28 October 2025

# Trading conduct report 19-25 October 2025

Market monitoring weekly report

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## 1. Overview

1.1. This week the average spot price decreased by $18/MWh to $7/MWh. The decline in spot prices was likely due to increased hydro storage, high wind generation, and reduced demand resulting from mild temperatures. There was also some lower demand due to weather-related disconnections[1].

1.2. On Thursday, during severe weather conditions, high prices were observed in the North Island, and the HVDC tripped due to high winds.

1.3. The high proportion of hydro generation and low thermal generation persisted, with solar generation exceeding thermal generation this week.

1.4. National hydro storage increased to 89% nominally full and around 140% of the historical average. However, this includes storage at Manapōuri and Te Anau, which is expected to spill.

## 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 19-25 October 2025:

(a) The average spot price for the week was $7/MWh, a decrease of around $18/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $27/MWh.

2.3. Spot prices remained low, generally under $20/MWh throughout the week, except on Thursday when they spiked due to severe weather conditions.

2.4. On Thursday, severe weather caused multiple HVDC trips due to high winds. HVDC Pole 2 experienced a capacity reduction, followed by a trip, and later operated at reduced capacity. HVDC Pole 3 also tripped, triggering an under-frequency event.

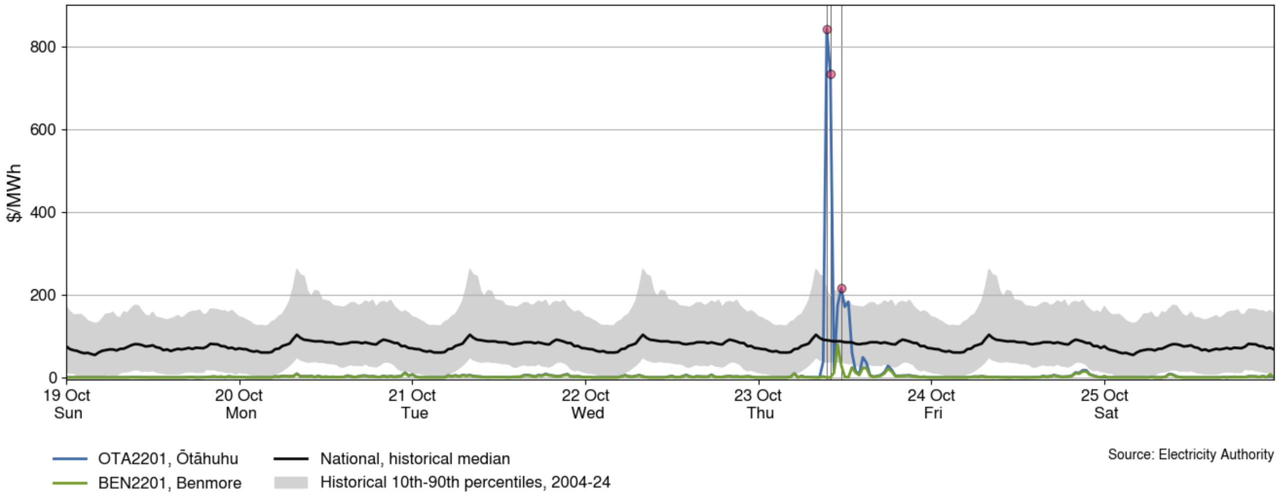
2.5. On Thursday, the highest price of the week was observed at 9.30am, with prices reaching $842/MWh at Ōtāhuhu and $0.01/MWh at Benmore. During this time, HVDC Pole 2 tripped. Later, at 10.00am, prices at Ōtāhuhu reached $732/MWh, while Benmore remained at $0.01/MWh, coinciding with the tripping of HVDC Pole 3.

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90$^{th}$ percentiles adjusted for inflation. Prices greater than quartile 3 (75$^{th}$ percentile) plus 1.5 times the inter-quartile range of historic prices, plus the

[1] Progress made to restoring power to the top half of the South Island and West Coast | Transpower,
Update on power outage affecting parts of the top half of the South Island and West Coast – 10:40am 23 October | Transpower,
Parts of the top half of the South Island and West Coast without power after fault | Transpower

difference between this week's median and the historic median, are highlighted with a vertical black line.

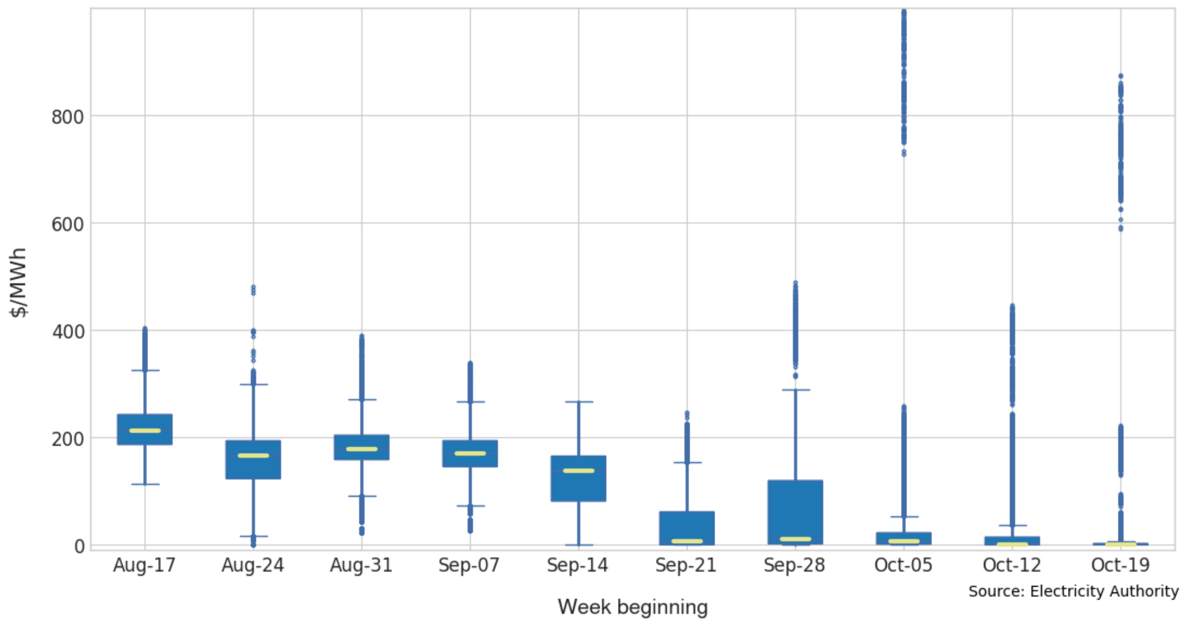
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 19-25 October 2025**




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 skewed lower, but with some high-priced outliers. The median price was $0.80/MWh and most prices (middle 50%) fell between $0.03/MWh and $3/MWh.

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

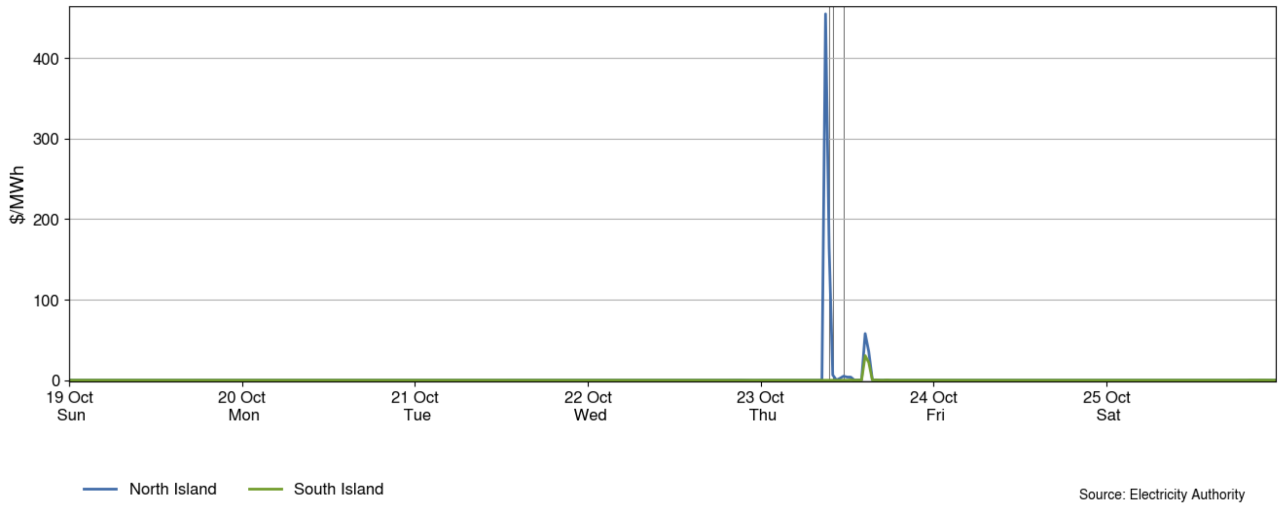


# 3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were under $1/MWh throughout the week, except on Thursday, when due to the severe weather conditions high price spikes were observed.

