10 November 2026

Trading conduct report 1-7 November 2026

Market monitoring weekly report

Trading conduct report 1-7 November 2026

1. Overview

1.1. Prices increased this week due to higher demand, constrained HVDC flow which limited the export of cheaper South Island generation north, periods of low wind generation and an increased reliance on peaker generation. There was also substantial price separation across most of the week. National controlled storage increased to 80% nominally full and ~125% of the historical average, however, most of this was in South Island catchments.

1.2. Note that two trading periods starting 11.30am and 12.00pm on Thursday are missing data this week, due to a data pipeline outage.

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 1-7 November:

(a) The average spot price for the week was $64/MWh, an increase of around $42/MWh compared to the previous week.

(b) 95% of prices fell between $1/MWh and $227/MWh.

2.3. Prices have increased this week due to low intermittent generation, there was frequent price separation between the North and South Island, with HVDC capacity reduced due to the continuation of planned transmission equipment outages near Benmore and Haywards substations. These outages contributed to the HVDC being constrained for much of the week. North Island hydro generation continues to be priced quite high as North Island hydro storage levels remain low. This has meant that the price at Ōtāhuhu has been particularly sensitive to periods of higher demand.

2.4. The highest price at Ōtāhuhu was $301/MWh at 7:30pm on Wednesday. At this time the price at Benmore was $10/MWh. This price occurred during a period of price separation from 4.00pm to 9.00pm where the price at Ōtāhuhu was above $200/MWh. During this period:

(a) Wind generation was below 100MW.

(b) Solar generation was decreasing as the sun was setting.

(c) Additional North Island hydro generation and thermal peaker generation was dispatched. Due to low North Island hydro storage levels this generation is currently priced quite high.

2.5. From 5.30am to 7.30am on Wednesday prices at Ōtāhuhu were above $200/MWh, reaching a maximum of $287/MWh at 7.00am. During this period the price at Benmore ranged from $10/MWh to $213/MWh. At the same time:

(a) Wind generation was below 300MW.

(b) Solar generation was below 50MW for most of the period.

(c) Additional thermal peaker generation was dispatched.

(d) Ōhau A unit 6 tripped off in the 5:30am trading period, causing an unexpected loss of 64MW.

2.6. At 9.00pm on Tuesday the price at Ōtāhuhu spiked up to $233/MWh. At this time the price at Benmore was $10/MWh. During this period:

(a) Wind generation was below 350MW and was 50MW lower than forecast.

(b) Additional thermal peaker generation was dispatched.

(c) Meridian's Ruakākā battery priced up ~40MW from ~$182/MWh to ~$281/MWh for this trading period.

2.7. At 9.30pm on Thursday the price at Ōtāhuhu spiked up to $241/MWh. At this time the price at Benmore was $10/MWh. During this period:

(a) Demand was 65MW higher than forecast.

(b) Wind generation was 306MW.

(c) Thermal baseload and peaker generation were decreasing near to zero.

(d) Meridian's Ruakākā battery priced up ~40MW from ~$127/MWh to ~$226/MWh for this trading period.

(e) Genesis' Huntly battery advised 0MW of capacity for this period and accordingly offered 0MW, this is down from the 40MW offered in the previous trading period.

(f) Contact's Glenbrook battery was dispatched for reserve.

2.8. At 6.30am on Thursday the price at Ōtāhuhu spiked up to $240/MWh. At this time the price at Benmore was $10/MWh. During this period:

(a) Wind generation was below 200MW and was 36MW lower than forecast.

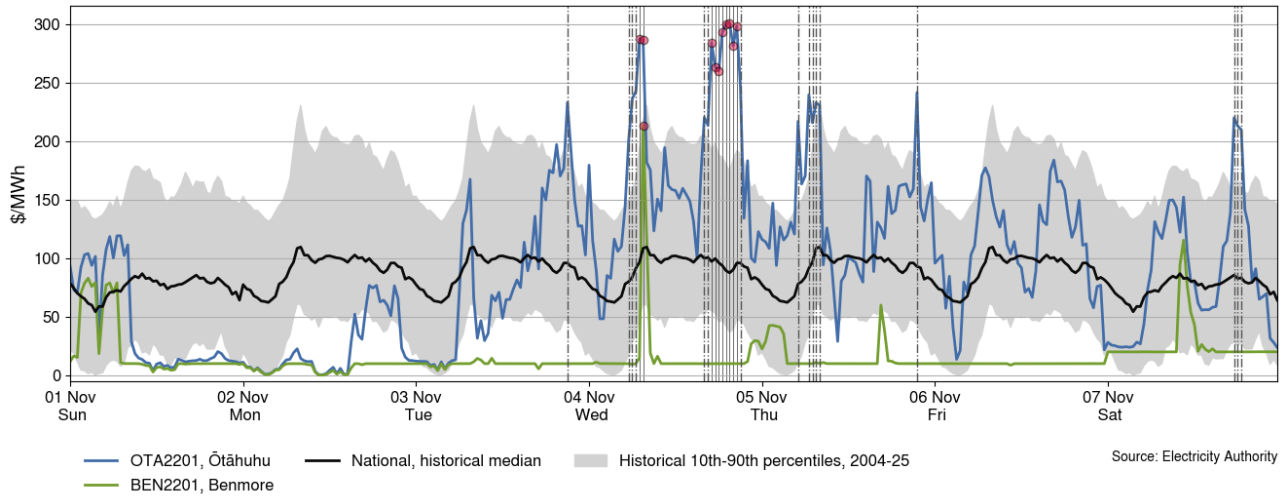
(b) Additional thermal generation was dispatched.

2.9. At 5.30pm on Sunday the price at Ōtāhuhu spiked up to $220/MWh. At this time the price at Benmore was $20/MWh. During this period:

(a) Wind generation was below 200MW and was 114MW lower than forecast.

2.10. 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.

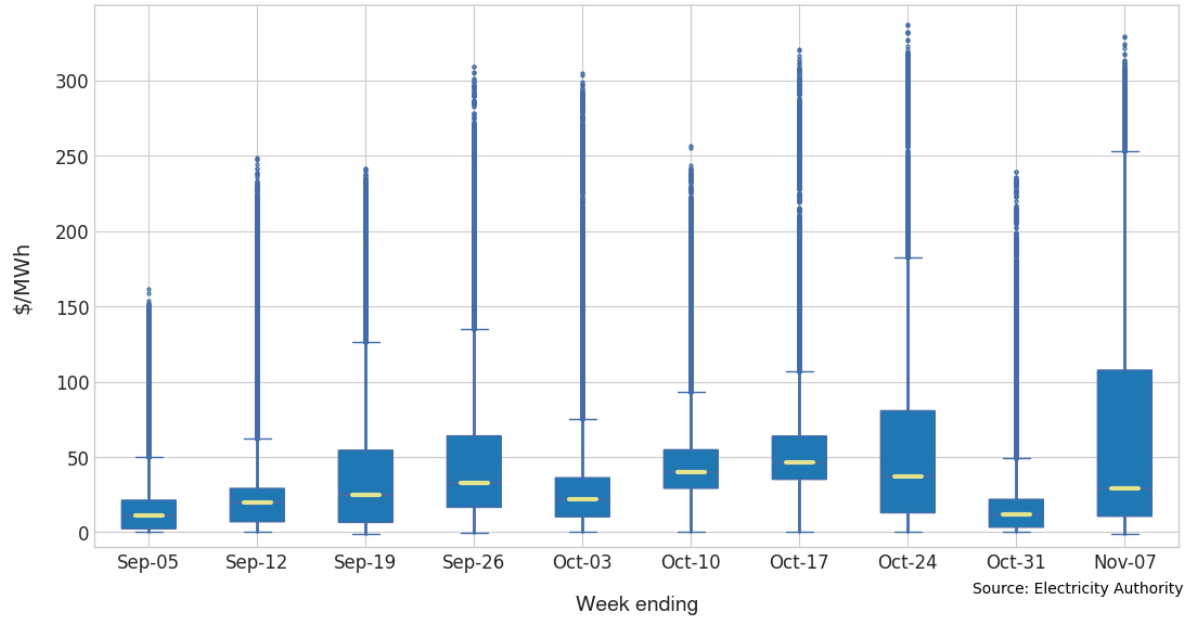
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 1-7 November



2.11. 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.

