12 January 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report
4-10 January 2026

Market monitoring weekly report

Trading conduct report 4-10 January 2026

1. Overview

1.1. This week the average spot price increased by $1.50/MWh to $2/MWh, with demand increasing slightly following the holiday period. The proportion of hydro and solar generation increased this week, while the proportion of geothermal and wind generation decreased. Thermal generation remains very low. National hydro storage increased slightly to 98% nominally full and ~125% of the historical average for this time of the year.

2. Spot prices

2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.

2.2. Between 4-10 January:

(a) The average spot price for the week was $2/MWh, an increase of around $1.50/MWh compared to the previous week.

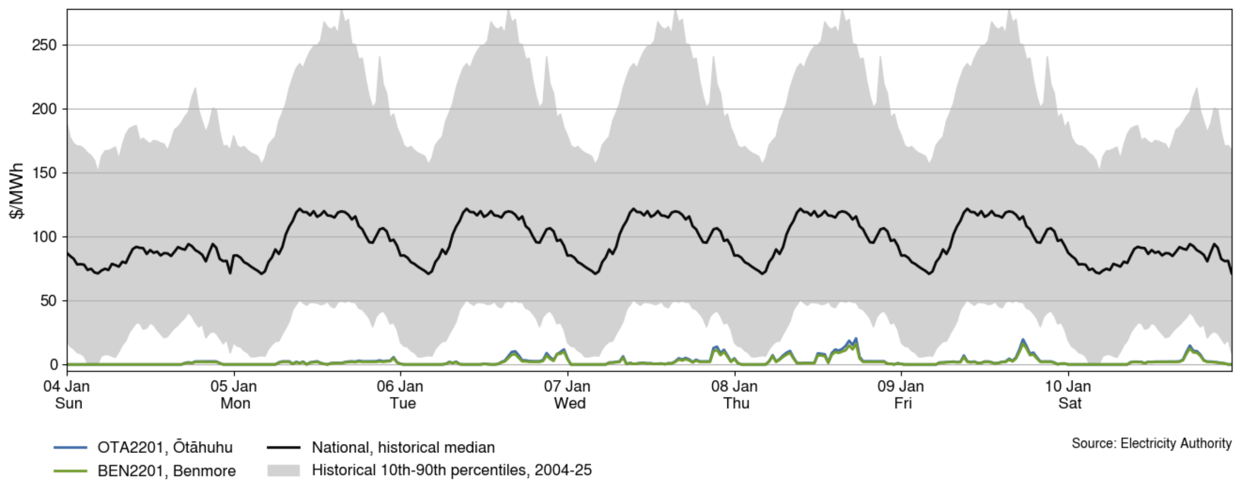
(b) 95% of prices fell between $0.01/MWh and $12/MWh.

2.3. Prices were mostly below $15/MWh at Ōtāhuhu and mostly below $10 at Benmore this week. Prices were very low on Sunday and Monday.

2.4. The highest Ōtāhuhu price of the week was $20/MWh at 5.30pm on Thursday. At this time, demand was 110MW higher than forecast.

2.5. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. There were no 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, nor other notable prices, to highlight this week.

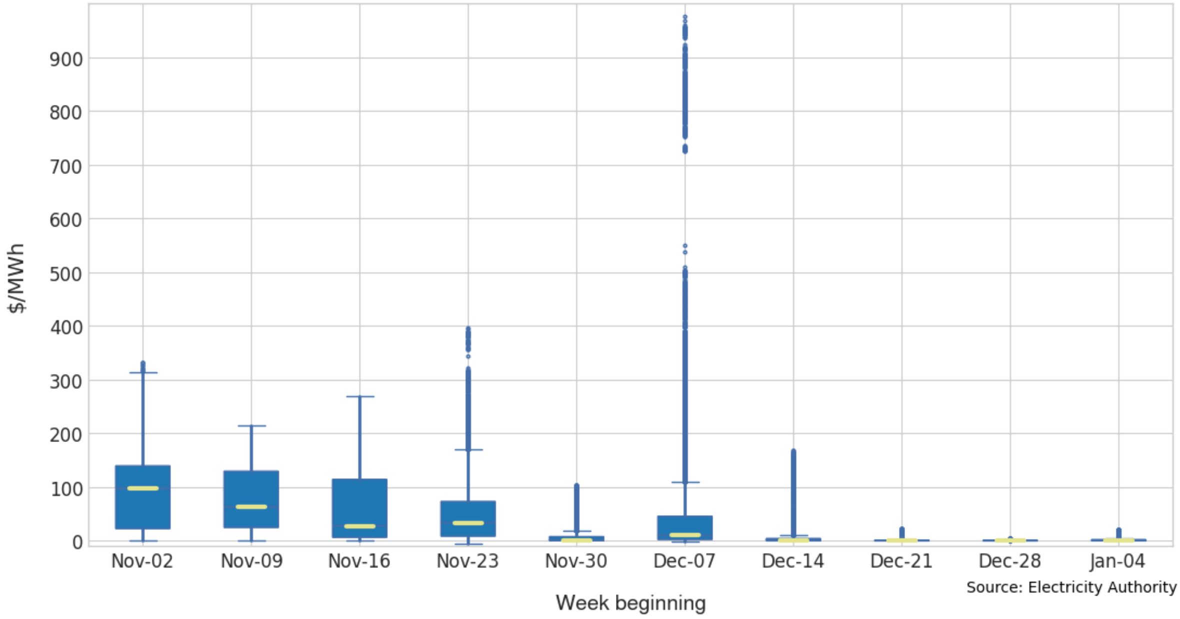
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 4-10 January



2.6. 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.

2.7. The distribution of spot prices this week was slightly wider compared to last week. The median price was $1/MWh and most prices (middle 50%) fell between $0.01/MWh and $2/MWh.

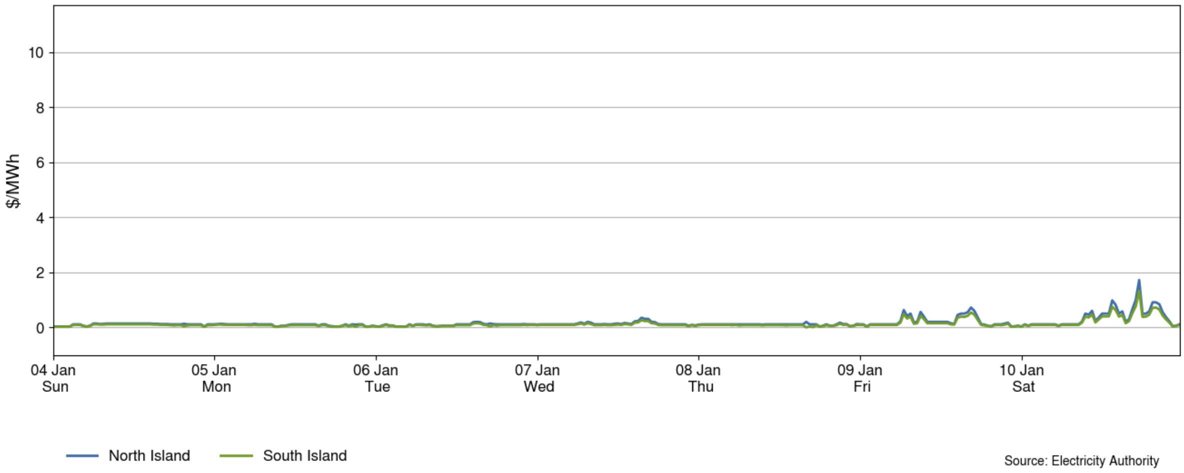
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