3.2. The highest FIR price spike occurred on Thursday at 9.00am, when the HVDC pole 2 first experienced a reduction in capacity and the reserve required to cover pole 3 increased. Prices reached $455/MWh (with one 5-minute price of $3,185/MWh) in the North Island while prices in the South Island were $0.04/MWh.

**Figure 3: Fast instantaneous reserve price by trading period and island, 19-25 October 2025**

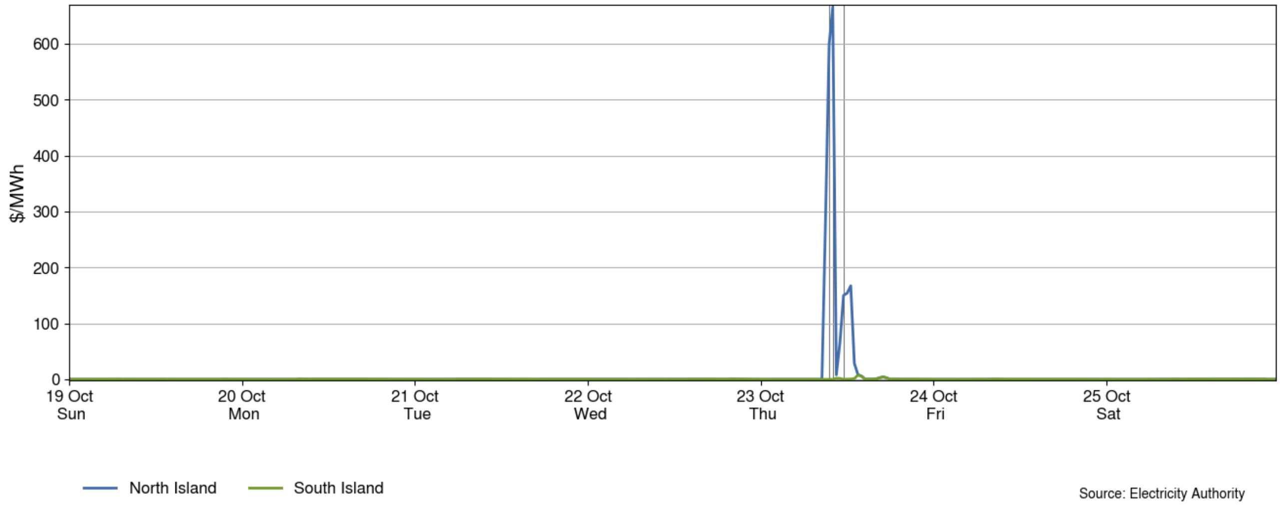



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were also under $1/MWh throughout the week, except on Thursday, due to the HVDC trips when high price spikes occurred.

3.4. The SIR price spikes occurred on Thursday at between 9:30am and 12.30pm, with prices reaching around $665/MWh at 10:00am in the North. Island (there were some 5 minute prices over the $1,000/MWh during this period). While prices in the South Island were $0.05/MWh.

3.5. During this period either higher reserve was needed to cover the remaining pole while one was out and/or more expensive reserve was needed when higher North Island energy dispatch was needed to cover the difference left during the HVDC trips. During these times no thermal baseload and thermal peakers were dispatched.

**Figure 4: Sustained instantaneous reserve by trading period and island, 19-25 October 2025**



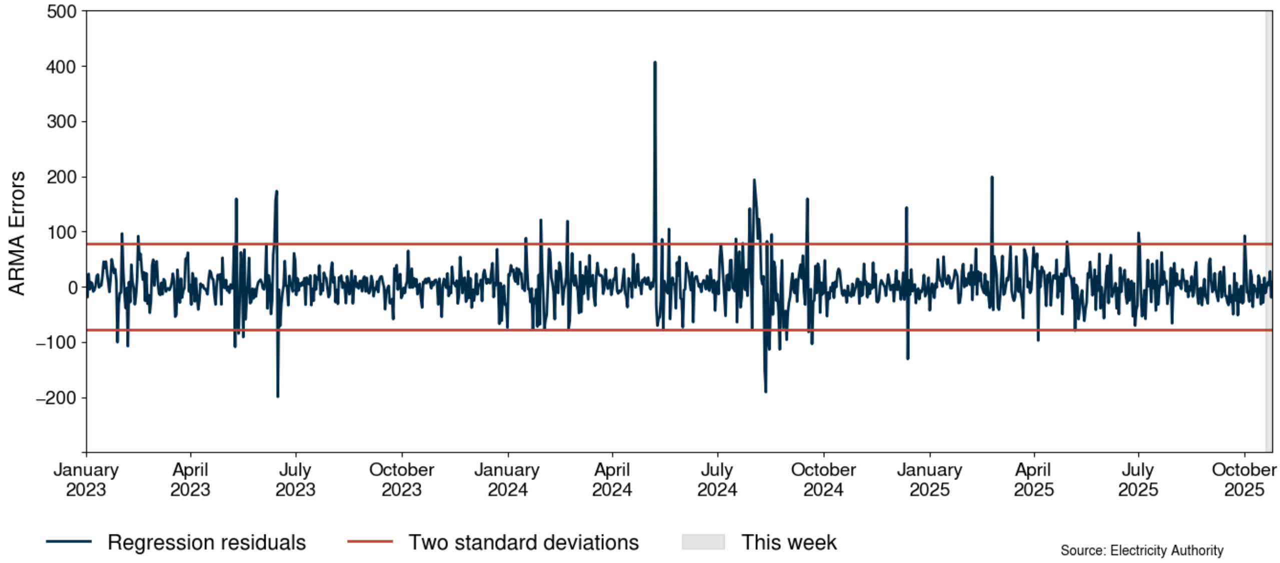

# 4. Regression residuals

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 2023 - 25 October 2025**

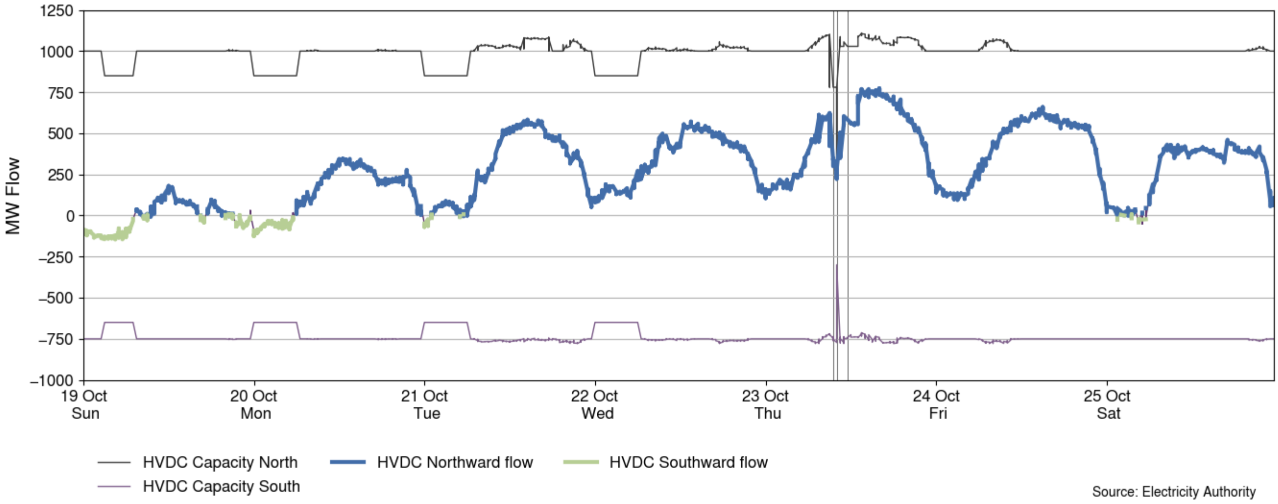


# 5. HVDC

5.1. Figure 6 shows the HVDC flow between 19-25 October 2025. HVDC flows were mostly Northward this week despite high wind generation due to high hydro generation and low thermal generation. Northward HVDC flow was highest at 4.00pm on Thursday with a flow of 773MW.

