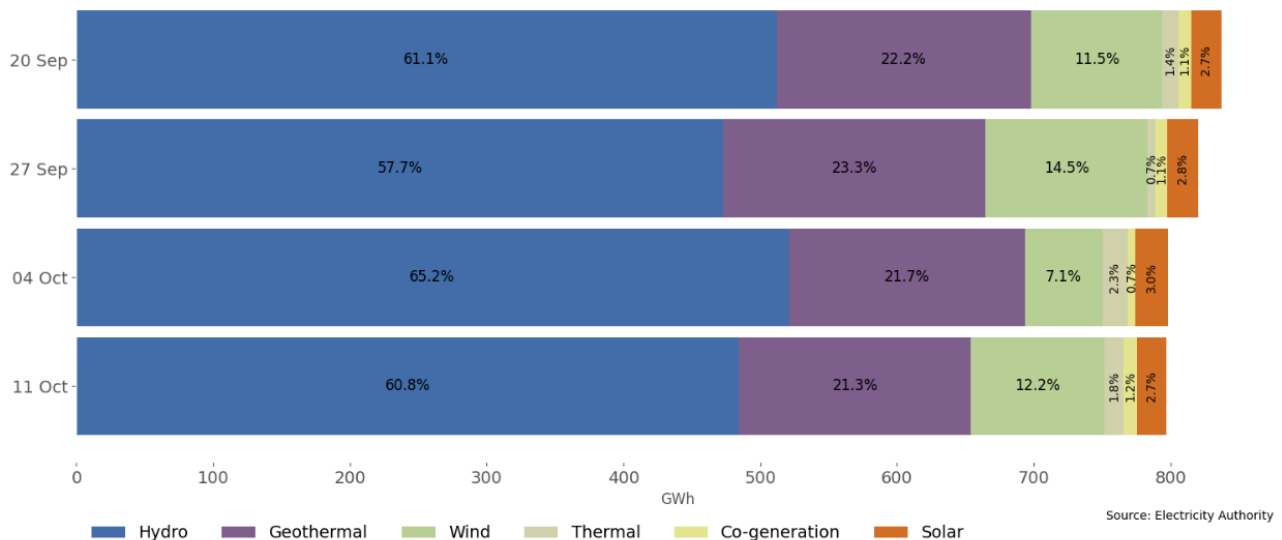
7.19. The highest marginal price of \$290/MWh was set by Arapuni at 6:30pm on Monday. The most common marginal technology was hydro and the second most common technology was battery. Most marginal prices were between \$10-100/MWh.

Figure 16: Prices of marginal generation, 11-17 October



7.20. As a percentage of total generation, between 11-17 October, total weekly hydro generation was 60.8%, geothermal 21.3%, wind 12.2%, thermal 1.8%, co-generation 1.2%, and solar (grid connected) 2.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 20 September and 17 October



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 11-17 October ranged from ~1,626MW to ~2,798MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 11-17 October

