6 January 2025

Trading conduct report 22 December 2024 - 4 January 2025

Market monitoring weekly report

Trading conduct report 22 December 2024 - 4 January 2025

1. Overview

1.1. This trading conduct report covers the two-week period from 22 December 2024 to 4 January 2025. Spot prices were low over the last fortnight due to low demand during the holiday period and a high proportion of renewable generation. National hydro storage reduced to ~93% full. HVDC flow remains mostly northward and thermal generation has been low.

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 22 December 2024 - 4 January 2025:

(a) the average wholesale spot price across all nodes was $4/MWh.

(b) 95% of prices fell between $0.01/MWh and $17/MWh.

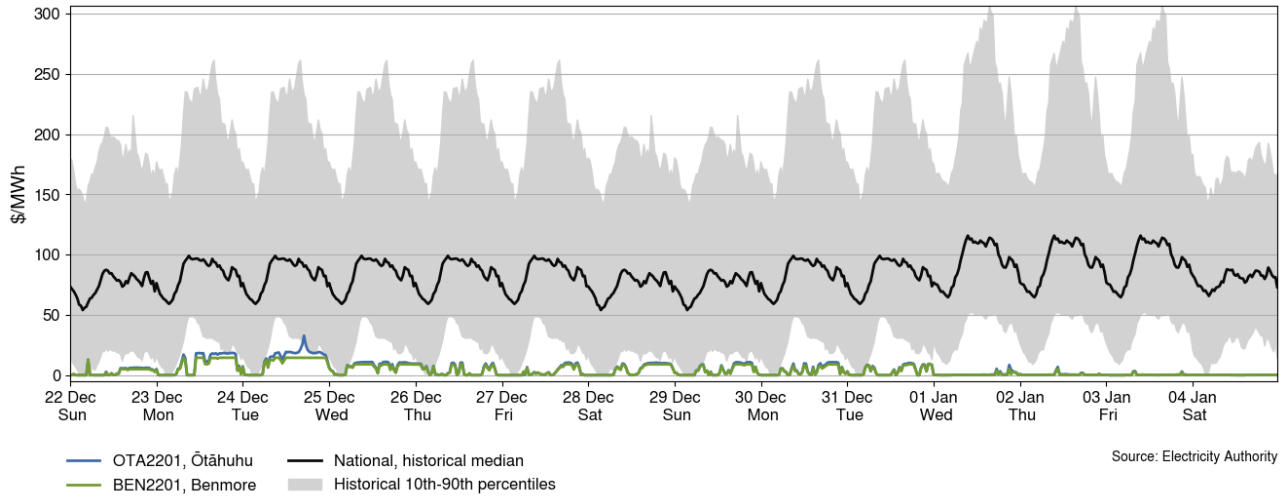
2.3. Across the holiday period most spot prices were within $0.12/MWh and $8/MWh. From 22-29 December, the weekly average spot price was $5.95/MWh, decreasing to $1.95/MWh the following week.

2.4. The highest price at Ōtāhuhu was $33/MWh at 5.00pm on Tuesday 24 December when hydro generation and HVDC northward flow were at their highest for the fortnight.

2.5. Prices were almost entirely below the historic 10th percentile during the last fortnight. This is likely the result of reduced holiday demand and a high proportion of renewable generation.

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation.

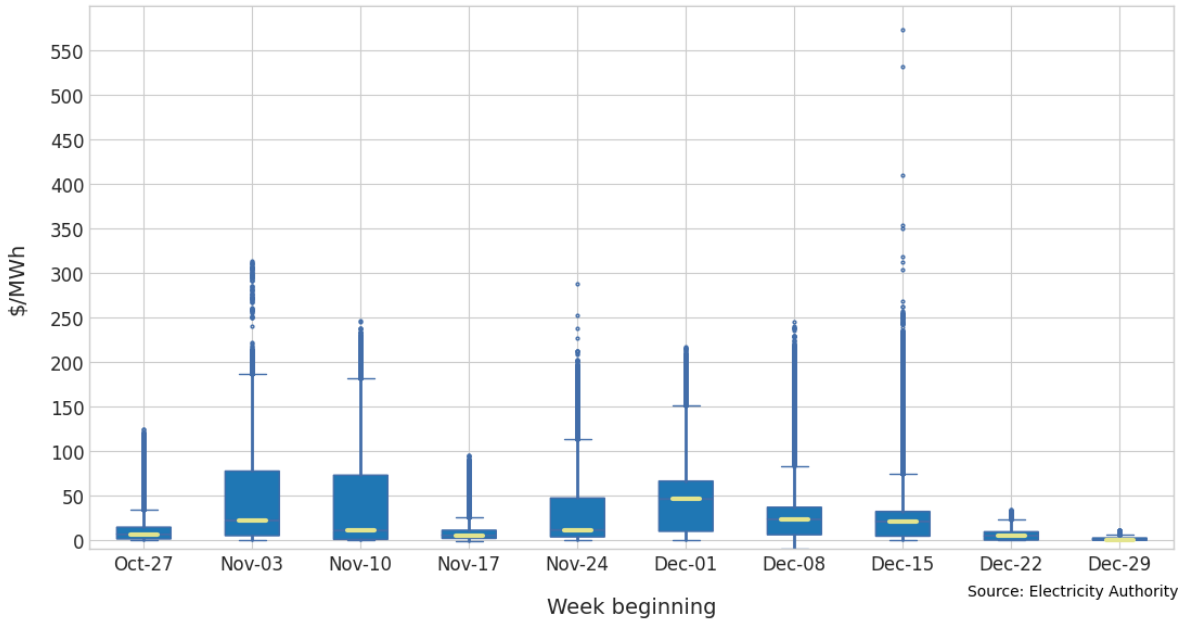
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 22 December 2024 - 4 January 2025



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. Prices for the last two weeks have been very low with a narrow distribution. The median price was $4.90/MWh for the week starting 22 December and $0.23/MWh for the week starting 29 December. The middle 50% of prices dropped from $0.04-9.50/MWh in the week starting 22 December to $0.17-2.55/MWh in the week starting 29 December.

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 and sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. FIR and SIR prices were mostly below $1/MWh for the last two weeks. The highest North Island FIR price was $7/MWh at 5.00pm on Tuesday 24 December when the HVDC northward flow was high and the HVDC was setting the North Island risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 22 December 2024 - 4 January 2025

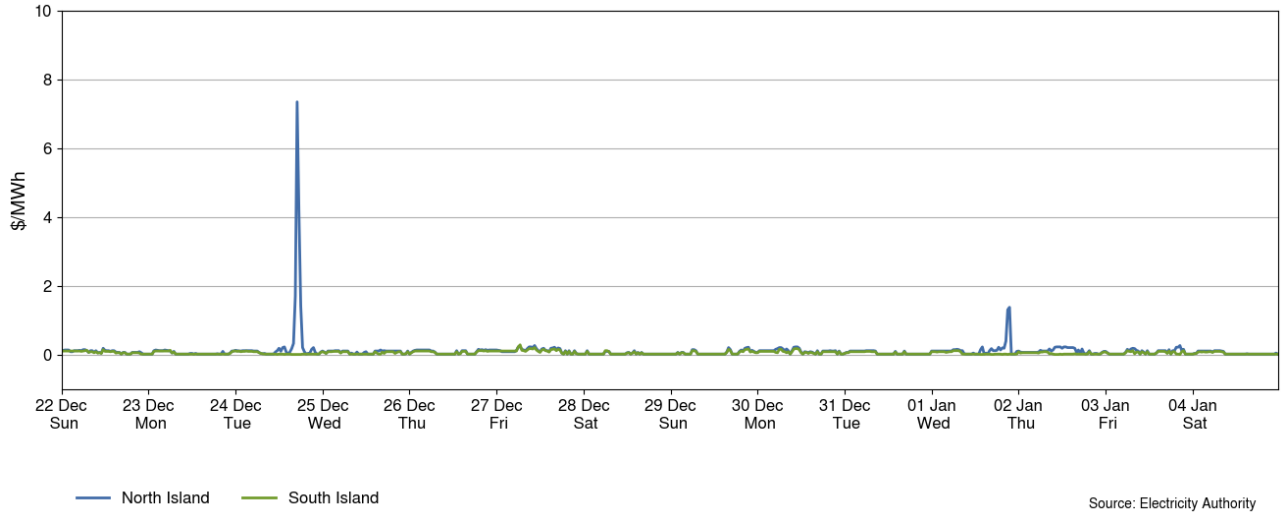
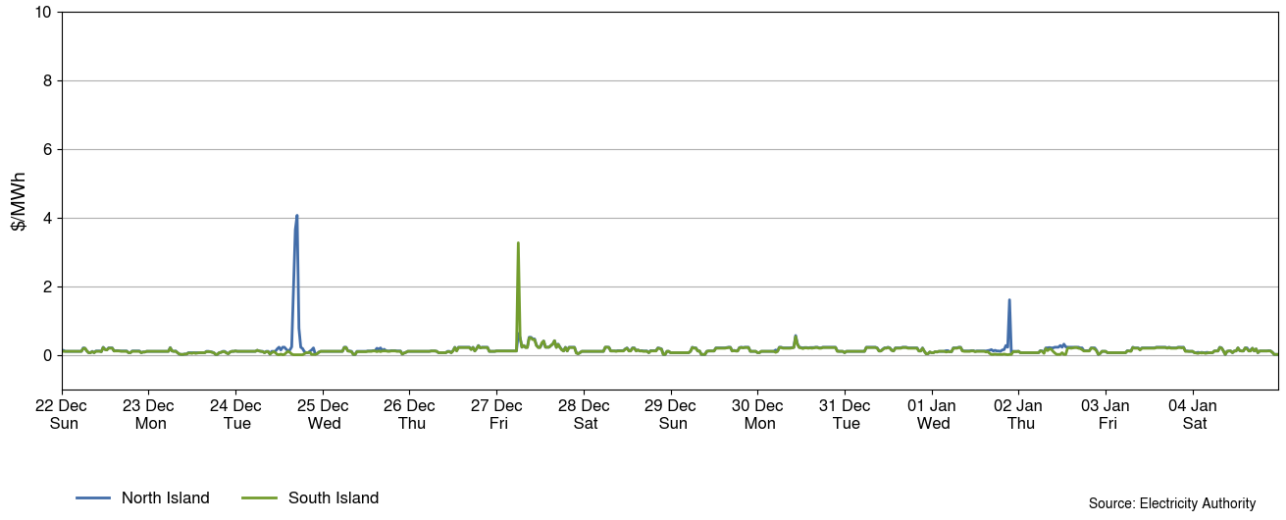


