3 February 2025

Trading conduct report 26 January-1 February

Market monitoring weekly report

Trading conduct report 26 January-1 February

1. Overview

1.1. Spot prices have decreased slightly this week but remain high due to low wind most days, increased thermal generation, a continued low inflow sequence and hydro storage dropping to 81% full. Several line outages and constraints led to some high and low prices.

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 26 January-1 February:

(a) The average wholesale spot price across all nodes was $172/MWh, a decrease of around $10/MWh compared to the previous week.

(b) 95% of prices fell between $0.16/MWh and $277/MWh.

2.3. Prices are still high this week due to several days of low wind, declining hydro storage and constraint limiting export of energy from geothermal units on Friday and Saturday[1].

2.4. The highest price at Ōtāhuhu was $332/MWh at 8:00pm on Friday. At the same time some other prices in the North Island were negative, with the lowest being -$145/MWh at Edgecumbe. Wind was low at this time, and the geothermal unit energy exports were constrained in the North Island and likely contributed to the higher prices downstream of the constraints, while the spring washer effect[2] led to negative prices in the east of the North Island.

2.5. The highest spot price at any node this week occurred at Tiwai and was $384/MWh on Saturday at 8.30pm. This was due to line constraints in the Southland region.

2.6. On Monday at 3am, prices spiked to $228/MWh at Benmore. This was due to a sudden drop in wind causing large wind generation forecast inaccuracies. At gate closure wind was over forecast by 137MW and 2 hours ahead of gate closure wind was over forecast by 303MW.

2.7. On Thursday, prices at Ōtāhuhu increased to a maximum of $311/MWh at 3pm. Demand was frequently higher than forecast on Thursday, especially during peak periods. At the time of the highest price, demand was 94MW higher than forecast. Wind was also lower than forecast frequently on Thursday afternoon, with the greatest forecasting inaccuracy of 90MW over forecast two hour ahead of gate closure for the time of the highest price. High prices on Saturday were similarly due to wind over forecasting and demand under forecasting.

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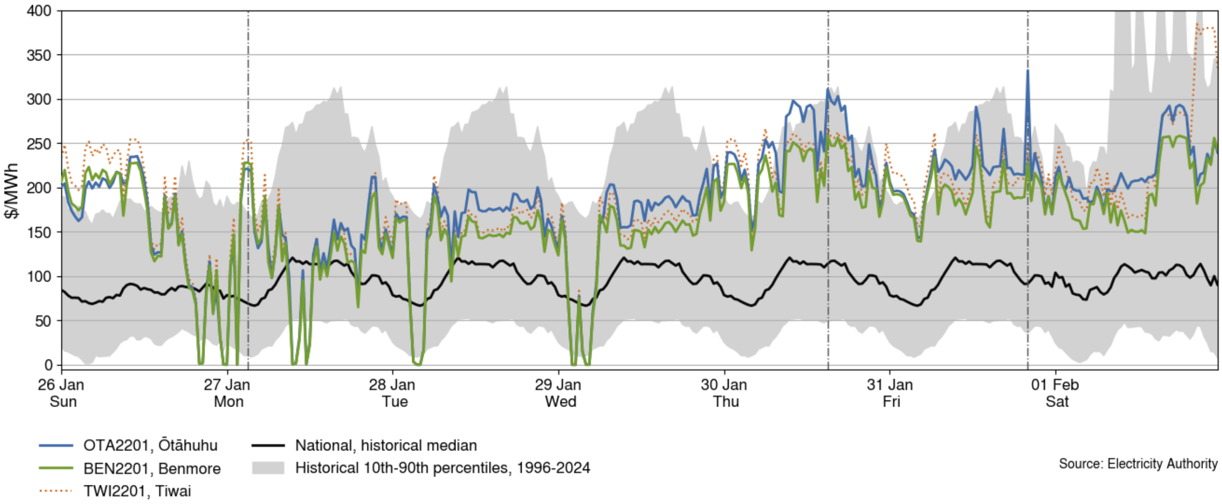
[1] THI_WKM Planned Outage For CAN.pdf

[2] The Spring Washer Effect: introduction - YouTube, The Spring Washer Effect: section 1 - marginal pricing, The Spring Washer Effect: section 2 - binding constraints, The Spring Washer Effect: section 3 - a spring washer scenario

2.8. Price separation of roughly $30/MWh occurred this week, especially on days with low North Island wind (Tuesday, Thursday-Saturday) as these lulls in wind are being firmed with additional North Island hydro or thermal generation.

2.9. Figure 1 shows the wholesale spot prices at Benmore, Ōtāhuhu and Tiwai 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.

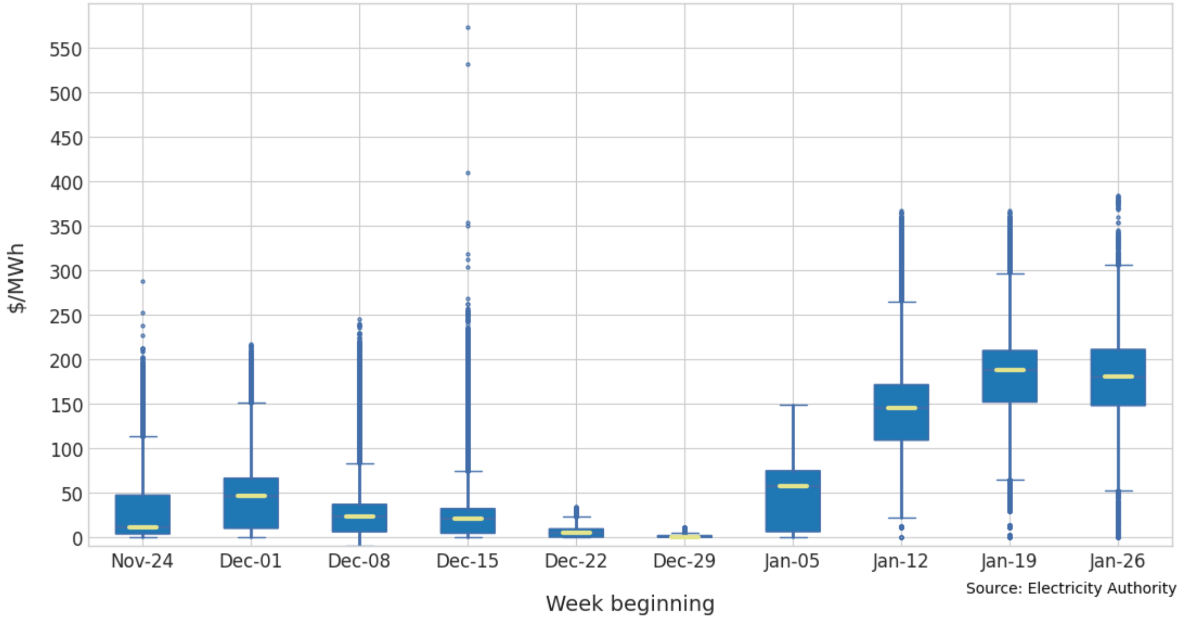
Figure 1: Wholesale spot prices at Benmore, Ōtāhuhu, and Tiwai, 26 January-1 February



2.10. 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.

2.11. The distribution of spot prices this week was very similar to last week. The median price was $180/MWh and most prices (middle 50%) fell between $148/MWh and $211/MWh.