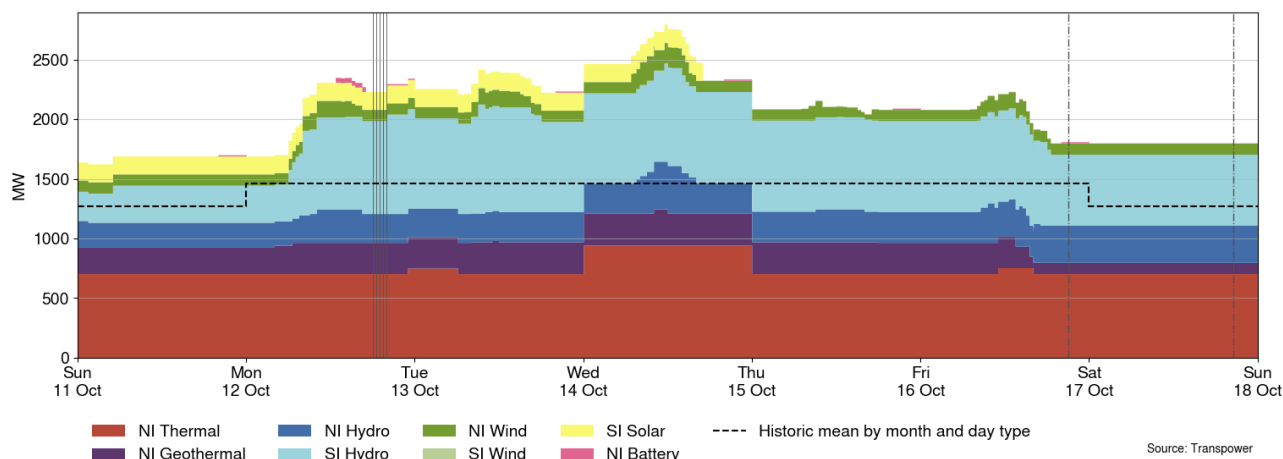
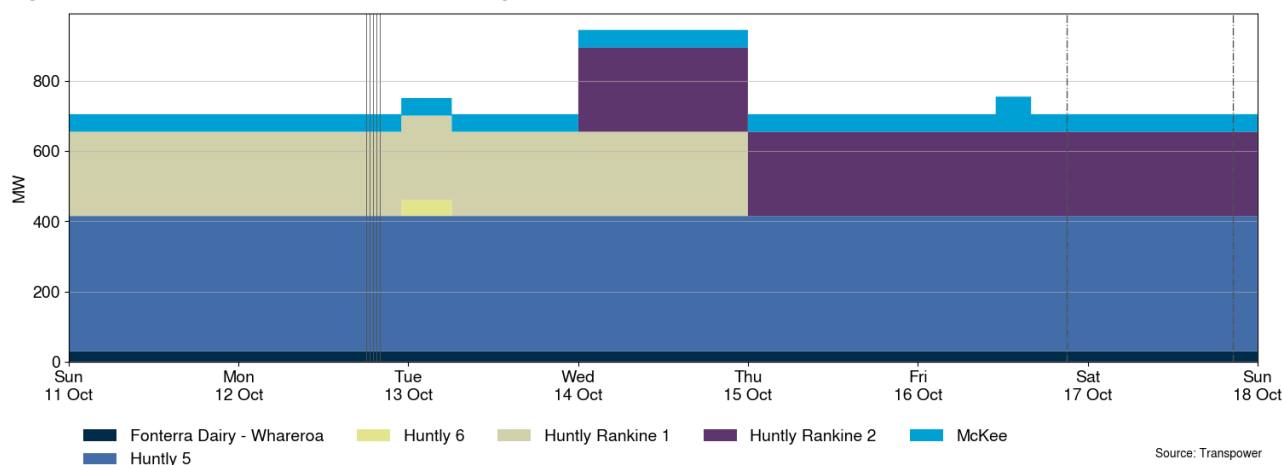


Figure 19: Total MW loss from thermal outages, 11-17 October



8.2. Notable outages include:

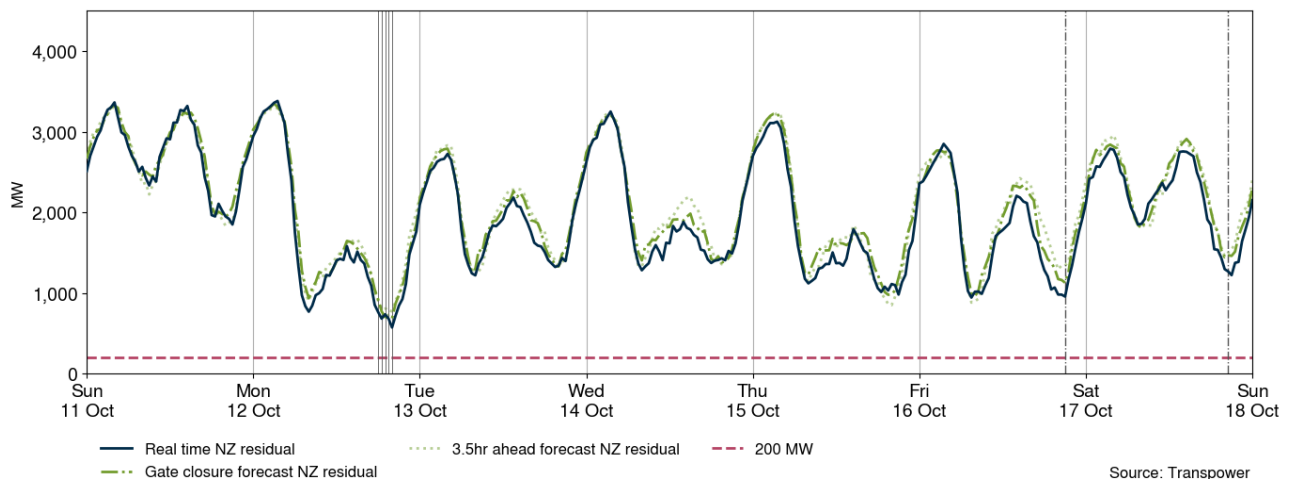
Plant	Partial or Full	End Date
Huntly 1	Full	14 October 2026
Ōhau A	Full	15 October 2026
Te Mihi	Full	16 October 2026
Kōwhai Park	Full	17 October 2026
Tekapō B	Partial	17 October 2026
Stratford Peaker 1	Full	19 October 2026
Maraetai units 1,2,3,8,9	Full	19 October 2026
Huntly 2	Full	21 October 2026
Aviemore unit 4	Full	21 October 2026
Ōhau A unit 5	Full	23 October 2026
Huntly 5	Full	28 October 2026
Kaiwaikawe wind farm	Partial	30 November 2026
Manapōuri unit 7	Full	4 December 2026
Manapōuri unit 2	Full	2 July 2027