Figure 4: Sustained instantaneous reserve by trading period and island, 22 December 2024 - 4 January 2025



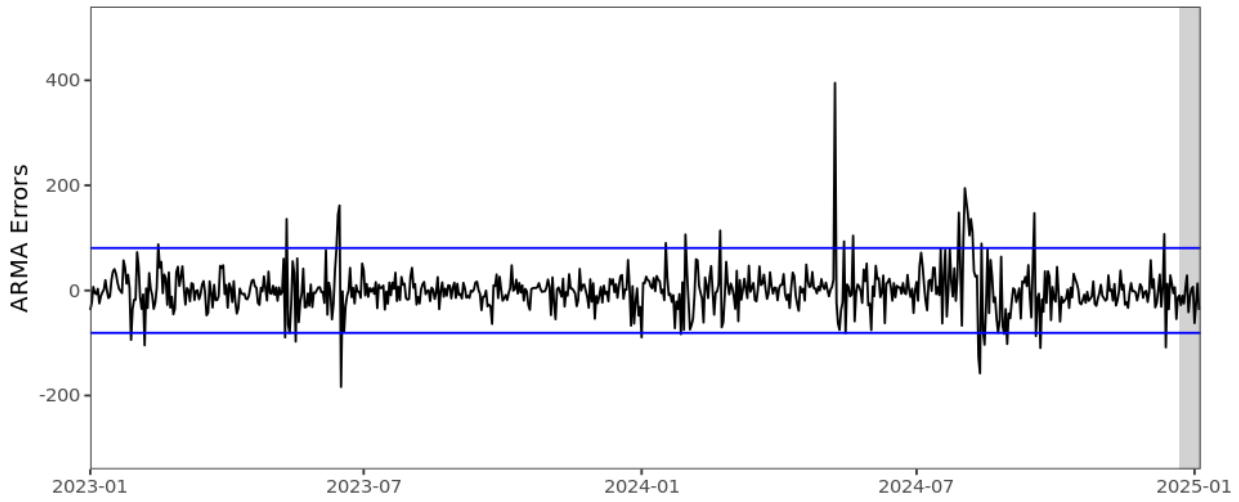
4. Regression residuals

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 fortnight, 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 – 4 January 2025

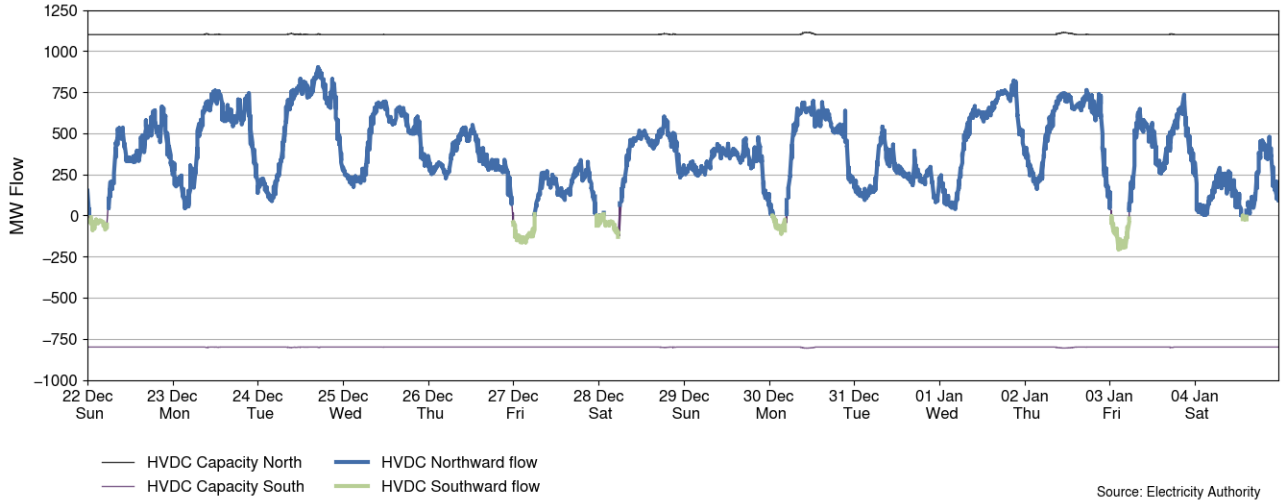


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 22 December 2024 - 4 January 2025. HVDC flows were mostly northward with some brief periods of overnight southward flow.

Figure 6: HVDC flow and capacity, 22 December 2024 - 4 January 2025



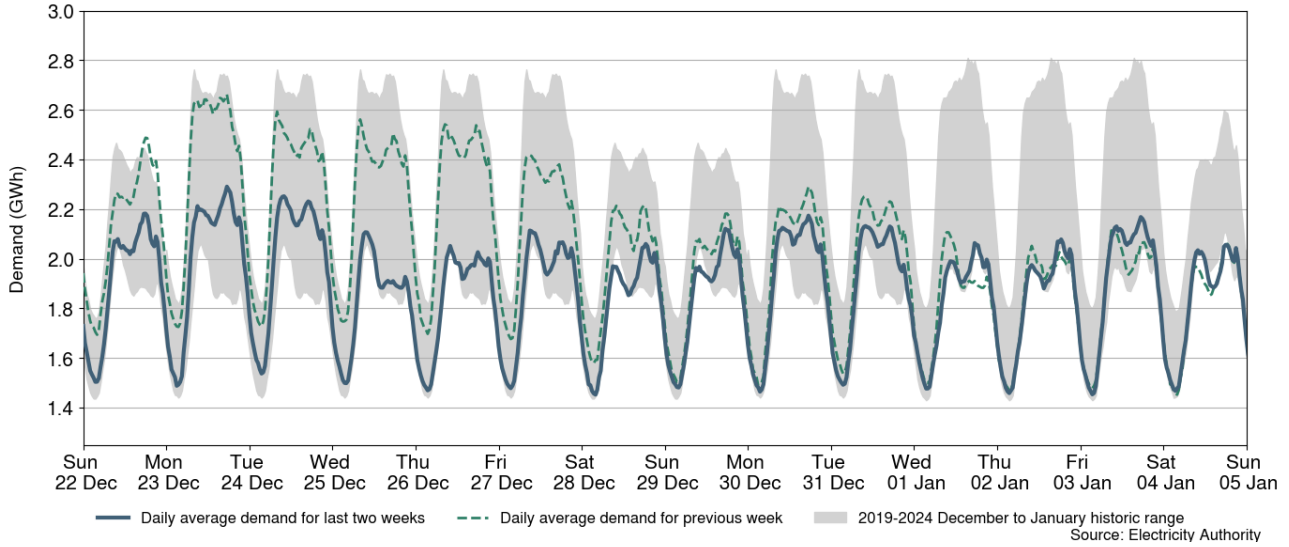
Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 22 December 2024 - 4 January 2025, compared to the historic range and the demand of the previous week. Demand was near the low end of the historic range from 25 December when the holiday period began.