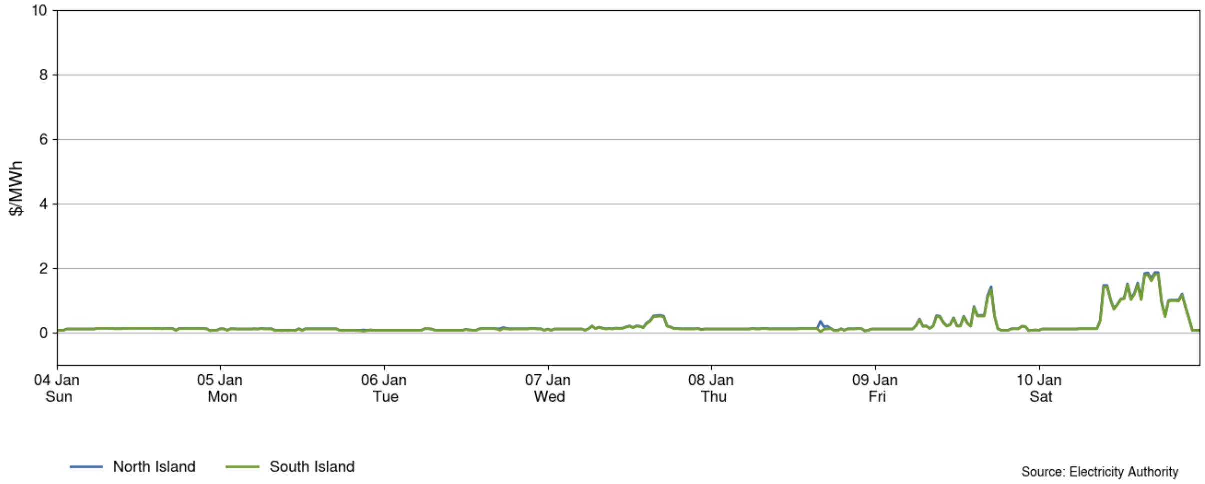
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices across both the North and South Islands remained below $2/MWh this week.

Figure 3: Fast instantaneous reserve price by trading period and island, 4-10 January



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices across both the North and South Islands also remained below $2/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 4-10 January



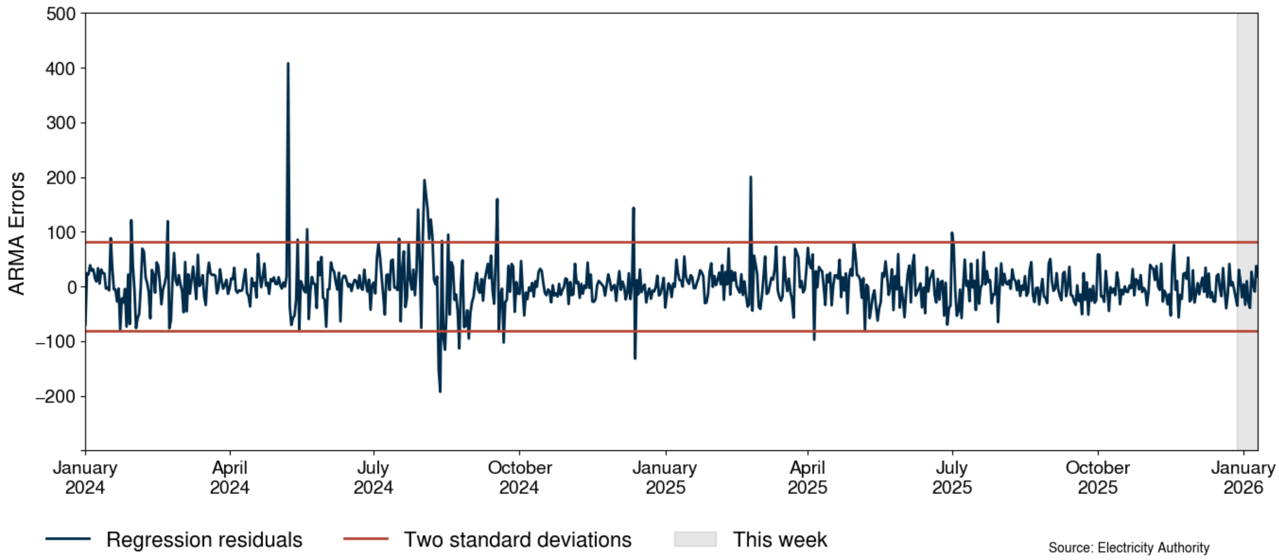
4. Regression residuals

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 - 10 January 2026

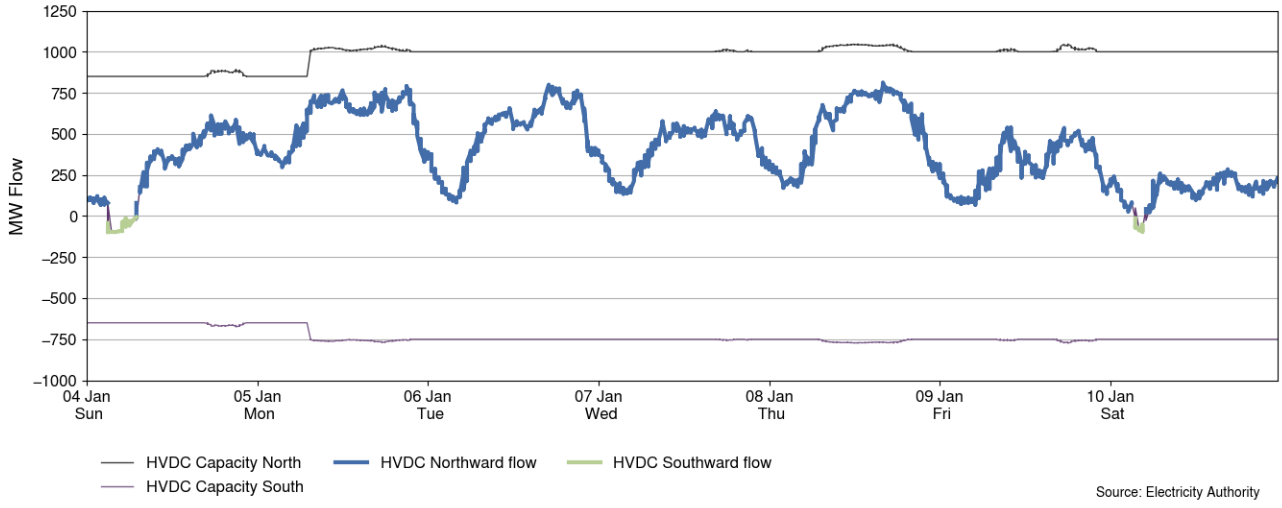


5. HVDC

5.1. Figure 6 shows the HVDC flow between 4-10 January. HVDC flows were mostly northward, with periods of southward flow overnight on Sunday and Saturday.