5.2. On Thursday, severe weather conditions caused a series of HVDC trips due to high winds. HVDC Pole 2 experienced a reduction in capacity between 9.18am-10.30am[2]. However, it tripped at 9.24am[3], initially resulting in an unplanned outage until 6.00pm[4]. This unplanned outage was revised to end at 10.20am[5]. HVDC Pole 2 resumed operation with reduced capacity until 2.00pm[6]. Additionally, at 10.15am HVDC Pole 3 tripped[7], causing an underfrequency event.

**Figure 6: HVDC flow and capacity, 19-25 October 2025**




# 6. Demand

6.1. Figure 7 shows national demand between 19-25 October 2025, compared to the historic range and the demand of the previous week. Overall demand was lower this week compared to last week, due to above average temperatures. The highest demand of the week was around 2.72GWh at 8.00am on Monday. Note that the demand discrepancy on Thursday was contributed to by various disconnections[1].

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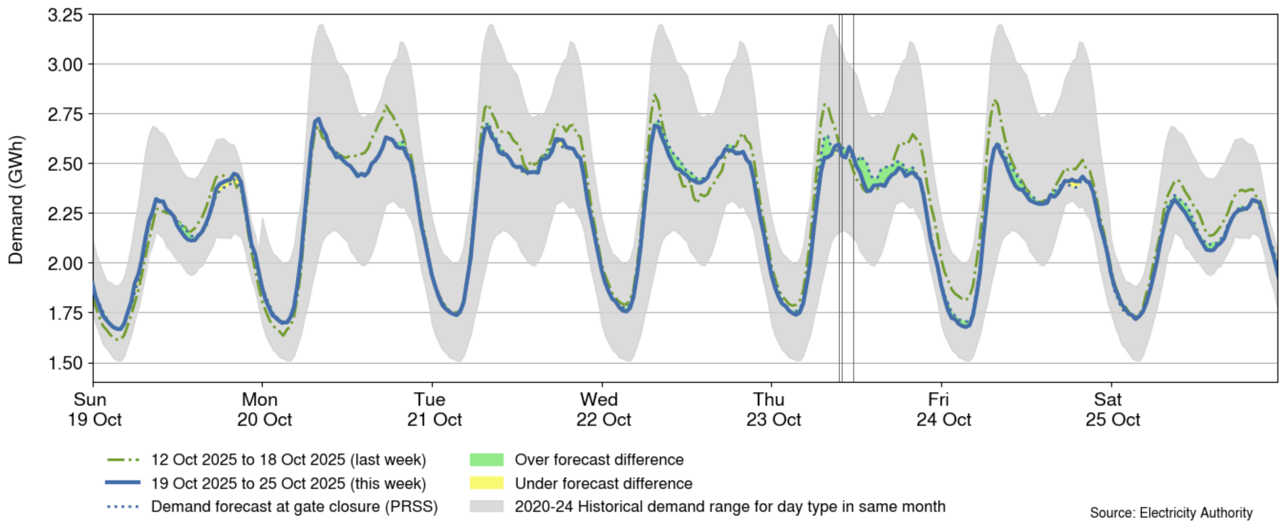
[2] CAN HVDC Pole 2 Reduced Capability 6757275039.pdf
[3] EXN Voltage National Pole 2 tripped 6757275086.pdf
[4] CAN Unplanned Outage HVDC Pole 2 6757275103.pdf
[5] CAN Unplanned Outage HVDC Pole 2 6757791667.pdf
[6] CAN HVDC Pole 2 Reduced Capability 6757624816.pdf
[7] EXN Frequency Voltage National Benmore Haywards 1 Tripped 6757791662.pdf

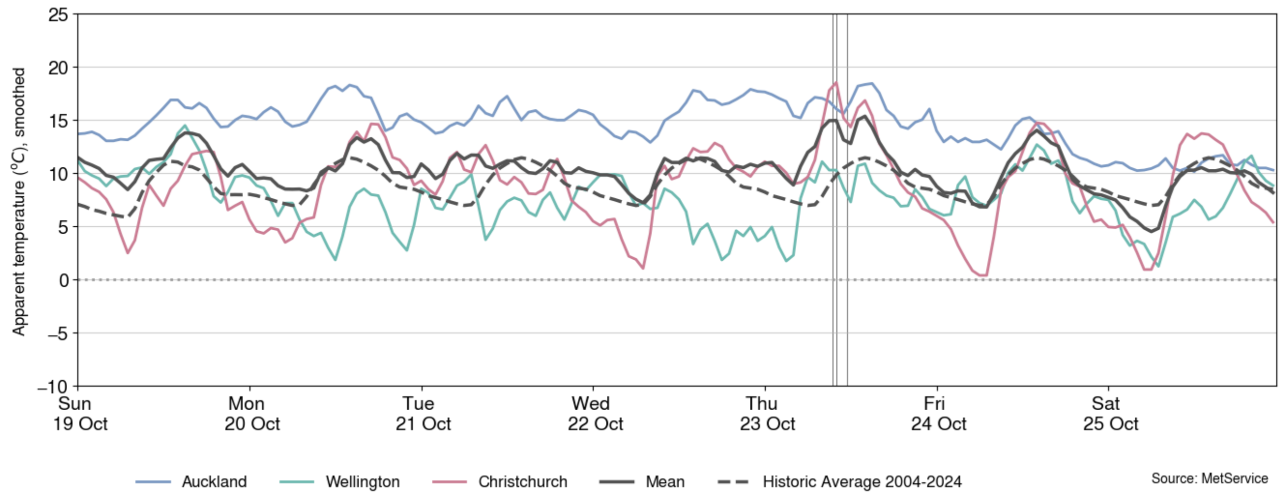
**Figure 7: National demand, 19-25 October 2025 compared to the previous week**




6.2. Figure 8 shows the hourly apparent temperature at main population centres from 19-25 October 2025. 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 9°C to 19°C in Auckland, 0°C to 15°C in Wellington, and 0°C to 19°C in Christchurch.

**Figure 8: Temperatures across main centres, 19-25 October 2025**

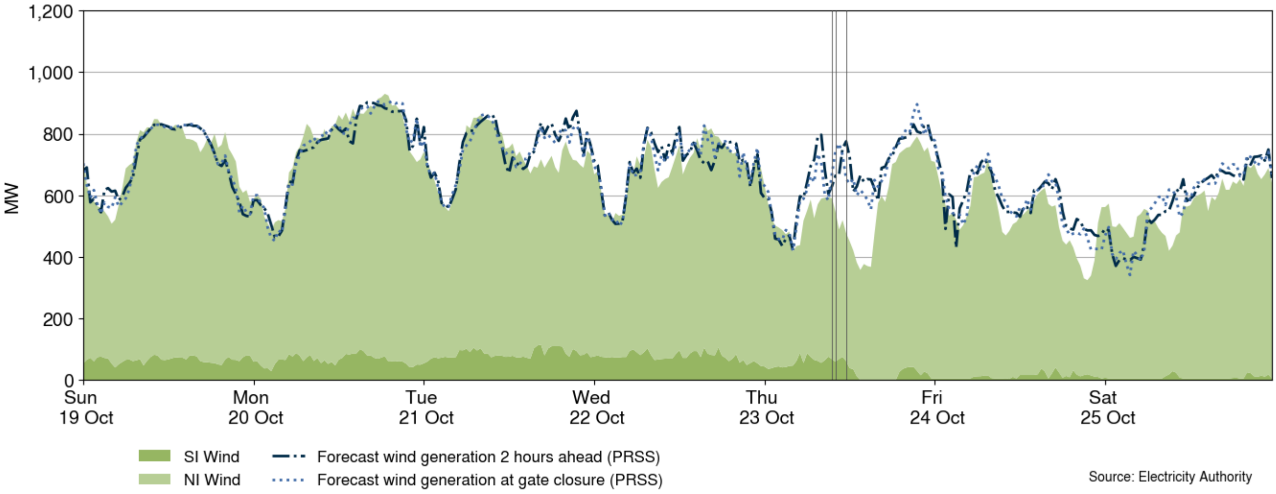



# 7. Generation

7.1. Figure 9 shows wind generation and forecast from 19-25 October 2025. This week wind generation varied between 324MW and 930MW, with a weekly average of 653MW. Wind generation was mostly above 800MW from Sunday to Wednesday with an overnight drop in generation.