6.2. The maximum demand this fortnight was around 2.29GWh (4.58GW) at 5:30pm on Monday 23 December.

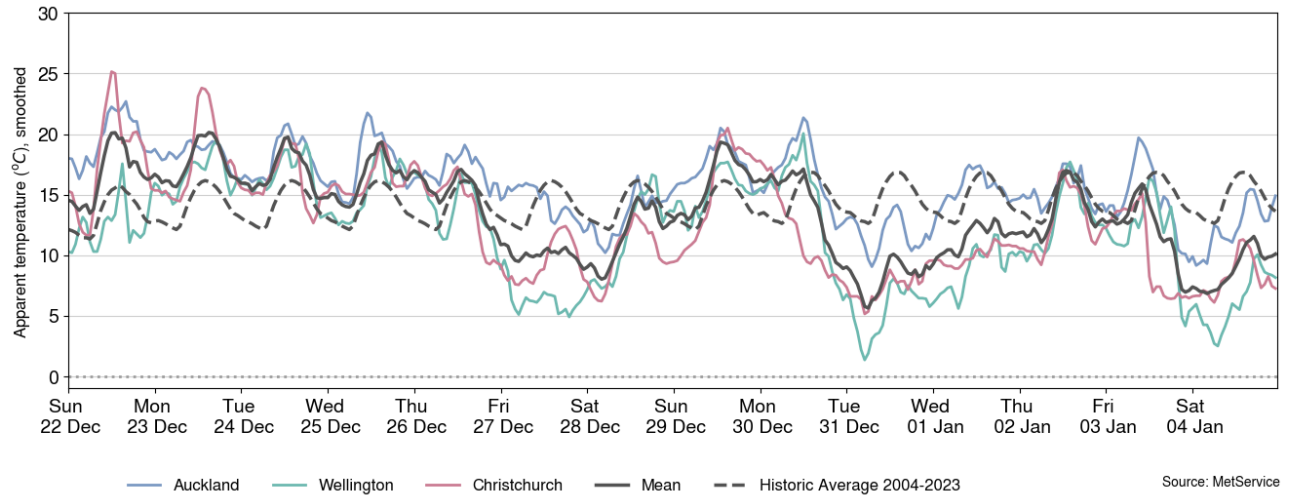
Figure 7: National demand, 22 December 2024 - 4 January 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 22 December 2024 - 4 January 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.

6.4. Apparent temperatures for the last two weeks ranged from 8°C to 24°C in Auckland, 1°C to 20°C in Wellington, and 4°C to 26°C in Christchurch. Apparent temperatures were mostly at or below the historic average during the last two weeks, except for 22-26 December and 29-30 December when they were above average.

Figure 8: Temperatures across main centres, 22 December 2024 - 4 January 2025

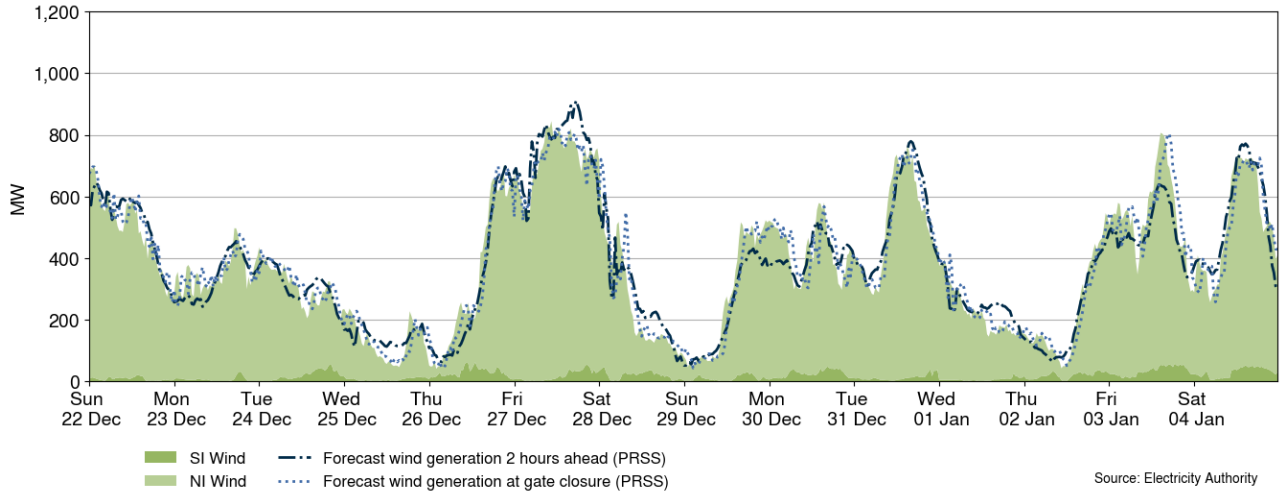


7. Generation

7.1. Figure 9 shows wind generation and forecast from 22 December 2024 - 4 January 2025. Wind generation varied between 41MW and 844MW, with an average of 378MW. Wind generation was highest on 27 December with a daily average of 725MW and lowest on 25 December with a daily average of 131MW.

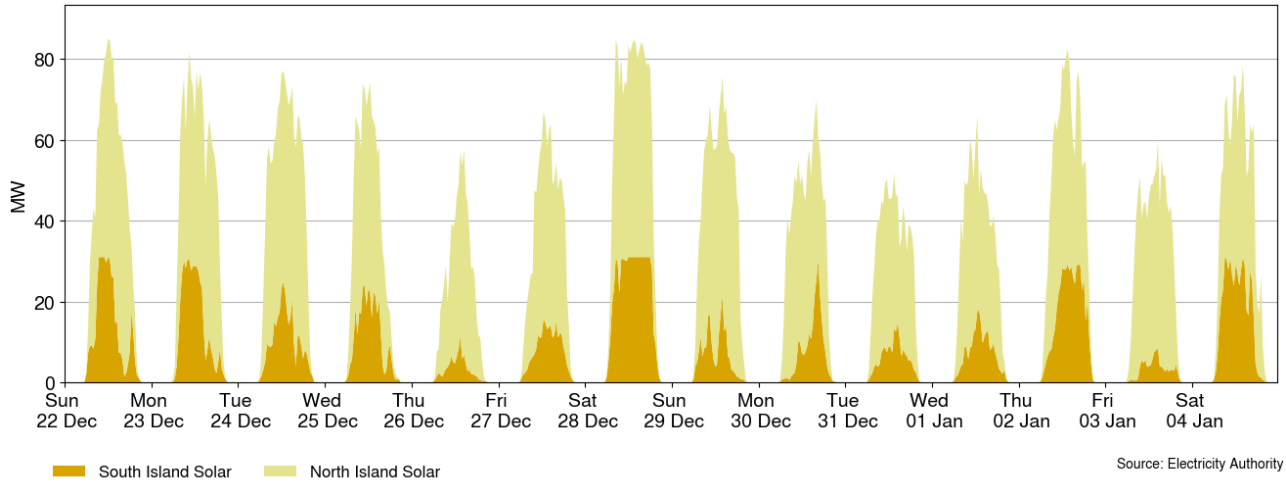
7.2. The greatest negative discrepancy between wind generation and the gate closure forecast was ~190MW at 7.30am on 28 December.

Figure 9: Wind generation and forecast, 22 December 2024 - 4 January 2025



7.3. Figure 10 shows solar generation from 22 December 2024 - 4 January 2025. Solar generation peaked above 60MW most days in the last fortnight, except for 26 and 31 December and 3 January.