5.2. The highest northward flow occurred at 4.00pm on Thursday with a flow of around 813MW.

Figure 6: HVDC flow and capacity, 4-10 January



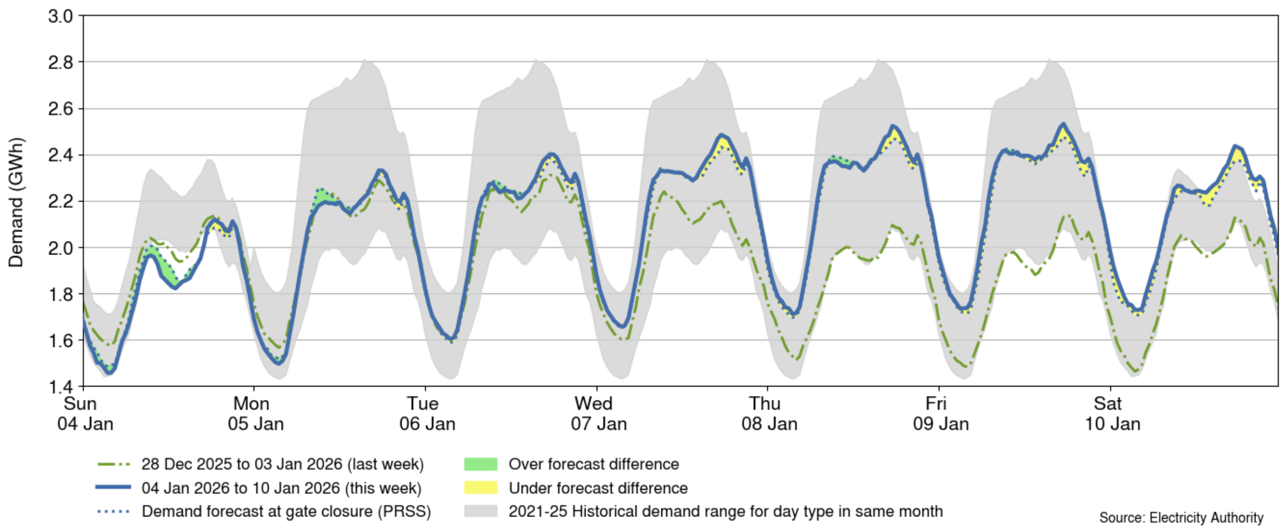
6. Demand

6.1. Figure 7 shows national demand between 4-10 January, compared to the historic range and the demand of the previous week.

6.2. Demand was higher overall compared to last week, increasing from Tuesday onwards likely due to the holiday period ending. On Sunday, demand was often lower than the historic demand range, while on Saturday, demand was often higher than the historic demand range.

6.3. The highest demand of the week was around 2.53GWh at 5.30pm on Friday.

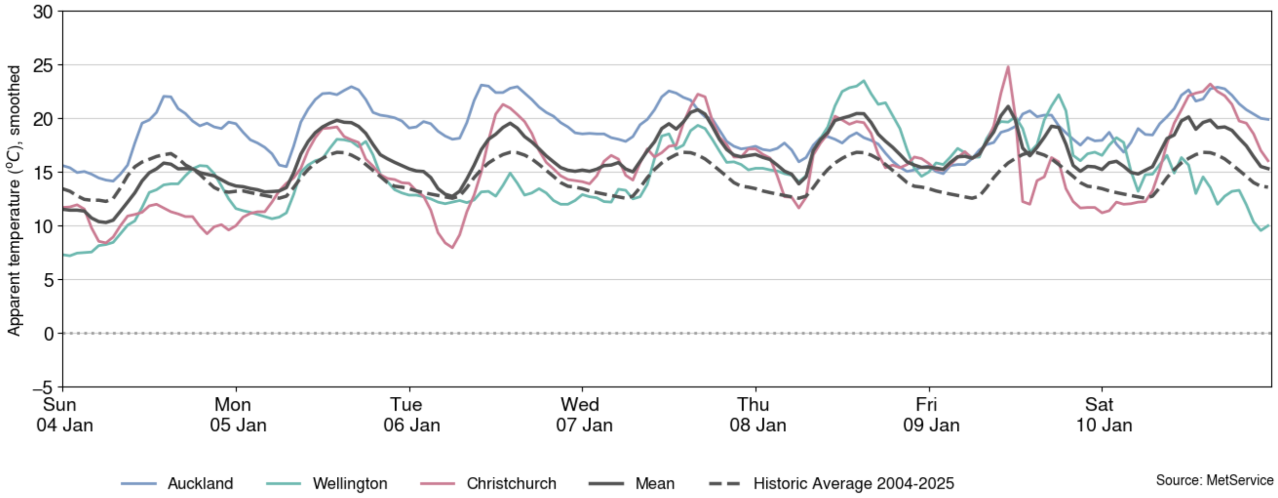
Figure 7: National demand, 4-10 January compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 4-10 January. 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 14°C to 23°C in Auckland, 7°C to 24°C in Wellington, and 8°C to 26°C in Christchurch.

Figure 8: Temperatures across main centres, 4-10 January

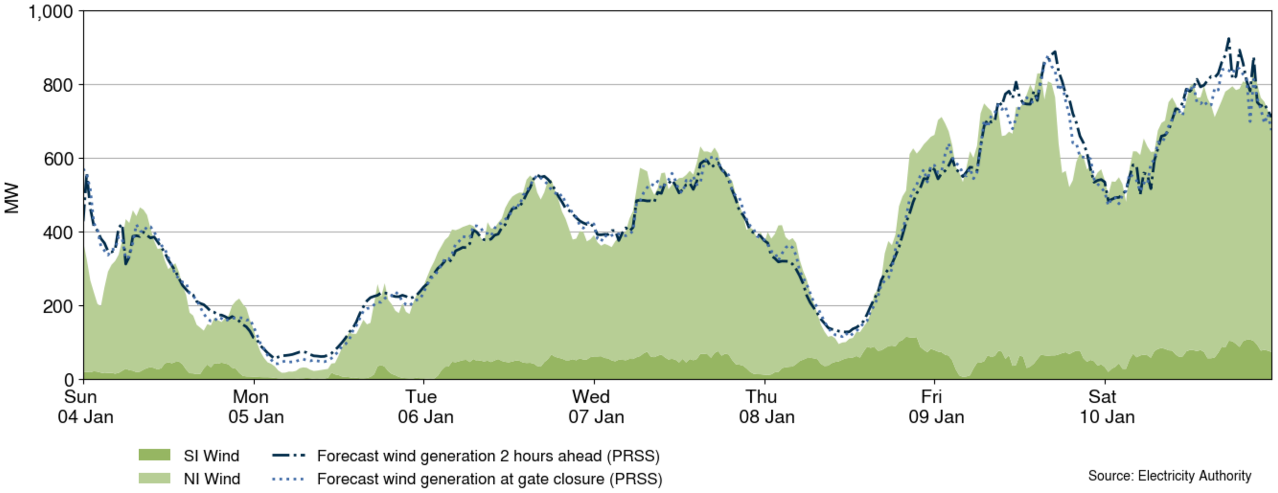


7. Generation

7.1. Figure 9 shows wind generation and forecast from 4-10 January. This week wind generation varied between 17MW and 853MW, with a weekly average of 428MW.

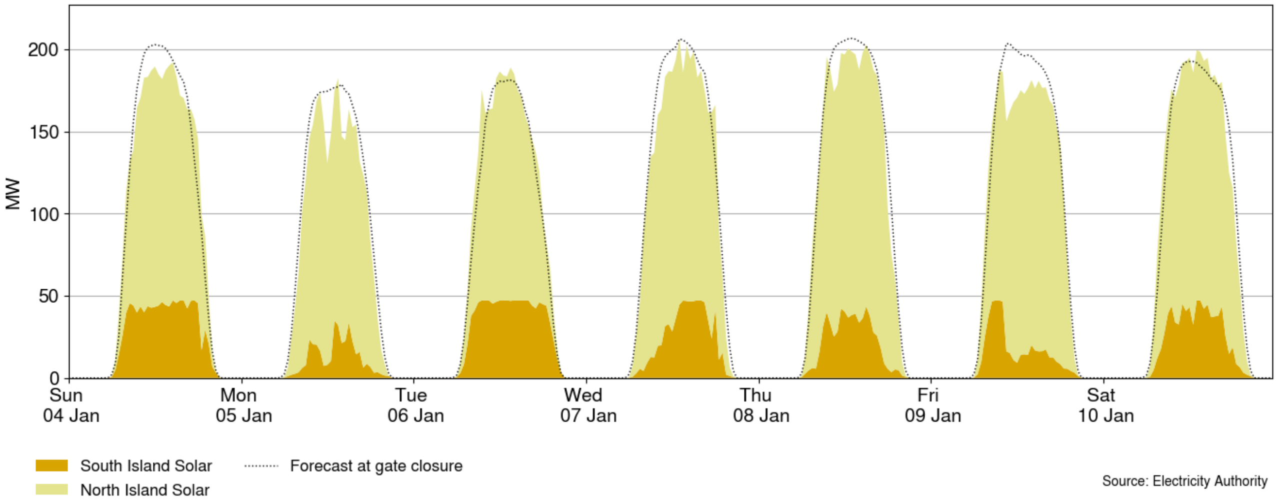
7.2. Wind generation was lowest on Monday and highest on Friday and Saturday. Wind forecasting errors on Sunday and Friday were an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 4-10 January



7.3. Figure 10 shows grid connected solar generation from 4-10 January. Solar generation reached above 180MW daily, peaking on Wednesday at 1.00pm at around 207MW.

