5 January 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 21 December 2025 - 3 January 2026

Market monitoring weekly report

Trading conduct report 21 December 2025 - 3 January 2026

1. Overview

1.1. Spot prices were low this fortnight with an average spot price of $1/MWh, mostly due to lower demand during the holiday period and high hydro storage. The proportion of geothermal and wind generation increased compared to the previous fortnight, while the proportion of hydro and thermal generation decreased. National hydro storage decreased to 97% nominally full and ~134% of the historical 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 21 December 2025 - 3 January 2026:

(a) The average spot price was $1/MWh, a decrease of around $6/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $7/MWh.

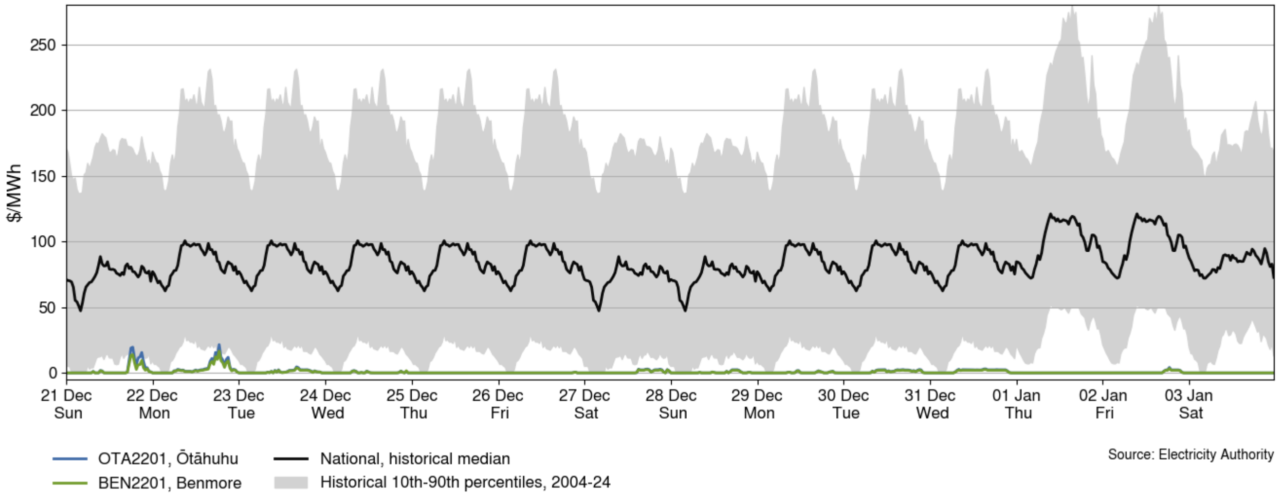
(c) These low prices were driven by high hydro storage and lower demand during the holiday period.

2.3. The highest Ōtāhuhu price was $22/MWh on Monday 22 December at 6.30pm. At this time demand was 31MW higher than forecast and wind was 55MW lower than forecast.

2.4. Prices also spiked to around $20/MWh on Sunday 21 December between 6.00pm-6.30pm following trips at Tauhara and TOPP2.

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. 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.

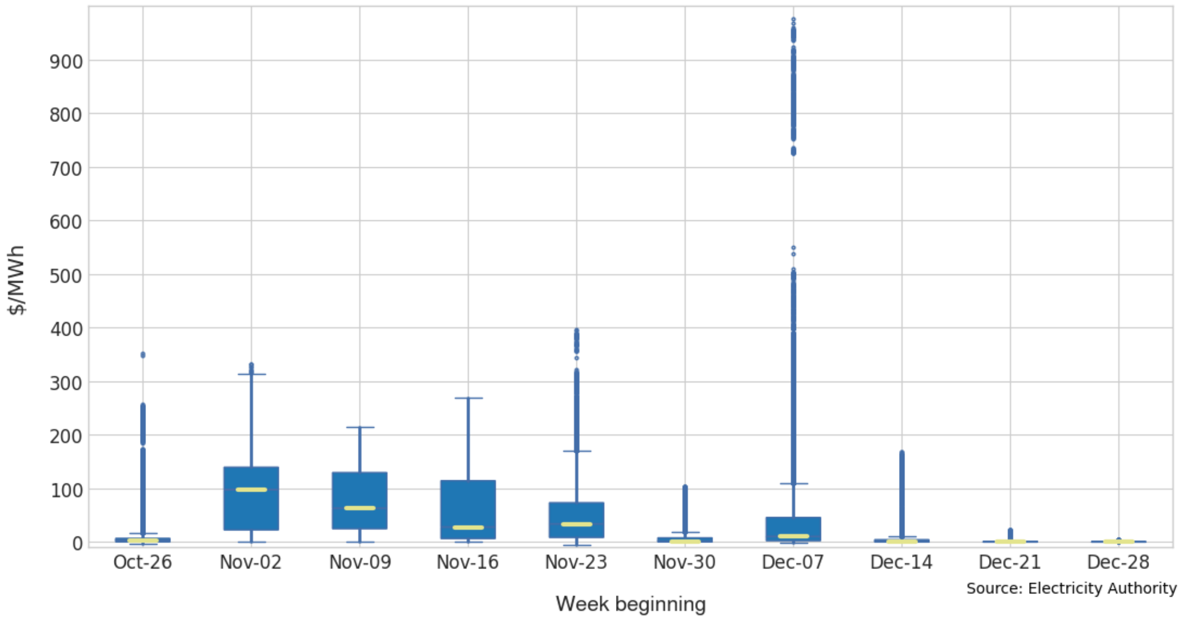
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 21 December 2025 - 3 January 2026



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 for the last two weeks was narrower compared to previous weeks. The median price for the week beginning 21 December was $0.02/MWh and most prices (middle 50%) fell between $0.01/MWh and $1/MWh. The median price for the week beginning 28 December decreased to $0.01/MWh, with most prices (middle 50%) falling between $0.01/MWh and $0.64/MWh.

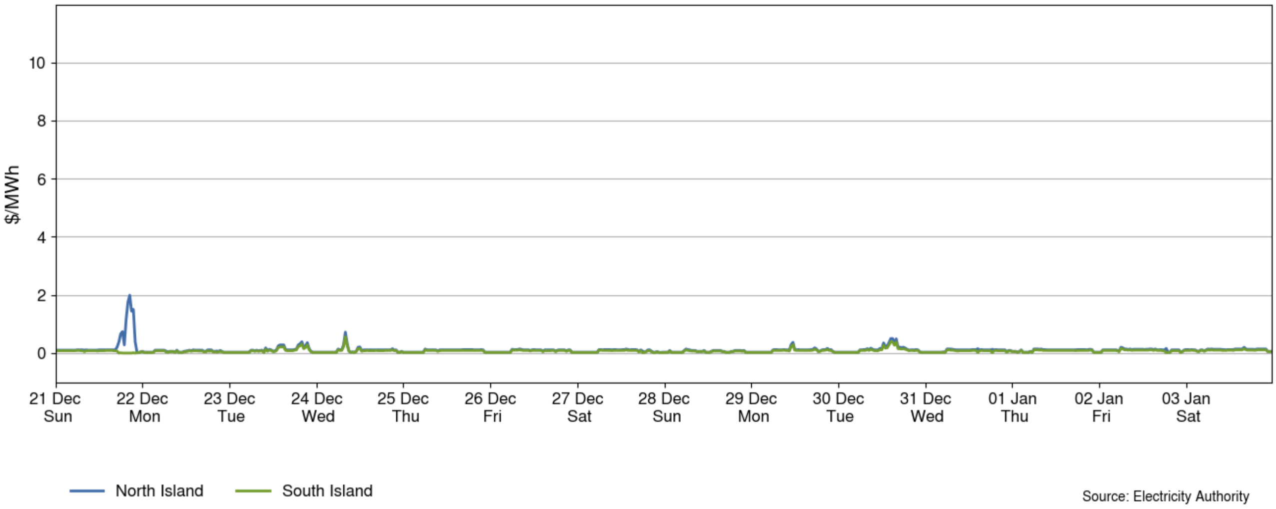
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