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 11-17 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 lower than 200MW this week.

Figure 20: National generation balance residuals, 11-17 October



10. Storage/fuel supply

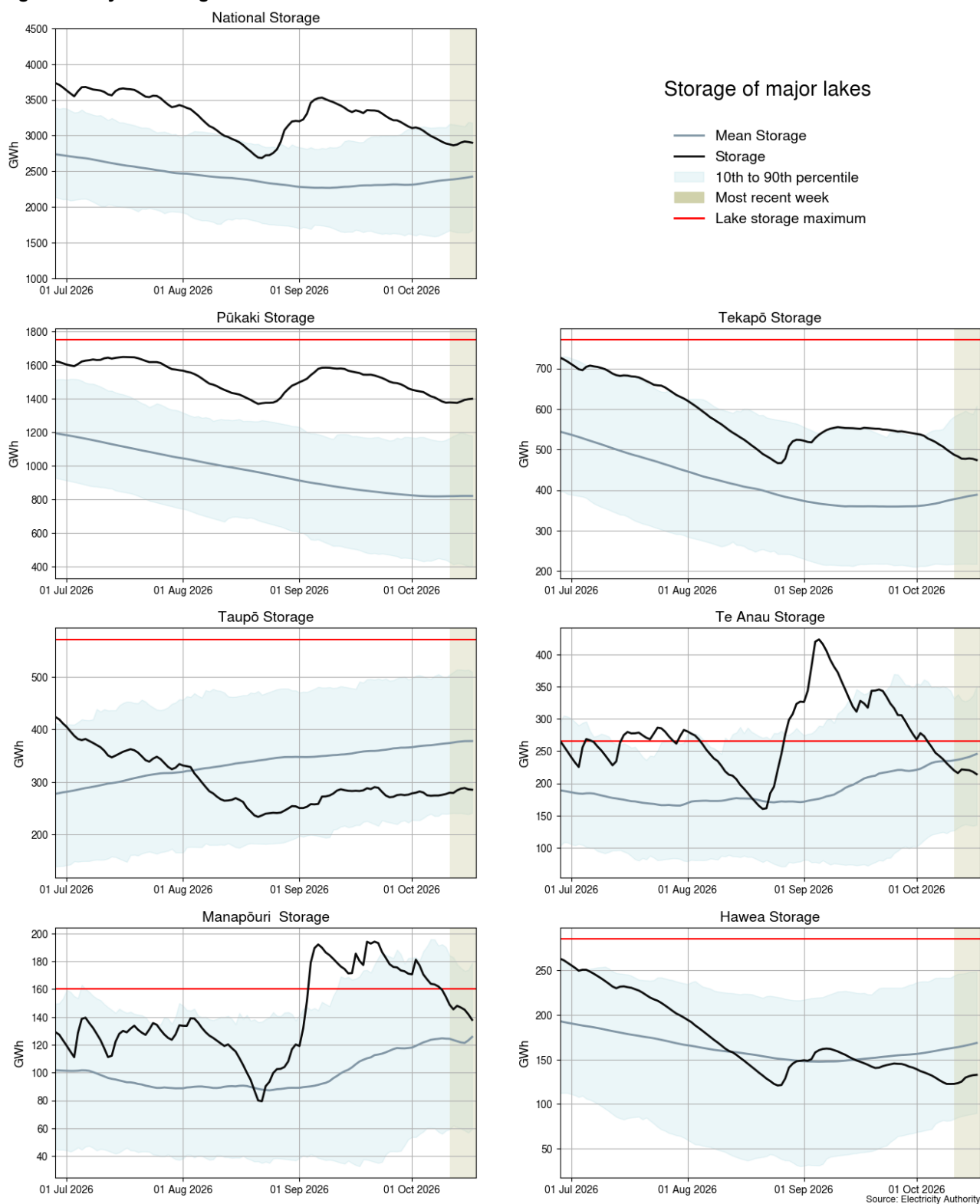
- 10.1. Storage at Lake Pūkaki (82% full) is significantly higher than the historic 90th percentile for this time of year.
- 10.2. Storage at Lake Tekapō (61% full) is above average for this time of year.
- 10.3. Storage at Lake Taupō is (50% full) is below average for this time of year.
- 10.4. Storage at Lake Te Anau (79% full) is below average for time of year.
- 10.5. Storage at Lake Manapōuri (85% full) is above average for this time of year.
- 10.6. Storage at Lake Hawea (47% full) is below 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 10th to 90th percentiles.
- 10.8. National controlled storage was 74% nominally full and ~119% of the historical average for this time of the year.
- 10.9. Storage at Lake Pūkaki (82% full³) is significantly higher than the historic 90th percentile for this time of year.
- 10.10. Storage at Lake Tekapō (61% full) is above average 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 (79% full) is below average for time of year.