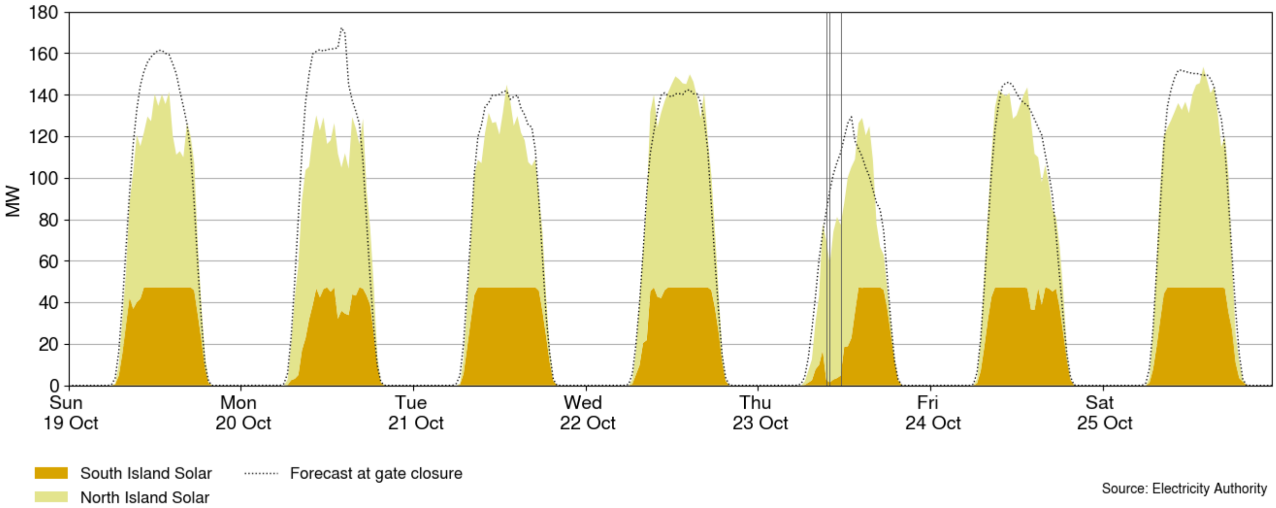
7.2. On Thursday, wind generation was lower due to several wind generators not being able to generate due to the severe weather conditions. Between Friday and Saturday, wind generation remained mostly above 400 MW.

**Figure 9: Wind generation and forecast, 19-25 October 2025**




7.3. Figure 10 shows grid connected solar generation from 19-25 October 2025. Solar generation peaked above 120MW most days and reached a maximum of around 153MW on Saturday at 2.00pm.

**Figure 10: Grid connected solar generation, 19-25 October 2025**



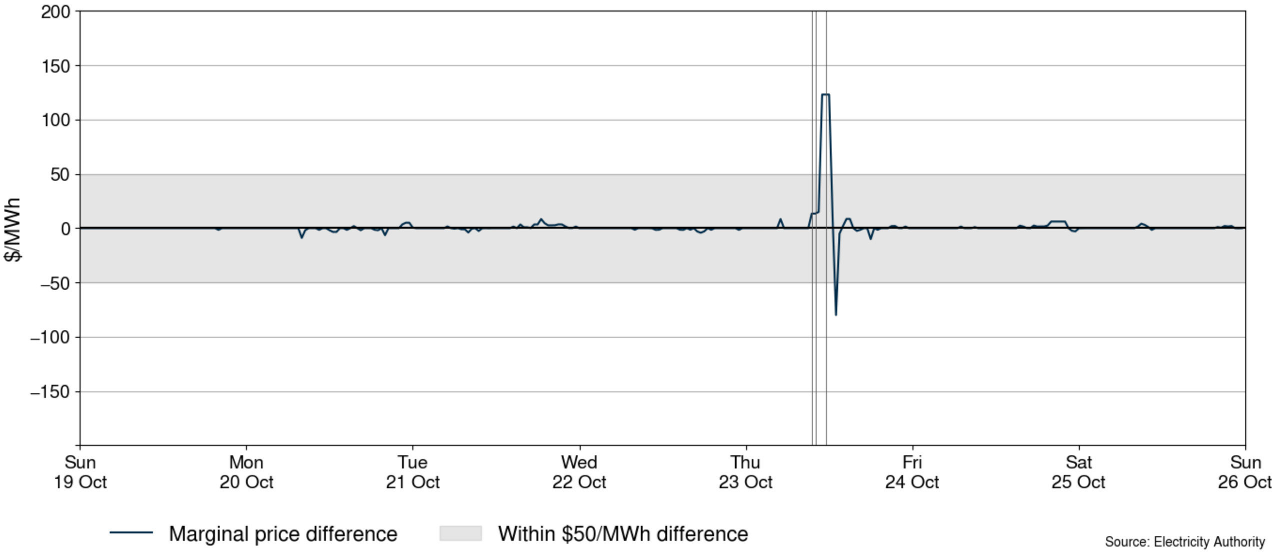

7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[8]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can

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

signal that forecasting inaccuracies had a large impact on the final price for that trading period.

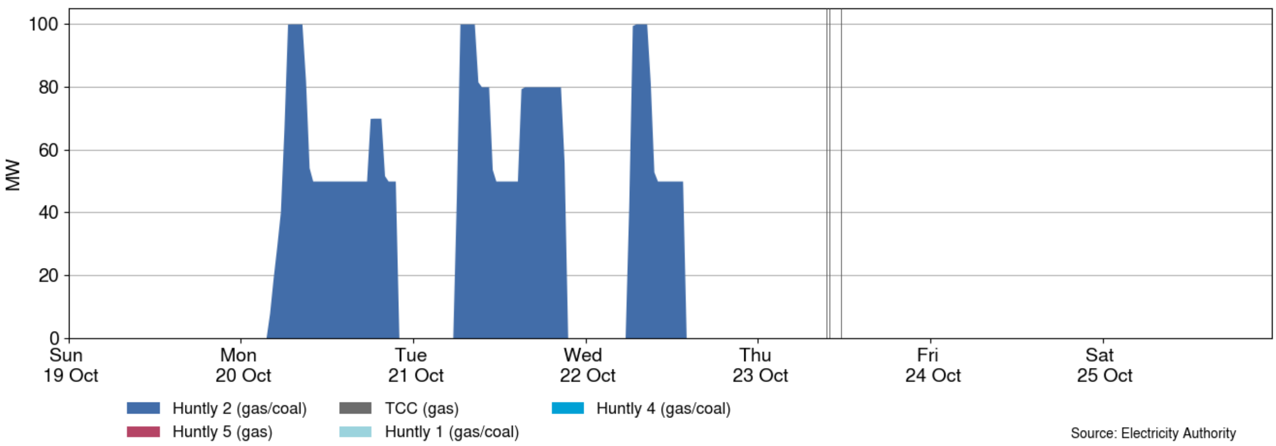
7.5. Marginal price differences were minimal this week, except on Thursday when positive price difference of +$123/MWh occurred during the severe weather event.

**Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 19-25 October 2025**




7.6. Figure 12 shows the generation of thermal baseload between 19-25 October 2025. Huntly 2 generated during the daytime from Monday to Wednesday.