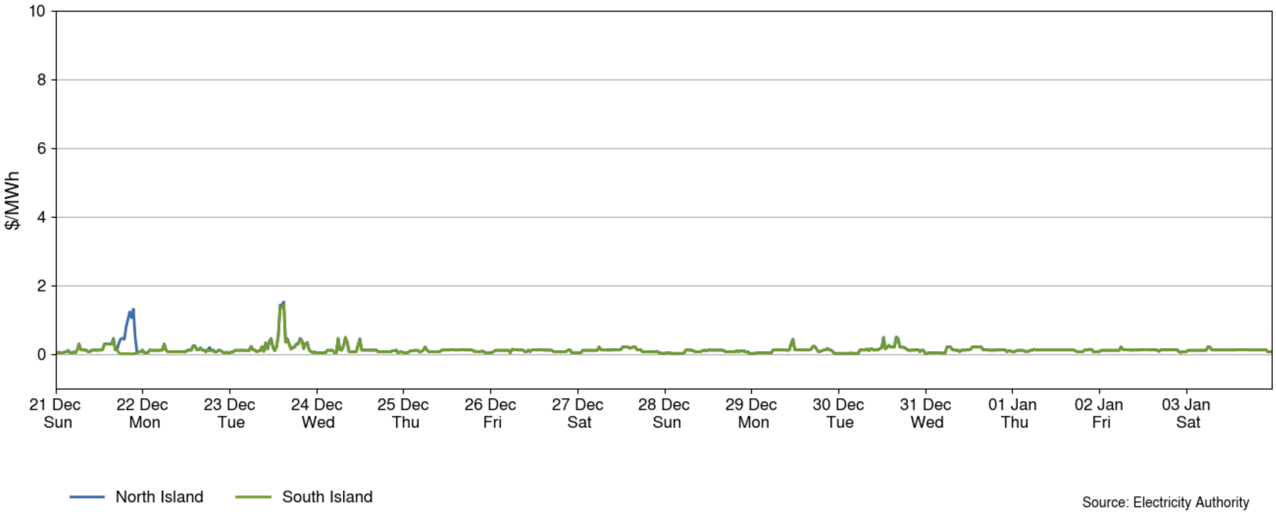
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices across both the North and South Islands were below $2/MWh during this period.

Figure 3: Fast instantaneous reserve price by trading period and island, 21 December 2025 - 3 January 2026



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 were also below $2/MWh during this period.

Figure 4: Sustained instantaneous reserve by trading period and island, 21 December 2025 - 3 January 2026



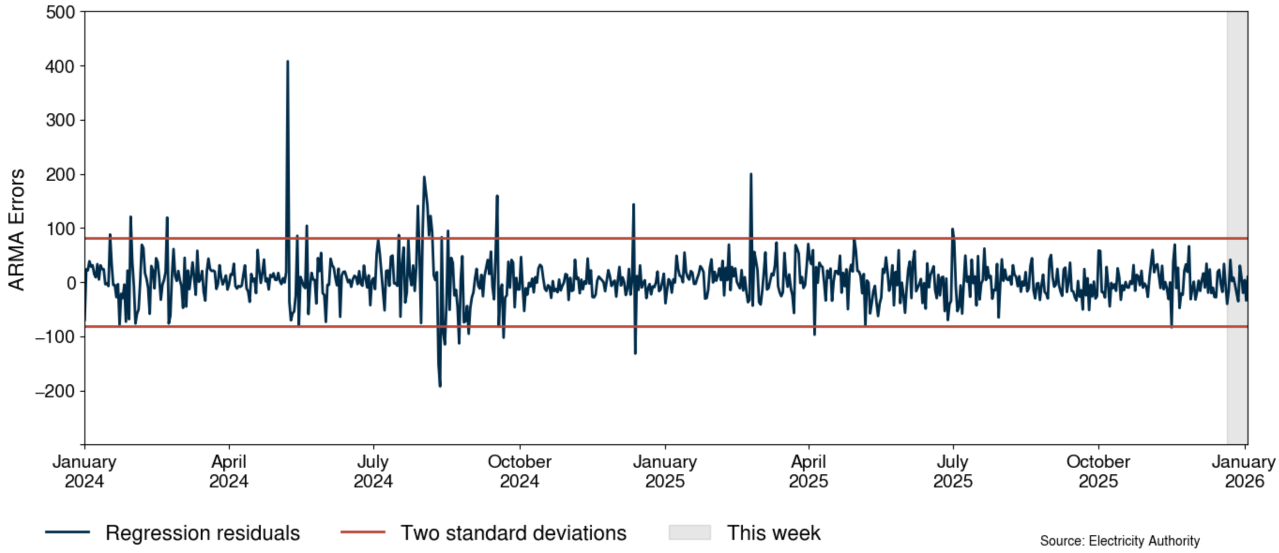
4. Regression residuals

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. During this period, there were no residuals above or below two standard deviations, indicating that prices were similar to those predicted by the model.

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

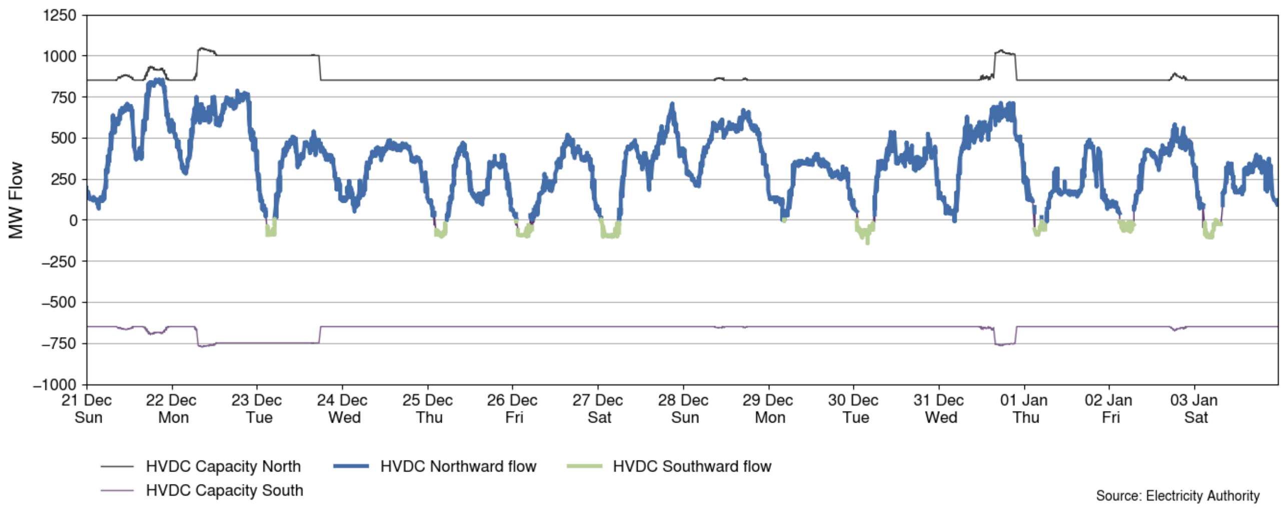


5. HVDC

5.1. Figure 6 shows the HVDC flow between 21 December 2025 - 3 January 2026. HVDC flows were mostly northward, with periods of southward flow overnight at times.

5.2. The highest northward flow occurred at 8.30pm on Sunday 21 December with a flow of around 855MW.

Figure 6: HVDC flow and capacity, 21 December 2025 - 3 January 2026

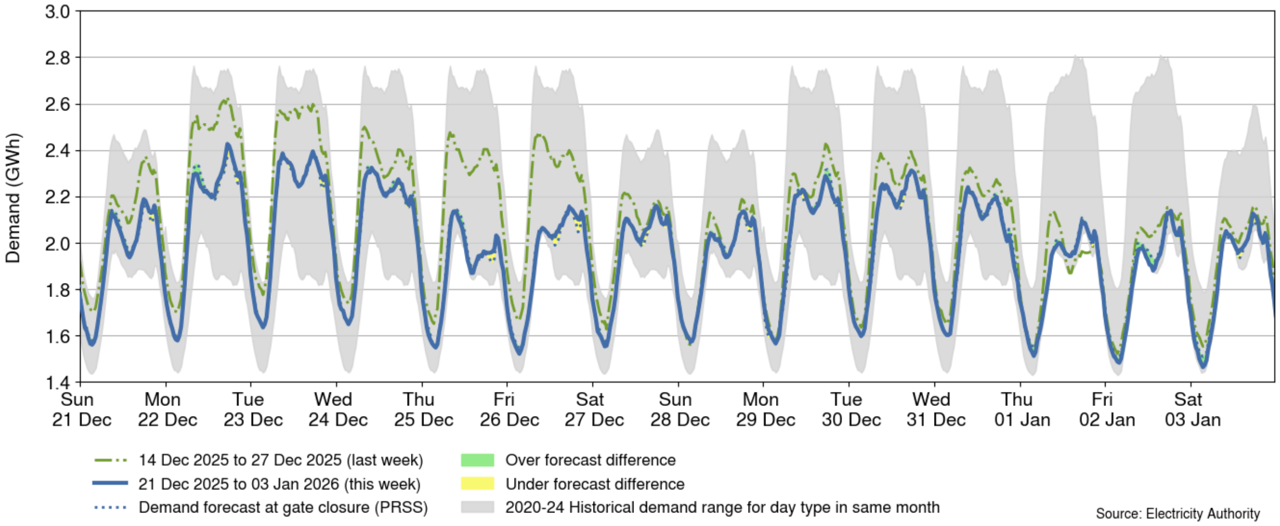


6. Demand

6.1. Figure 7 shows national demand between 21 December 2025 - 3 January 2026, compared to the historic range and the demand of the previous week.