Figure 10: Solar generation, 22 December 2024 - 4 January 2025



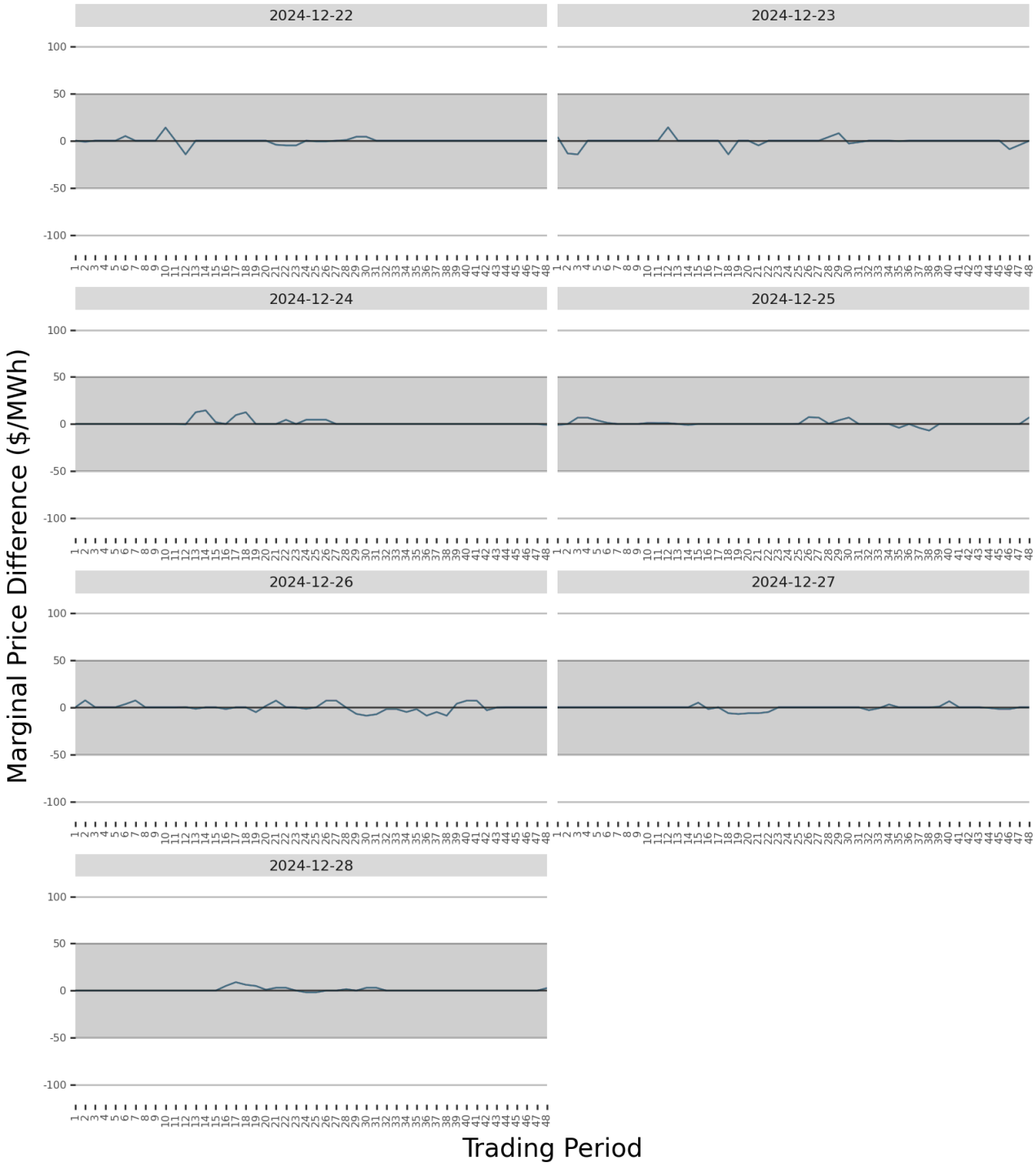
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 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

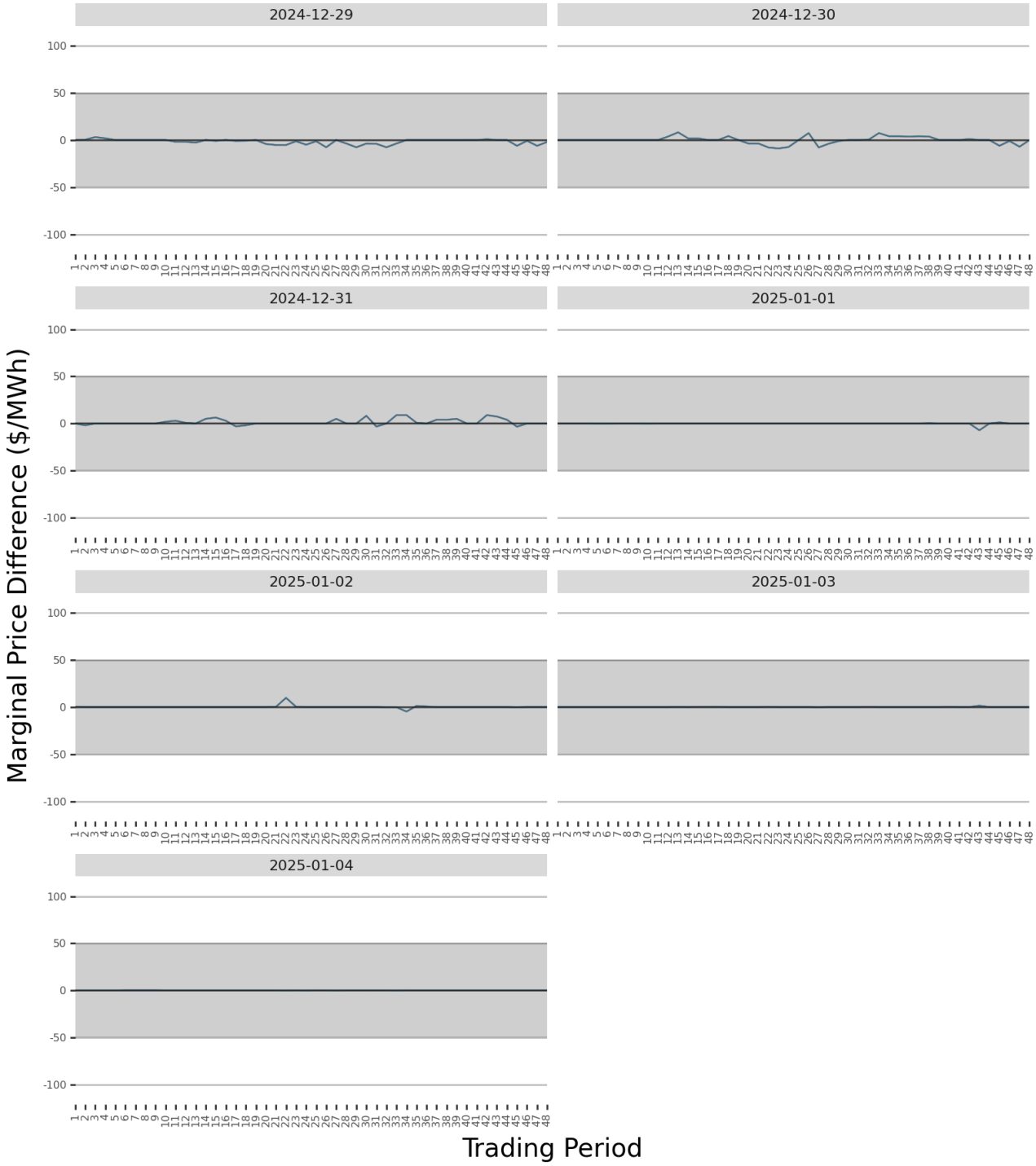
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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

7.5. Marginal price differences were less than $50/MWh every day in the last fortnight.

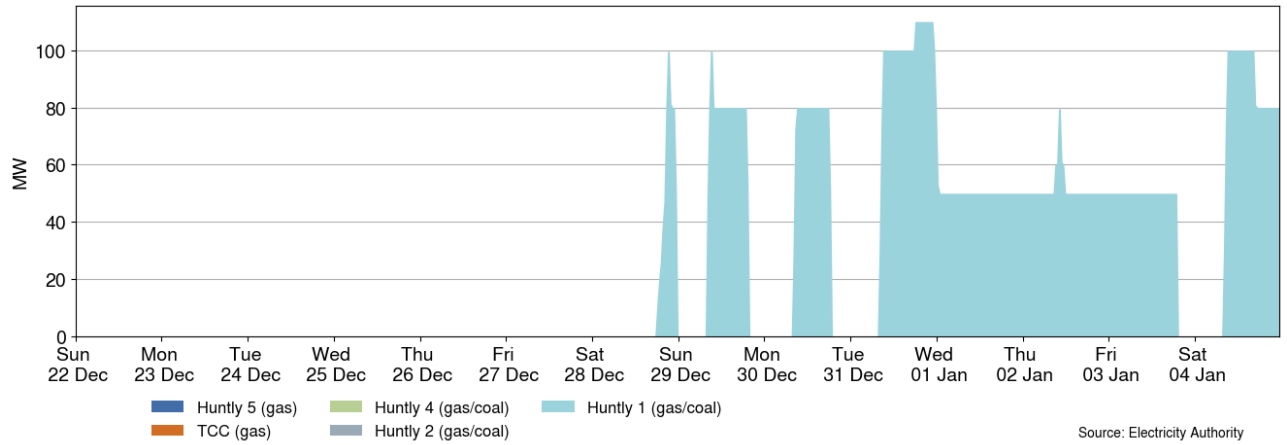
Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 22 December 2024 - 4 January 2025