**Figure 12: Thermal baseload generation, 19-25 October 2025**

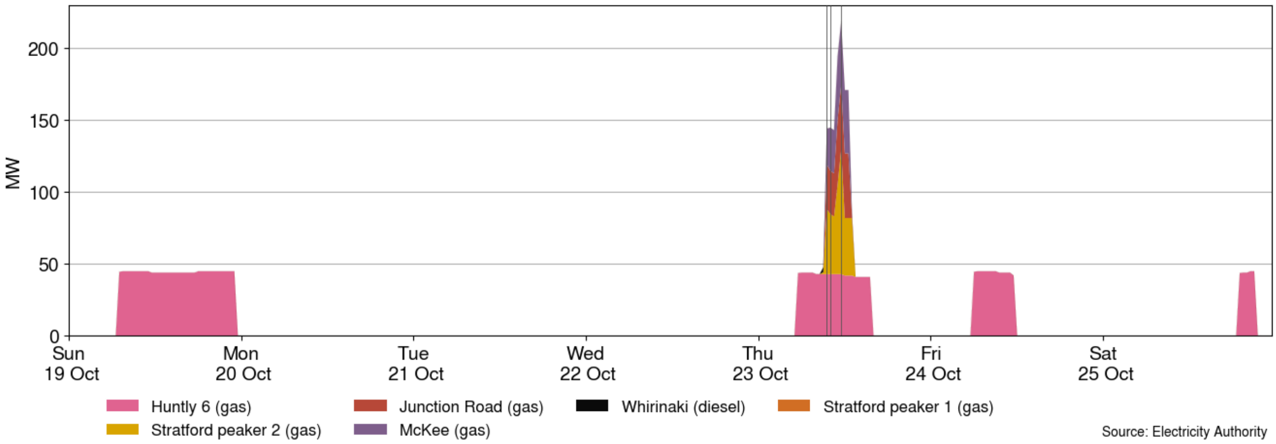



7.7. Figure 13 shows the generation of thermal peaker plants between 19-25 October 2025.

7.8. Huntly 6 ran continuously between the morning and evening peaks on Sunday and Thursday, during the morning peak on Friday, and during the evening peak on Saturday.

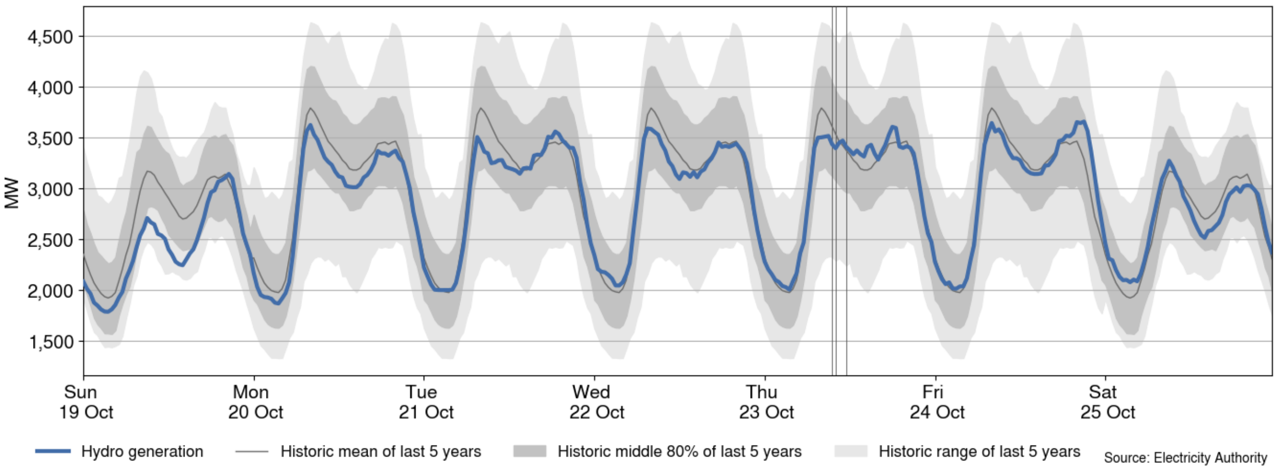
7.9. On Thursday during the severe weather event several peakers were dispatched to meet a combination of energy and reserve requirements, Junction Road, Stratford peaker 2, and McKee ran. Whirinaki was also dispatched at 9.00am.

**Figure 13: Thermal peaker generation, 19-25 October 2025**



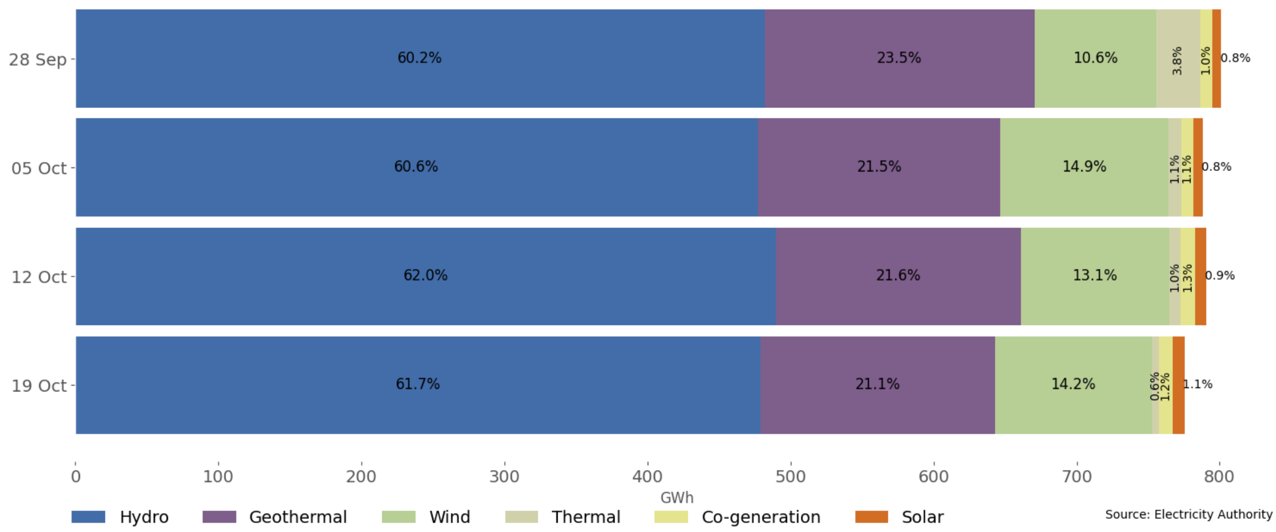

7.10. Figure 14 shows hydro generation between 19-25 October 2025. Hydro generation remained mostly within the middle 80% of historic generation. Hydro generation was low on Sunday likely due to high wind generation.

**Figure 14: Hydro generation, 19-25 October 2025**




7.11. As a percentage of total generation, between 19-25 October 2025, total weekly hydro generation was 61.7%, geothermal 21.1%, wind 14.2%, thermal 0.6%, co-generation 1.2%, and solar (grid connected) 1.1%, as shown in Figure 15.

**Figure 15: Total generation by type as a percentage each week, between 28 September and 25 October 2025**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 19-25 October 2025 ranged between ~1,675MW and ~2,719MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 31 October 2025.

(b) Huntly 2 was on outage between 24-25 October 2025.

(c) Huntly 4 is on extended partial outage until 31 October 2025.

(d) Kawerau geothermal was on outage until 28 October 2025.

(e) Benmore unit 6 is on outage until 10 November 2025.

8.3. Some long-term outages include:

(a) Ōhau A is on partial outage until 4 February 2026.

(b) Ōhau C is on partial outage until 13 January 2026.

(c) Roxburgh unit 5 is on outage until 25 February 2026.

(d) Rangipo unit 6 is on outage until 29 March 2026.

(e) Manapōuri unit 4 is on outage until 12 June 2026.