6.2. Demand was generally low due to the holiday period, declining sharply from Thursday 25 December. The highest demand of this period was around 2.43GWh at 5.30pm on Monday 22 December.

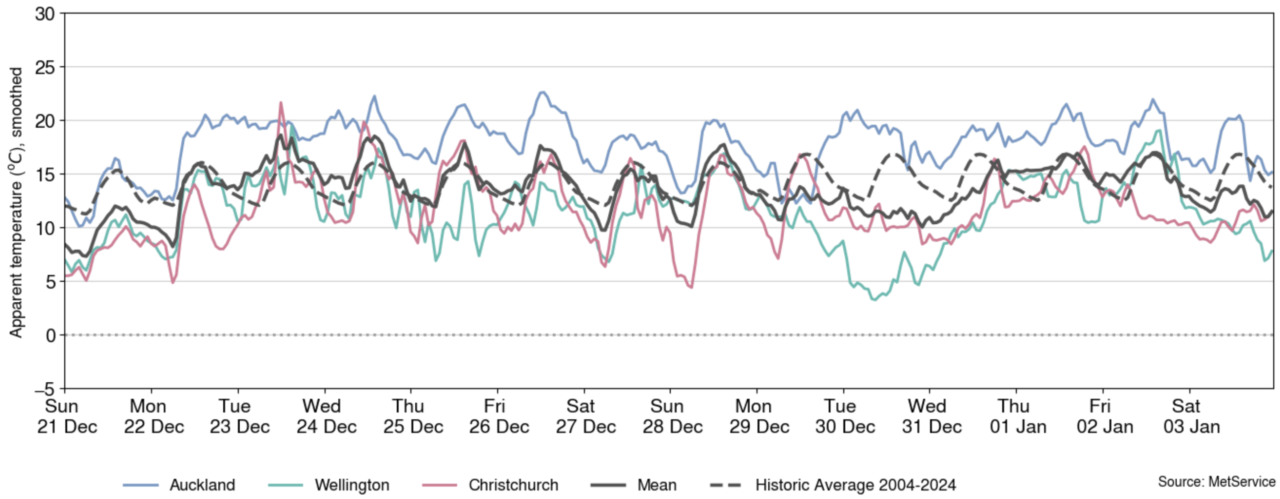
Figure 7: National demand, 21 December 2025 - 3 January 2026 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 21 December 2025 - 3 January 2026. 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.

6.4. Apparent temperatures ranged from 10°C to 23°C in Auckland, 2°C to 20°C in Wellington, and 4°C to 24°C in Christchurch.

Figure 8: Temperatures across main centres, 21 December 2025 - 3 January 2026



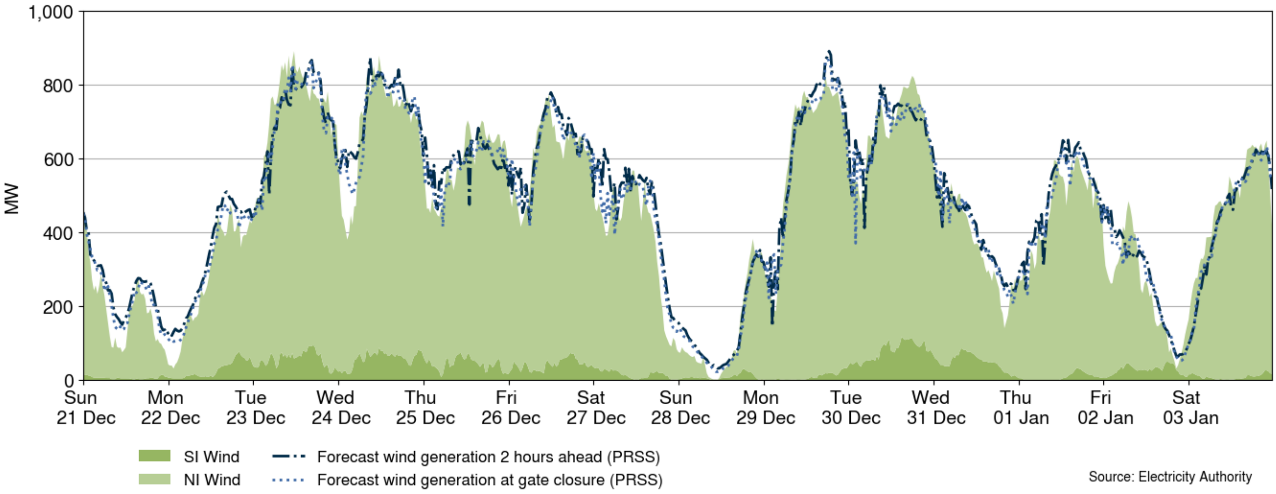
7. Generation

7.1. Figure 9 shows wind generation and forecast from 21 December 2025 - 3 January 2026. During this period, wind generation varied between 1MW and 891MW, with an overall average of 461MW.

7.2. Wind generation was generally high, mostly remaining above 400MW between 22-27 December and 29-31 December.

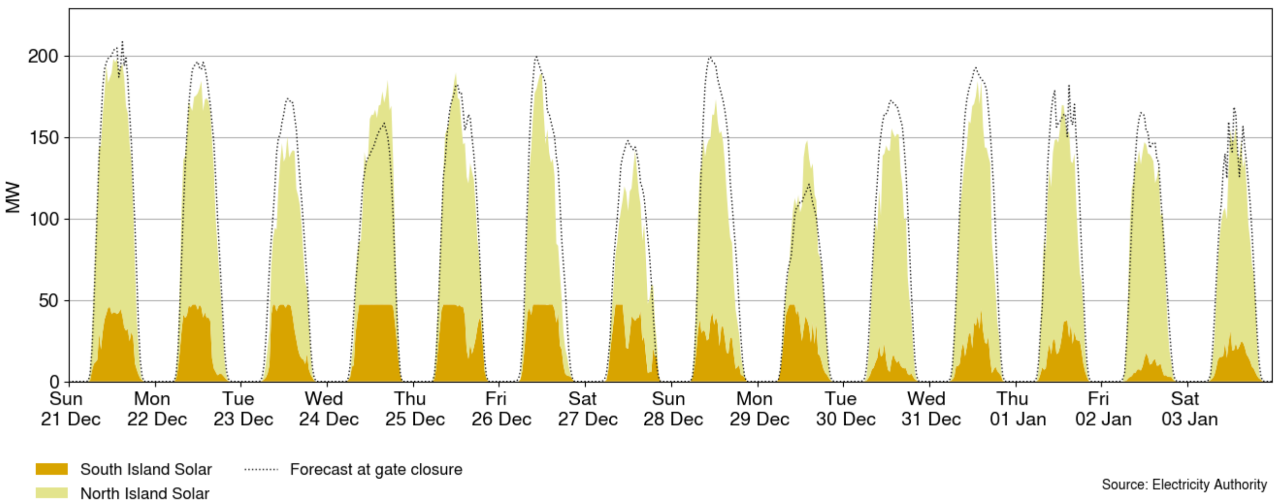
7.3. Wind generation was lowest on Sunday 21 December, Sunday 28 December and Friday 2 January. Wind forecasting errors on Wednesday 24 December and Friday 2 January mornings were an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 21 December 2025 - 3 January 2026



7.4. Figure 10 shows grid connected solar generation from 21 December 2025 - 3 January 2026. Solar generation reached above 140MW daily, peaking on Sunday 21 December at 12.30pm at around 198MW.

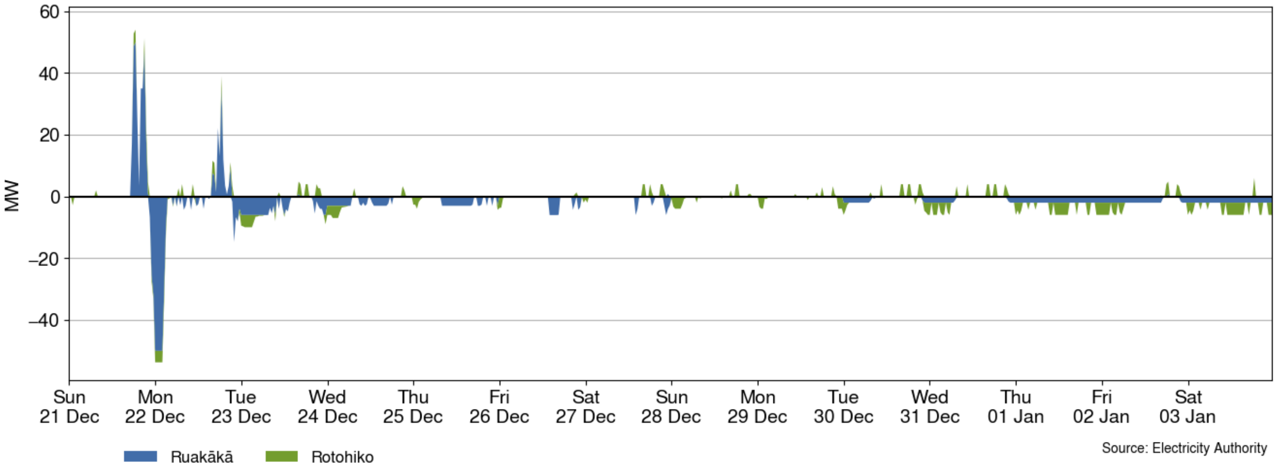
Figure 10: Grid connected solar generation, 21 December 2025 - 3 January 2026



7.5. 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.