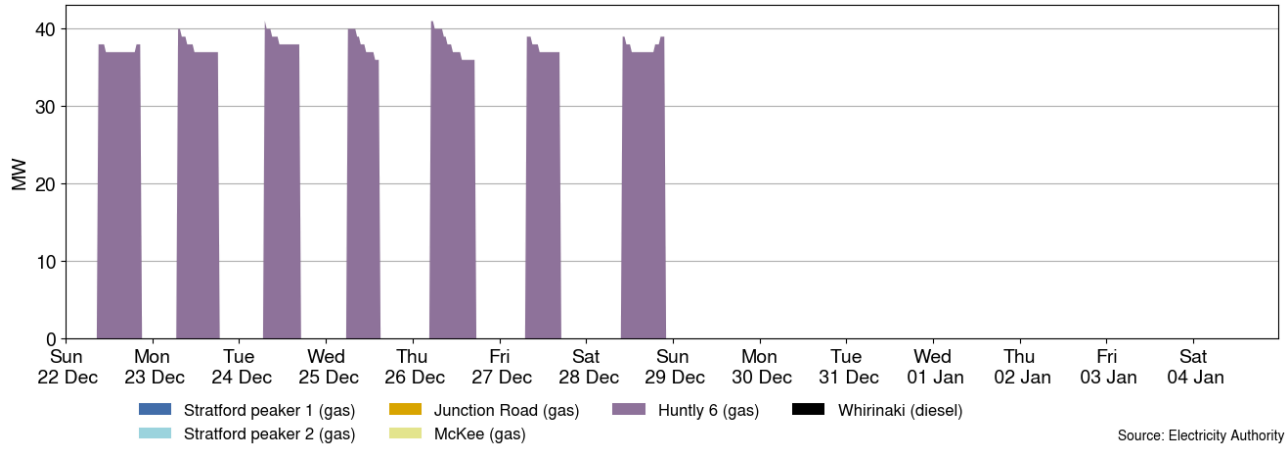
7.6. Figure 12 shows the generation of thermal baseload between 22 December 2024 - 4 January 2025. Thermal baseload generation was provided by Huntly 1 from 28 December, which ran continuously from 31 December to 3 January.

Figure 12: Thermal baseload generation, 22 December 2024 - 4 January 2025



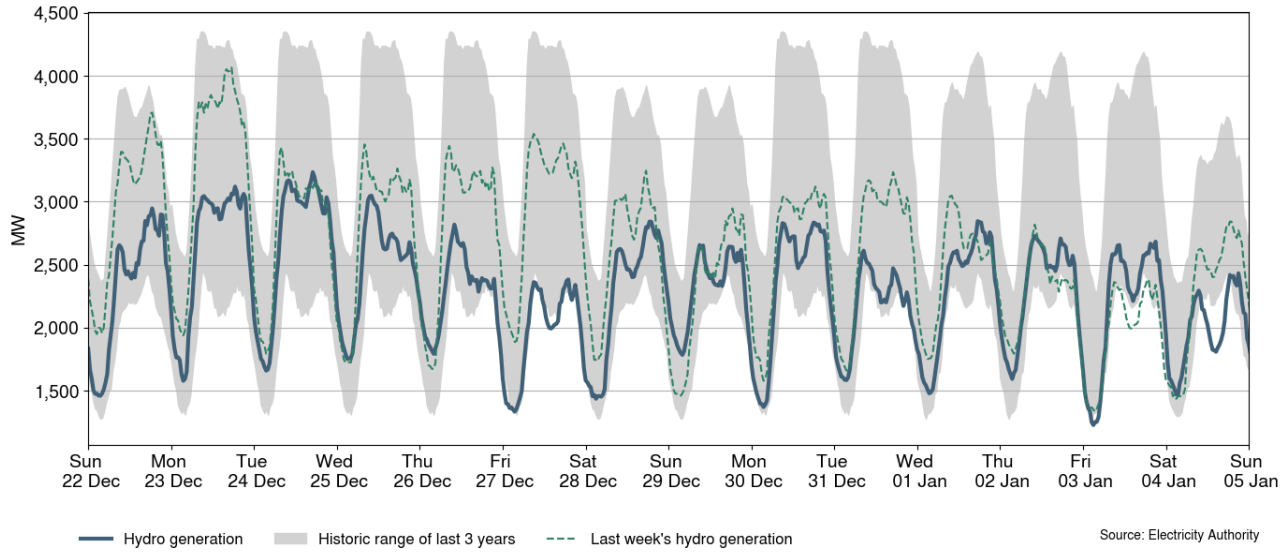
7.7. Figure 13 shows the generation of thermal peaker plants between 22 December 2024 - 4 January 2025. Peaker generation was provided by Huntly 6 during the day from 22 December to 28 December.

Figure 13: Thermal peaker generation, 22 December 2024 - 4 January 2025



7.8. Figure 14 shows hydro generation between 22 December 2024 - 4 January 2025. Hydro generation was highest on 24 December and then was at the low end of the historic range for the rest of the fortnight, likely because of reduced demand over the holiday period.

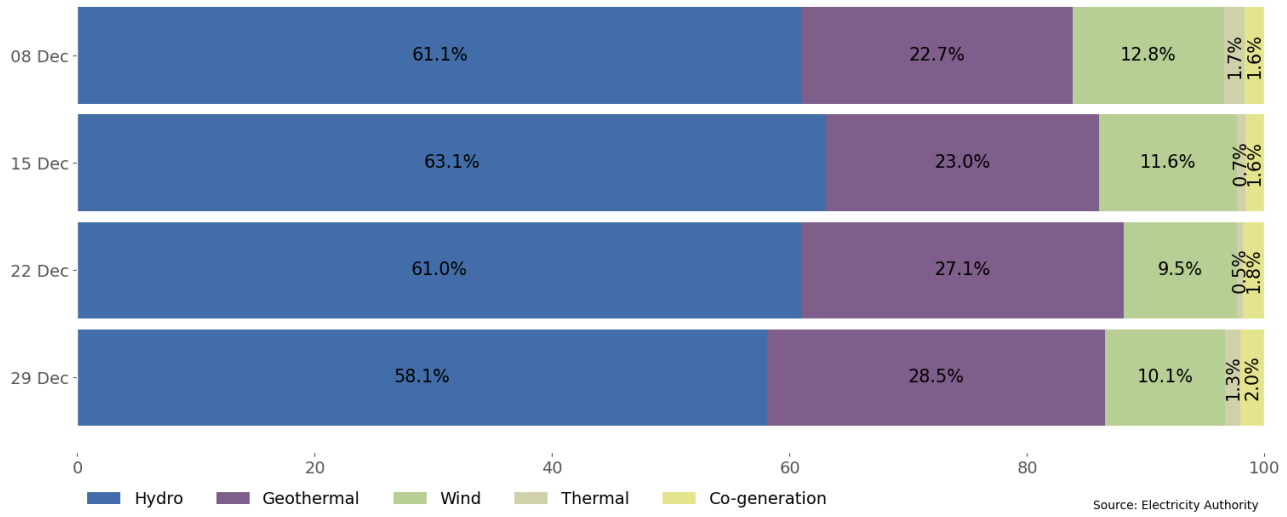
Figure 14: Hydro generation, 22 December 2024 - 4 January 2025



7.9. Figure 15 shows the generation composition for the last four weeks. Over the last fortnight, wind generation was steady at around 10% of the generation mix and hydro generation provided between 58-61% of total generation. Thermal generation over the last fortnight was low, contributing only 0.5% of the total generation mix for the week starting 22 December.

7.10. Total geothermal generation was steady over the last fortnight, but reduced demand meant that geothermal provided a greater proportion of the generation mix, increasing from 23% to 28.5%

Figure 15: Total generation by type as a percentage each week, 8 December 2024 – 4 January 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 22 December 2024 - 4 January 2025 ranged between ~950MW and ~1,200MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 14 March 2025.

(b) Huntly 4 is on outage until 10 January 2025.

(c) Manapōuri unit 4 is on outage until 18 September 2025.

(d) Rangipō unit 6 is on outage until 11 April 2025.