**Figure 16: Total MW loss from generation outages, 19-25 October 2025**

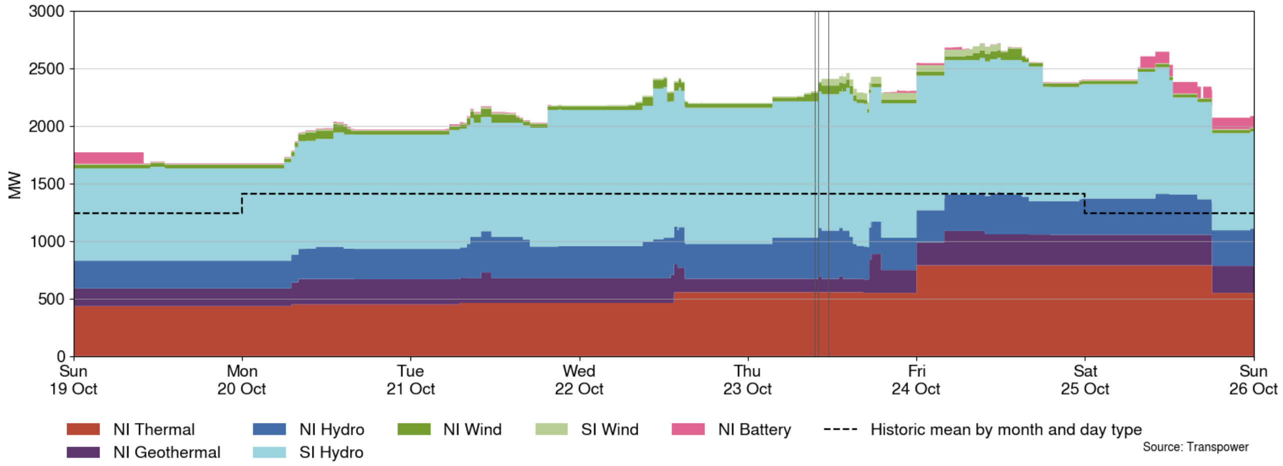
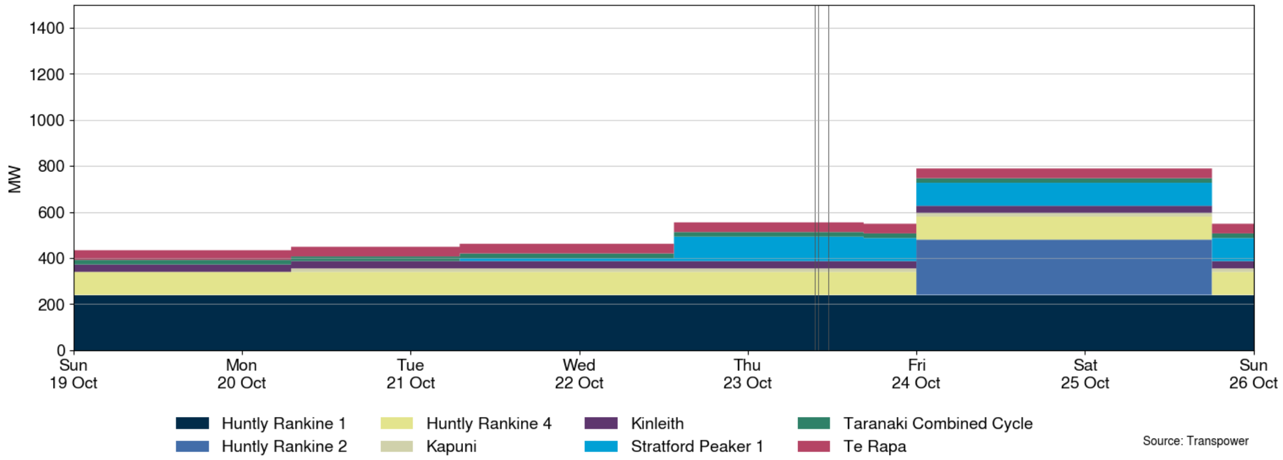



**Figure 17: Total MW loss from thermal outages, 19-25 October 2025**

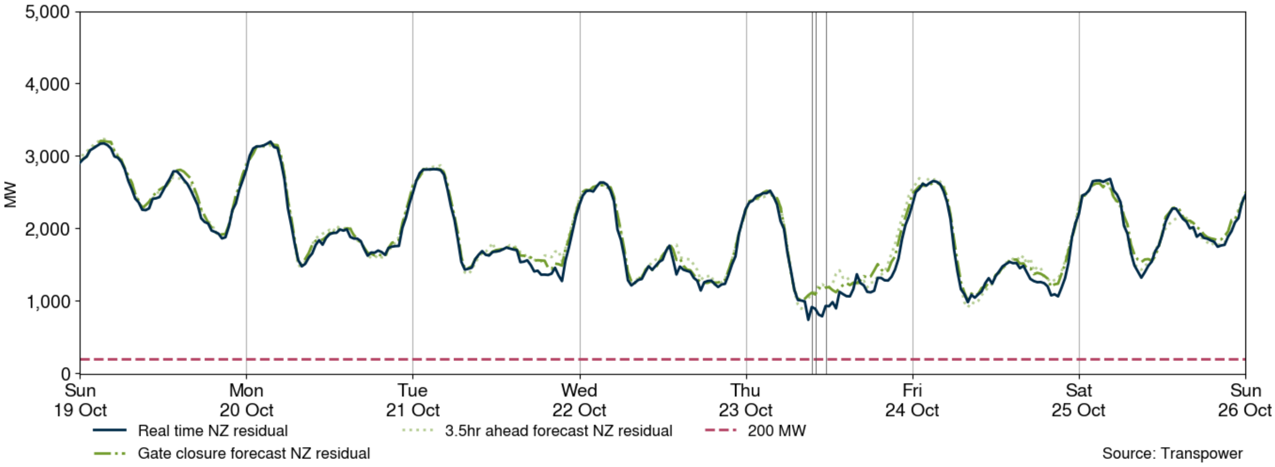



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 19-25 October 2025. 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 low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Overall, residuals were healthy this week. The lowest national residual was 739MW on Thursday at 9.00am.

**Figure 18: National generation balance residuals, 19-25 October 2025**




## 10. Storage/fuel supply

10.1. Figure 19 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. As of 26 October 2025, national controlled hydro storage increased to 89% of nominal full and ~140% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (66% full[9]) and Lake Takapō (84% full) is close to their respective 90th percentile.

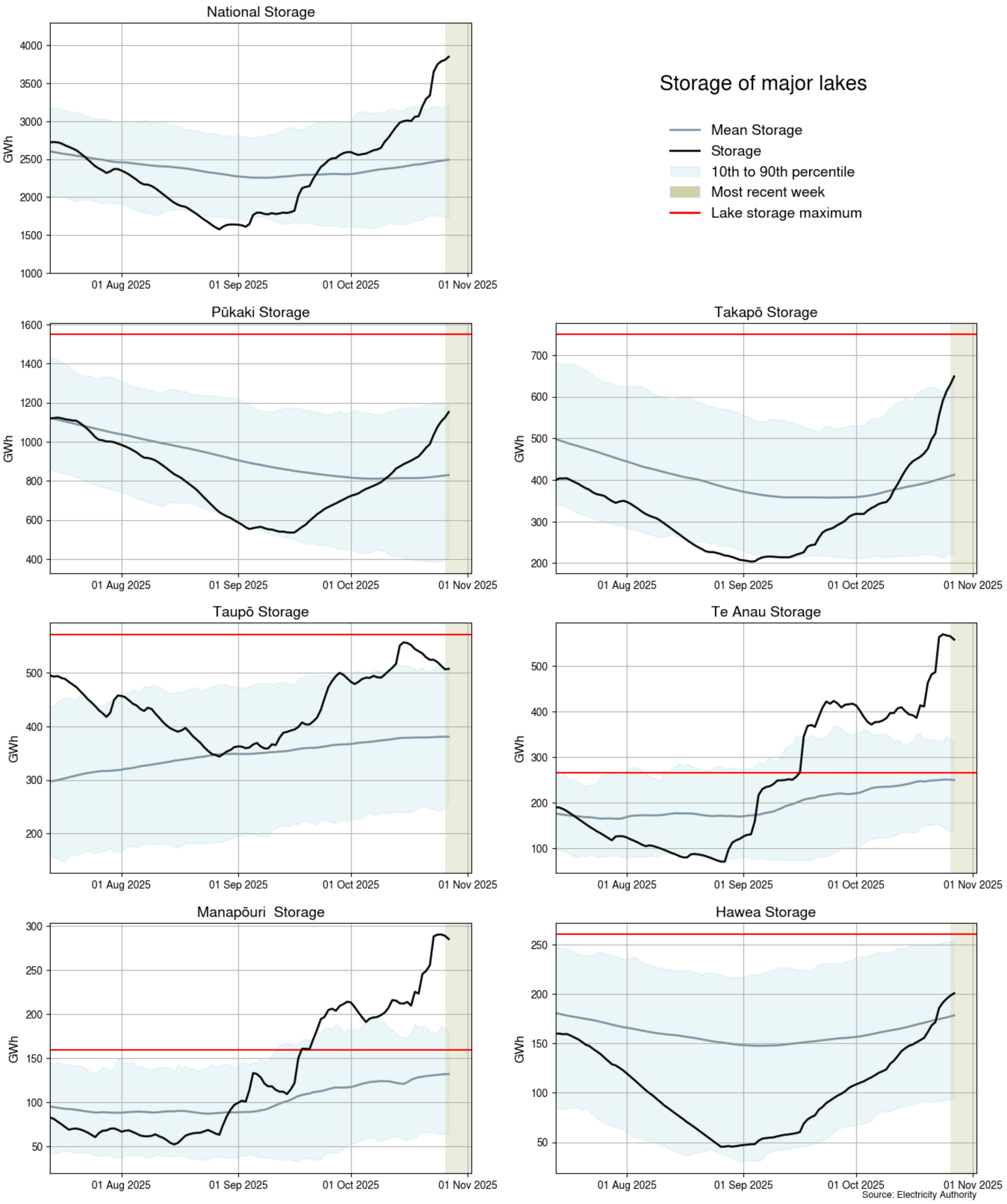
10.4. Storage at Lake Te Anau (210% full) and Lake Manapōuri (182% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities. Spill continues down the lower Waiau river[10].