7.6. During this period, the batteries mostly discharged at times of higher prices on the evenings of Sunday 21 December and Monday 22 December. Otherwise, the batteries were mostly charging during the holiday period while prices were low, likely to maintain a sufficient state of charge to offer reserves.

Figure 11: Grid scale battery charge and discharge, 21 December 2025 - 3 January 2026

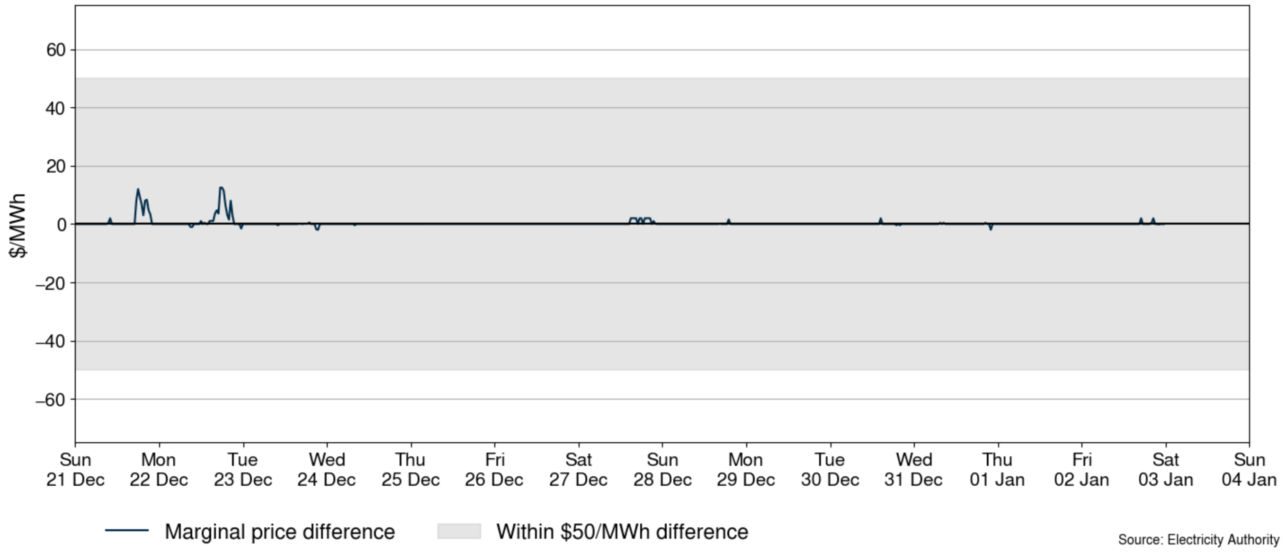


7.7. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing 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 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. No trading periods during this time had a marginal price difference above or below $50/MWh.

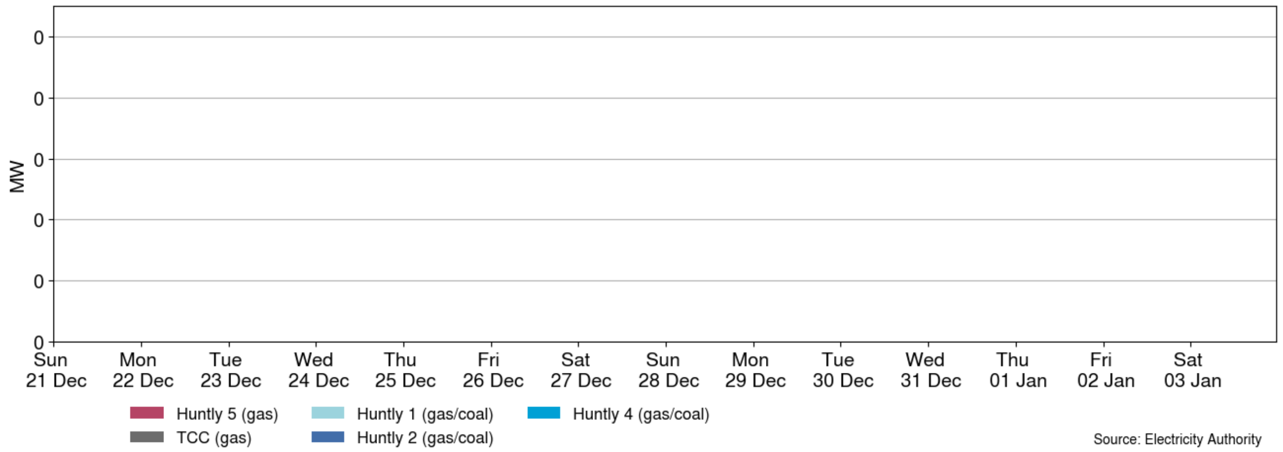
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 21 December 2025 - 3 January 2026



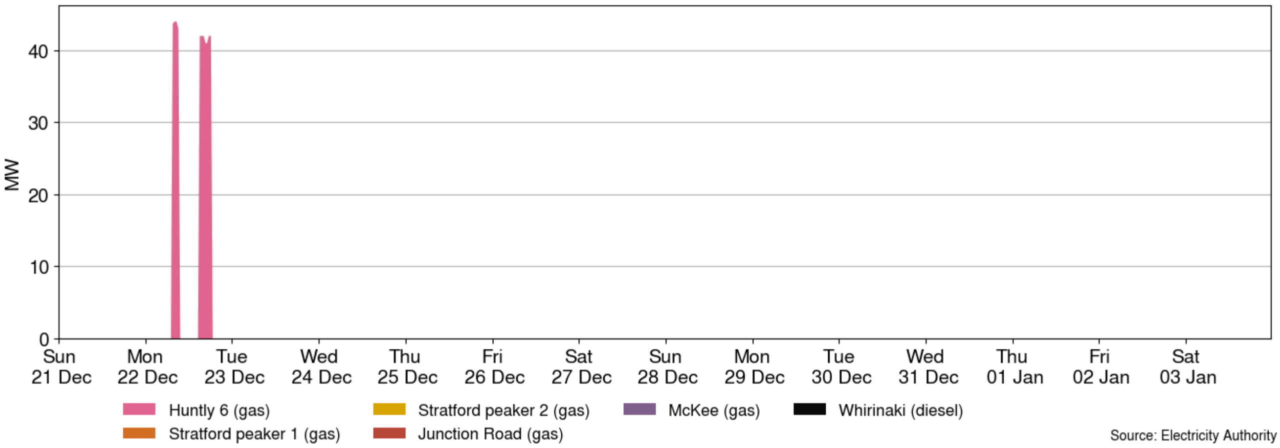
7.9. Figure 13 shows the generation of thermal baseload between 21 December 2025 - 3 January 2026. No thermal baseload generation ran during this time.

Figure 13: Thermal baseload generation, 21 December 2025 - 3 January 2026



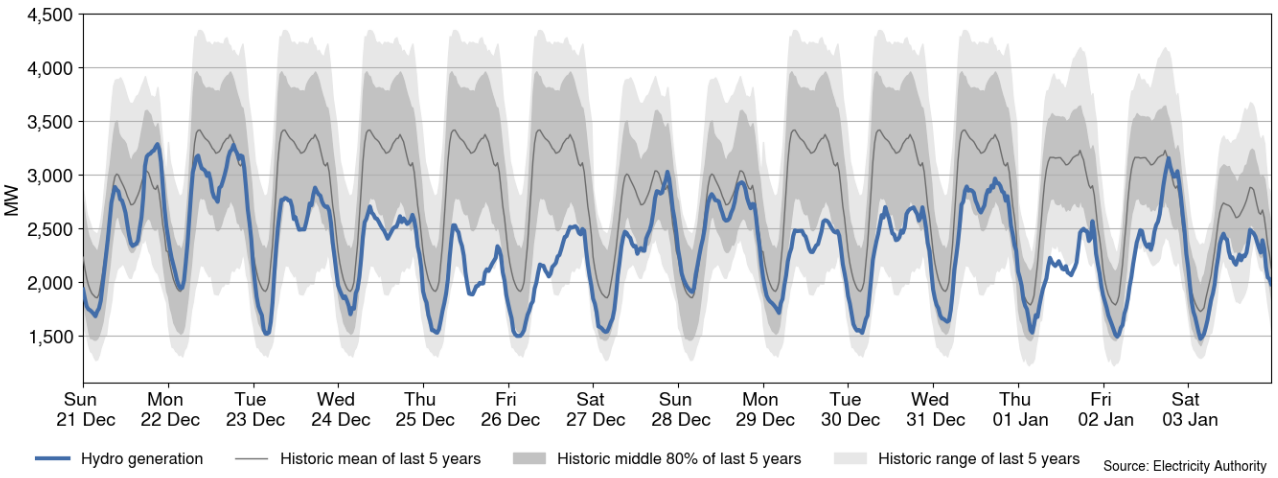
7.10. Figure 14 shows the generation of thermal peaker plants between 21 December 2025 - 3 January 2026. Huntly 6 ran during the morning and evening peak on Monday 22 December. No other thermal peaker generation ran during this period.