Figure 16: Total MW loss from generation outages, 22 December 2024 - 4 January 2025

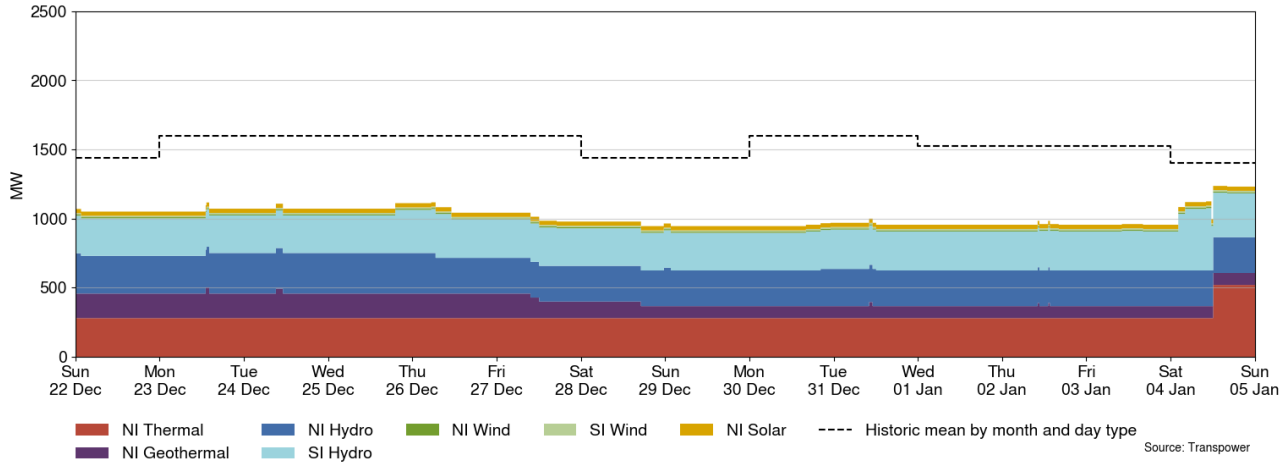
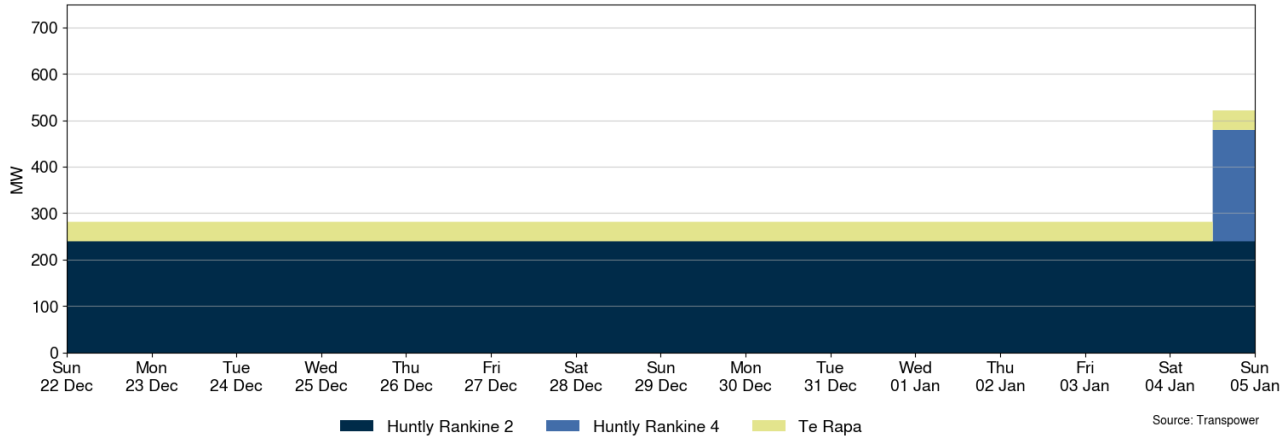


Figure 17: Total MW loss from thermal outages, 22 December 2024 - 4 January 2025

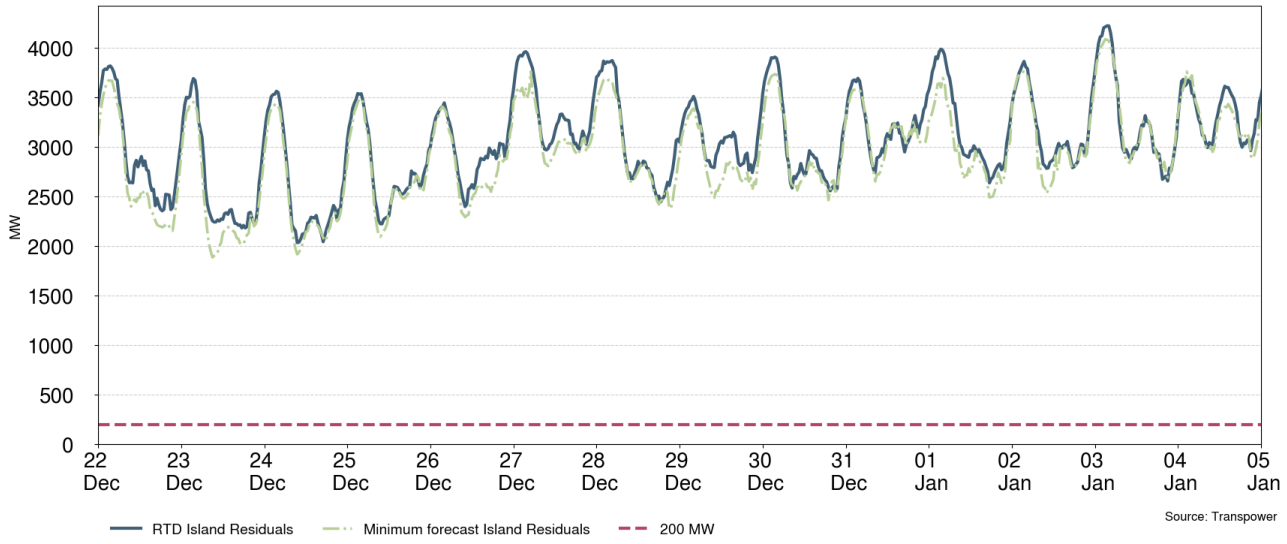


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 22 December 2024 - 4 January 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. The minimum North Island residual this fortnight was ~1,200MW at 6.00pm on 28 December.

Figure 18: National generation balance residuals, 22 December 2024 - 4 January 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.

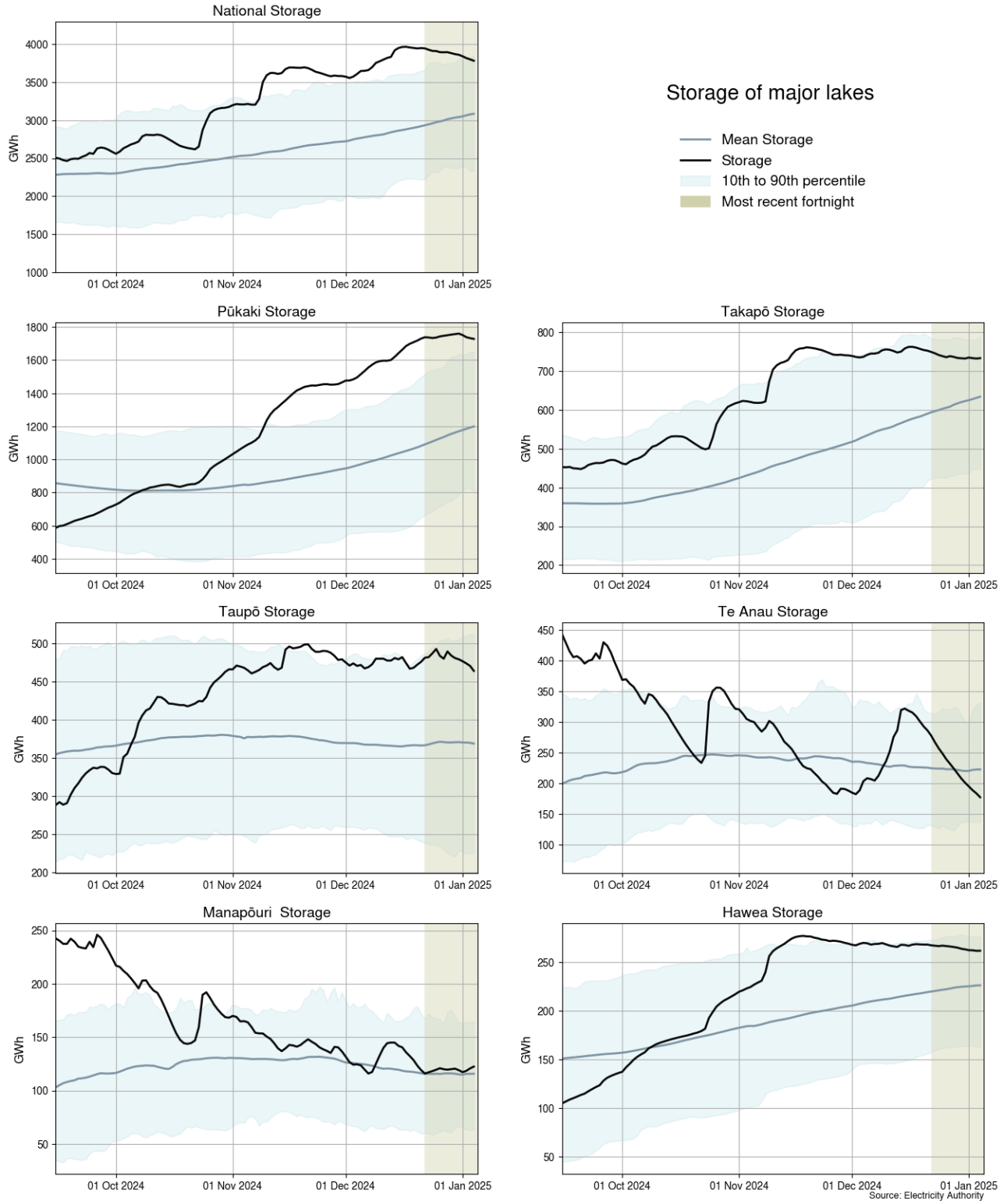
10.2. National controlled storage has decreased to below the 90th percentile over the last fortnight. As of 4 January, national storage was ~93% nominally full and ~122% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki has remained steady above its 90th percentile and is currently 98% full. Storage at Lakes Takapō (95% full) and Hawea (92% full) decreased slightly and are between their respective historical mean and 90th percentile.[2]