2.12. The distribution of spot prices this week was wider than last week with fewer high-price outliers. The median price was $28/MWh and most prices (middle 50%) fell between $11/MWh and $108/MWh.

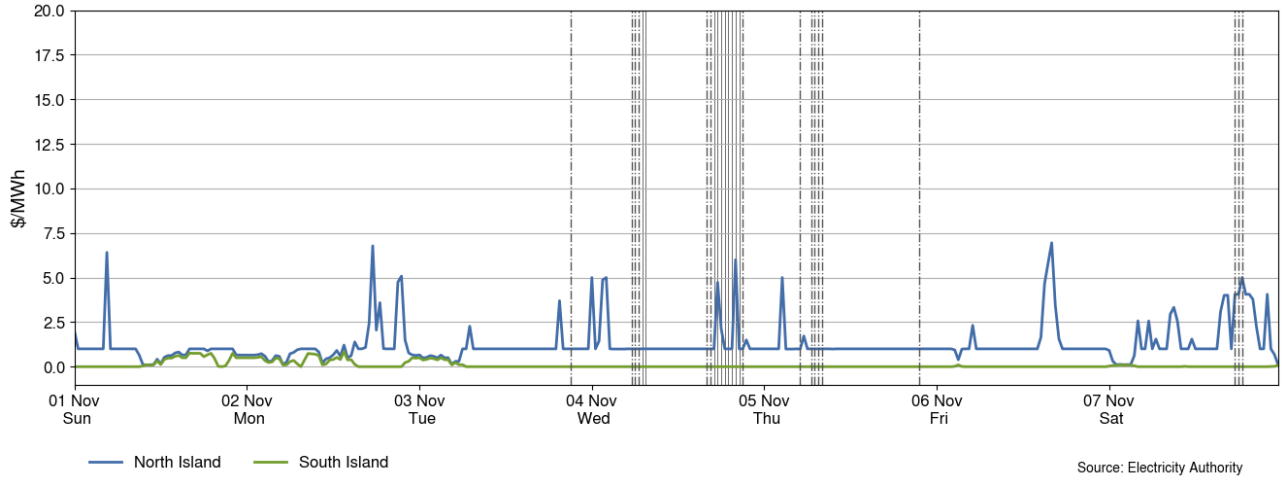
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

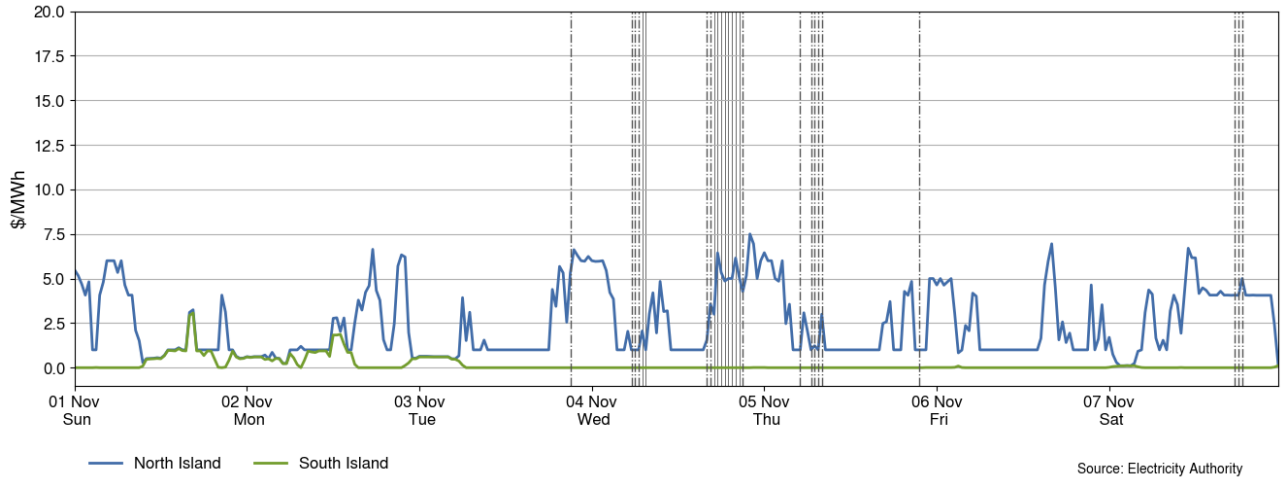
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week.

Figure 3: Fast instantaneous reserve price by trading period and island, 1-7 November



3.2. 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.

Figure 4: Sustained instantaneous reserve by trading period and island, 1-7 November



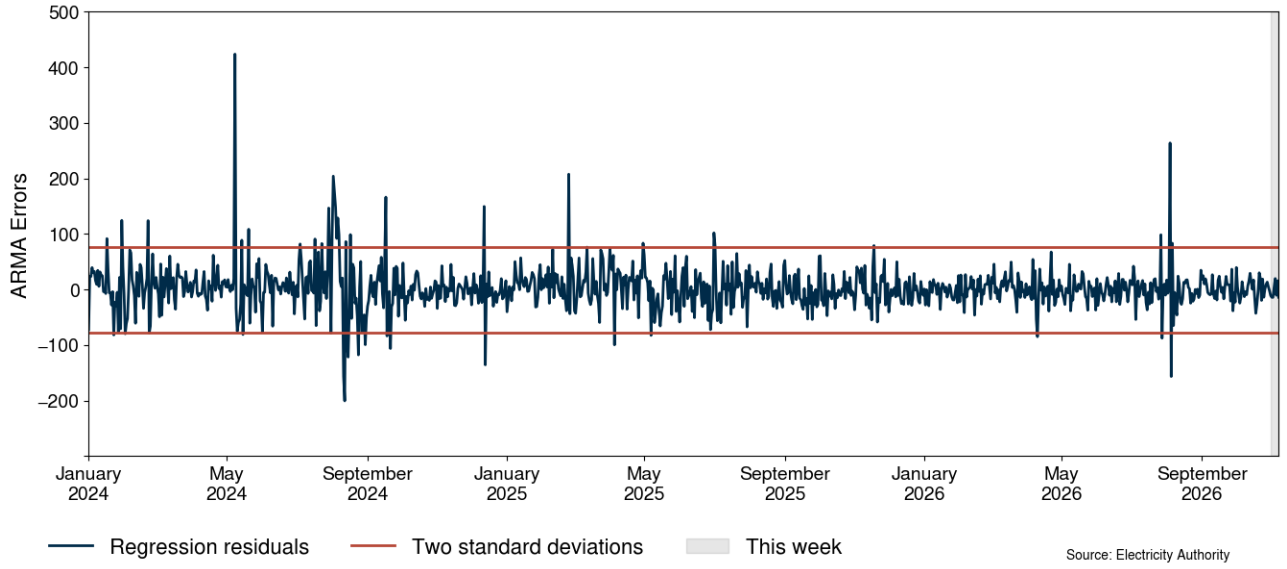
4. Regression residuals

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 - 7 November 2026



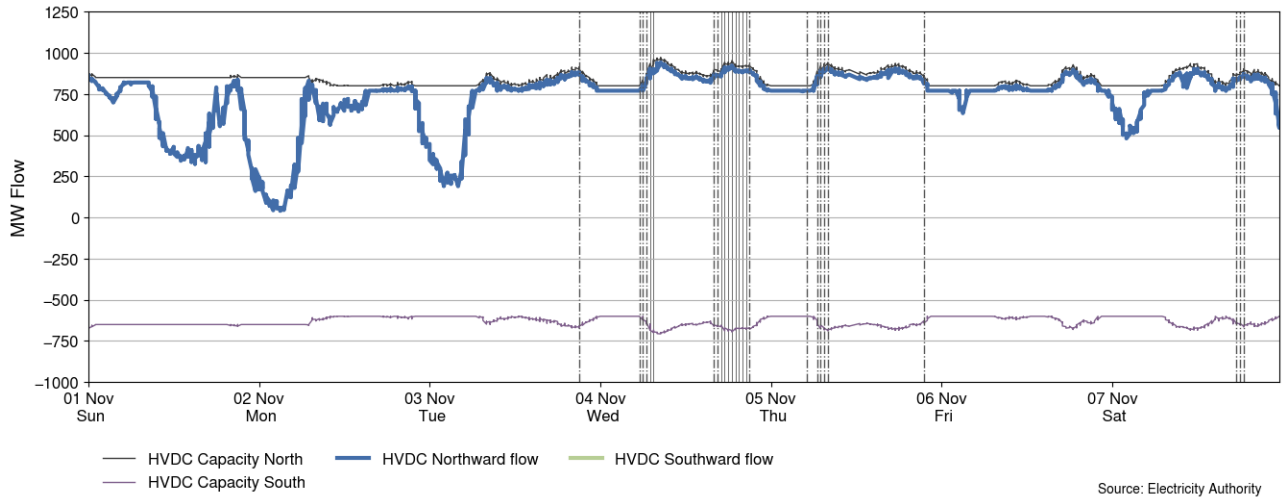
5. HVDC

5.1. Figure 6 shows the HVDC flow between 1-7 November. HVDC[1] flows were entirely northward this week and often close to capacity across the second half of the week.