10.5. Storage at Lake Taupō (88% full) is touching its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (70% full) is above its historic mean.

[9] Percentage full values sourced from NZX hydrological summary 27 October 2025.
[10] Lake levels - renewable energy generation | Meridian Energy

**Figure 19: 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 20 shows an estimate of thermal SRMCs as a monthly average up to 1 October 2025. Coal was last updated on 1 August, so the previous prices were carried forward. The SRMCs for gas powered generation have decreased, while the SRMC for diesel fuelled generation has remained stable.

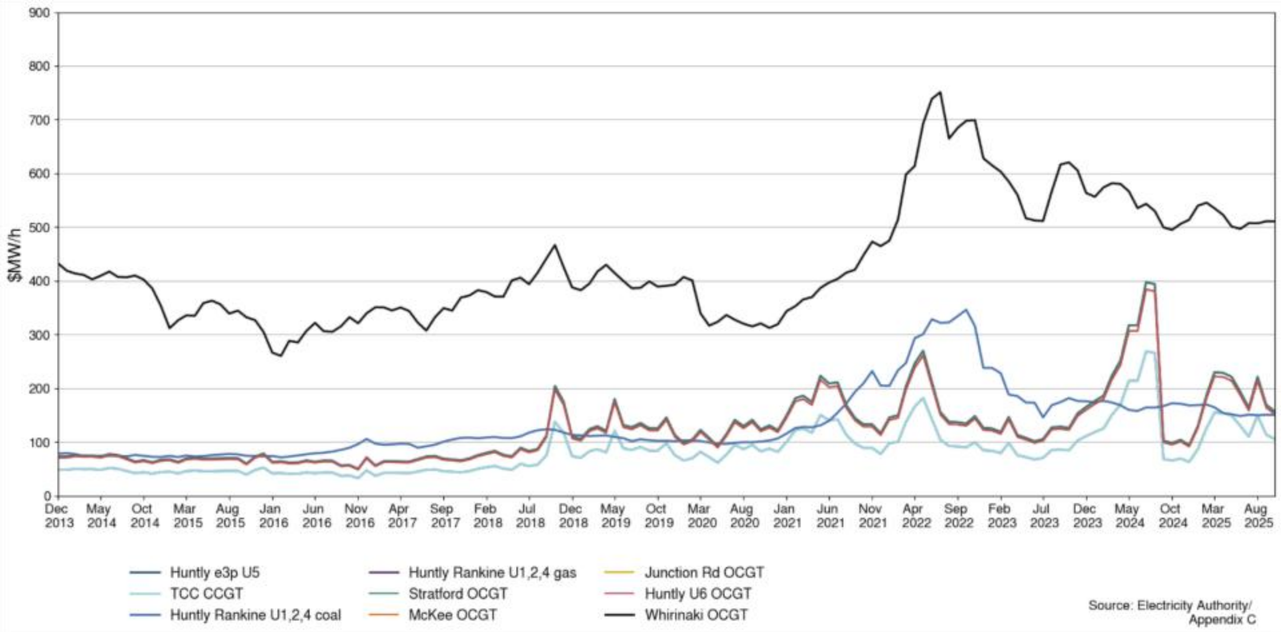
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$157/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $105/MWh and $157/MWh.

11.6. The SRMC of Whirinaki is ~$510/MWh.

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

**Figure 20: Estimated monthly SRMC for thermal fuels**

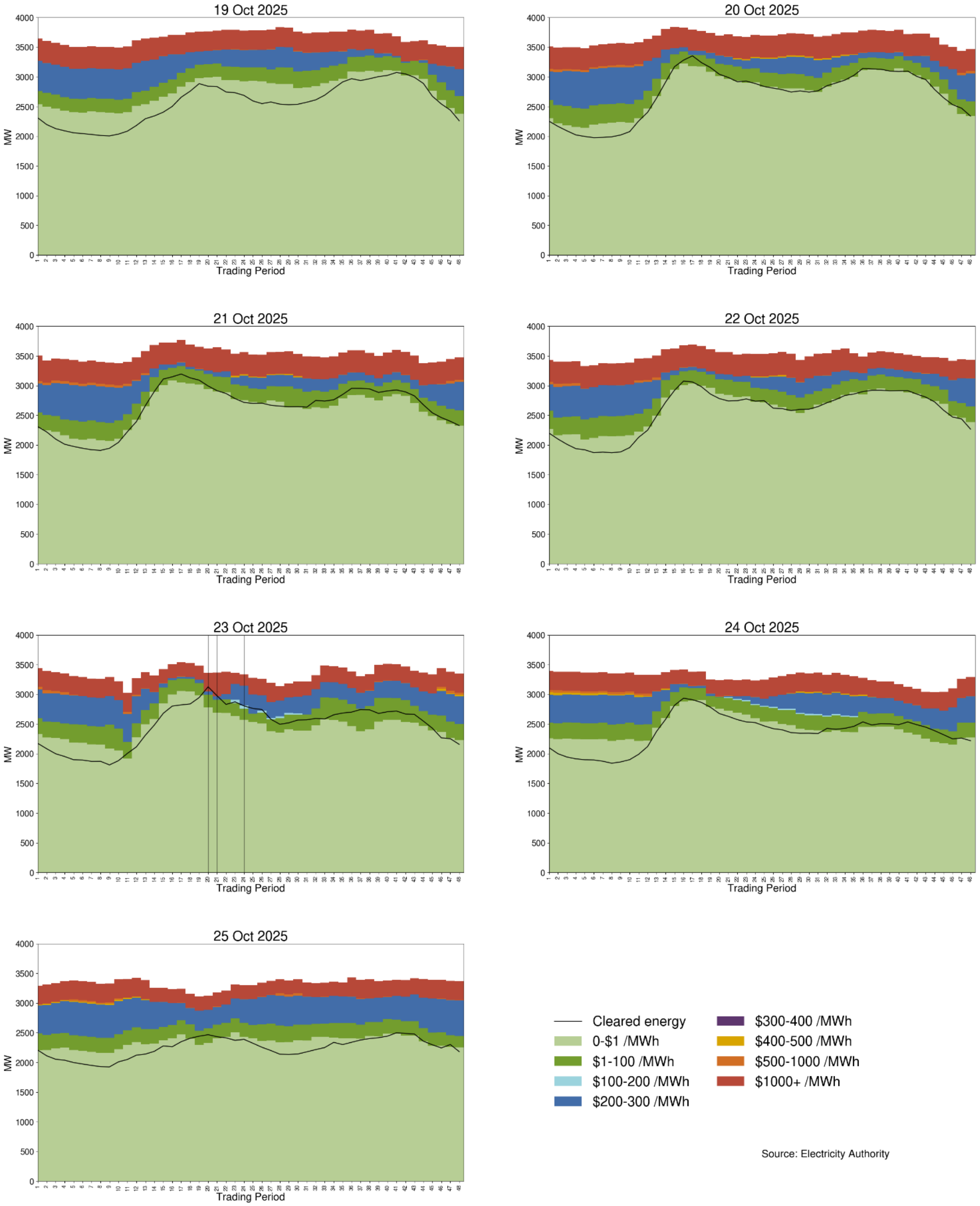



## 12. Offer behaviour

12.1. **Error! Reference source not found.** and 22 show this week's national daily offer stacks by Islands. The black line shows cleared energy, indicating the range of the average final price.