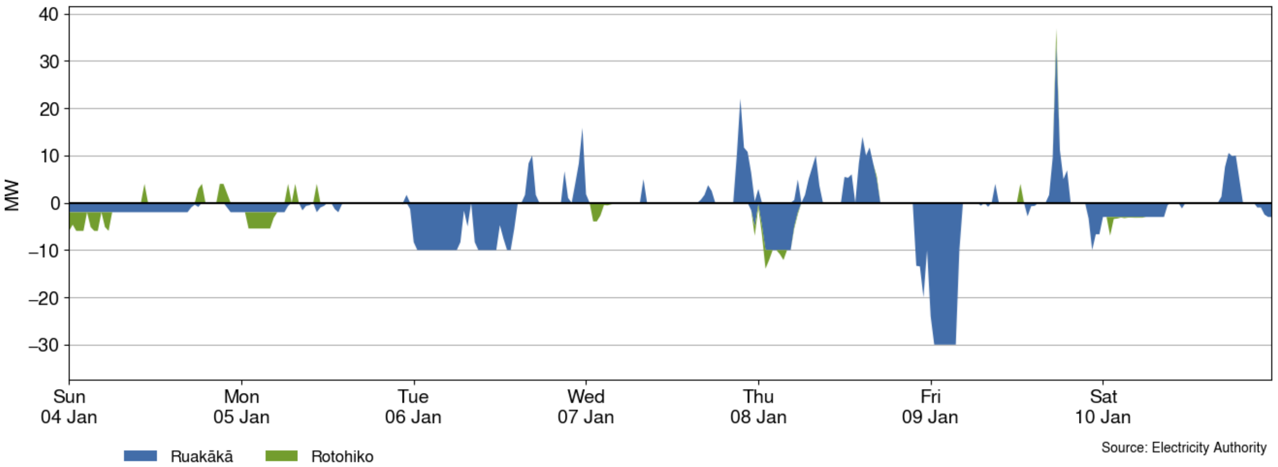
Figure 10: Grid connected solar generation, 4-10 January



7.4. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (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.

7.5. On Sunday and Monday, the batteries were mostly charging, likely to maintain a sufficient state of charge to offer reserves while prices were low. From Tuesday onwards, the batteries were mostly discharging at some point during the day and charging overnight.

Figure 11: Grid scale battery charge and discharge, 4-10 January



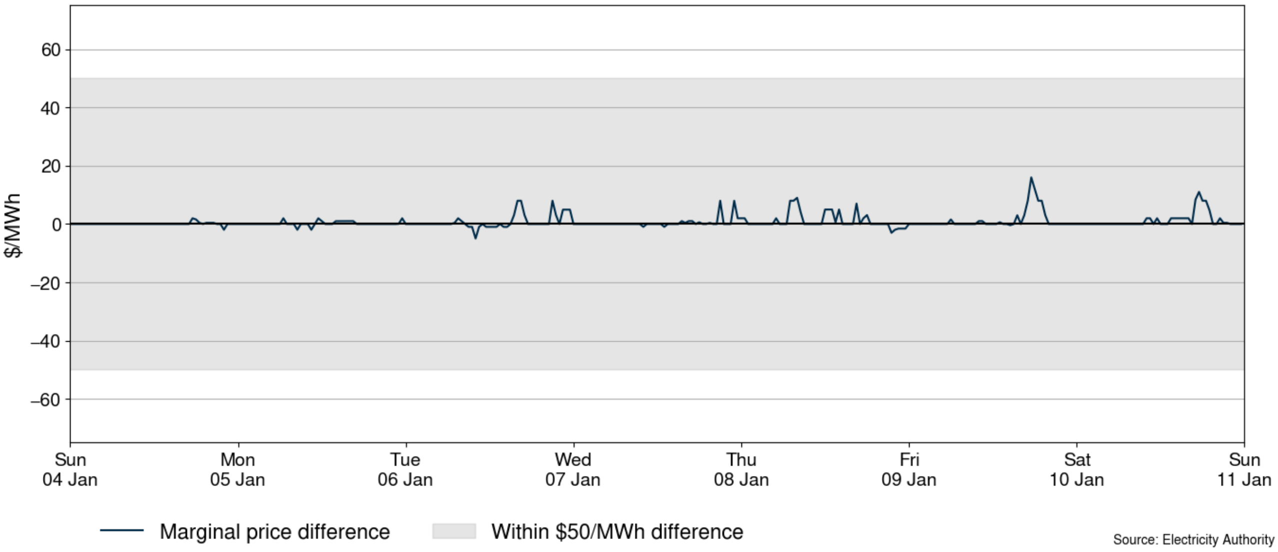
7.6. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or intermittent generation is over forecast. When the difference is negative, the opposite is

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

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.

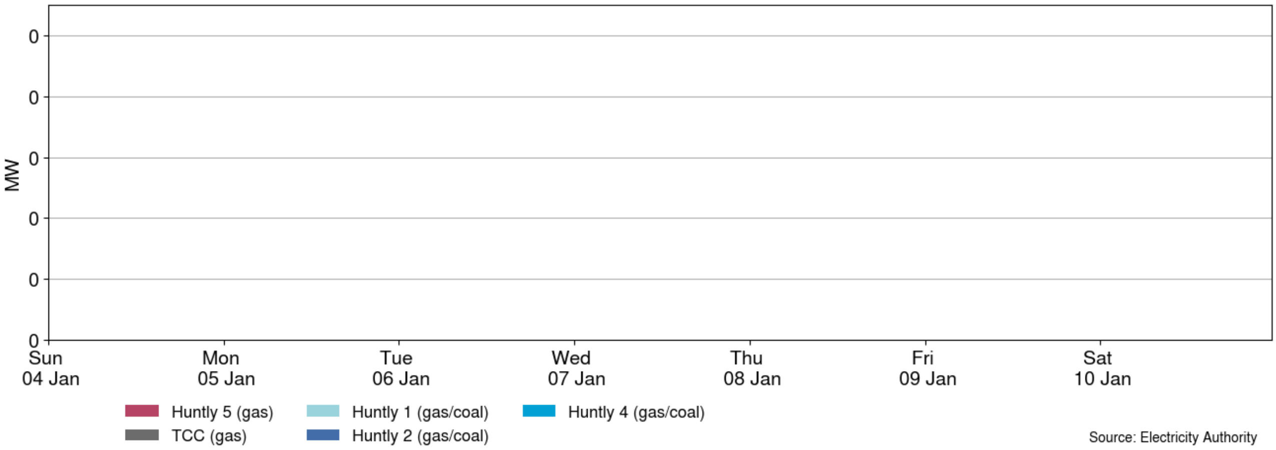
7.7. No trading periods this week had a marginal price difference above or below $50/MWh.