5.2. HVDC capacity was reduced due to planned transmission equipment outages near Benmore and Haywards substation.

5.3. The highest northward HVDC flow this week was 941MW which occurred at 8.30am on Wednesday. There was no southward HVDC flow this week.

Figure 6: HVDC flow and capacity, 1-7 November



[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.

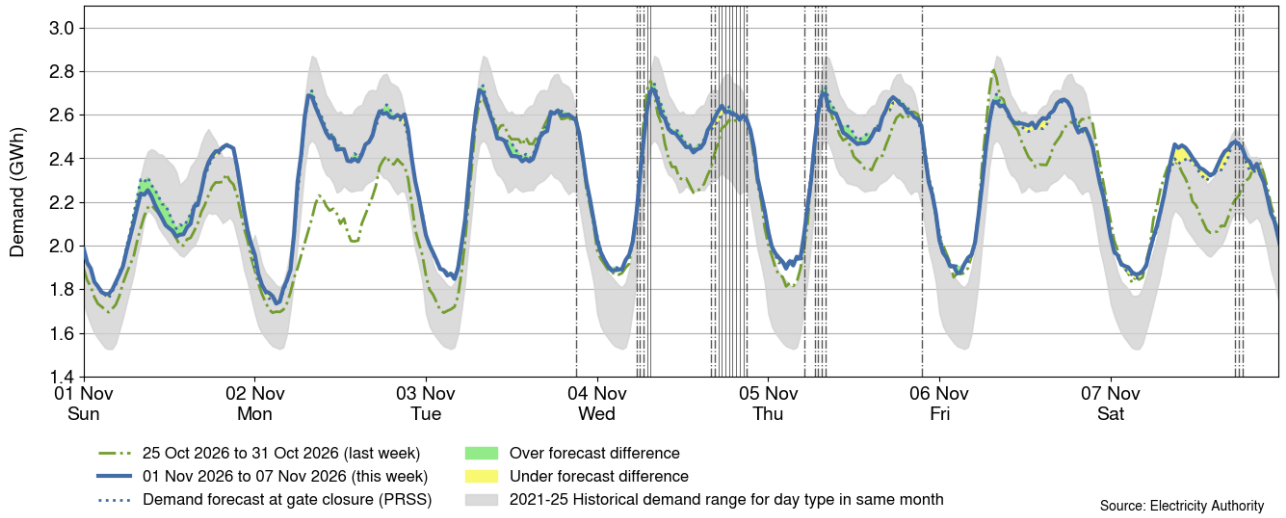
6. Demand

6.1. Figure 7 shows national demand between 1-7 November, compared to the historic range and the demand of the previous week. Demand was generally higher than last week.

6.2. The maximum demand this week was around 2.71GWh (5.43GW) at 8.00am on Wednesday.

6.3. Demand was between 56MW and 184MW lower than forecast on Sunday morning, and between 51MW and 148MW higher than forecast on Saturday morning.

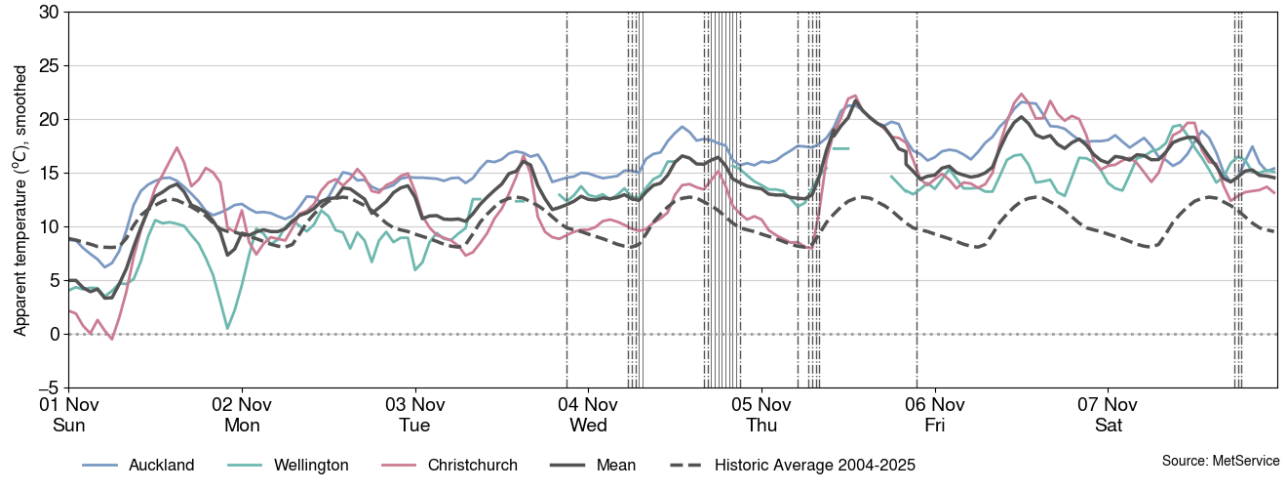
Figure 7: National demand, 1-7 November compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 1-7 November. 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.

6.5. Apparent temperatures ranged from 6°C to 22°C in Auckland, 0°C to 20°C in Wellington, and -2°C to 23°C in Christchurch. Temperatures rose throughout the week.

Figure 8: Temperatures across main centres, 1-7 November

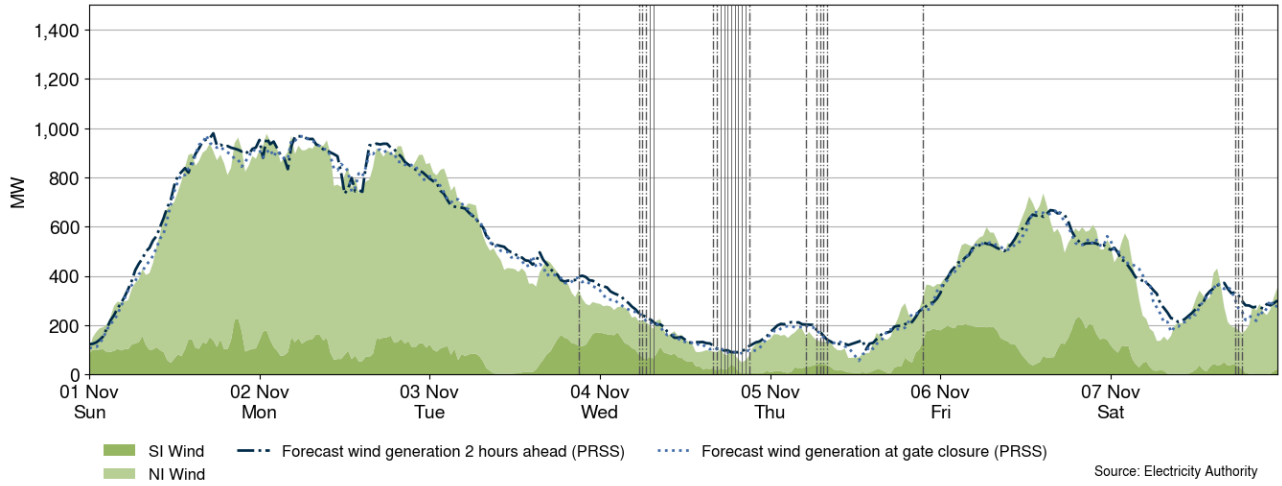


7. Generation

7.1. Figure 9 shows wind generation and forecast from 1-7 November. This week wind generation varied between 49MW and 977MW, with a weekly average of 457MW. Wind generation was high on Sunday and Monday, before dropping off throughout Tuesday. Wind generation reached below 100W on Wednesday evening.