10.4. Storage at Lake Manapōuri has remained steady near the historical mean and storage at Lake Te Anau has dropped below its historical mean in the last two weeks.

[2] Percentage full values sourced from NZX Hydro.

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 December 2024. The SRMC for gas fuelled generation has decreased compared to last month and the SRMC for coal and diesel fuelled generation remains similar to last month.

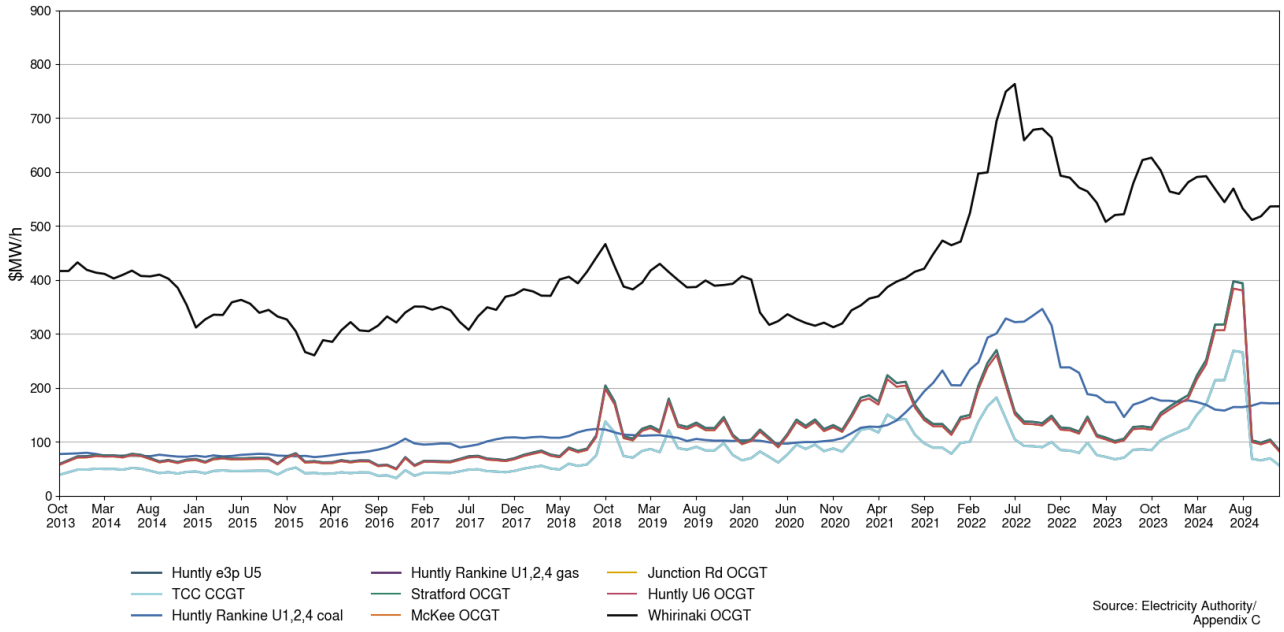
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$171/MWh, with the cost of running the Rankines on gas remaining lower at ~$85/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $56/MWh and $85/MWh.

11.6. The SRMC of Whirinaki is ~$536/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 and Figure 22 shows this fortnight'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 below $1/MWh in the last fortnight, likely due to reduced demand over the holiday period. Most offers were under $50/MWh and the $50-$100/MWh band became very small from 25 December.