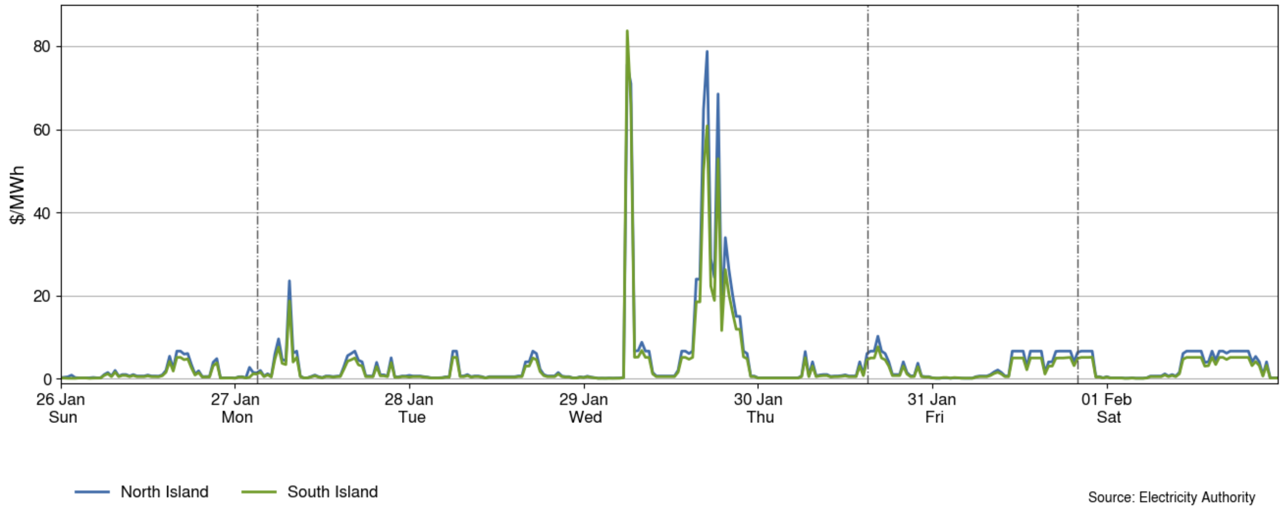
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

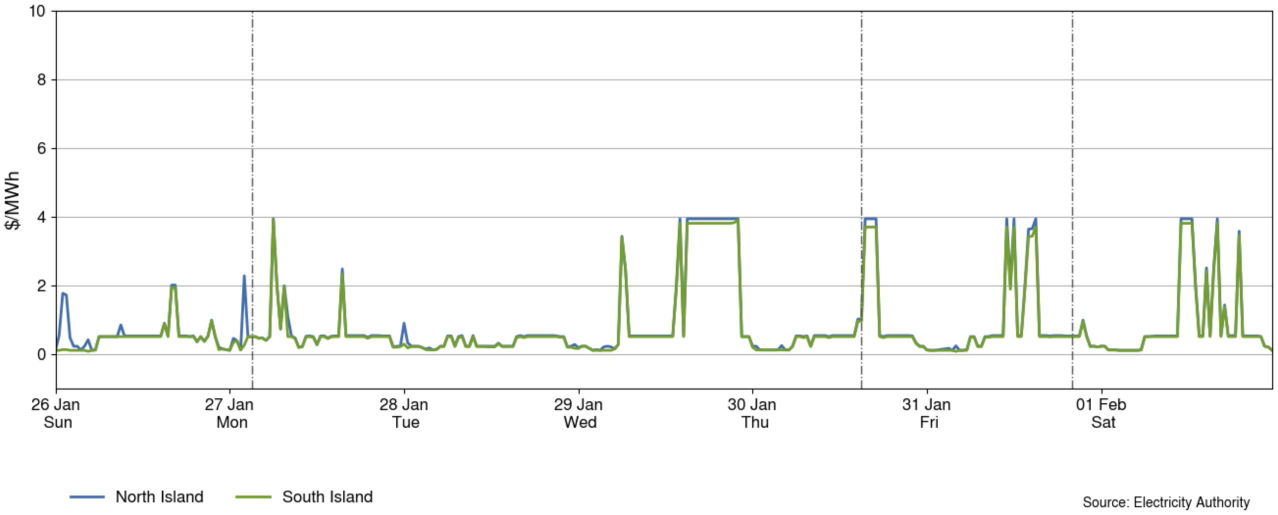
Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh this week. However, they exceeded $30/MWh several times on Wednesday. The first spike at 6am reached $84/MWh in the South Island and was due to North Island wind farms setting a high risk. Other spikes occurred between 16:30-19:30 in both islands. The monitoring team will be looking further into these reserve prices.

Figure 3: Fast instantaneous reserve price by trading period and island, 26 January-1 February



3.1. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh, reaching a maximum of $3.93/MWh in the North Island at 6am on Monday.

Figure 4: Sustained instantaneous reserve by trading period and island, 26 January-1 February



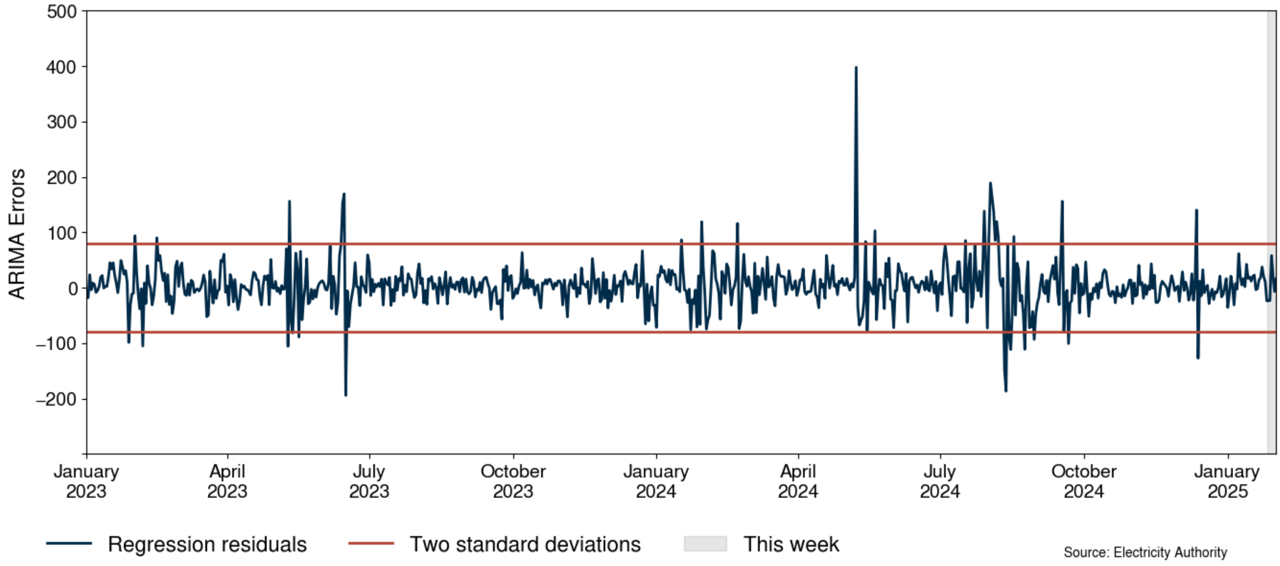
4. Regression residuals

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 the those predicted by the model.