³ Percentage full values sourced from NZX Hydro.

10.13. Storage at Lake Manapōuri (85% full) is above average for this time of year.

10.14. Storage at Lake Hawea (47% full) is below average for this time of year.

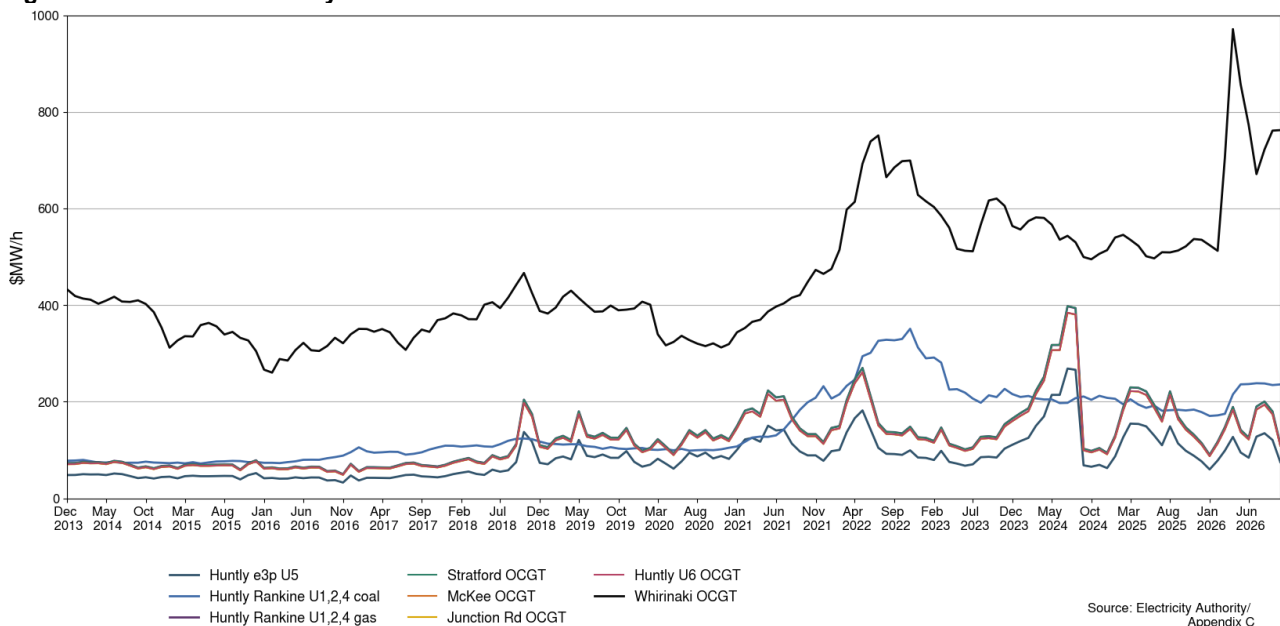
Figure 21: Hydro storage



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](#).