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, 4-10 January



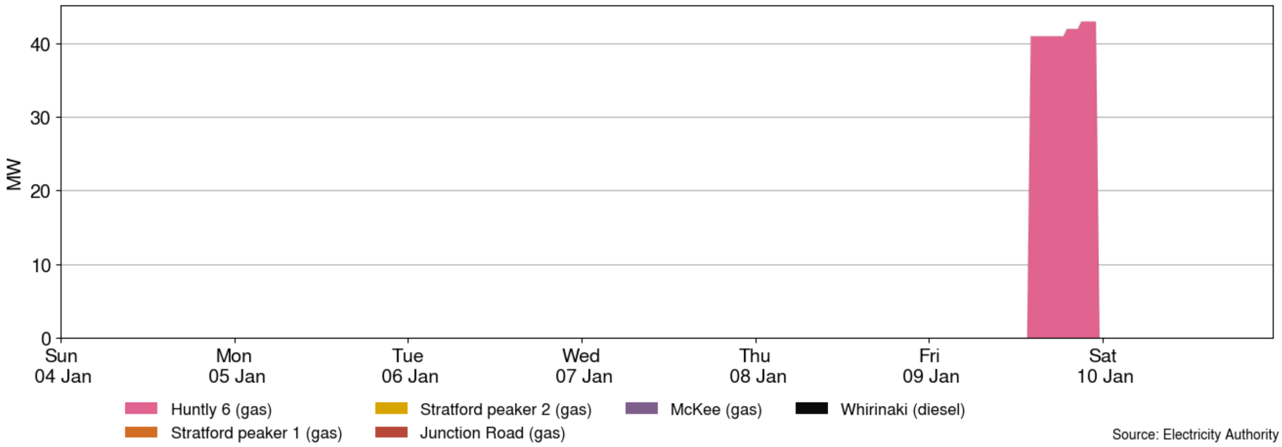
7.8. Figure 13 shows the generation of thermal baseload between 4-10 January. No thermal baseload ran this week.

Figure 13: Thermal baseload generation, 4-10 January



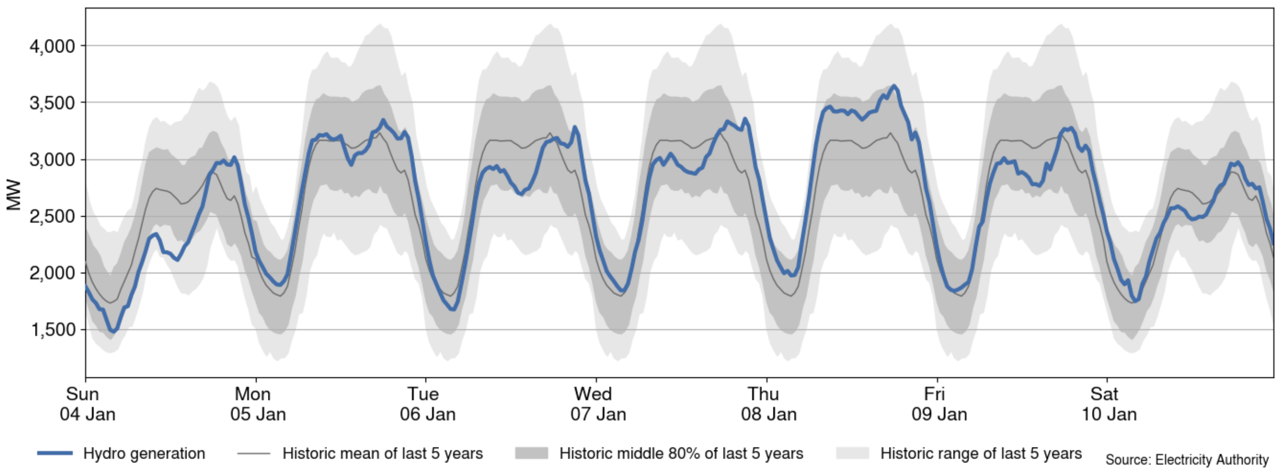
7.9. Figure 14 shows the generation of thermal peaker plants between 4-10 January. Huntly 6 ran between 2.00pm and 11.00pm on Friday, with intermittent generation declining during this time. No other thermal peaker generation ran during this week.

Figure 14: Thermal peaker generation, 4-10 January



7.10. Figure 15 shows hydro generation between 4-10 January. Hydro generation was close to or below the historic mean every day this week, aside from Thursday where a drop in wind resulted in higher hydro generation.

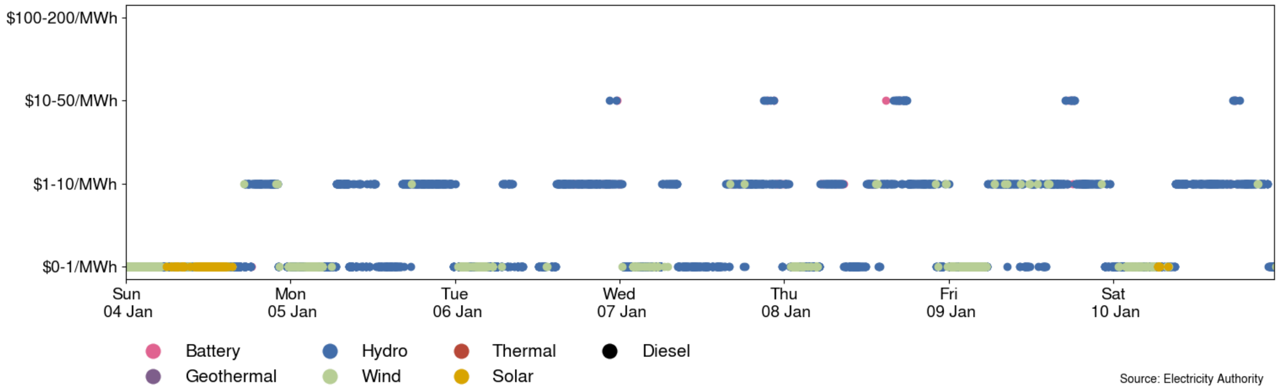
Figure 15: Hydro generation, 4-10 January



7.11. 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.

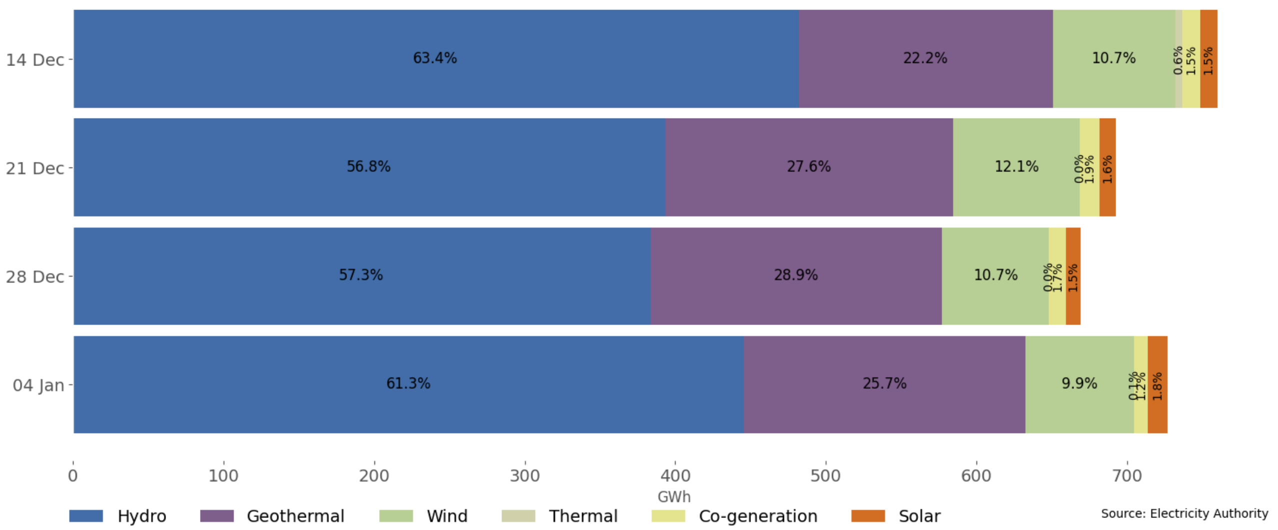
7.12. The highest prices this week were caused by Contact and Mercury hydro as well as the Ruakākā battery. The most common technology setting prices this week was hydro generation, with wind generation the most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 4-10 January