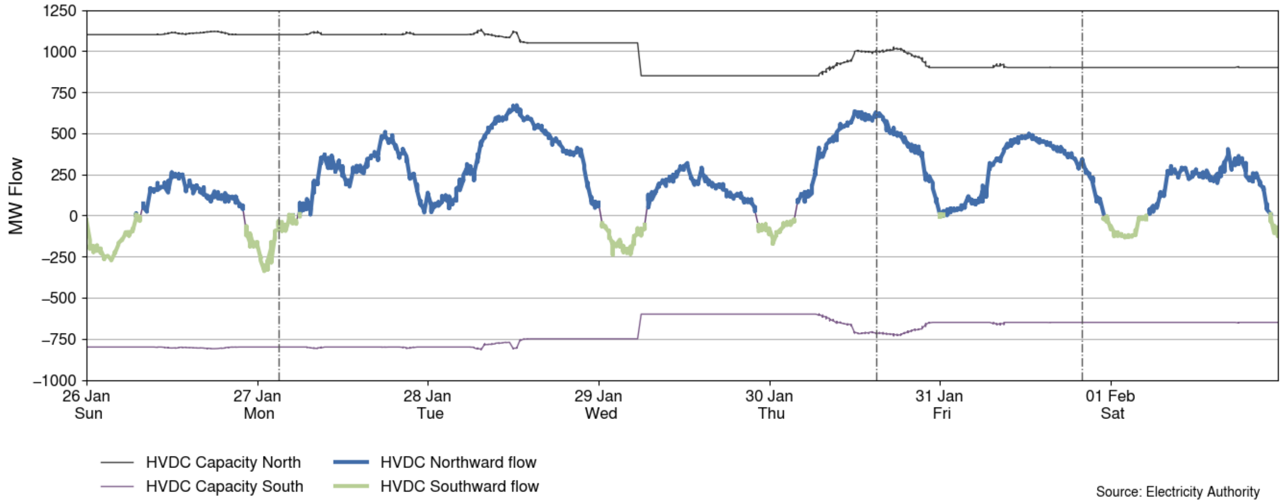
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 01 February 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 26 January-1 February. HVDC flows were mostly northward, reaching a maximum of 671MW northward flow at 7.30am on Tuesday. Northward flow was lower on Wednesday when wind was high. Nightime flow was often southward.

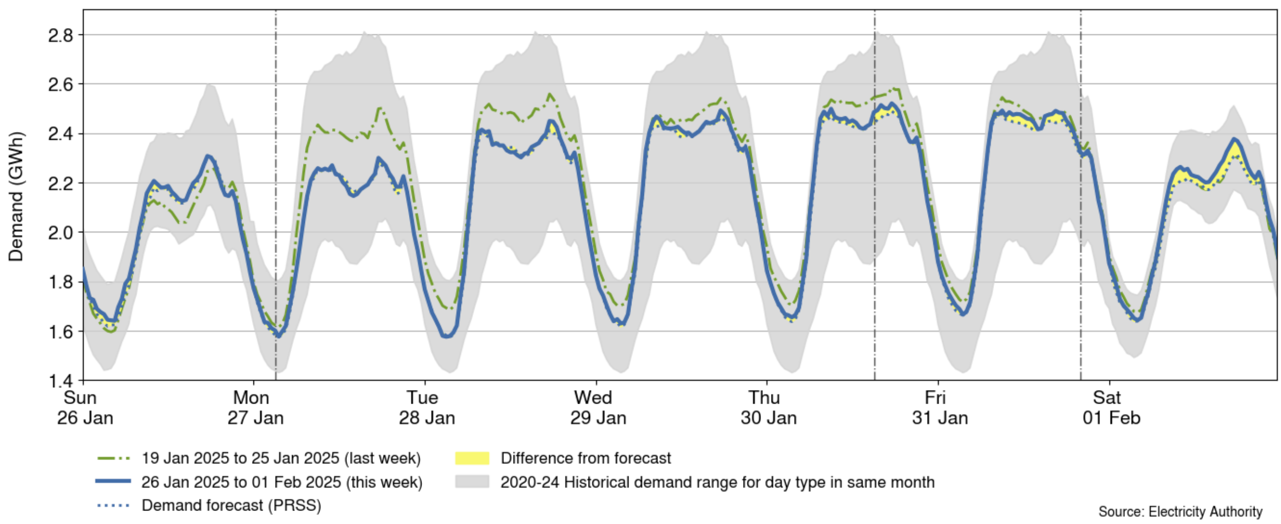
Figure 6: HVDC flow and capacity, 26 January-1 February



6. Demand

6.1. Figure 7 shows national demand between 26 January-1 February, compared to the historic range and the demand of the previous week. Demand was slightly lower than last week, especially on Monday due to Auckland Anniversary Day. Irrigation load in Canterbury, estimated using the load in Ashburton, decreased by ~36%. Demand was higher than forecast on Thursday afternoon, Friday during the day, and most of Saturday.

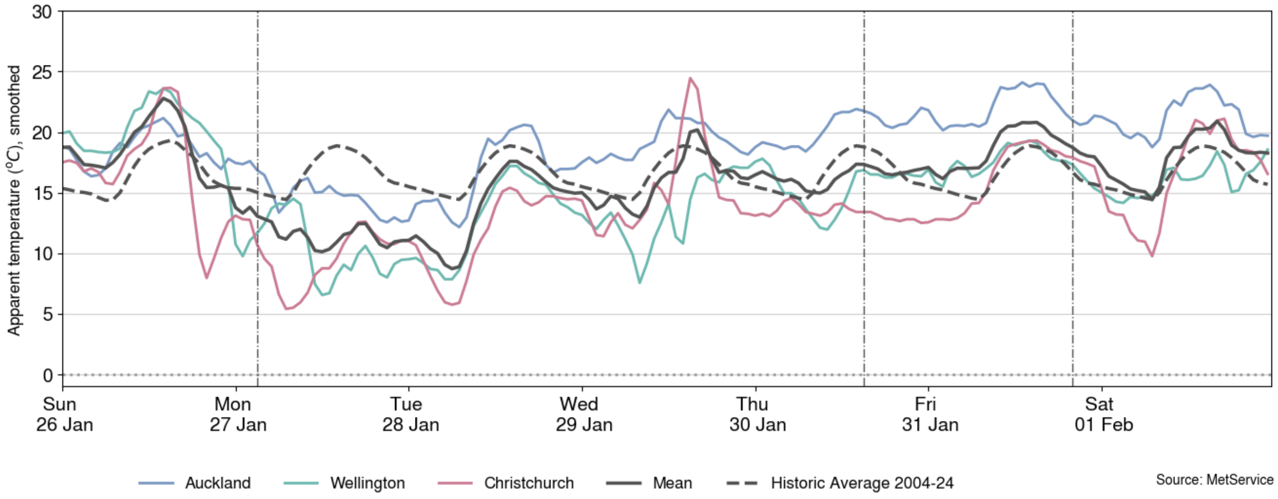
Figure 7: National demand, 26 January-1 February compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 26 January-1 February. 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 were close to average most days this week and below average on Monday. They ranged from 12°C to 25°C in Auckland, 6°C to 25°C in Wellington, and 5°C to 26°C in Christchurch.

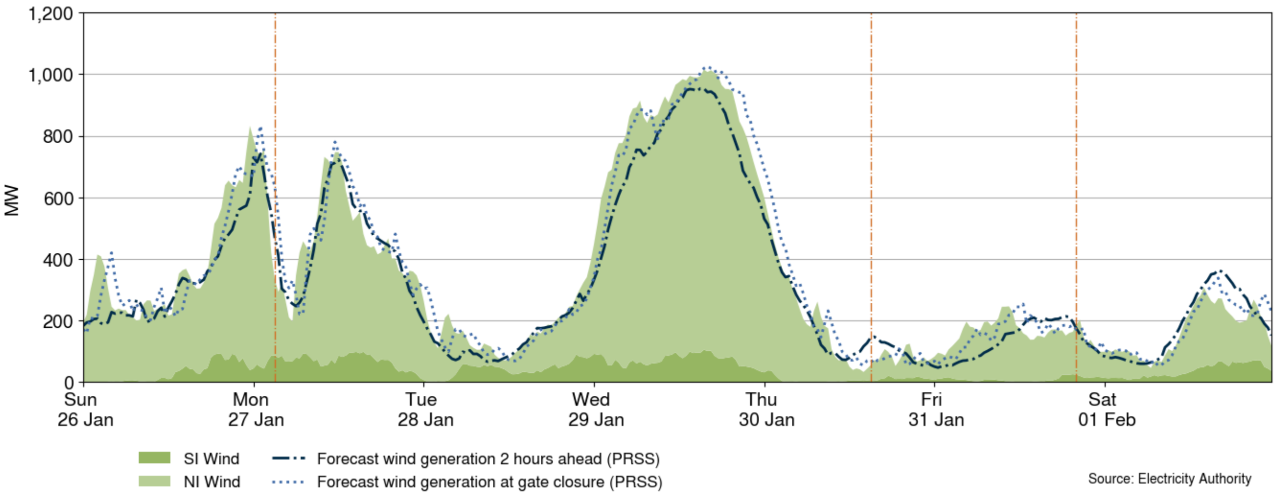
Figure 8: Temperatures across main centres, 26 January-1 February