7.2. Wind generation was lower than forecast on Saturday. These forecasting differences were due to an accumulation of errors at various wind farms.

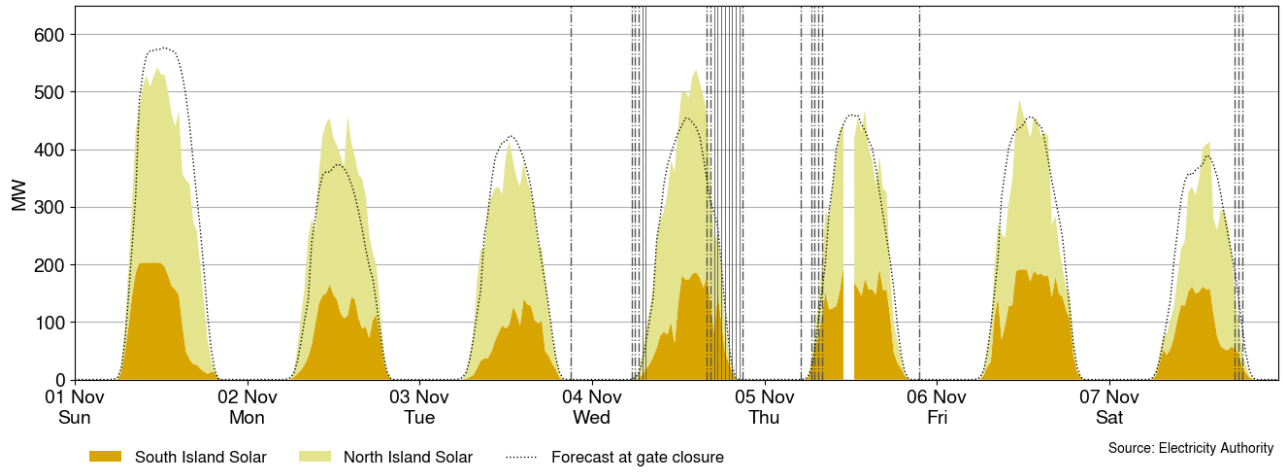
Figure 9: Wind generation and forecast, 1-7 November



7.3. Figure 10 shows grid connected solar generation from 1-7 November. Mean daytime solar generation this week was 261MW, peaking at 542MW on Sunday at 11:30am. Solar generation was lower this week compared to previous weeks.

7.4. Forecasting differences on Sunday are mainly due to Kōwhai Park solar farm. Other forecasting differences throughout the week are an accumulation of errors at various solar farms.

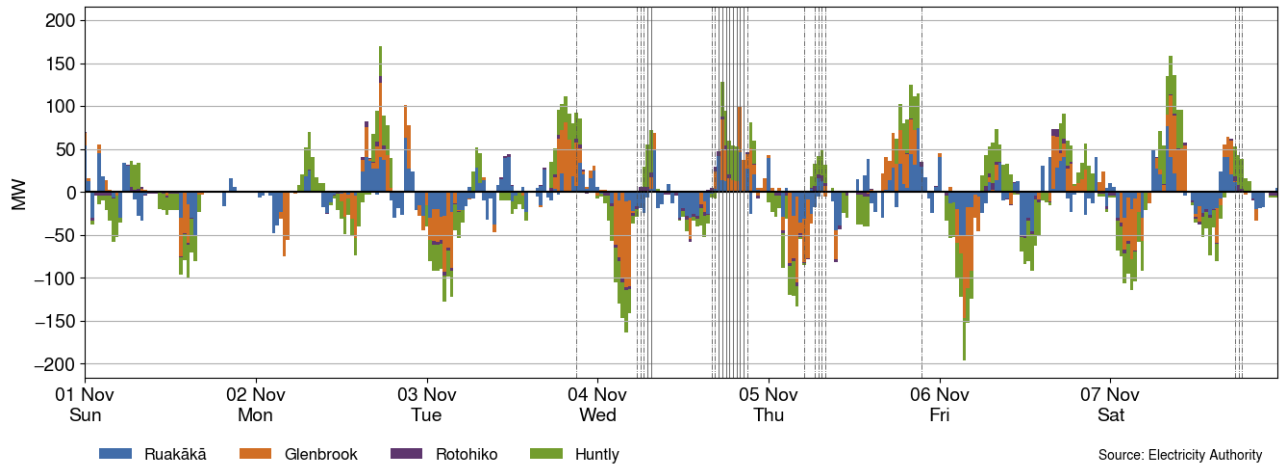
Figure 10: Grid connected solar generation, 1-7 November



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

Figure 11: Grid scale battery charge and discharge, 1-7 November



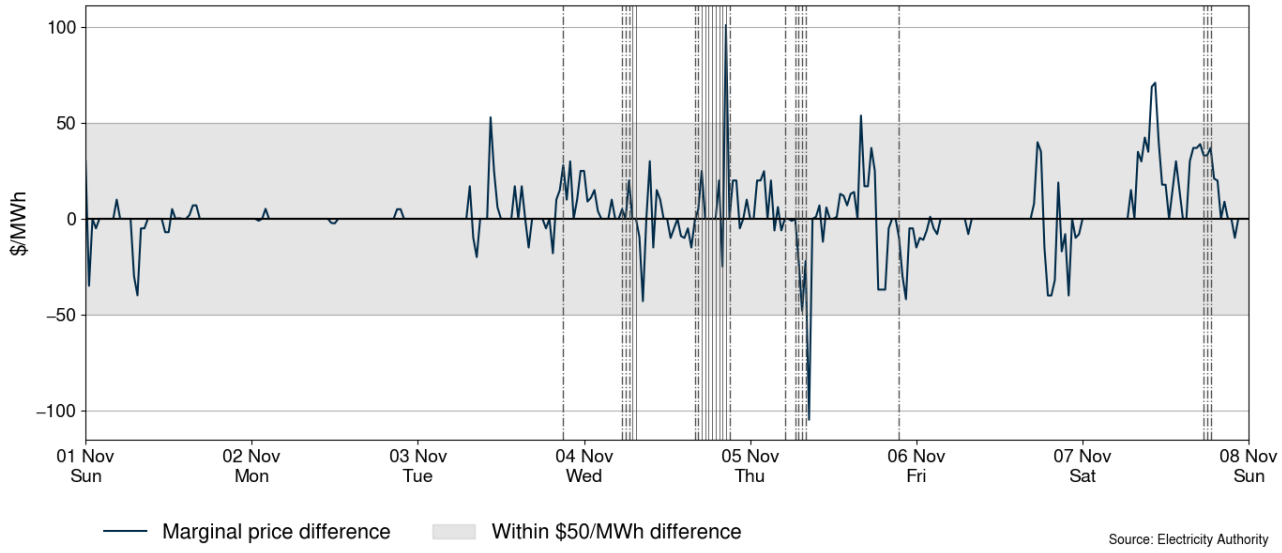
7.7. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing 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.

7.8. The largest positive marginal price forecast difference of $101/MWh occurred at 8.30pm on Wednesday. At this time demand was 37MW higher than forecast and intermittent generation was 36MW lower than forecast.

7.9. The largest negative marginal price forecast difference of $105/MWh occurred at 8.30am on Thursday. At this time demand was 91MW lower than forecast and intermittent generation was 95MW higher than forecast.