7.13. As a percentage of total generation, between 4-10 January, total weekly hydro generation was 61.3%, geothermal 25.7%, wind 9.9%, thermal 0.1%, co-generation 1.2%, and solar (grid connected) 1.8%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 14 December and 10 January



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 4-10 January ranged between ~1,559MW and ~2,695MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 4-10 January

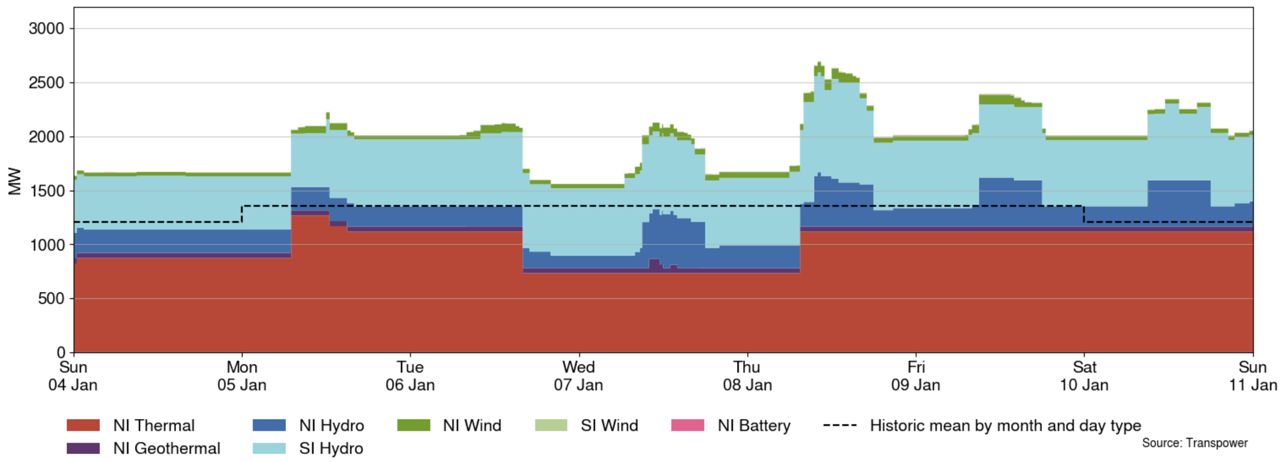
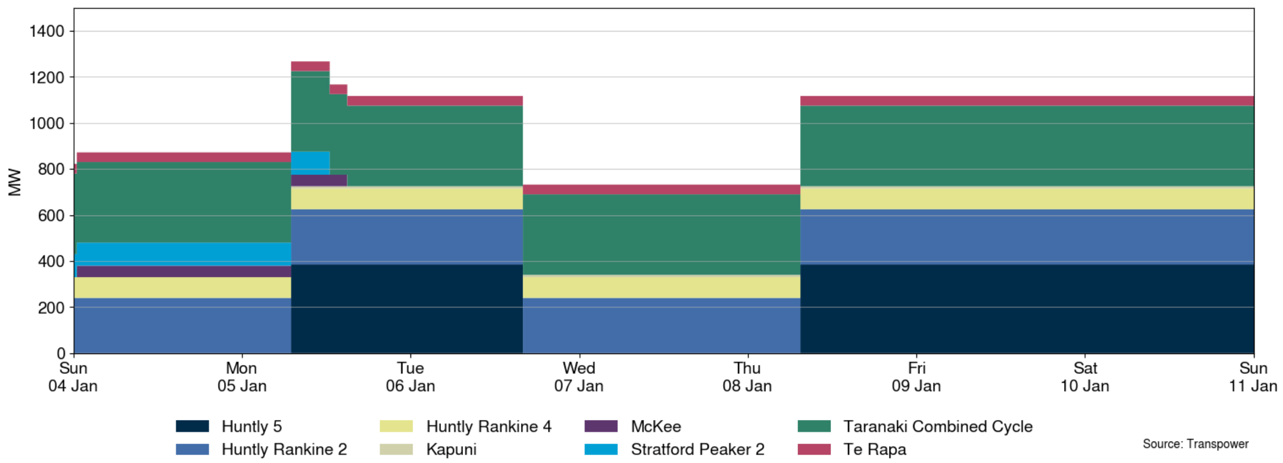


Figure 19: Total MW loss from thermal outages, 4-10 January



8.2. Notable outages include:

Plant	Partial or Full	End Date
Stratford Peaker 2	Full	5 January 2026
Huntly 5	Full	13 January 2026
Ōhau C	Partial	16 January 2026
Huntly 4	Partial	31 January 2026
Ōhau A	Partial	18 February 2026
Roxburgh unit 5	Full	11 March 2026
Rangipō unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Manapōuri unit 4	Full	12 June 2026
TCC[2]	Full	31 December 2027

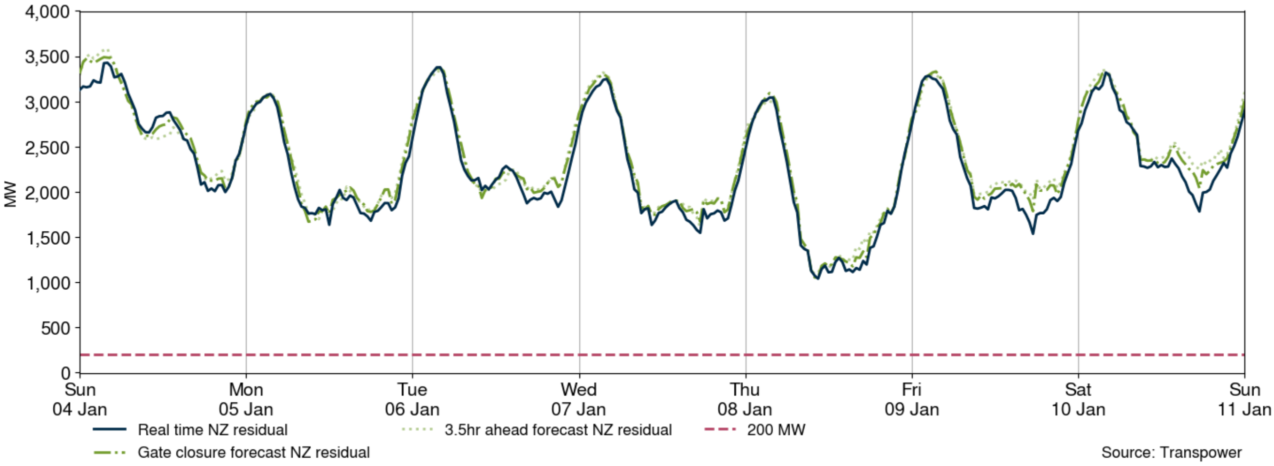
[2] This outage reflects Contact's intention to decommission TCC.

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 4-10 January. 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 1,039MW on Thursday at 10.30am.

Figure 20: National generation balance residuals, 4-10 January



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. As of 10 January, national controlled storage increased slightly to 98% nominally full and ~125% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (103% full[3]) is above its historic 90th percentile, while Lake Takapō (99% full) is below its historic 90th percentile. Lake Pūkaki has exceed its storage capacity and is spilling.