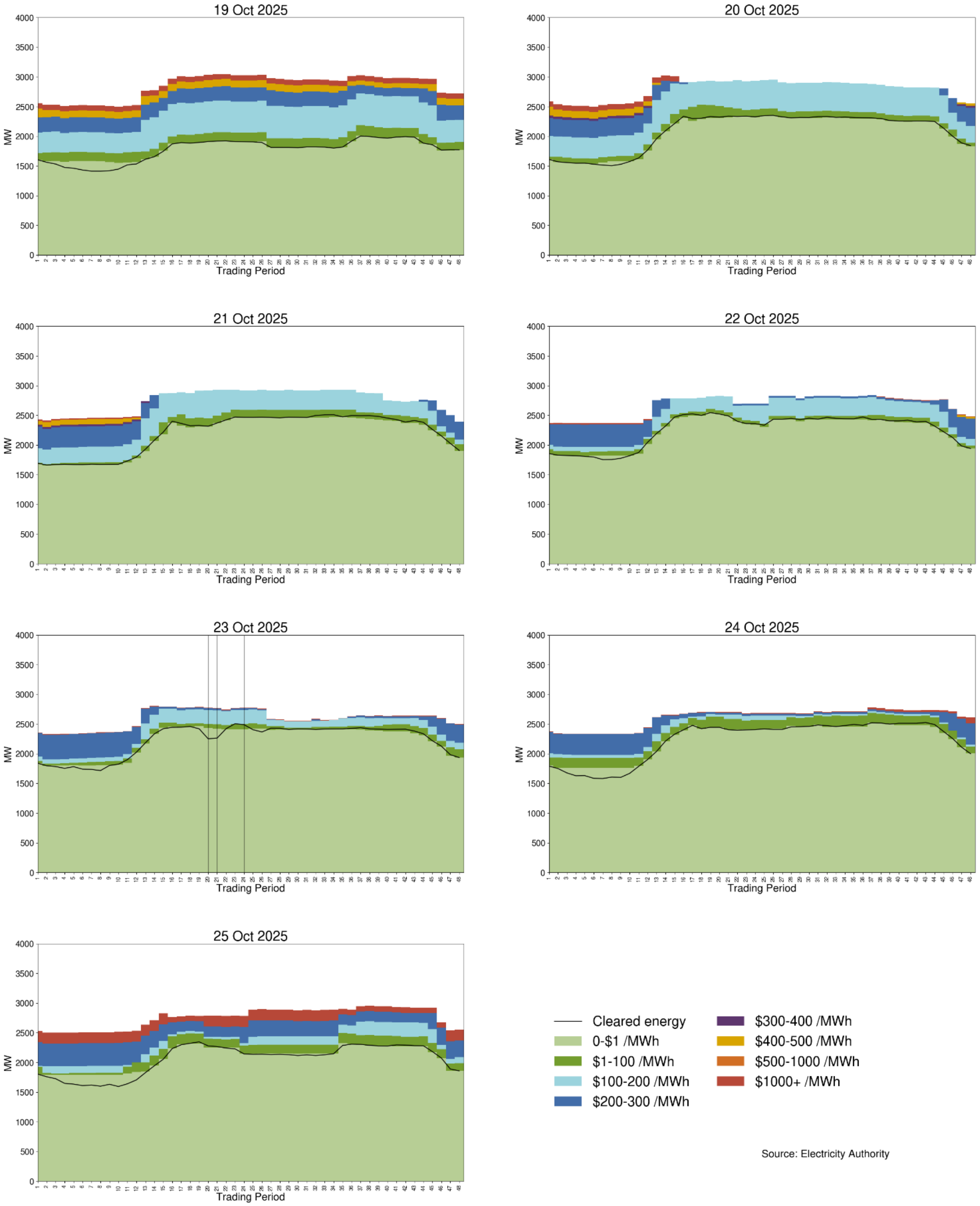
12.2. Most energy cleared below $100/MWh this week. However, due to severe weather conditions, some energy in the North Island cleared into the higher pricing bands when energy transfer was limited during the HVDC trips.

## Figure 21: Daily offer stacks (North Island)




Source: Electricity Authority

**Figure 22: Daily offer stacks (South Island)**

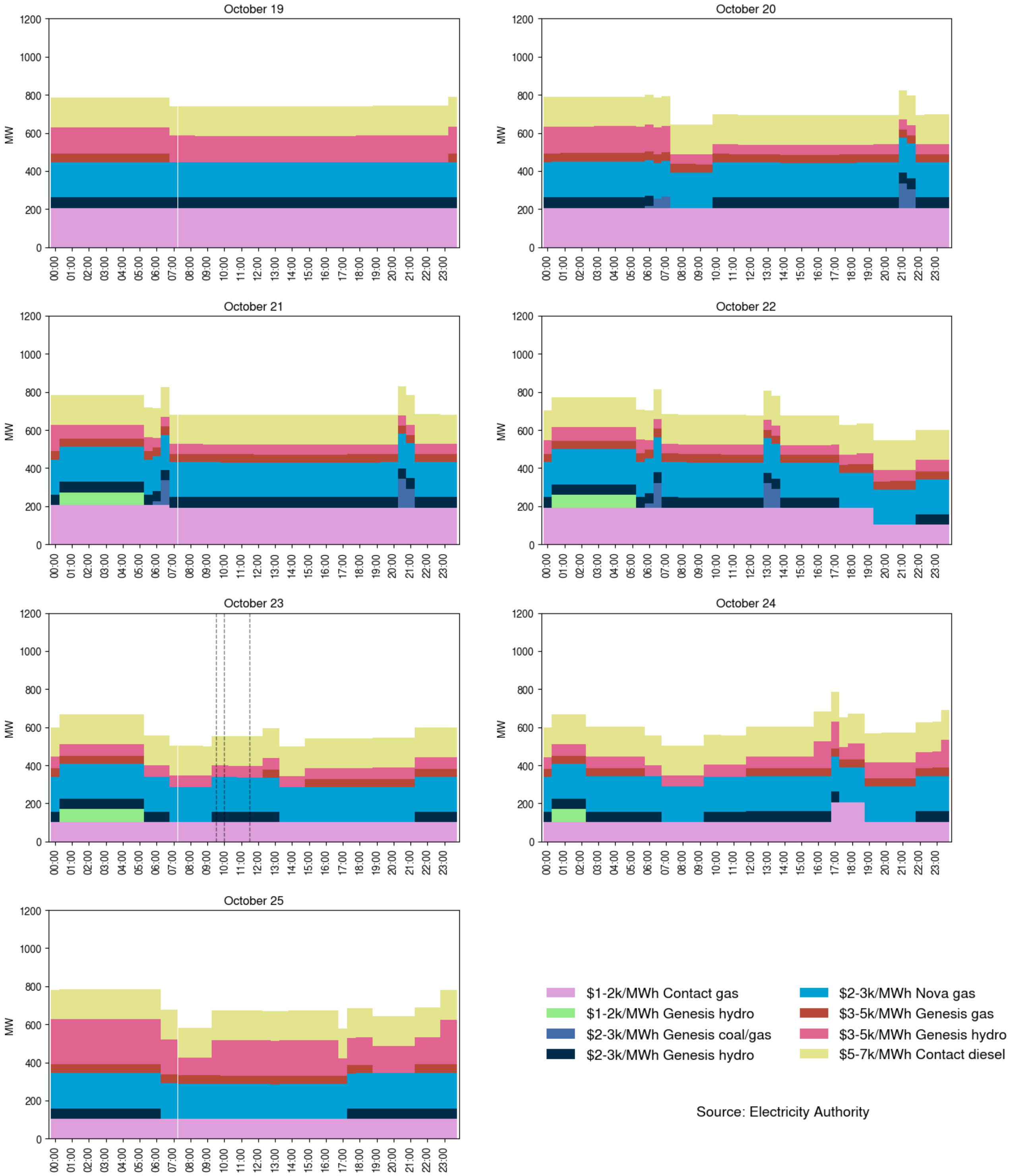



12.3. Figure 23 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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, wind 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 678MW per trading period was priced above $1,000/MWh this week, which is roughly 14% of the total energy available.

**Figure 23: 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 |
|---|---|---|---|---|---|
| 8/05/2025-9/05/2025 | Several | Further analysis | Genesis | Waikaremoana | Offers |
| 01/10/2025-04/-10/2025 | Several | Further analysis | Genesis | Huntly | Offers |
| 23/10/2025-26/10/2025 | Several | Further analysis | Meridian | Ruakākā | Offers |
| 24/10/2025-26/10/2025 | Several | Further analysis | Meridian | Ōhau chain | Offers |
| 21/10/2025-23/10/2025 | Several | Further analysis | Meridian | West Wind | Offers |