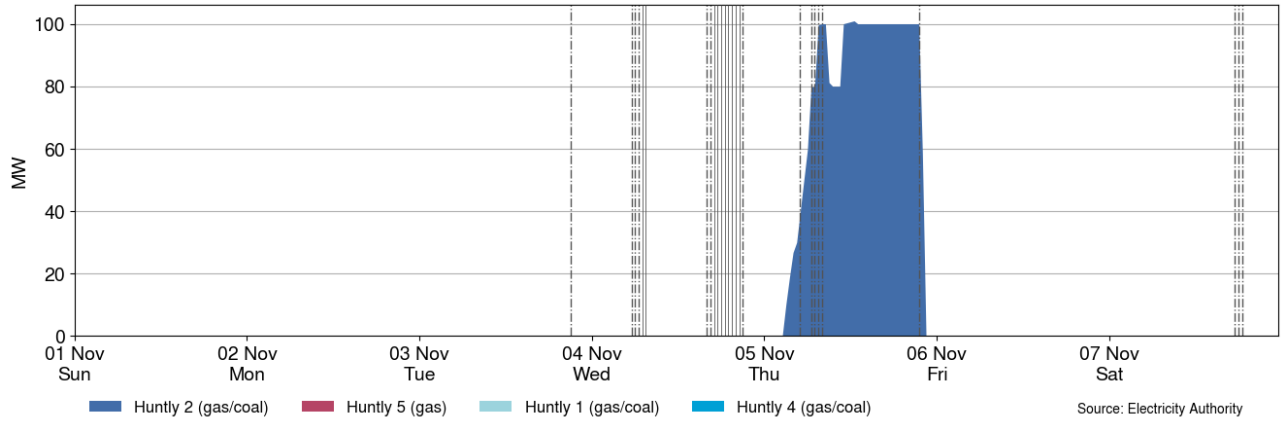
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 1-7 November



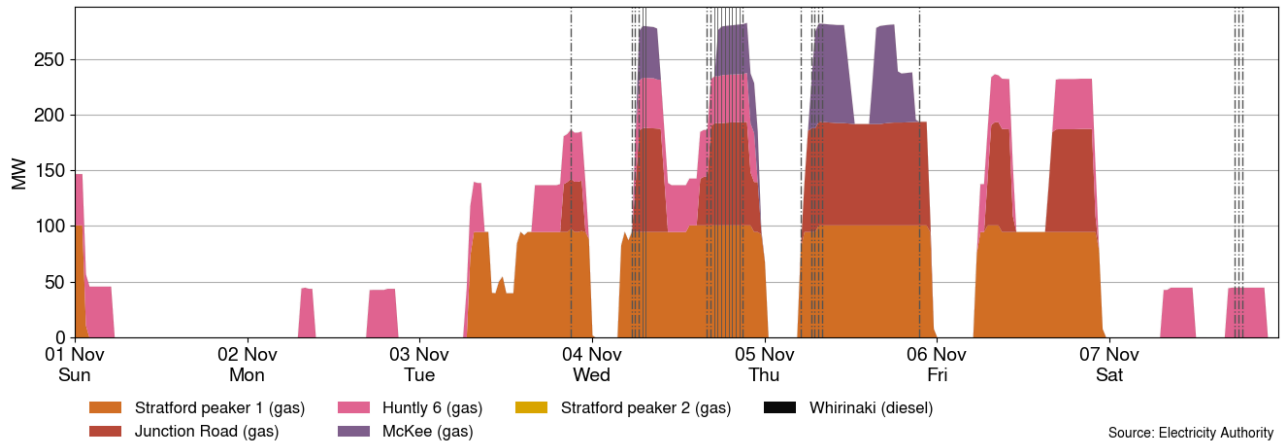
7.10. Figure 13 shows the generation of thermal baseload between 1-7 November. Huntly 2 was dispatched for baseload generation on Thursday.

Figure 13: Thermal baseload generation, 1-7 November



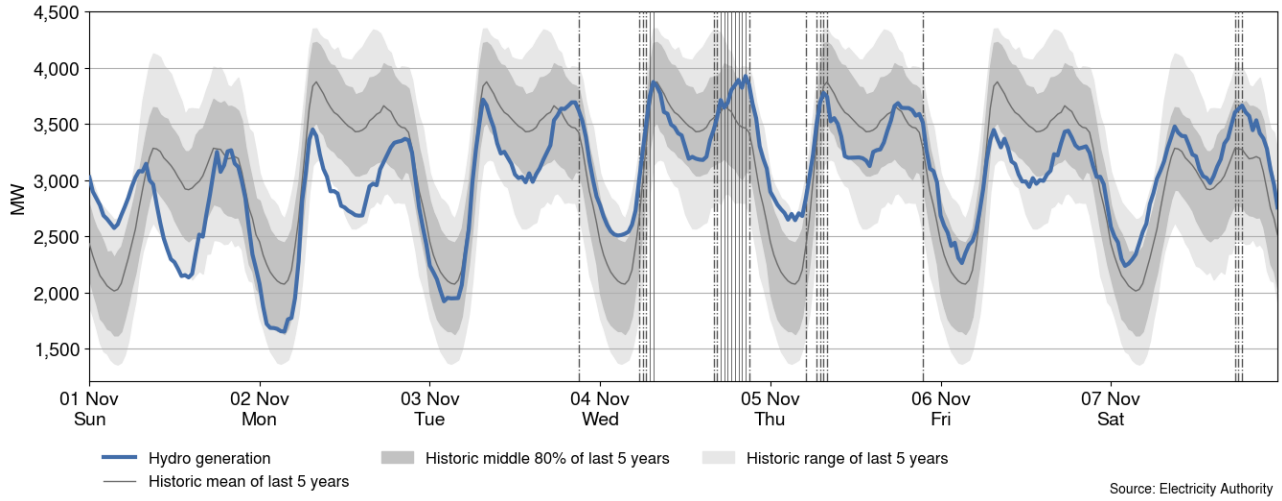
7.11. Figure 14 shows the generation of thermal peaker plants between 1-7 November. Thermal peaker generation was high throughout the second half of the week.

Figure 14: Thermal peaker generation, 1-7 November



7.12. Figure 15 shows hydro generation between 1-7 November. Hydro generation was mostly lower than average throughout the week. Overnight hydro generation was higher than average from Wednesday morning onward. This was likely due to the HVDC being constrained during this time, and wind generation being low.

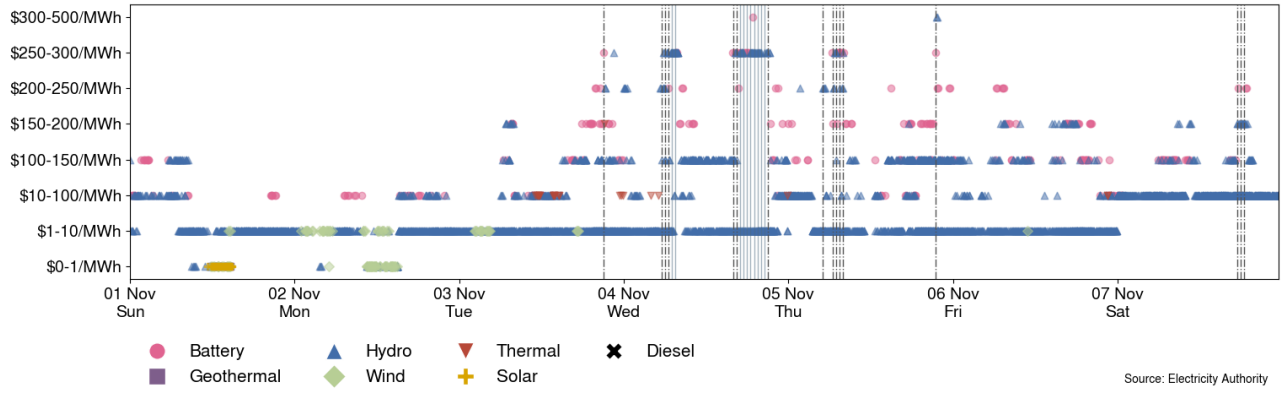
Figure 15: Hydro generation, 1-7 November



7.13. 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.