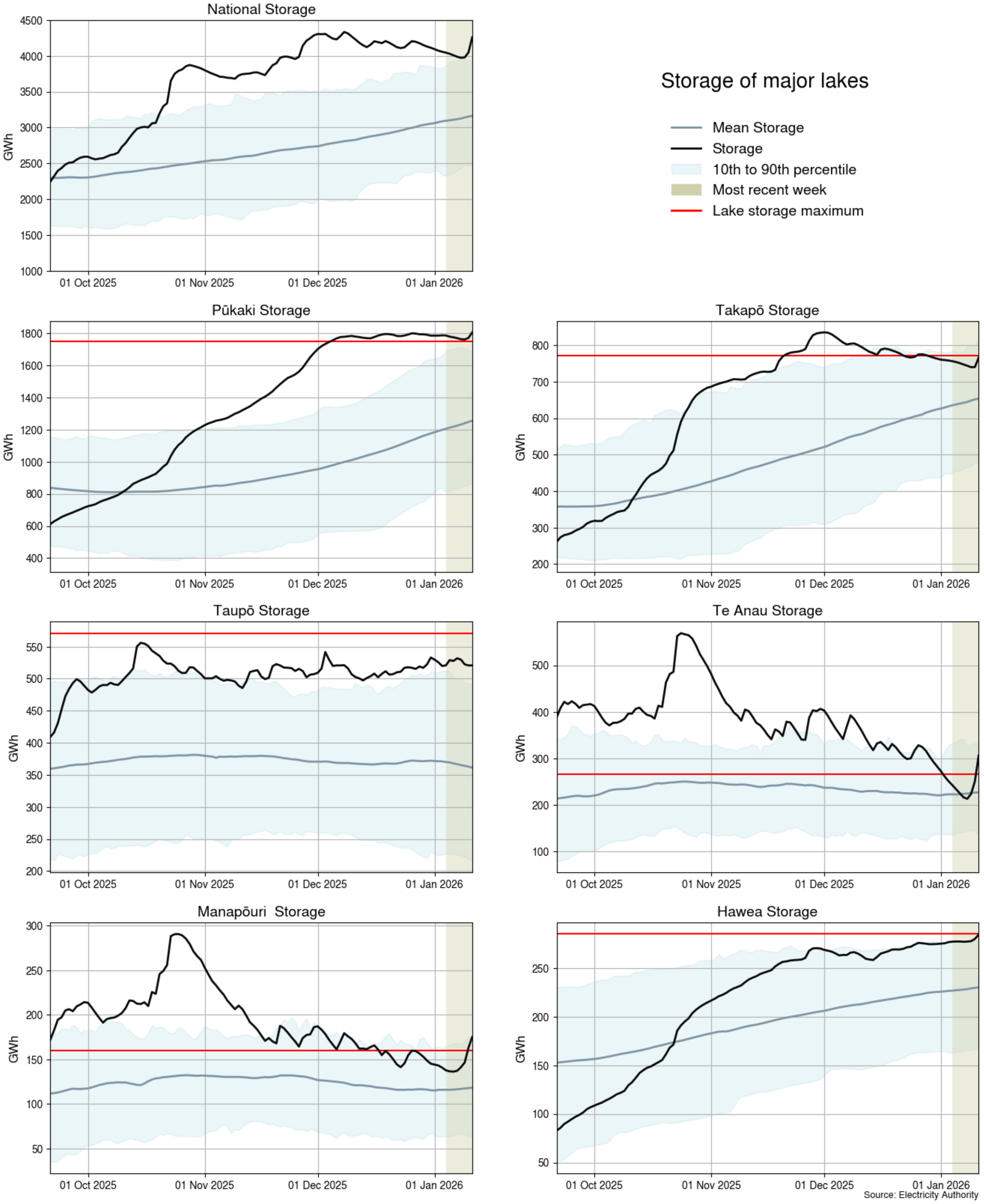
10.4. Storage at Lake Te Anau (115% full) is below its historic 90th percentile but is above its historic mean, with Lake Manapōuri (111% full) just below its historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (91% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (100% full) is close to its historic 90th percentile.

[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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 January 2026. The SRMCs for gas-powered generation have decreased, while the SRMCs for coal- and diesel-fuelled generation has remained stable.

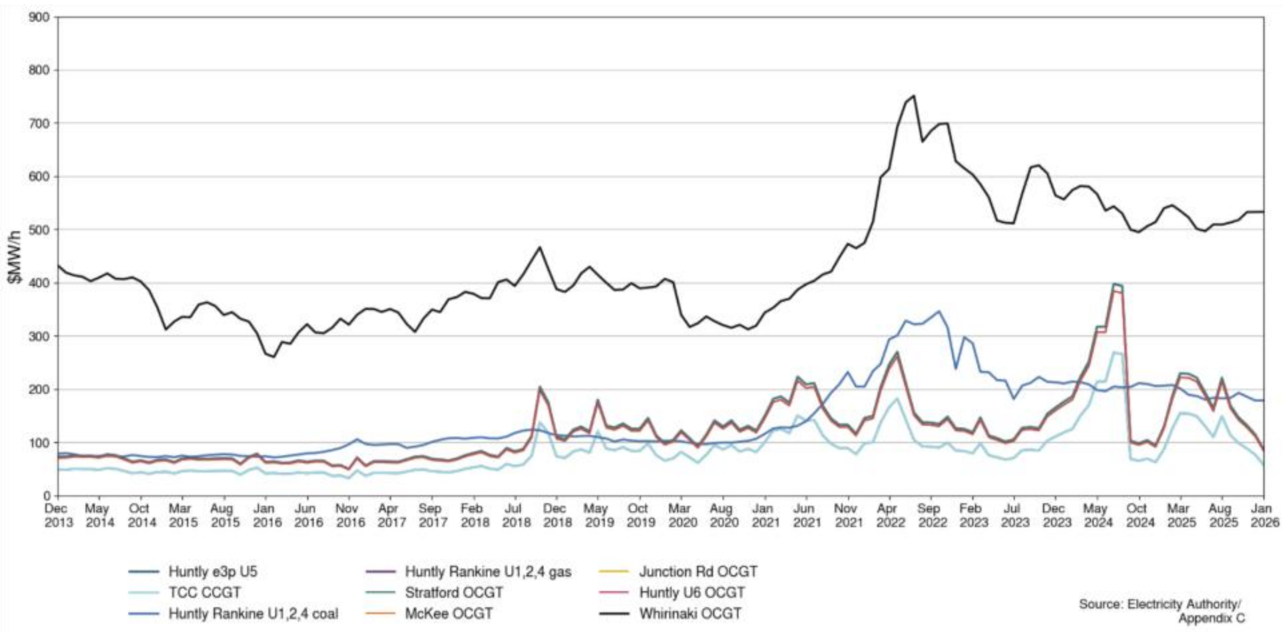
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$178/MWh. The cost of running the Rankines on gas is ~$86/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $57/MWh and $86/MWh.