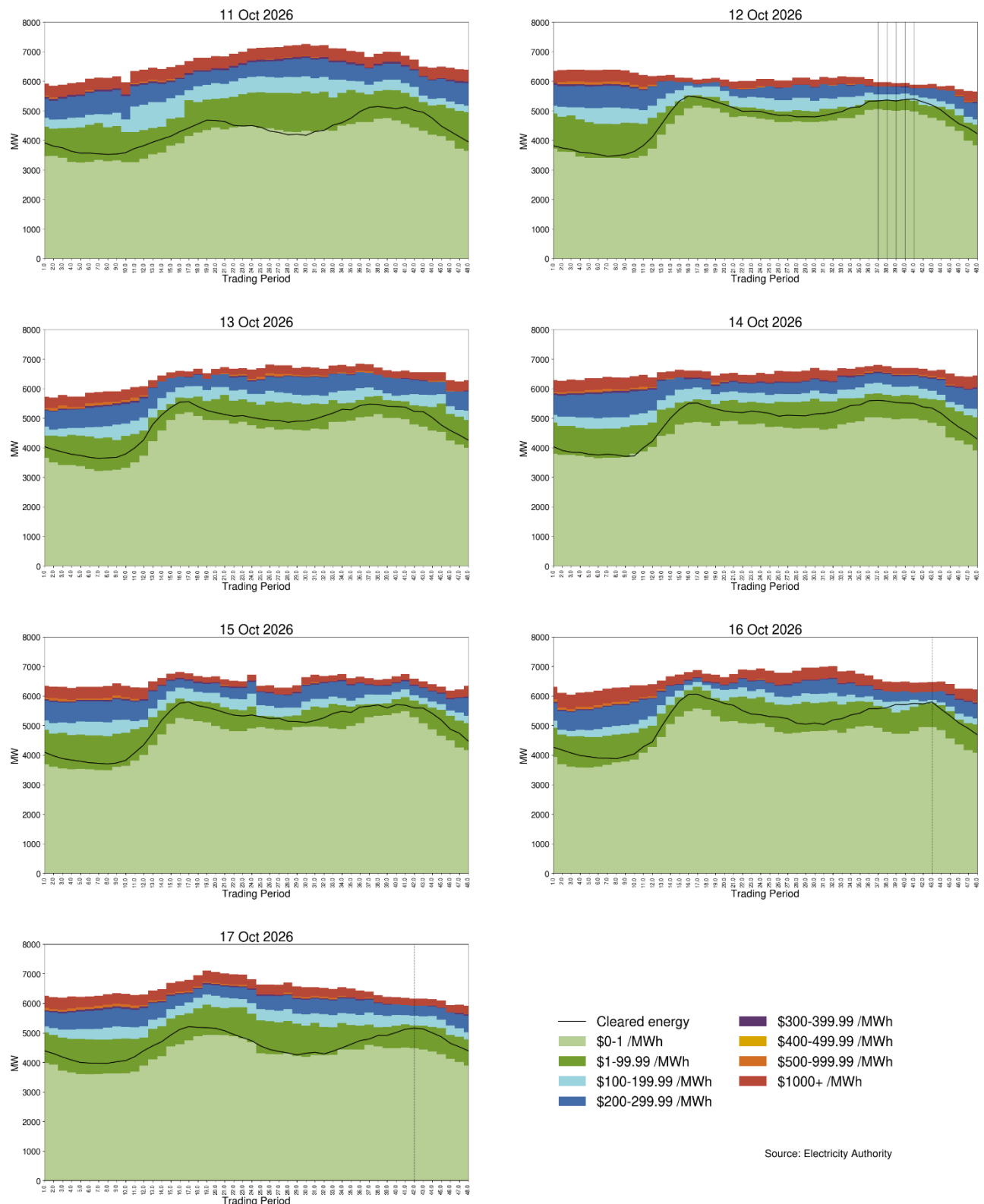
Figure 22: Estimated monthly SRMC for thermal fuels



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. This week most offers cleared between \$1-99/MWh except for times on Monday and Friday evenings where prices cleared between \$100-199/MWh.