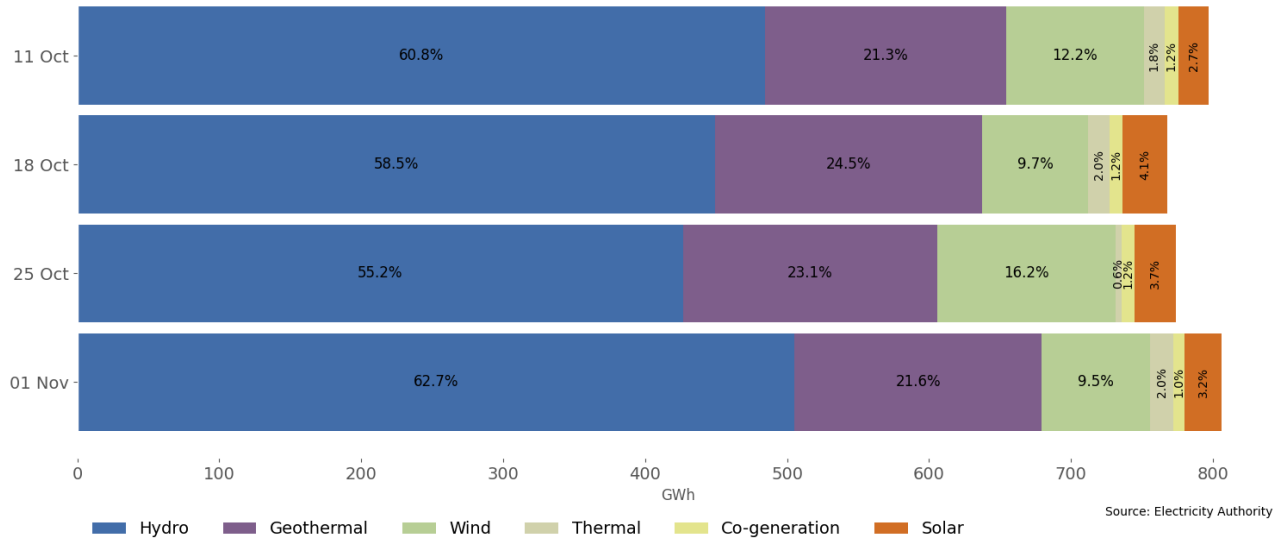
7.14. The highest marginal price of $320/MWh was set by Karāpiro at 9:30pm on Thursday. The most common marginal technology was hydro and the second most common technology was battery. Most marginal prices were between $1-10/MWh.

Figure 16: Prices of marginal generation, 1-7 November



7.15. As a percentage of total generation, between 1-7 November, total weekly hydro generation was 62.7%, geothermal 21.6%, wind 9.5%, thermal 2.0%, co-generation 1.0%, and solar (dispatchable) 3.2%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 11 October and 7 November



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 1-7 November ranged from ~1,121MW to ~1,758MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 1-7 November

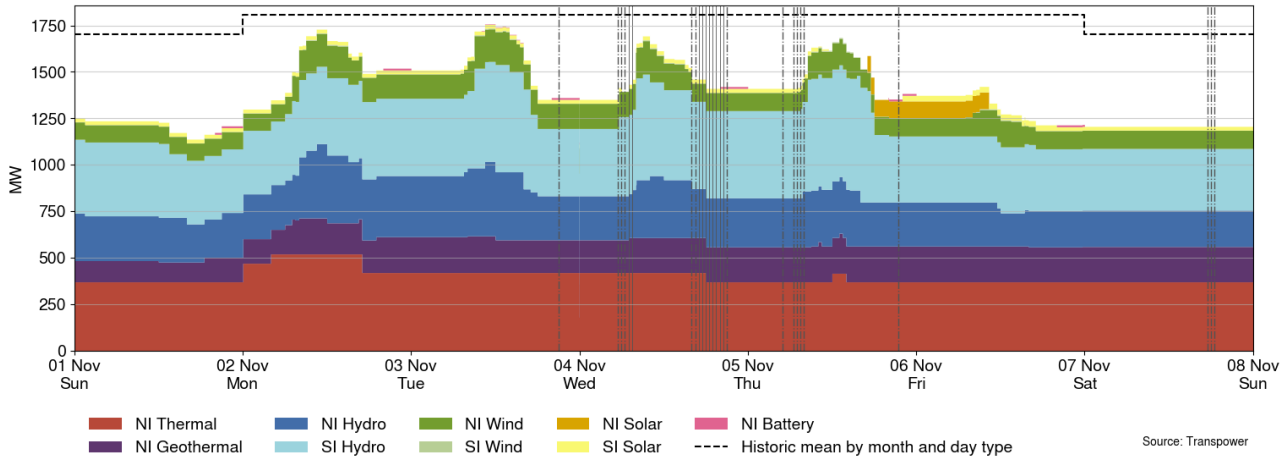
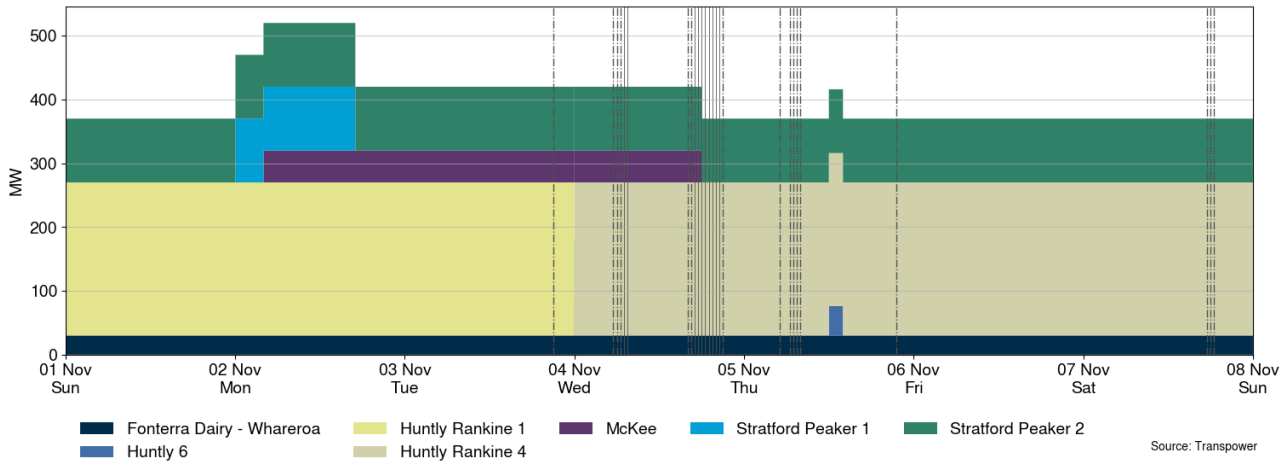


Figure 19: Total MW loss from thermal outages, 1-7 November



8.2. Notable outages include:

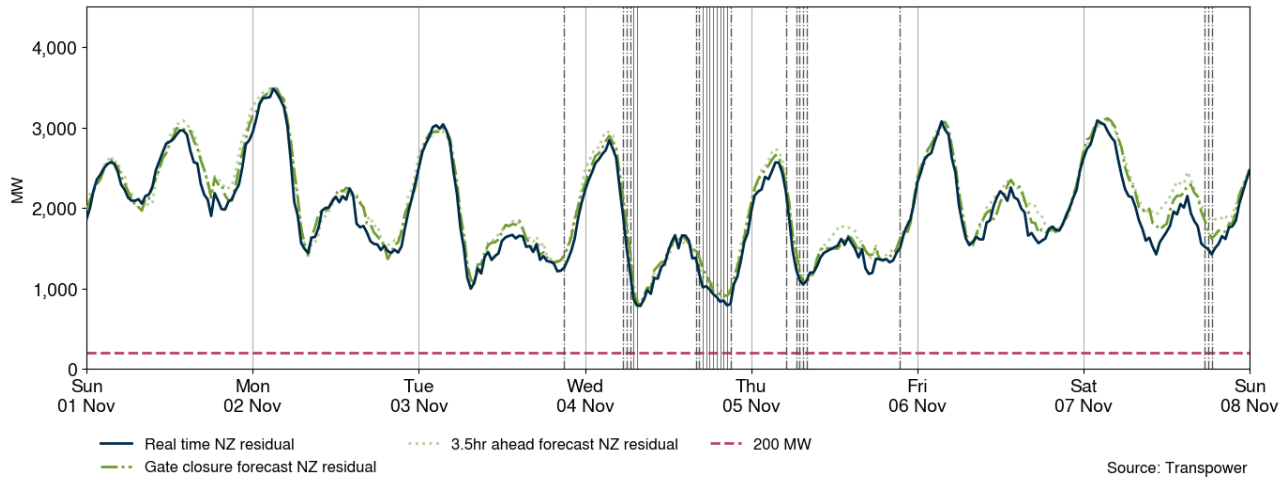
Plant	Partial or Full	End Date
Stratford Peaker 1	Full	2 November 2026
Huntly 1	Full	3 November 2026
Clyde unit 2	Full	5 November 2026
Ōhau Station	Full	7 November 2026
Stratford Peaker 2	Full	11 November 2026
Kaiwaikawe wind farm	Partial	30 November 2026
Manapōuri unit 7	Full	4 December 2026
Huntly 4	Full	31 January 2027
Ruakākā solar farm	Full	30 April 2027
Manapōuri unit 2	Full	2 July 2027

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 1-7 November. 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. National residual generation did not drop below 200MW this week.