11.6. The SRMC of Whirinaki is ~$533/MWh.

11.7. 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

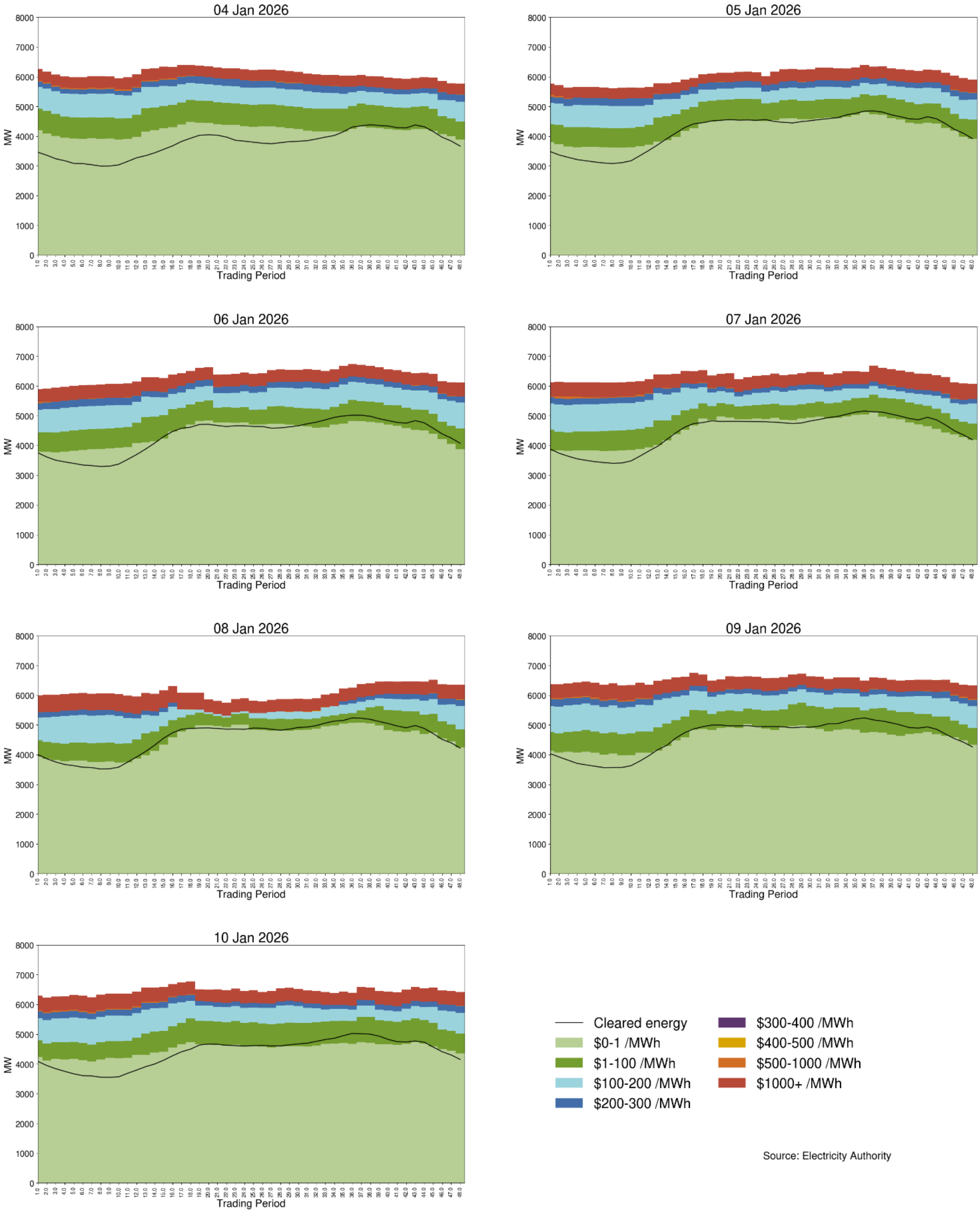


12. Offer behaviour

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, all offers cleared below $100/MWh. Offers between $200-300/MWh disappeared from the offer stack between 8.00am and 5.00pm on Thursday due to a planned Clyde unit 2 outage.

Figure 23: Daily offer stacks

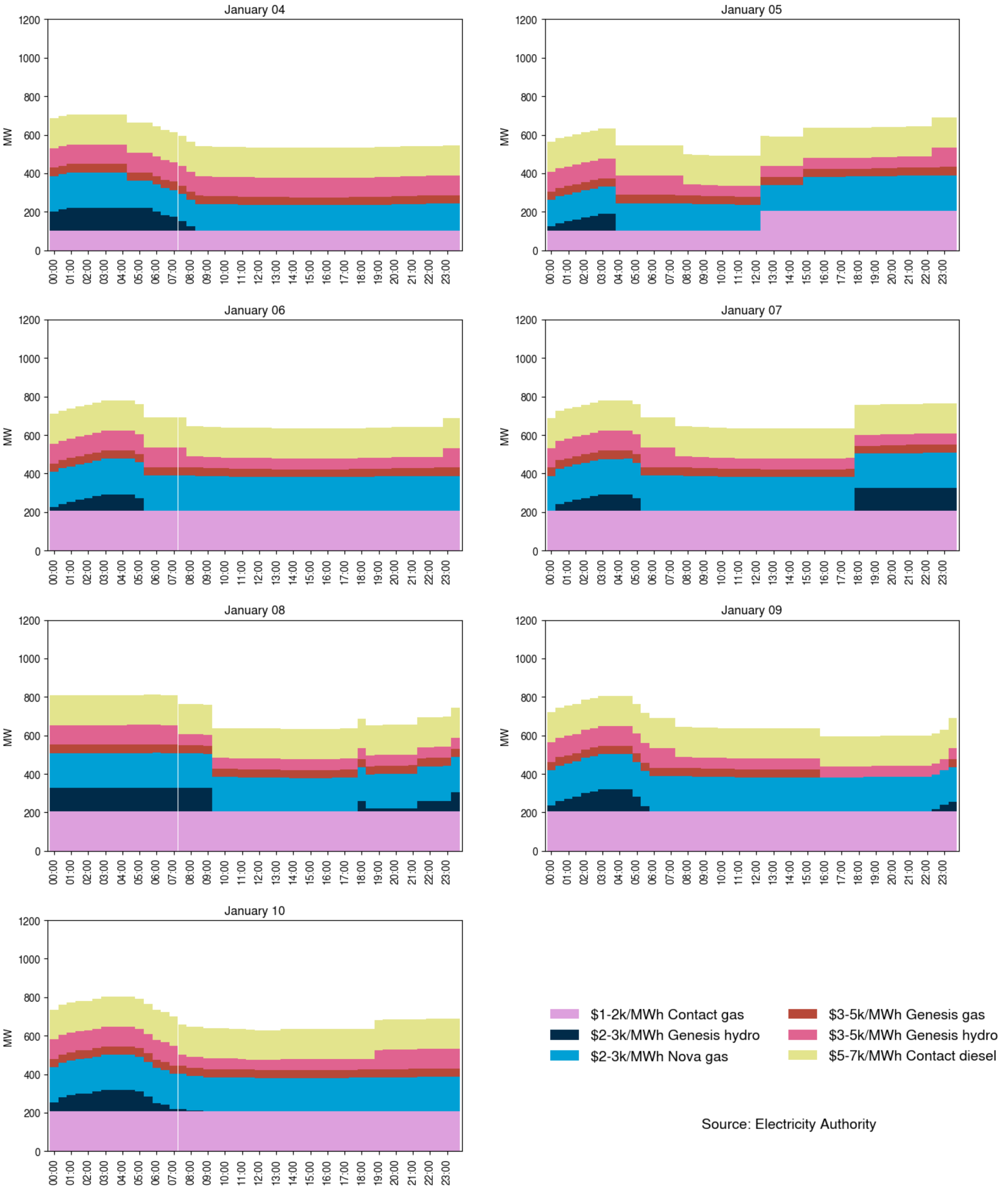


12.3. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 658MW per trading period was priced above $1,000/MWh this week, which is roughly 13% of the total energy available.

Figure 24: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

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

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
27/11/2025	27	Further analysis	Contact	Roxburgh	Offers
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
10/12/2025-20/12/2025	Several	Further analysis	Genesis	Tekapo	Offers
9/12/2025	36-48	Further analysis	Genesis	Huntly	Offers
24/12/2025-4/1/2026	Several	Further analysis	Contact	Clutha scheme	Generation