Figure 14: Thermal peaker generation, 21 December 2025 - 3 January 2026



7.11. Figure 15 shows hydro generation between 21 December 2025 - 3 January 2026. During this time, hydro generation fell from Monday 22 December and remained mostly low overall. Hydro generation increased above the historic mean on Friday 2 January when wind generation dropped below 150MW.

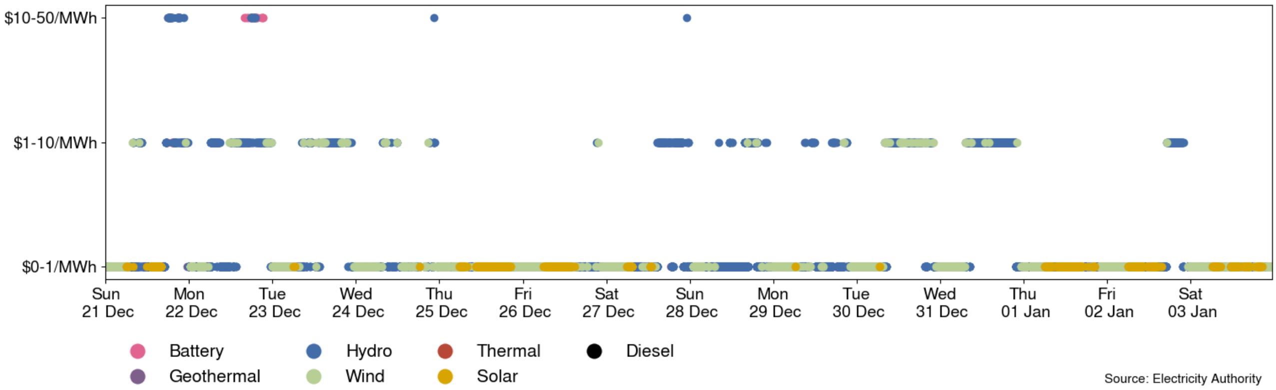
Figure 15: Hydro generation, 21 December 2025 - 3 January 2026



7.12. Figure 16 shows the distribution of marginal prices this fortnight and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.

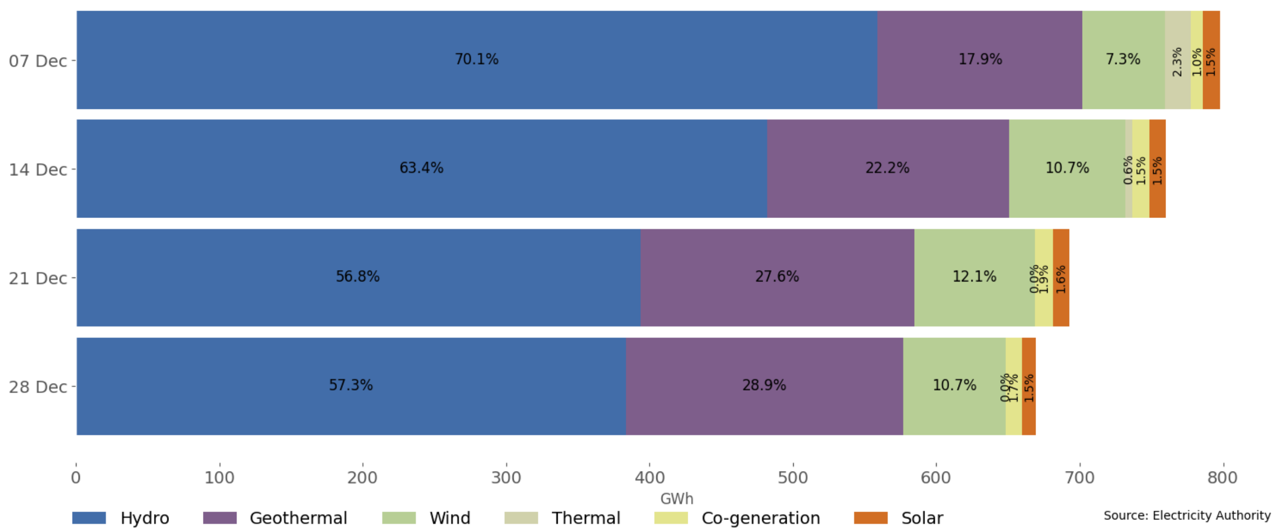
7.13. The highest prices this fortnight were caused by Mercury hydro and the Ruakākā battery on Sunday 21 December and Monday 22 December. The most common technology setting prices this fortnight was hydro generation, with wind generation the second most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 21 December 2025 - 3 January 2026



7.14. As a percentage of total generation between 21 December 2025 - 3 January 2026, hydro generation was between 56.8-57.3%, geothermal between 27.6-28.9%, wind between 10.7-12.1%, co-generation between 1.7-1.9%, and solar between 1.5-1.6%, as shown in Figure 17. Thermal generation was almost 0% of the total generation during this period.

Figure 17: Total generation by type as a percentage each week, between 7 December and 3 January



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 21 December 2025 - 3 January 2026 ranged between ~1,051MW and ~1,694MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 21 December 2025 - 3 January 2026

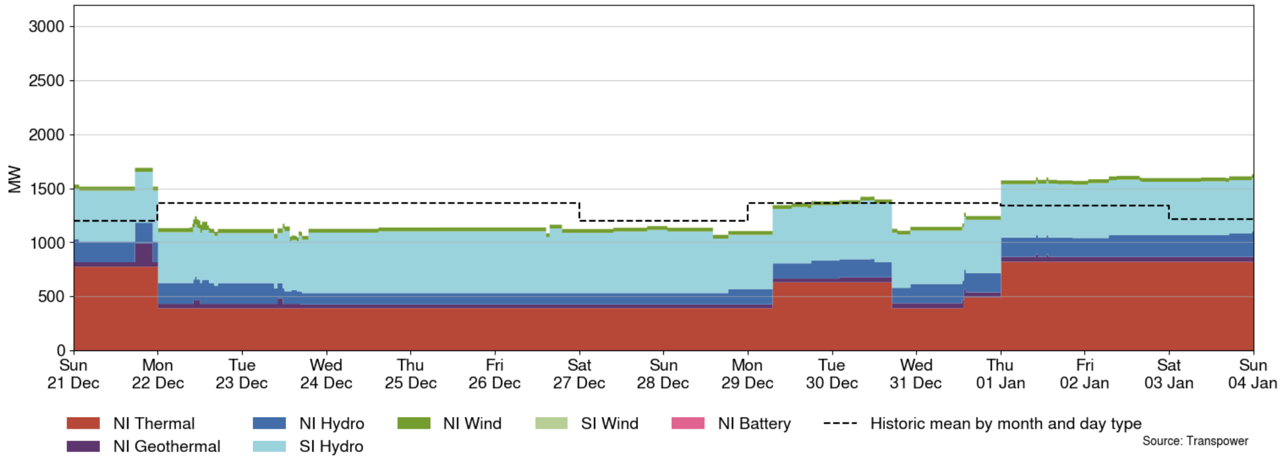
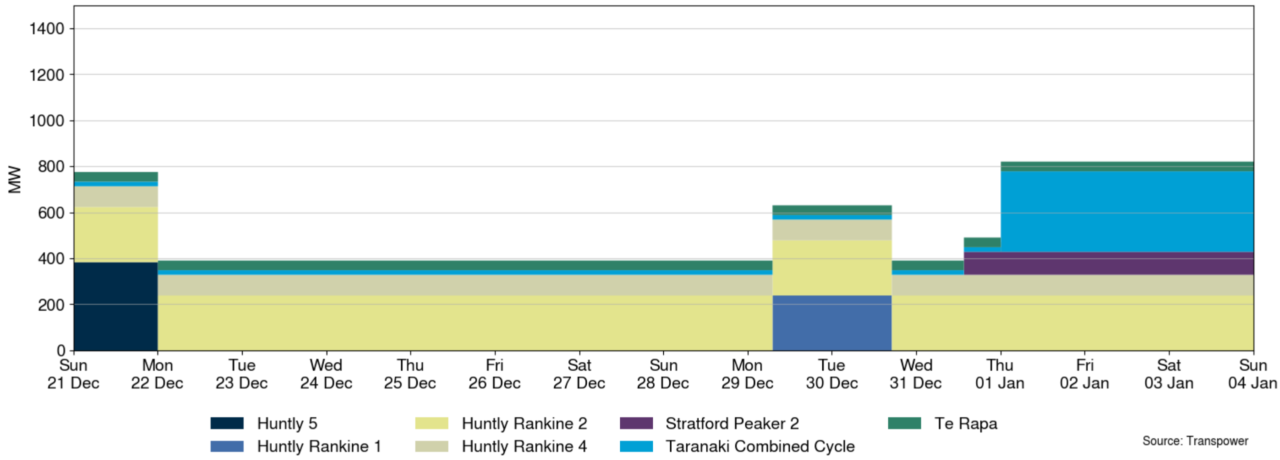