7. Generation

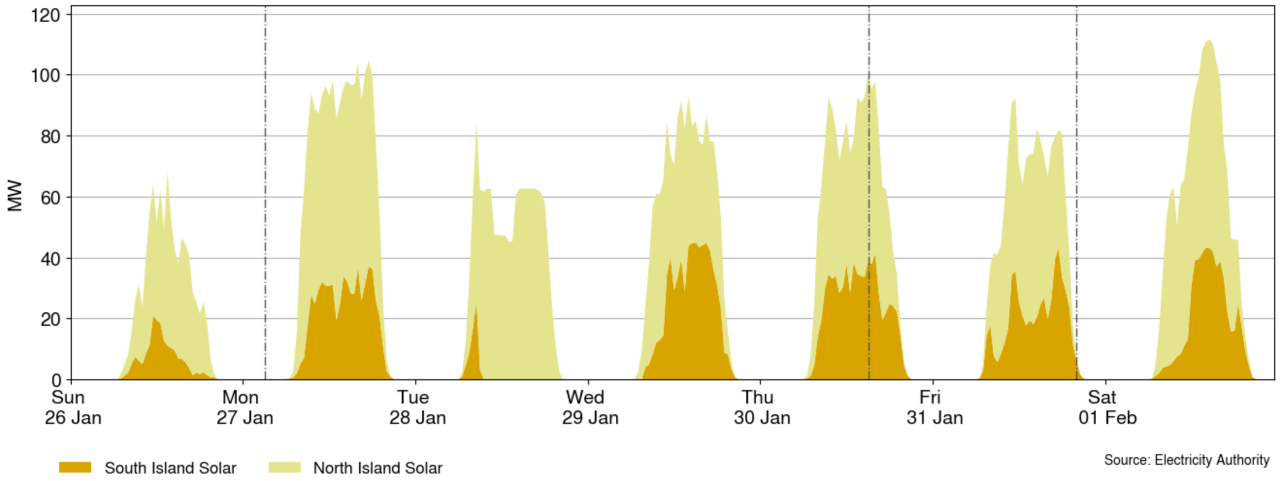
7.1. Figure 9 shows wind generation and forecast from 26 January-1 February. This week wind generation varied between 32MW and 1,015MW, with a weekly average of 339MW. Wind generation was very low on Tuesday and from Thursday, but consistently high on Wednesday.

Figure 9: Wind generation and forecast, 26 January-1 February



7.2. Figure 10 shows grid connected solar generation from 26 January-1 February. Solar generation reached a maximum of 112MW on Saturday. Solar generation was lower on Sunday and Tuesday.

Figure 10: Solar generation (grid connected), 26 January-1 February

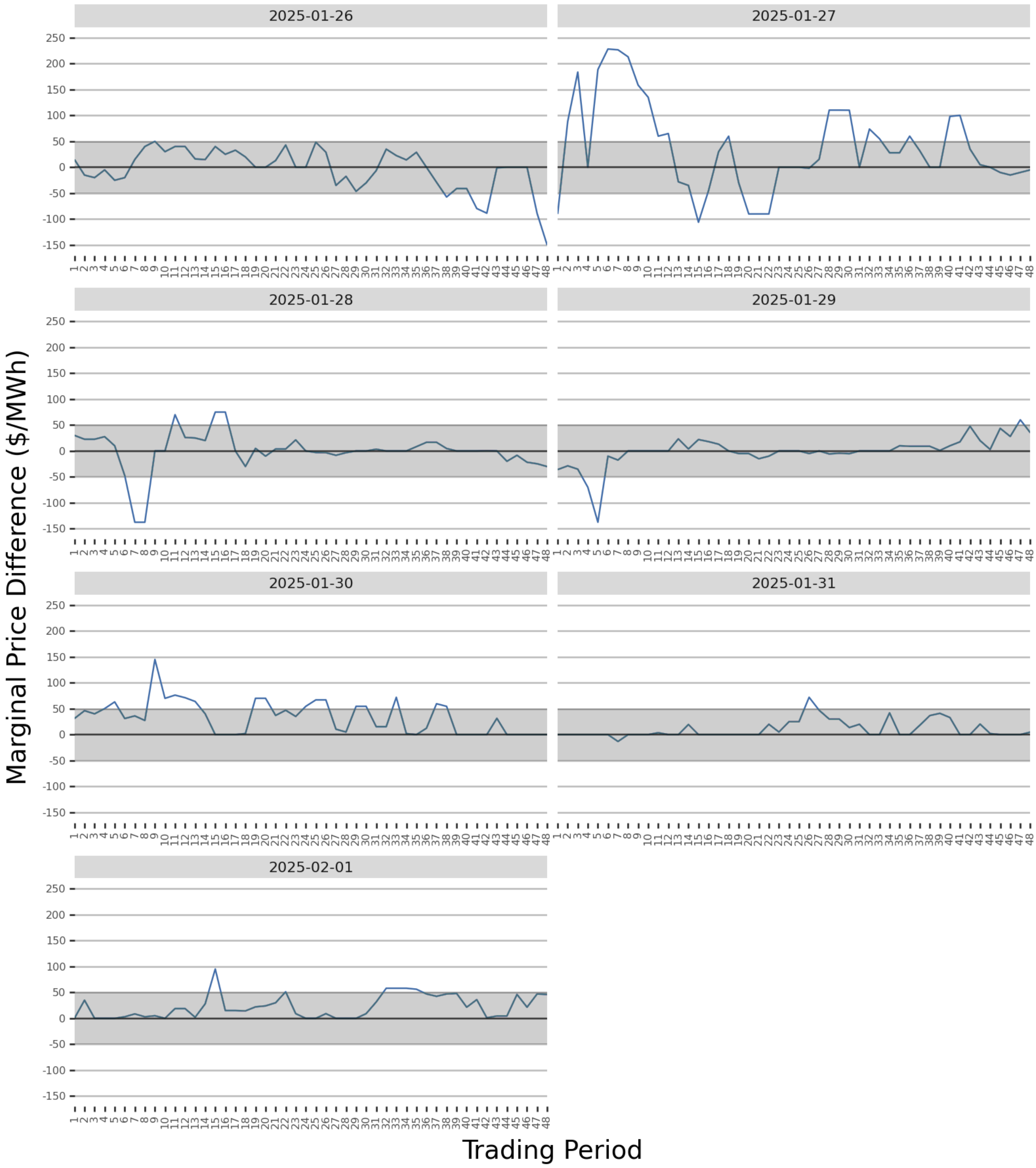


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[3]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.4. The greatest marginal price difference was $+228/MWh on Monday at 2.30am, during the morning of large wind over forecasting. There were several other absolute marginal price differences between $50-150/MWh this week, especially on Monday and Thursday. The differences on Monday morning were related to wind over-forecasting.