Figure 20: National generation balance residuals, 1-7 November



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 80% nominally full and ~125% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (87% full[3]) is significantly higher than the historic 90th percentile for this time of year.

10.4. Storage at Lake Tekapō (67% full) is above average for this time of year.

10.5. Storage at Lake Taupō is (55% full) has increased but remains below average for this time of year.

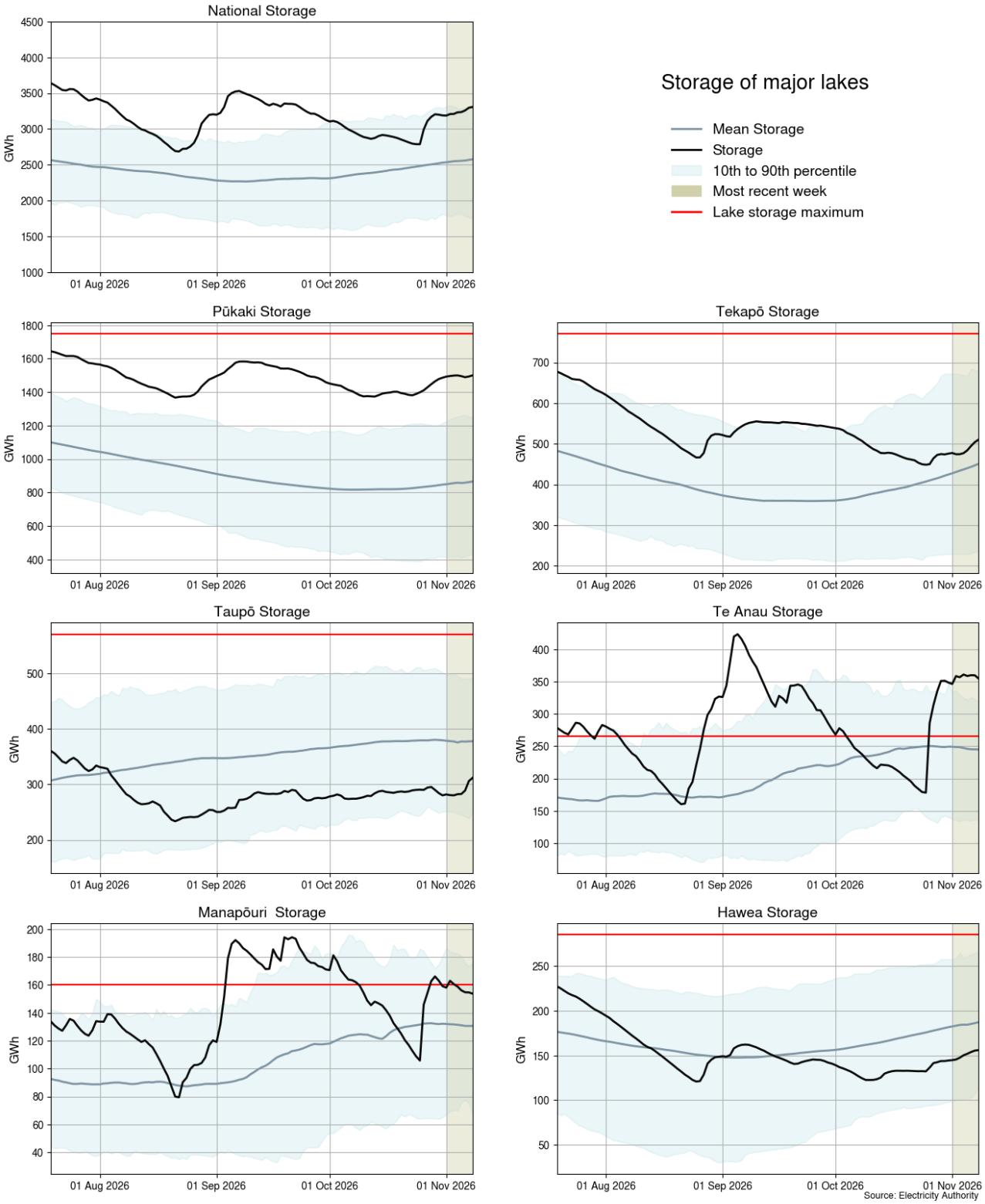
10.6. Storage at Lake Te Anau (134% full) is above the lake's historic 90th percentile for this time of year.

10.7. Storage at Lake Manapōuri (98% full) is above average for this time of year.

10.8. Storage at Lake Hawea (55% full) is below average for this time of year.

[3] 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 November 2026. The SRMCs for gas, coal, and diesel fuelled generation have mostly remained steady. The largest change was for gas fuelled generation which increased by ~$9/MWh.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$232/MWh, while the cost of running the Rankines on gas is ~$148/MWh.

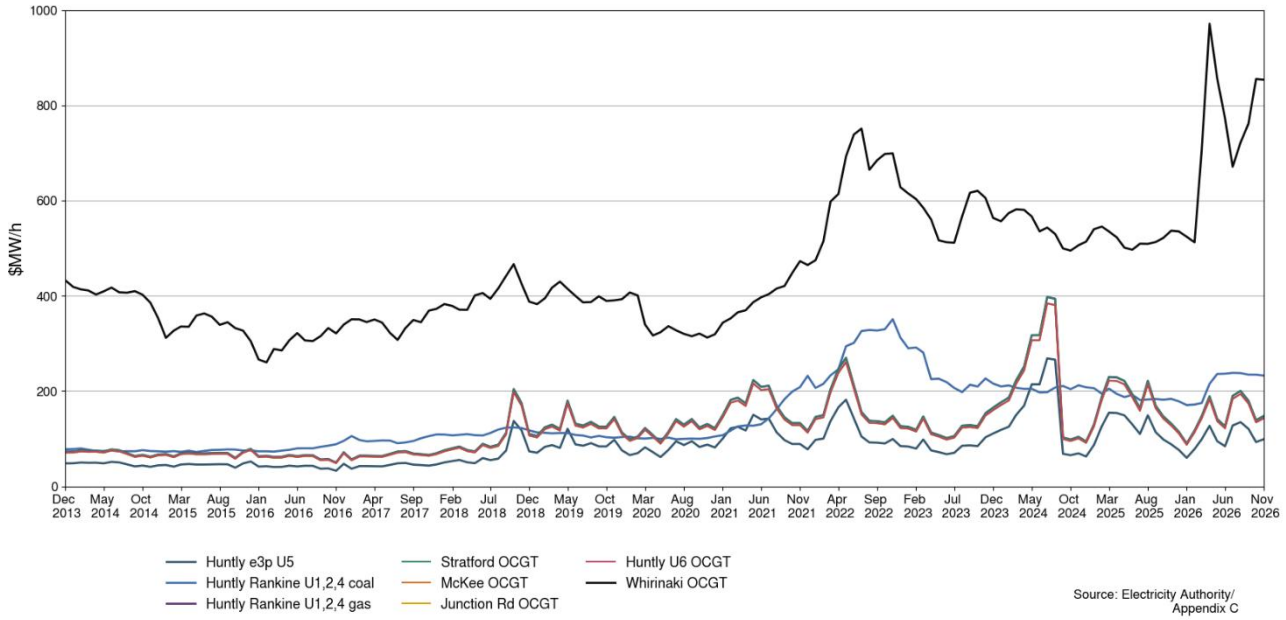
11.5. The SRMC of gas fuelled thermal plants is currently between $99/MWh and $148/MWh.