Figure 19: Total MW loss from thermal outages, 21 December 2025 - 3 January 2026



8.2. Notable outages include:

Plant	Partial or Full	End Date
Huntly 5	Full	21 December 2025
Huntly 1	Full	30 December 2025
Stratford Peaker 2	Full	5 January 2026
Ōhau C	Partial	16 January 2026
Huntly 4	Partial	31 January 2026
Ōhau A	Partial	18 February 2026
Roxburgh unit 5	Full	25 February 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

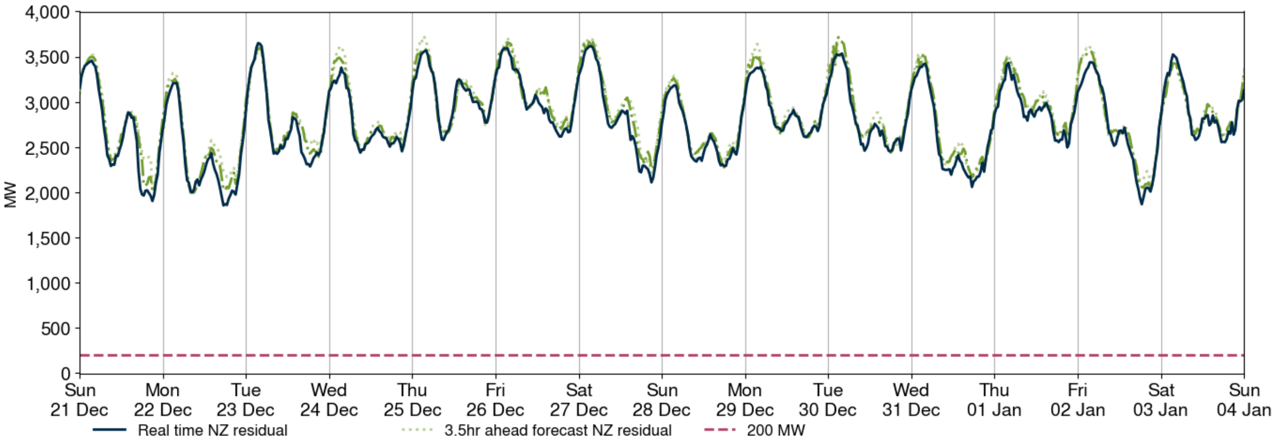
[2] This outage reflects Contact's intention to decommission TCC.

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 21 December 2025 - 3 January 2026. 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 during this period. The lowest national residual was 1,855MW on Monday 22 December at 5.30pm.

Figure 20: National generation balance residuals, 21 December 2025 - 3 January 2026



Source: Transpower

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 3 January 2026, national controlled storage was 97% nominally full and ~134% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (102% full[3]) is above its historic 90th percentile, while Lake Takapō (98% full) is just below its historic 90th percentile. Lake Pūkaki has exceeded its storage capacity and is spilling.

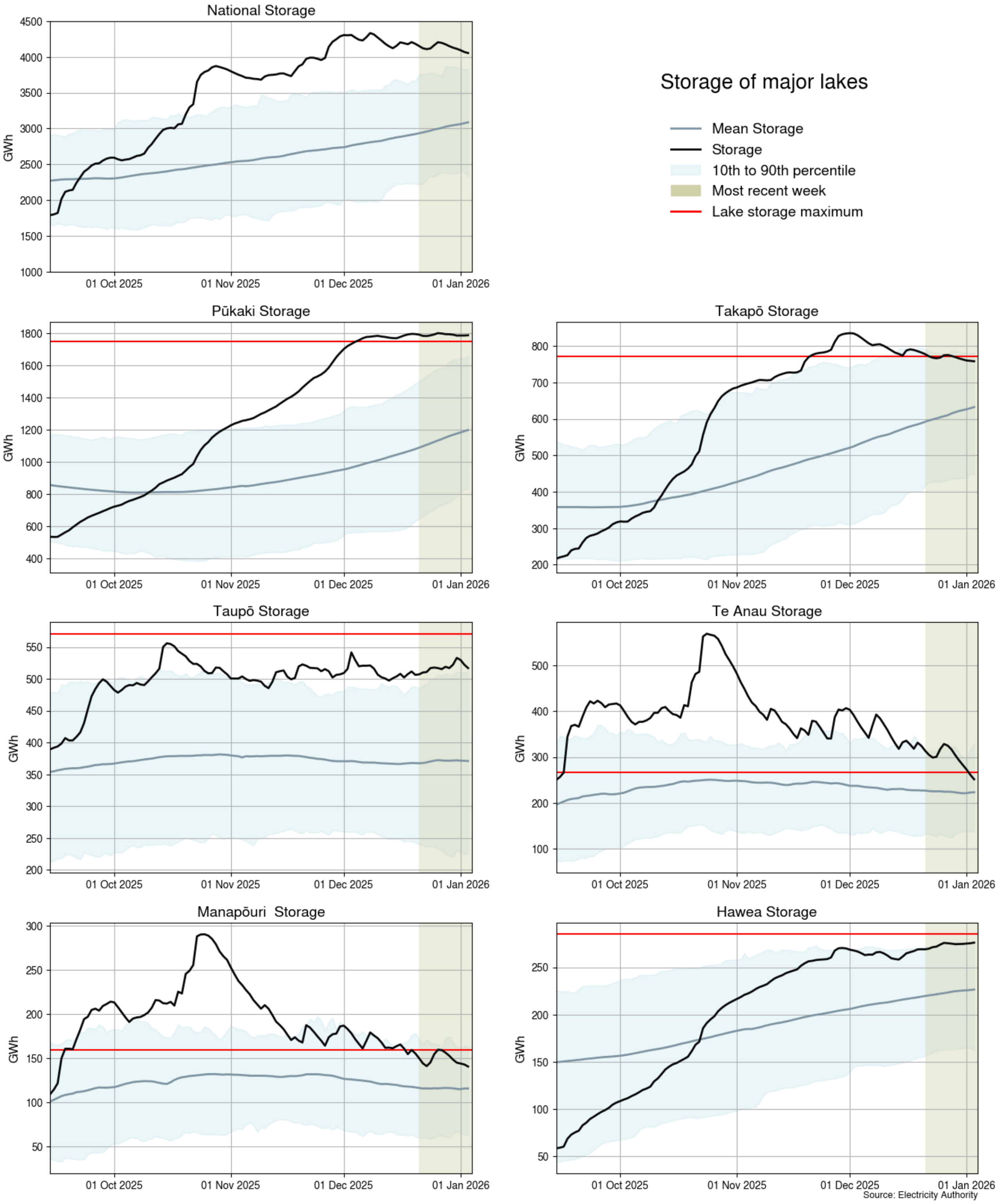
10.4. Storage at Lake Te Anau (92% full) is now below its historic 90th percentile, with Lake Manapōuri (88% full) also below its historic 90th percentile.