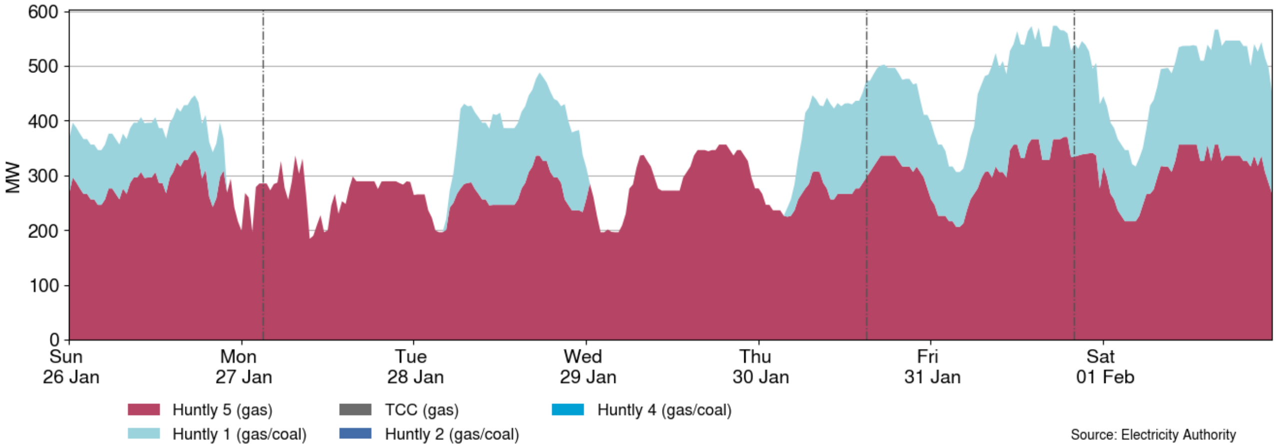
[3] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 26 January-1 February



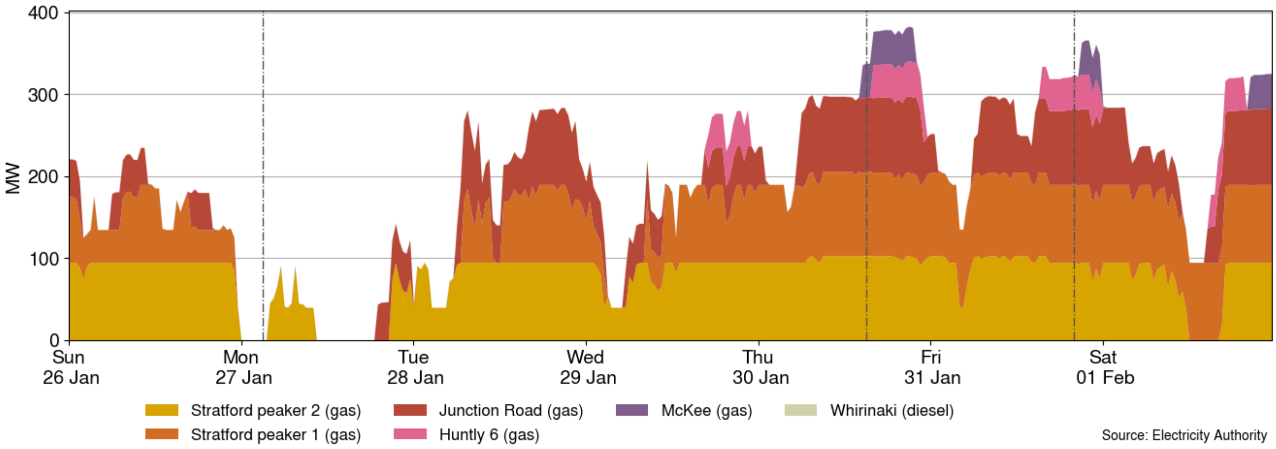
7.5. Figure 12 shows the generation of thermal baseload between 26 January-1 February. Huntly 5 generated baseload this week, with Huntly 1 generating every day except Monday and Wednesday when wind was higher.

Figure 12: Thermal baseload generation, 26 January-1 February



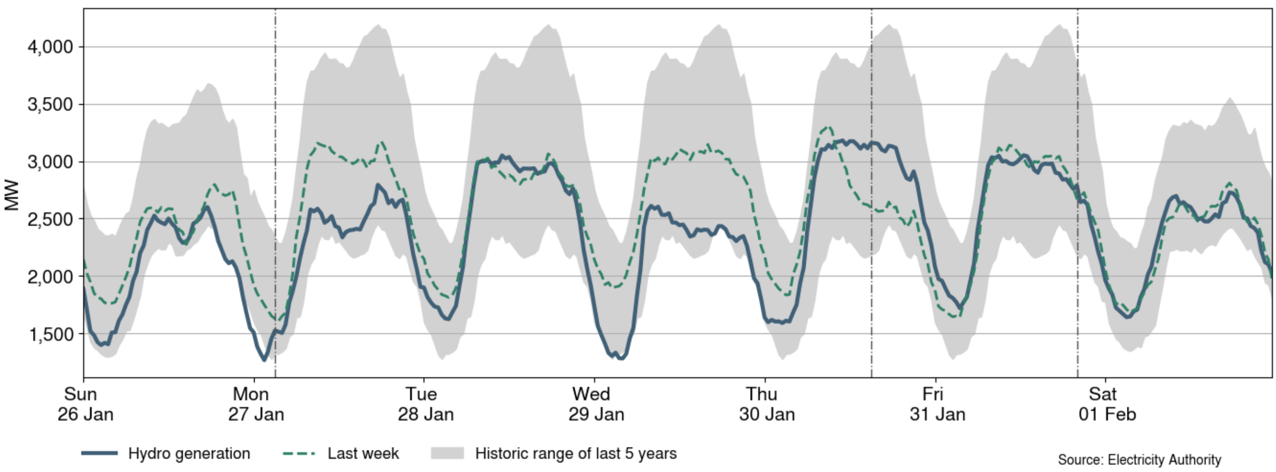
7.6. Figure 13 shows the generation of thermal peaker plants between 26 January-1 February. Stratford Peaker 2 generated every day. It was joined by Stratford Peaker 1 and Junction Road every day except Monday. Huntly 6 generated on days from Wednesday and McKee generated on days from Thursday.

Figure 13: Thermal peaker generation, 26 January-1 February



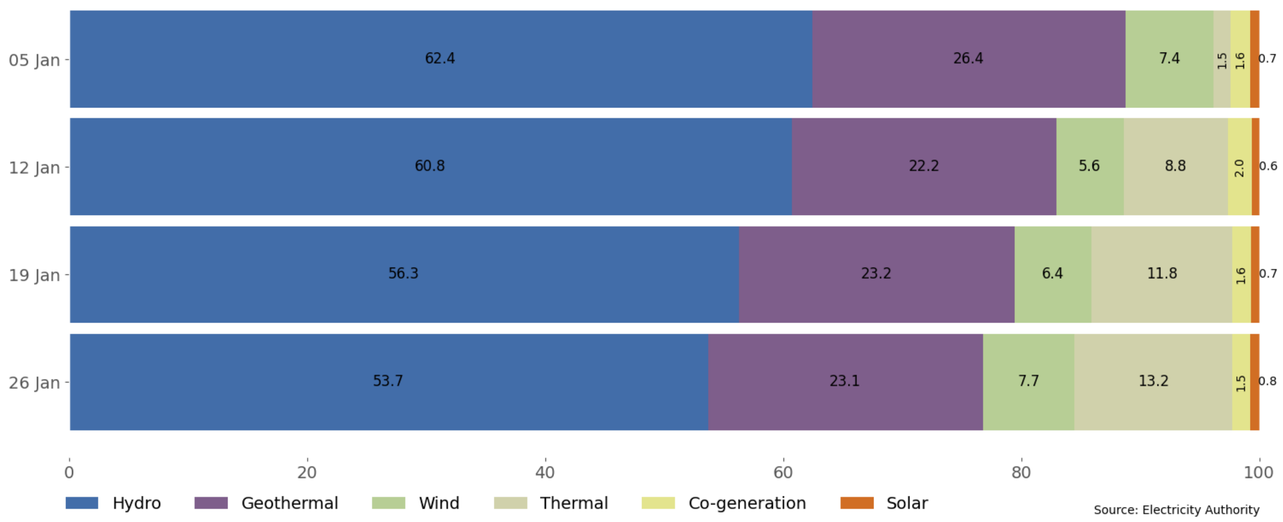
7.7. Figure 14 shows hydro generation between 26 January-1 February. Hydro generation was highest on Tuesday, Thursday and Friday when wind was low and demand was high.