Figure 23: Daily offer stacks



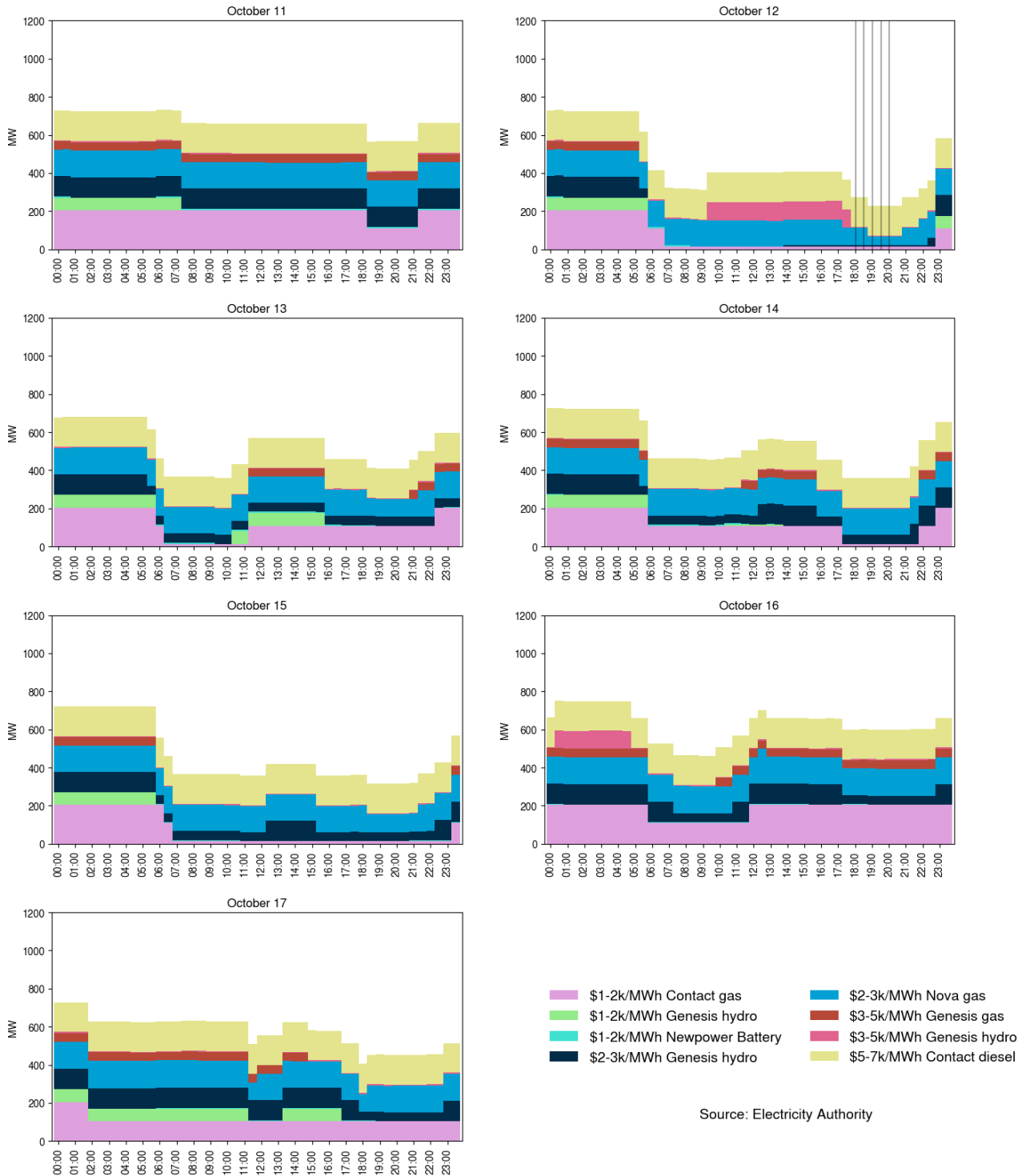
12.3. Figure 24 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 540MW per trading period was priced above \$1,000/MWh this week, which is roughly 10% of the total energy available.

Figure 24: High priced offers



13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions, however, we are looking further into the Huntly batteries offering for Monday evening.

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
05/10/2026-08/10/2026	Several	Further analysis	Genesis	Tekapō	Offers
12/10/2026	37-43	Further analysis	Genesis	Huntly battery	Offers