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

10.6. Storage at Lake Hawea (97% full) is also 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.

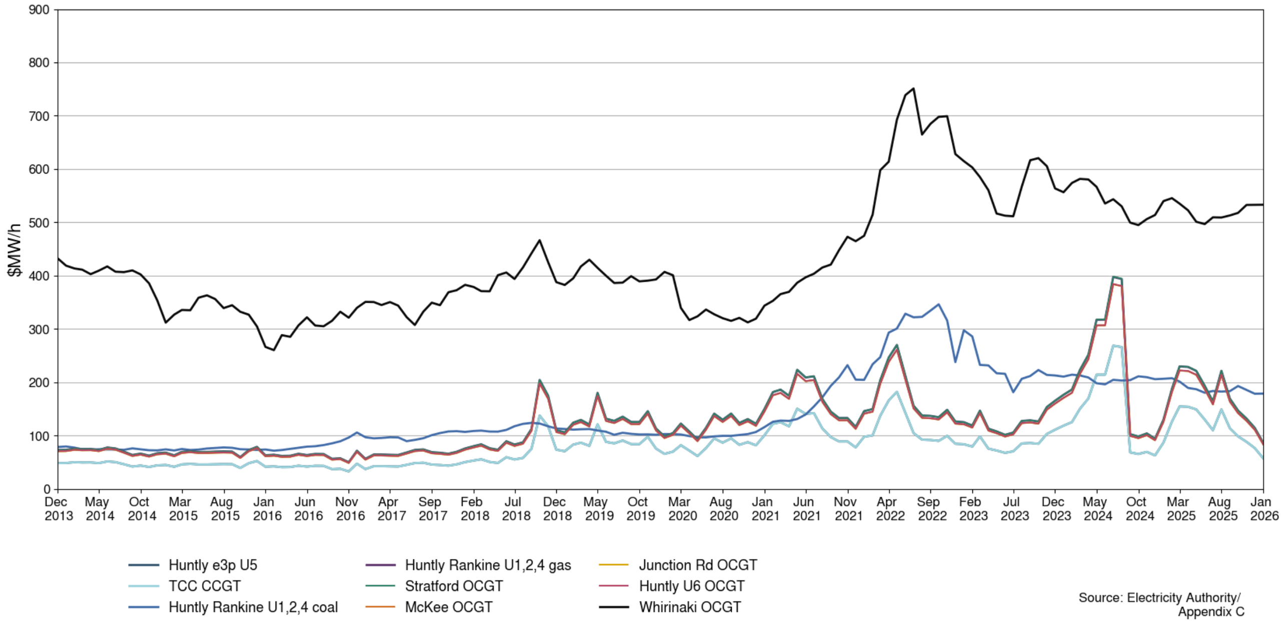
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$178/MWh. The cost of running the Rankines on gas is ~$86/MWh.

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

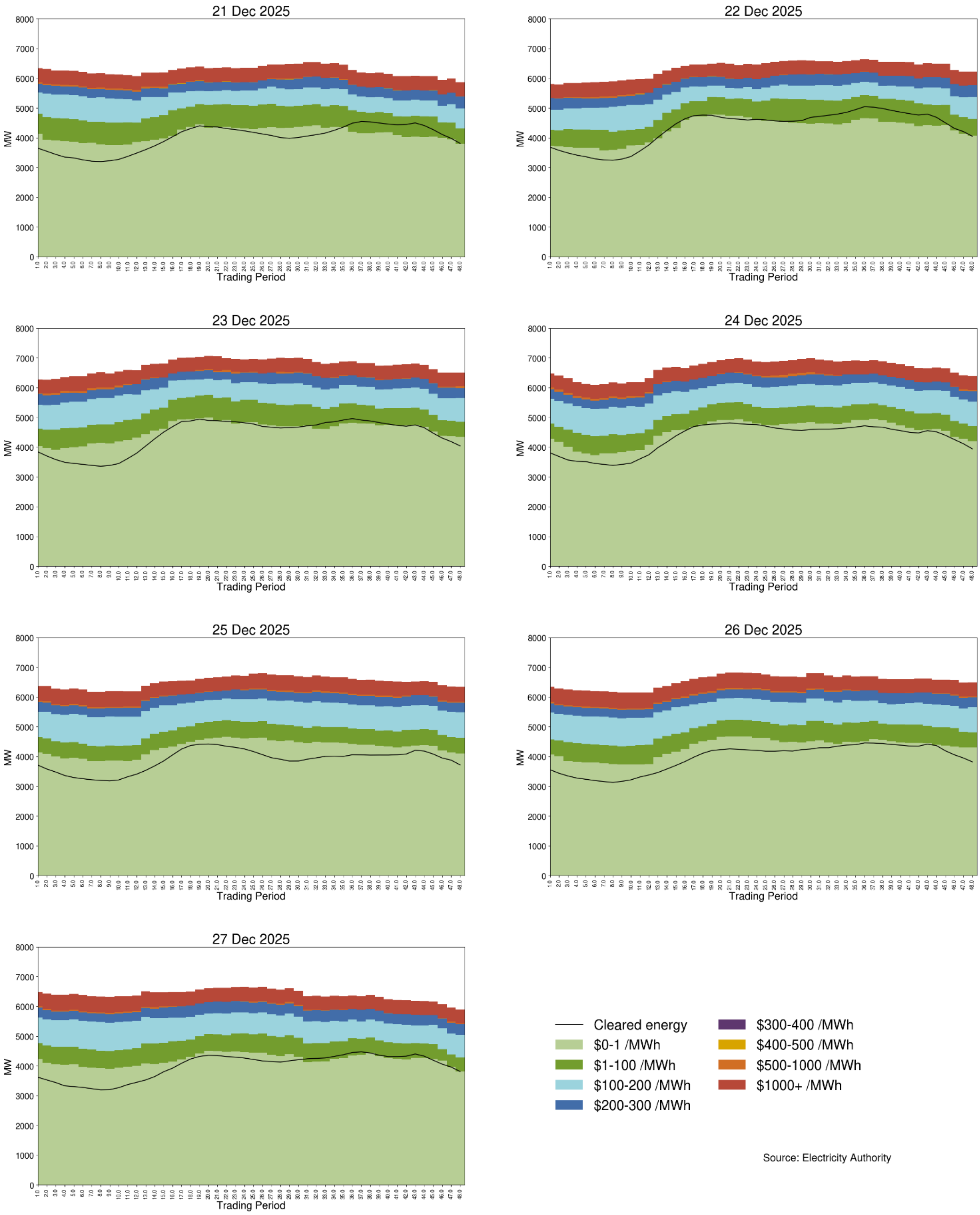


12. Offer behaviour

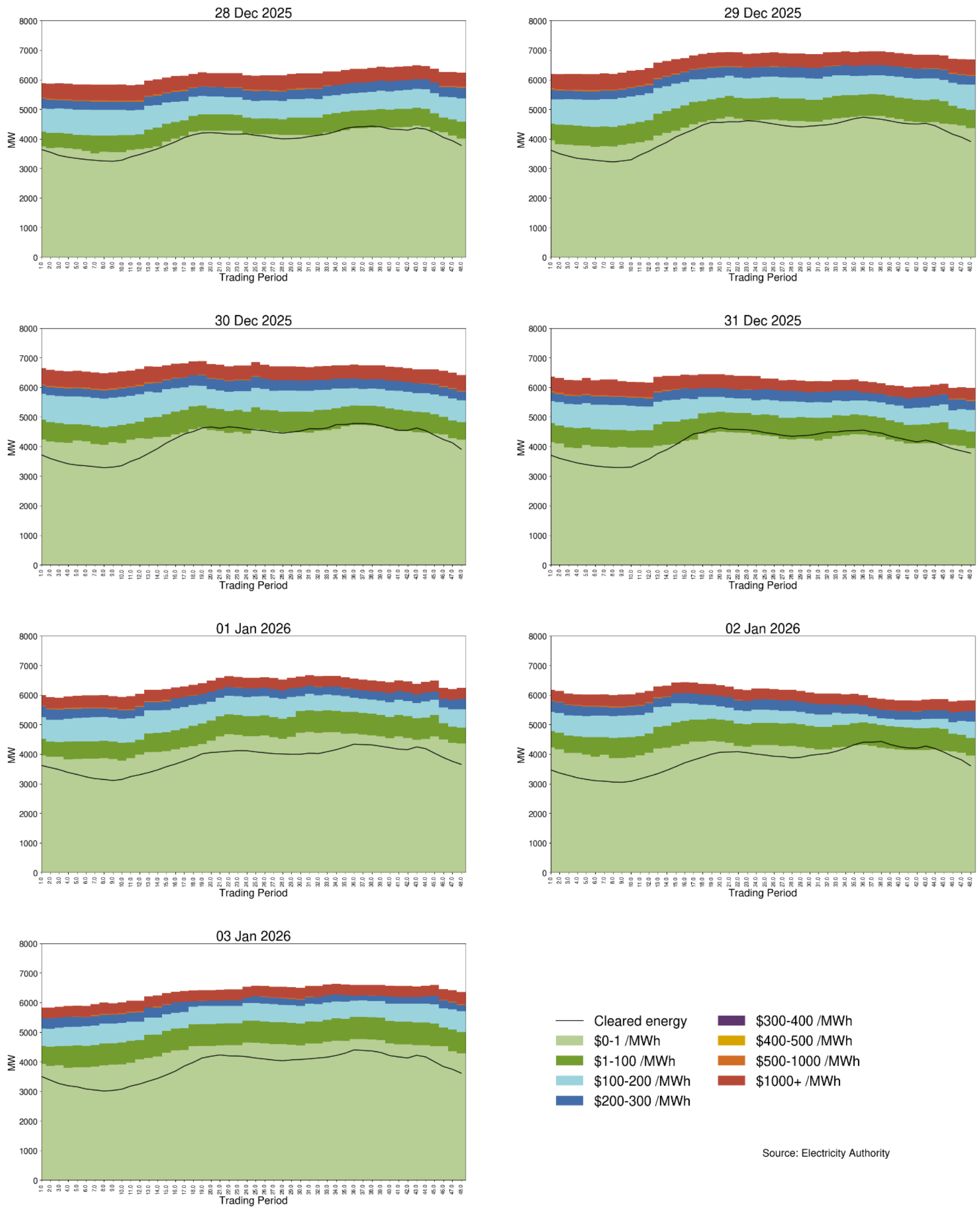
12.1. Figure 23 shows this fortnight's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. During this period, most offers cleared below $1/MWh, especially from Monday 22 December onwards.