Figure 14: Hydro generation, 26 January-1 February



7.8. As a percentage of total generation, between 26 January-1 February, total weekly hydro generation was 53.7%, geothermal 23.1%, wind 7.7%, thermal 13.2%, co-generation 1.5%, and solar (grid connected) 0.8% as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, 5 January and 1 February



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 26 January-1 February ranged between ~1,213MW and ~2,089MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 2 March.

(b) Manapōuri unit 2 was on outage on 28 January.

(c) Manapōuri unit 4 is on outage until 18 September.

(d) Clyde units 2-4 were on outage 29 January from 1-2.30pm.

(e) Clyde unit 1 is on outage until 25 June.

(f) Stratford Peaker 2 was on outage 1 February.

(g) Rangipo hydro is on outage until 11 April.

(h) McKee was on outage 31 January.

Figure 16: Total MW loss from generation outages, 26 January-1 February

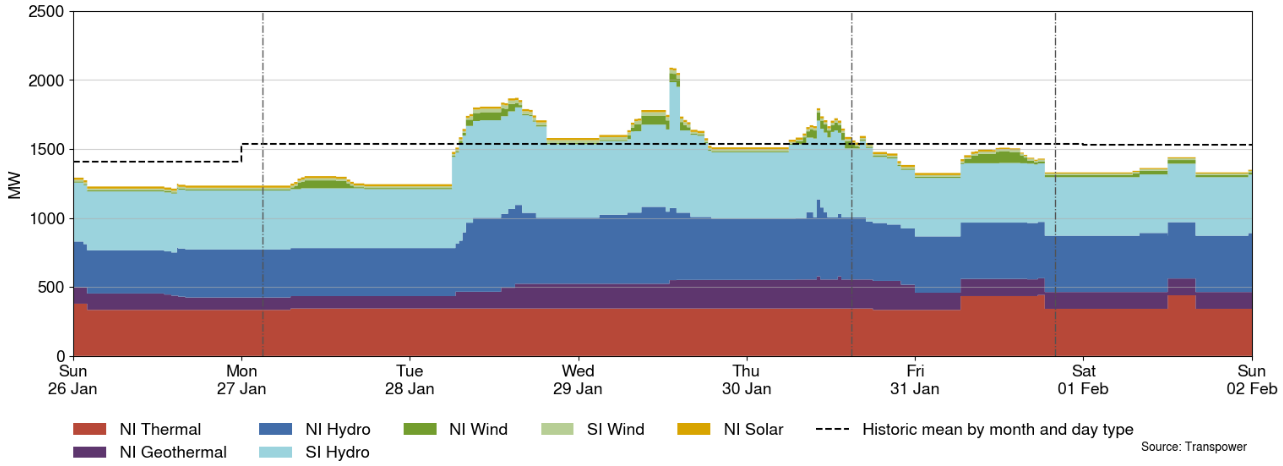
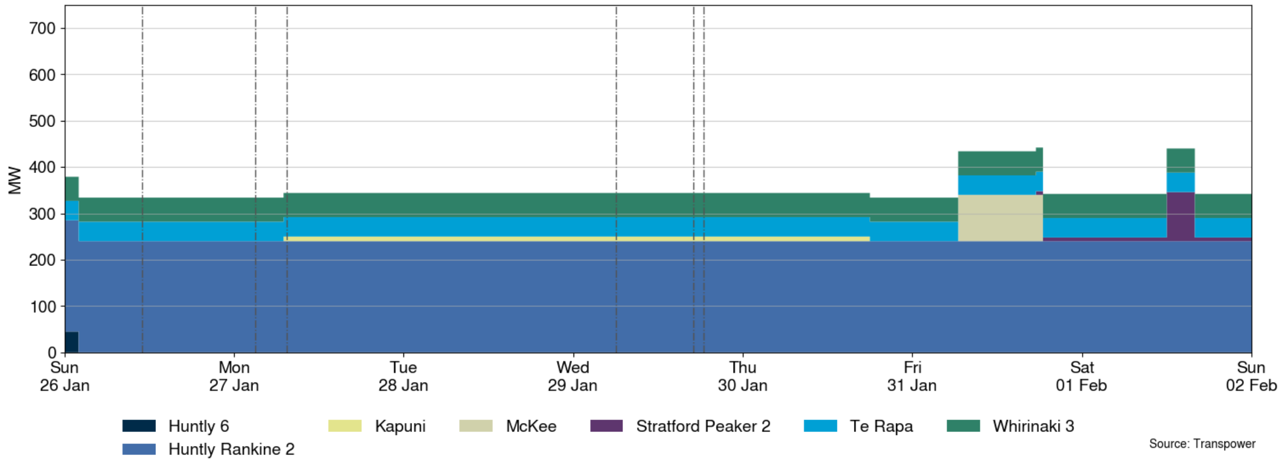


Figure 17: Total MW loss from thermal outages, 26 January-1 February

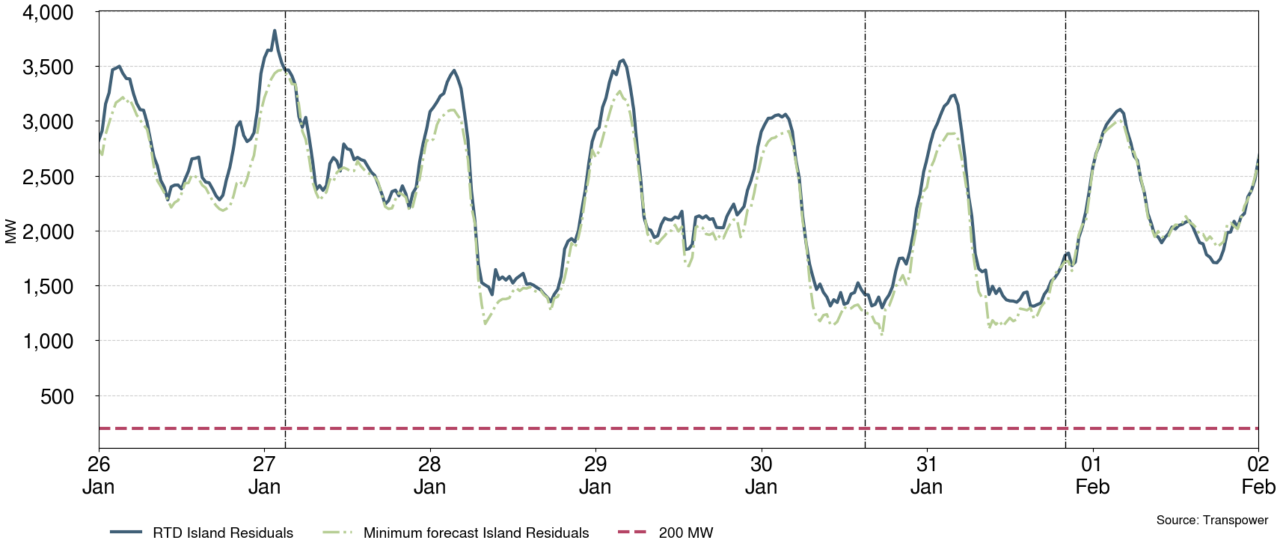


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 26 January-1 February. 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. The minimum North Island residual this week was ~475MW at 3.30pm on Friday.

Figure 18: National generation balance residuals, 26 January-1 February



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.