11.6. The SRMC of Whirinaki is ~$854/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

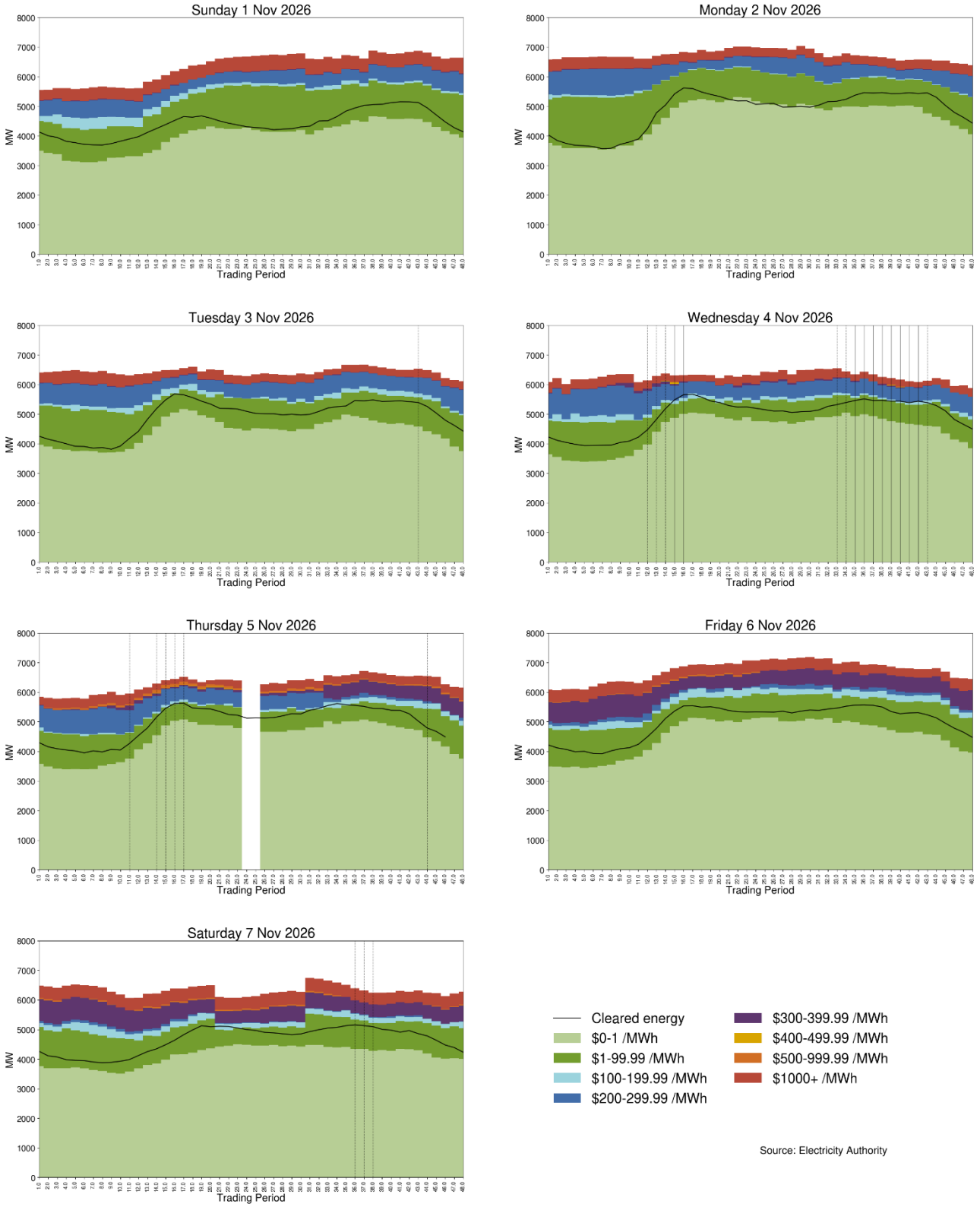
12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most energy cleared between $1-99/MWh, except for times on Wednesday evening, Thursday, and midday Sunday when energy cleared between $100-199/MWh. In addition to times on Wednesday morning when energy cleared between $200-399/MWh.

12.3. Planned transmission circuit outages near Wairakei and Whakamaru on Sunday saw an increase in offers above $1,000/MWh from various geothermal operators. We are still looking further into these offers.

12.4. Mercury priced up ~390MW of hydro generation from $200-299/MWh to $300-399/MWh at 4.00pm on Thursday. They also priced down ~50MW from $1-49/MWh to $0-0.9/MWh, and ~90MW from $200-299/MWh to $100-199/MWh.

Figure 23: Daily offer stacks

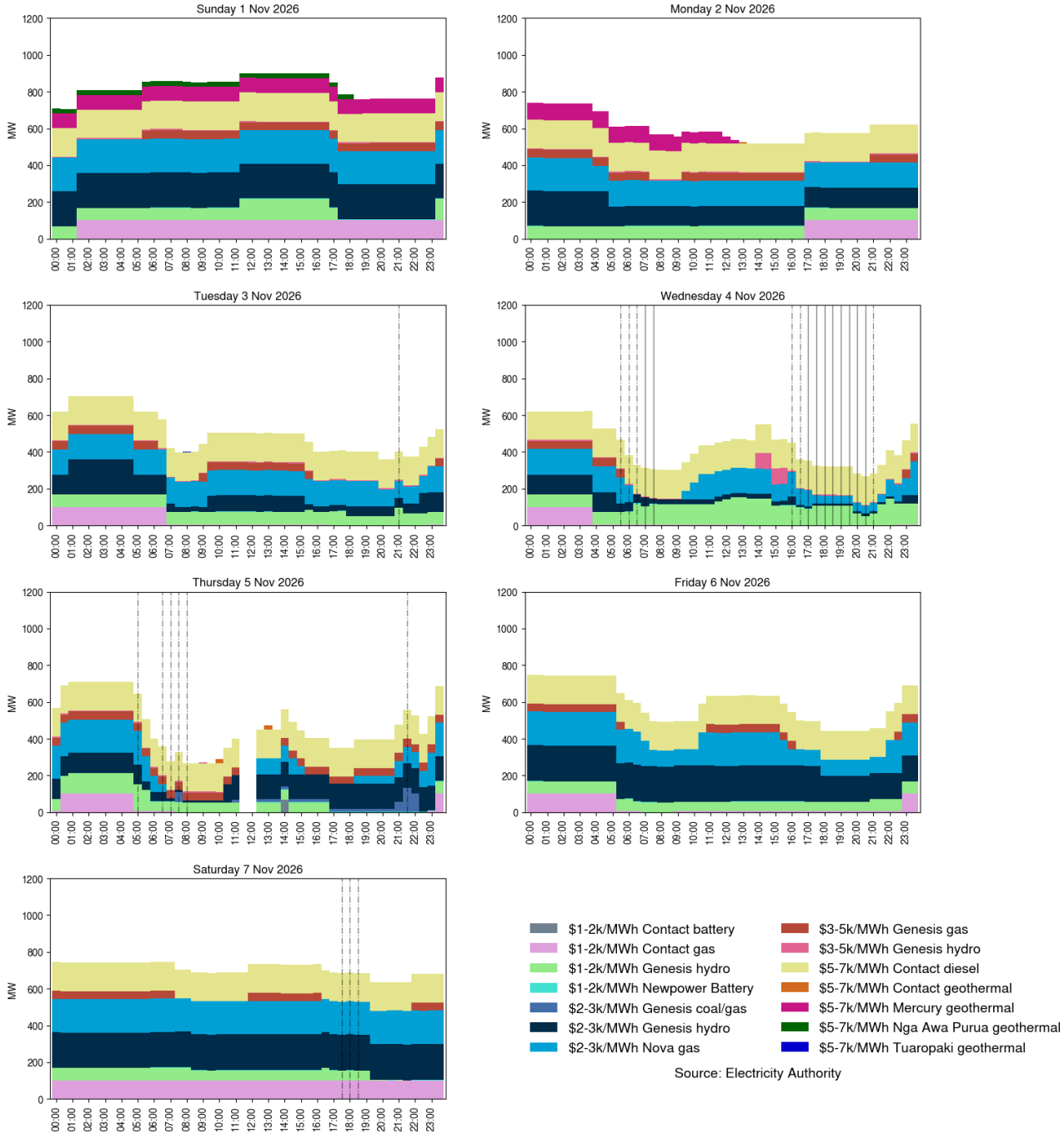


12.5. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.6. 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.

12.7. On average 602MW per trading period was priced above $1,000/MWh this week, which is roughly 7% 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.

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
05/10/2026-08/10/2026	Several	Further analysis	Genesis	Tekapō	Offers
12/10/2026	37-43	Further analysis	Genesis	Huntly battery	Offers
21/10/2026	42-48	Further analysis	Genesis	Huntly 1	Offers
30/10/2026-31/10/2026	Several	Further analysis	Several	Geothermal stations	Offers
27/10/2026	42, 43	Further analysis	Nova	Junction Road	Offers