Figure 23: Daily offer stacks



Source: Electricity Authority



Source: Electricity Authority

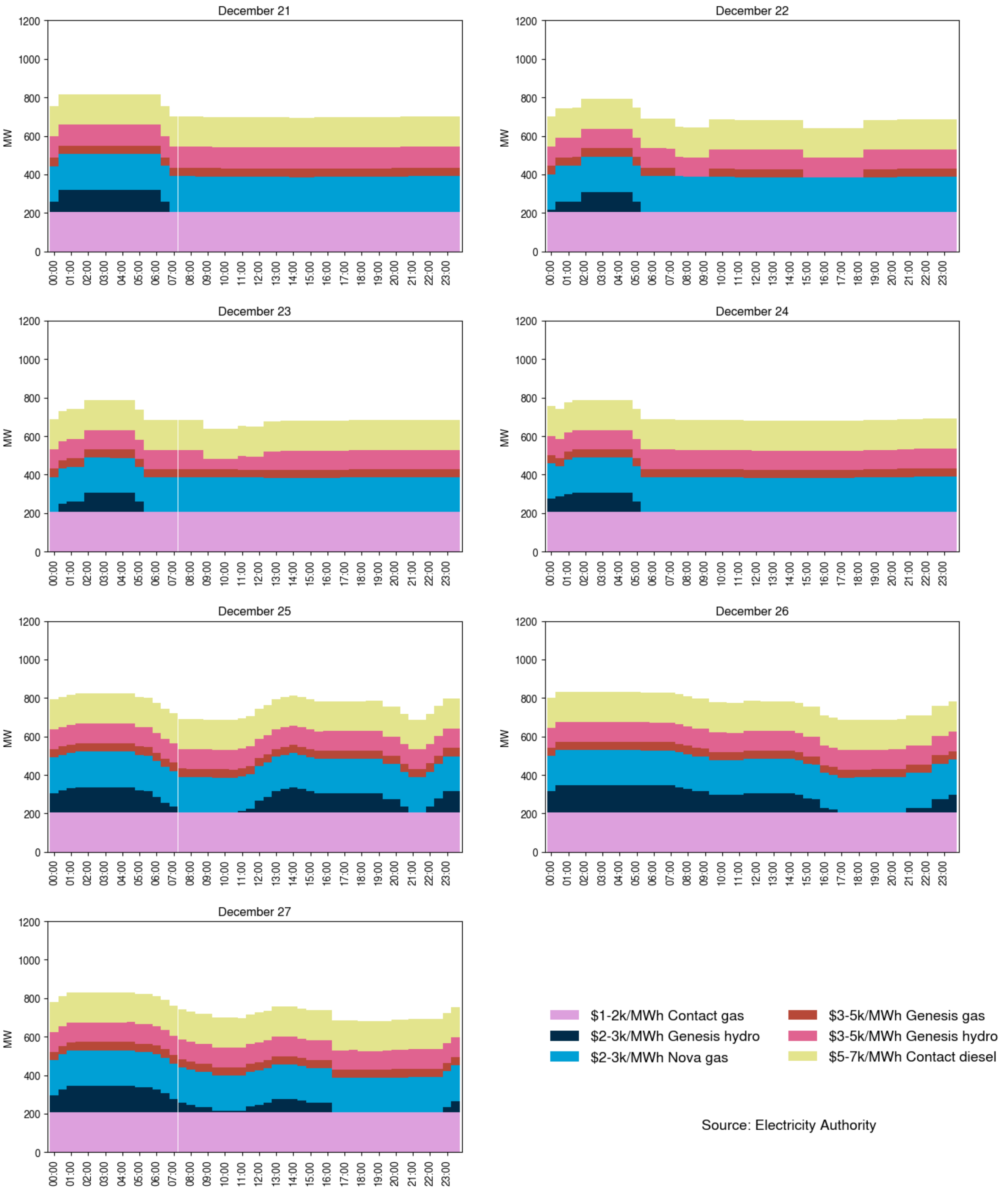
12.3. Figure 24 shows offers above $1,000/MWh in each trading period this fortnight. The largest proportion of these offers are fast start thermal operators.

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.

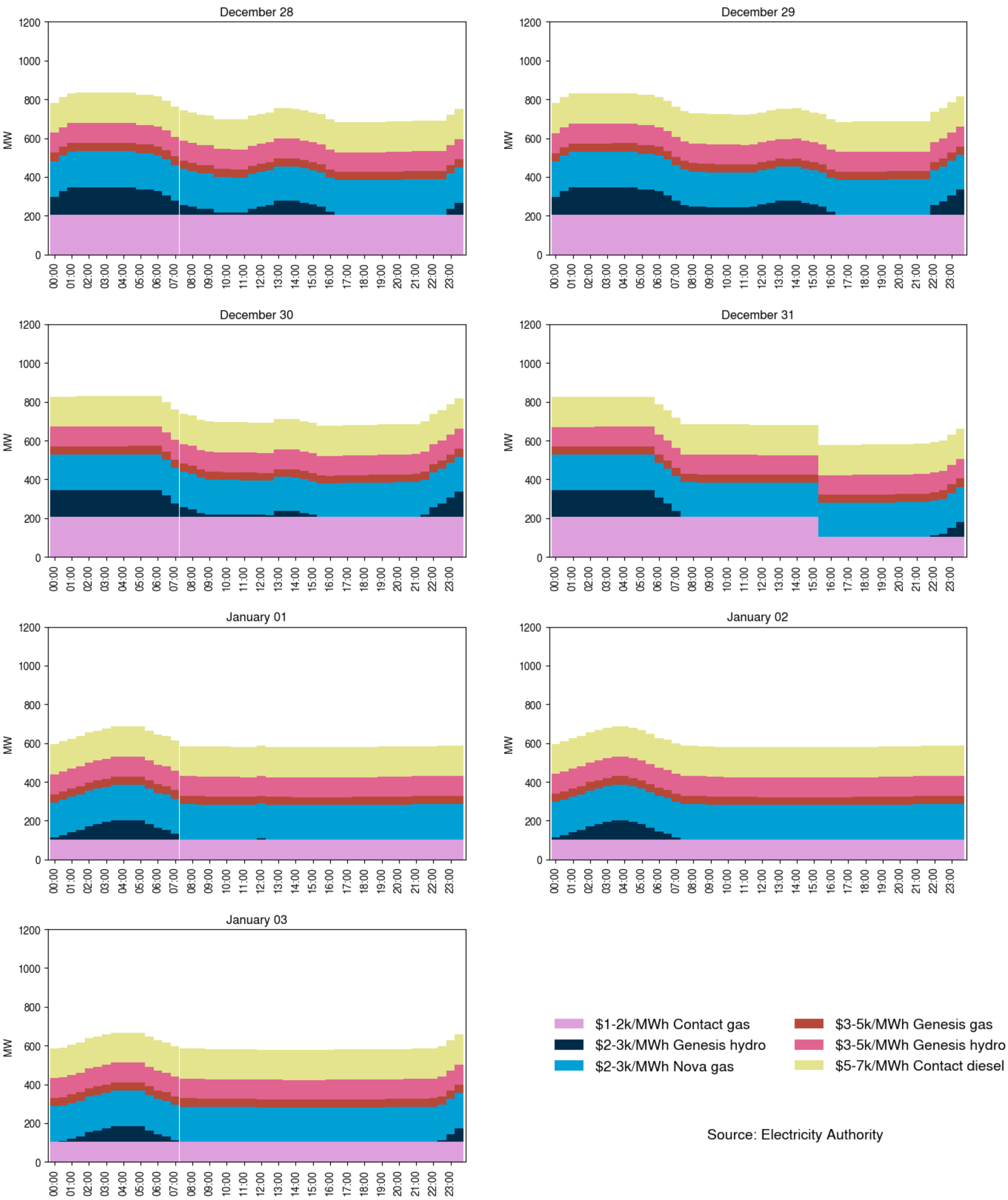
12.5. For the week beginning 21 December, an average of 730MW per trading period was priced above $1,000/MWh this week, or roughly 14% of the total energy available.

12.6. For the week beginning 28 December, an average of 676MW per trading period was priced above $1,000/MWh this week, or roughly 13% of the total energy available.

Figure 24: High priced offers



Source: Electricity Authority



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. Prices generally appeared to be consistent with supply and demand conditions during this period.

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
17/12/2025	19	Further analysis	Mercury	Waikato	Offers