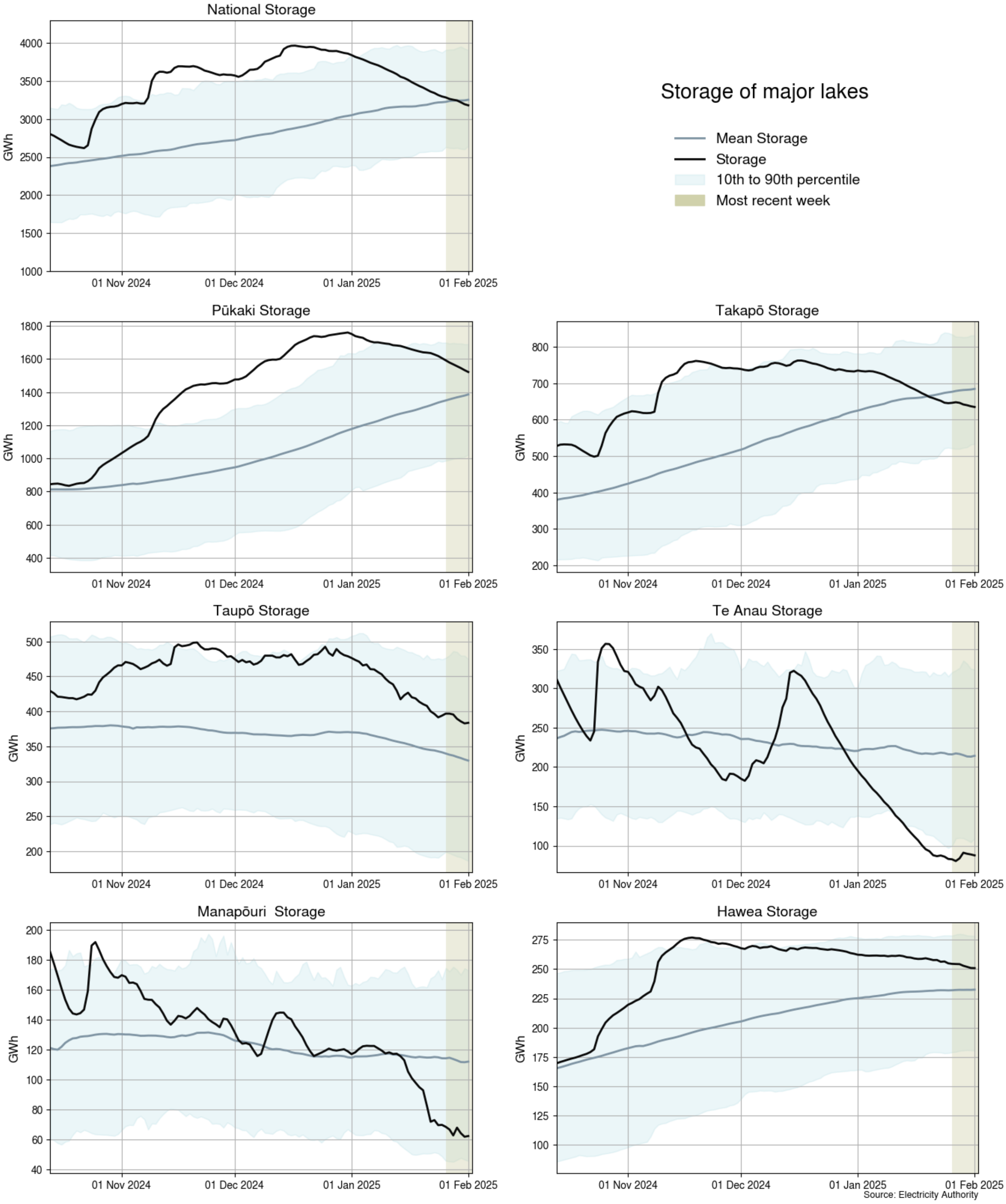
10.2. National controlled storage decreased again this week. As of 1 February storage was 81% nominally full and approximately equal to the historical average for this time of the year.

10.3. Lakes Pūkaki (86% full), Hawea (87% full) and Taupō (65% full) decreased and are still between their respective historical mean and 90th percentile.

10.4. Lakes Takapō (82% full) and Manapōuri decreased and are still between their respective historical mean and 10th percentile.

10.5. Lake Te Anau has remained roughly the same and is still below its historical 10th percentile.

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 January 2025. The SRMC for gas fuelled generation has increased compared to last month and the SRMC for coal and diesel fuelled generation remains similar to last month.

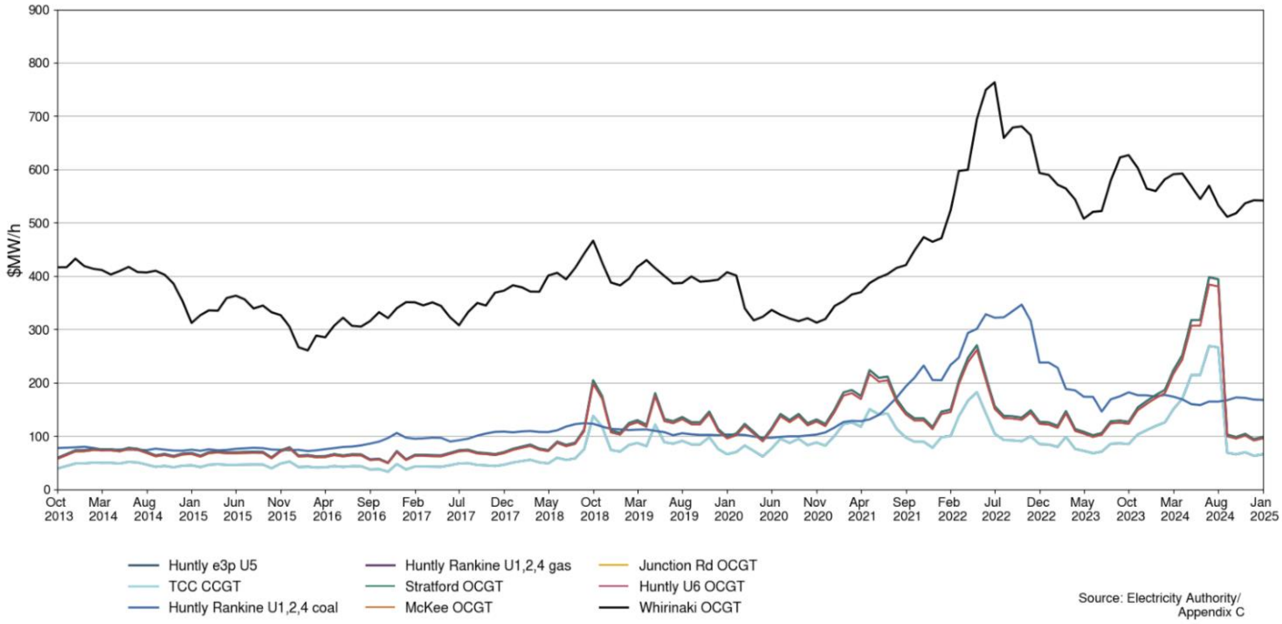
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$167/MWh, with the cost of running the Rankines on gas remaining lower at ~$98/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $66/MWh and $98/MWh.

11.6. The SRMC of Whirinaki is ~$541/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

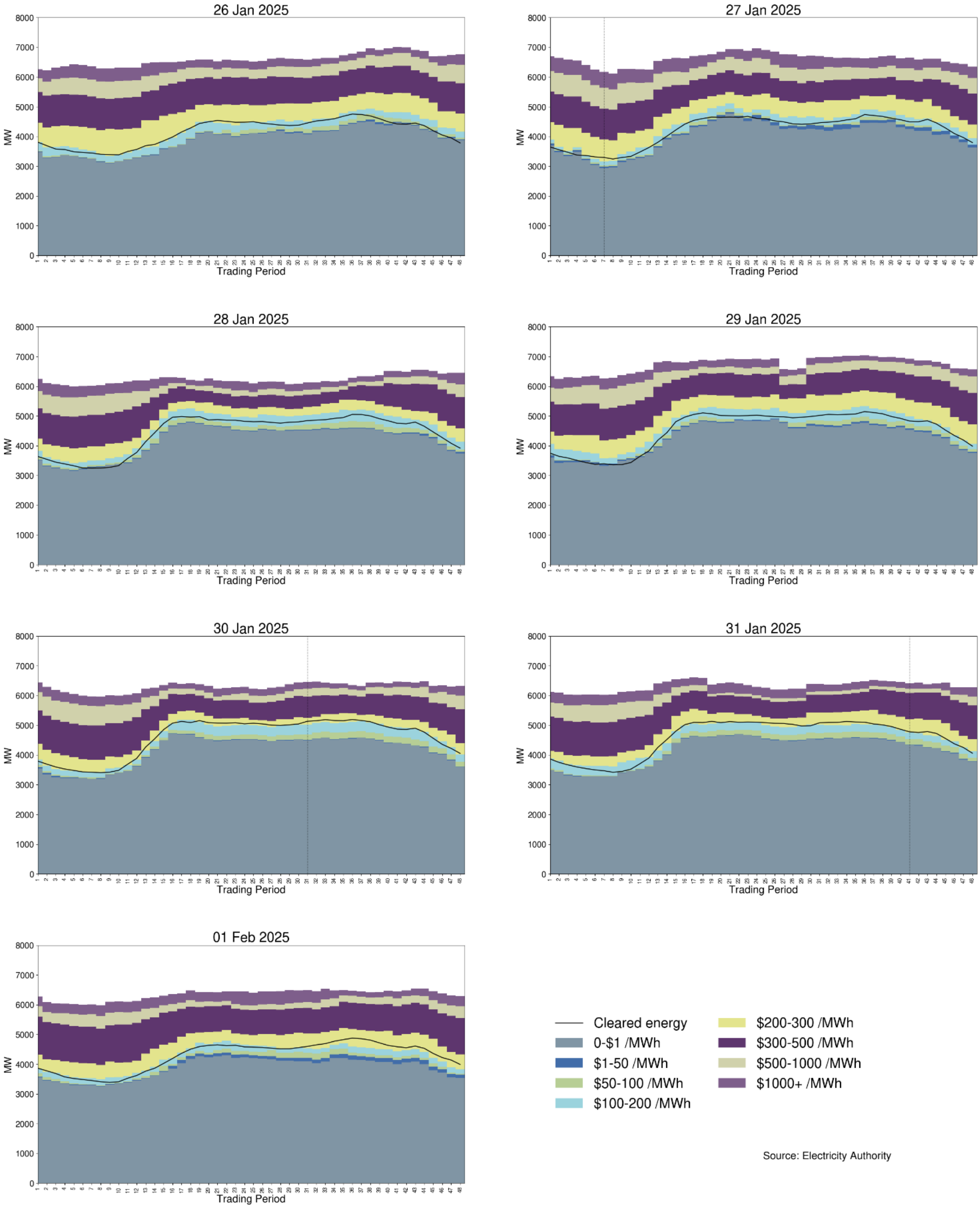


12. Offer behaviour

12.1. Figure 21 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 offers were clearing in the $100-200/MWh or $200-300/MWh bands this week. The drop in offers on 29 January was due to the Clyde unit outages.

Figure 21: Daily offer stacks



Source: Electricity Authority

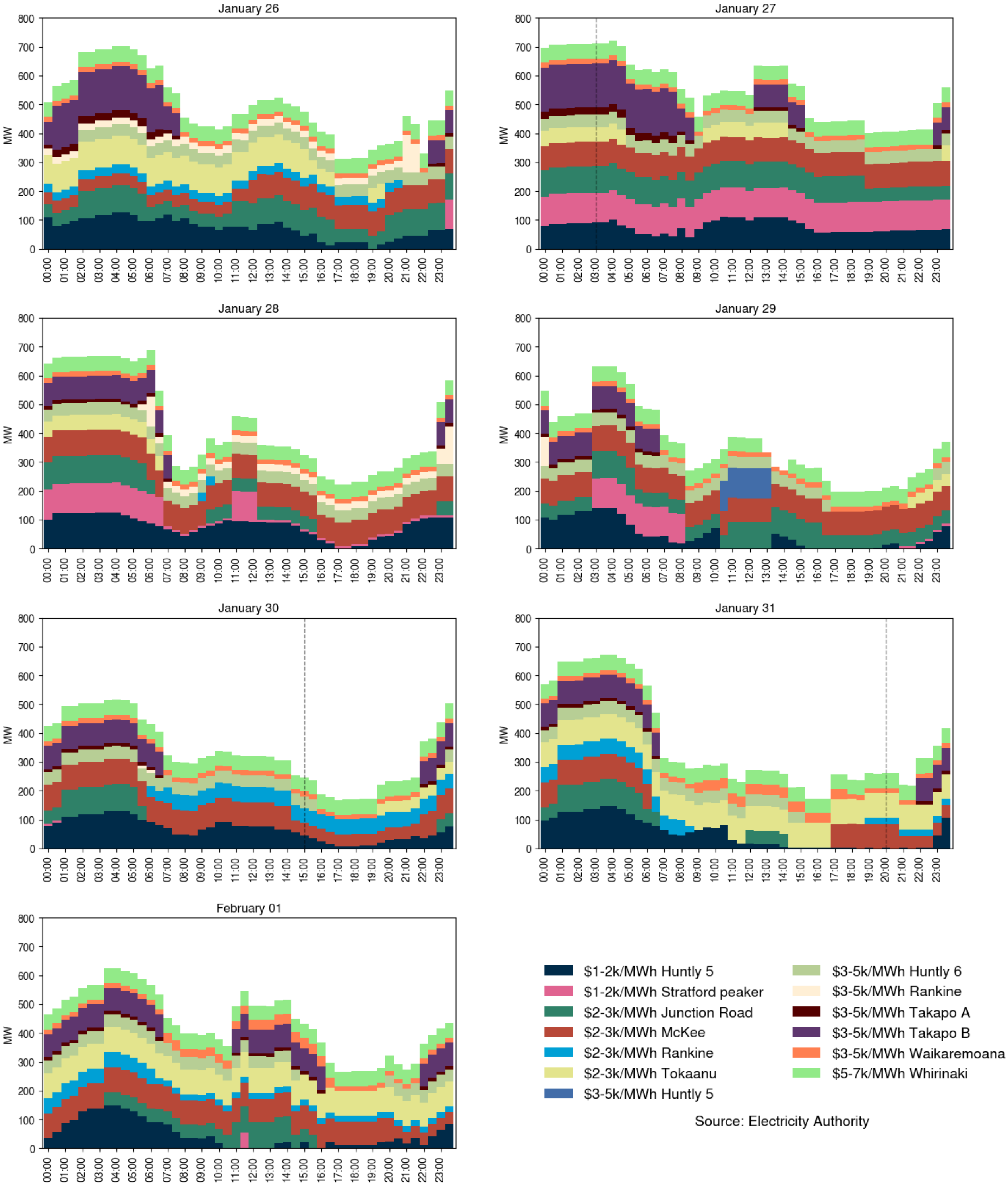
12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

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 426MW per trading period was priced above $1,000/MWh this week, which is roughly 7.8% of the total energy available. The highest proportion of high-priced energy occurred in the early hours of the morning.

12.6. The monitoring team will be looking further into high priced overnight offers at Takapō.

Figure 22: 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. The monitoring team is looking further into high overnight offers at Takapō.

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
14/06/2023-15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers
12-18/12/2024	Several	Further analysis	Genesis	Tokaanu	Hydro offers
26/01/2025-1/02/2025	Several	Further analysis	Genesis	Takapō	Hydro offers
29/01/2025	34-40	Further analysis	N.A	N.A	Reserve prices