Figure 21: Daily offer stacks from 22-28 December 2024

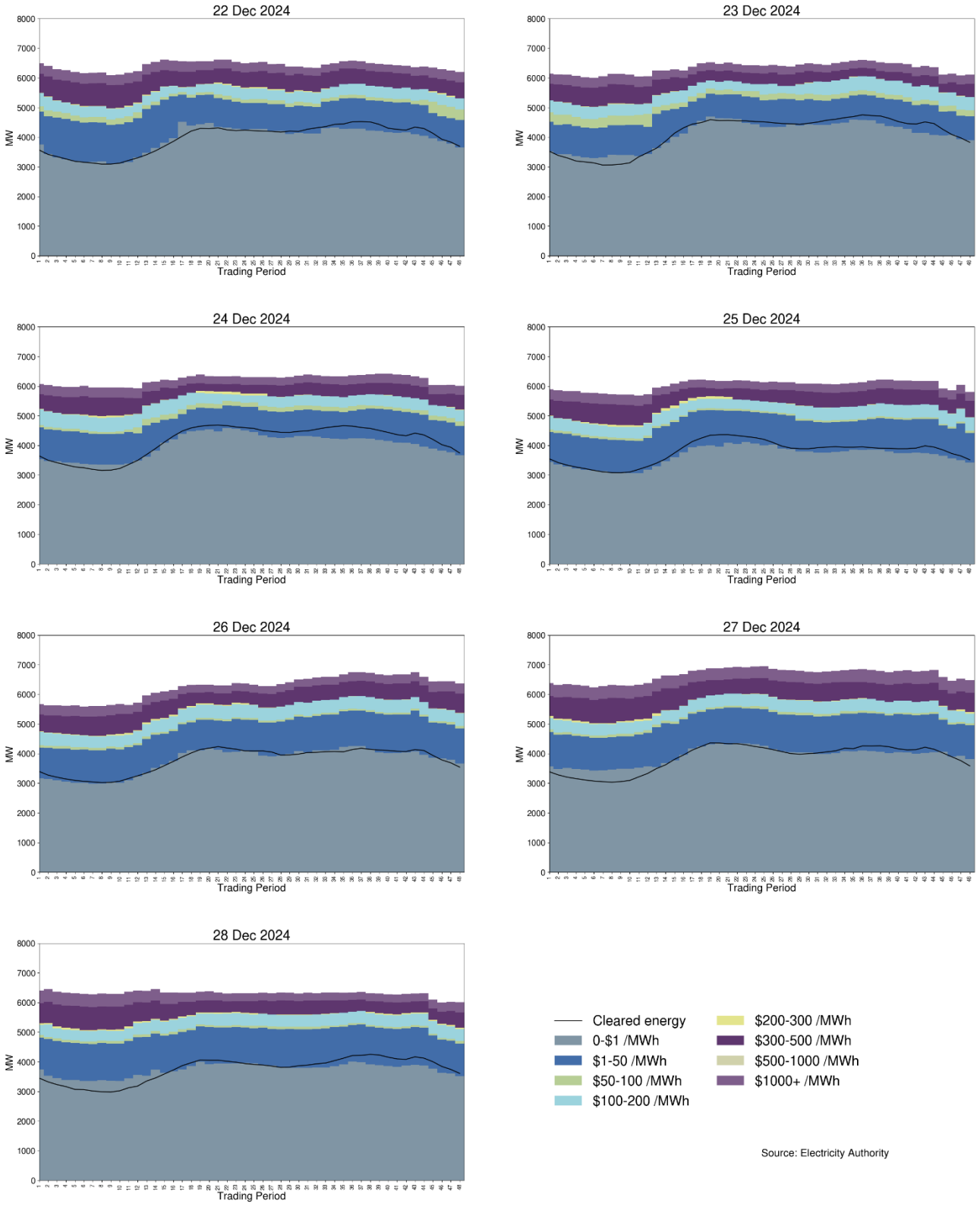
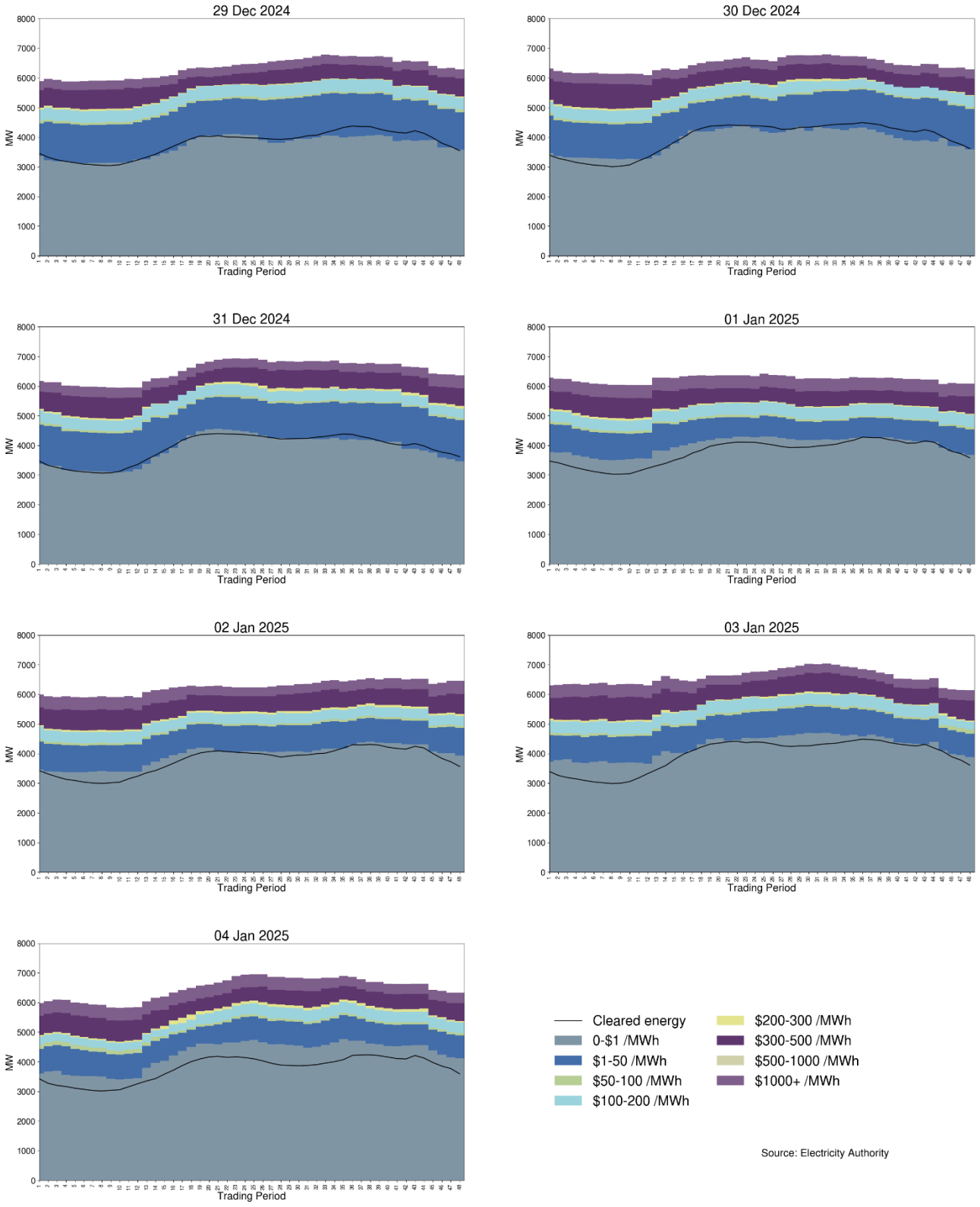


Figure 22: Daily offer stacks from 29 December 2024 - 4 January 2025



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. For the week starting 22 December, an average of 493MW or 7.8% of the total energy available was priced above $1000/MWh and for the week starting 29 December, 550MW or 8.6% of the total energy available was priced above $1000/MWh.

Figure 23: High priced offers from 22-28 December 2024

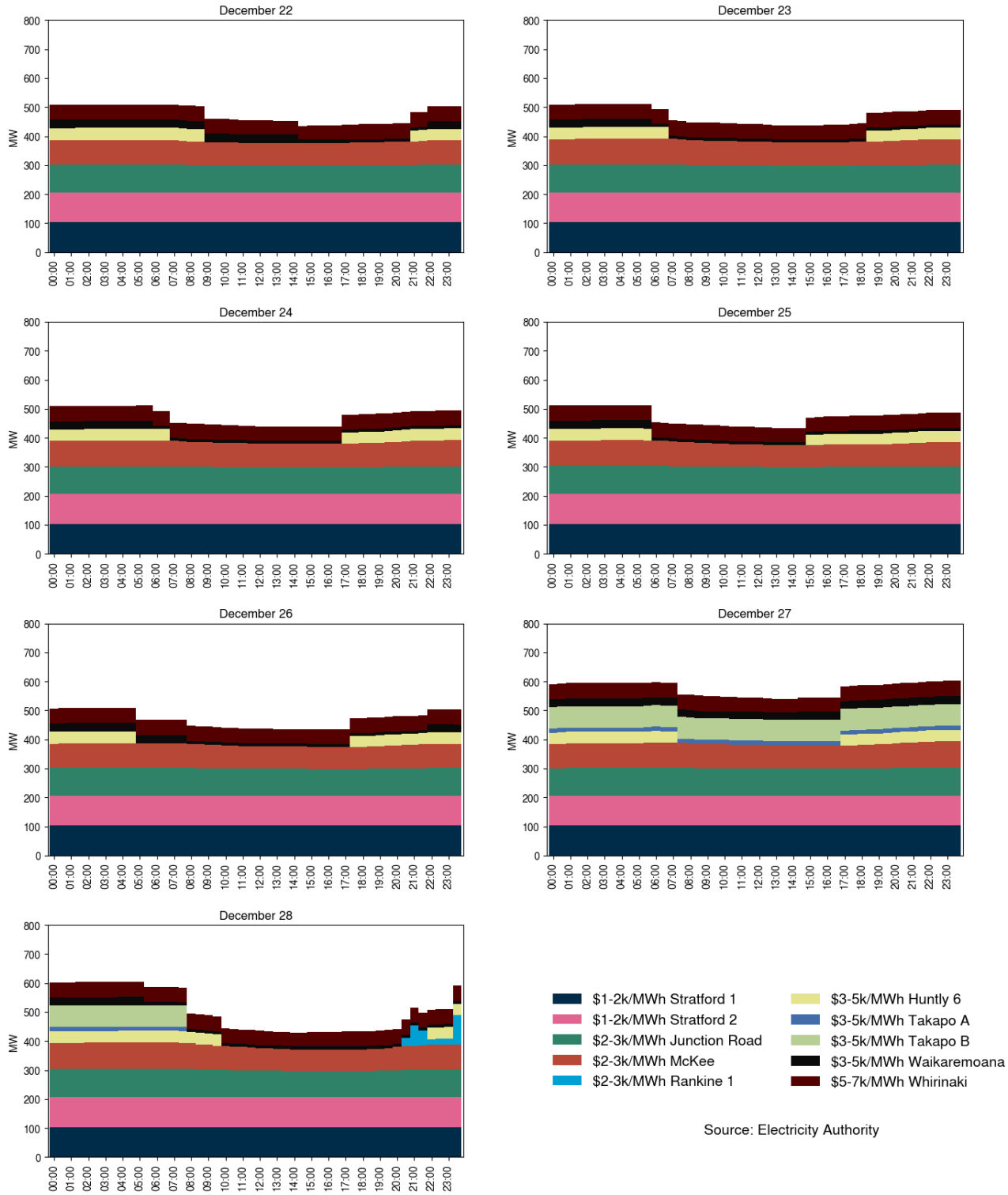
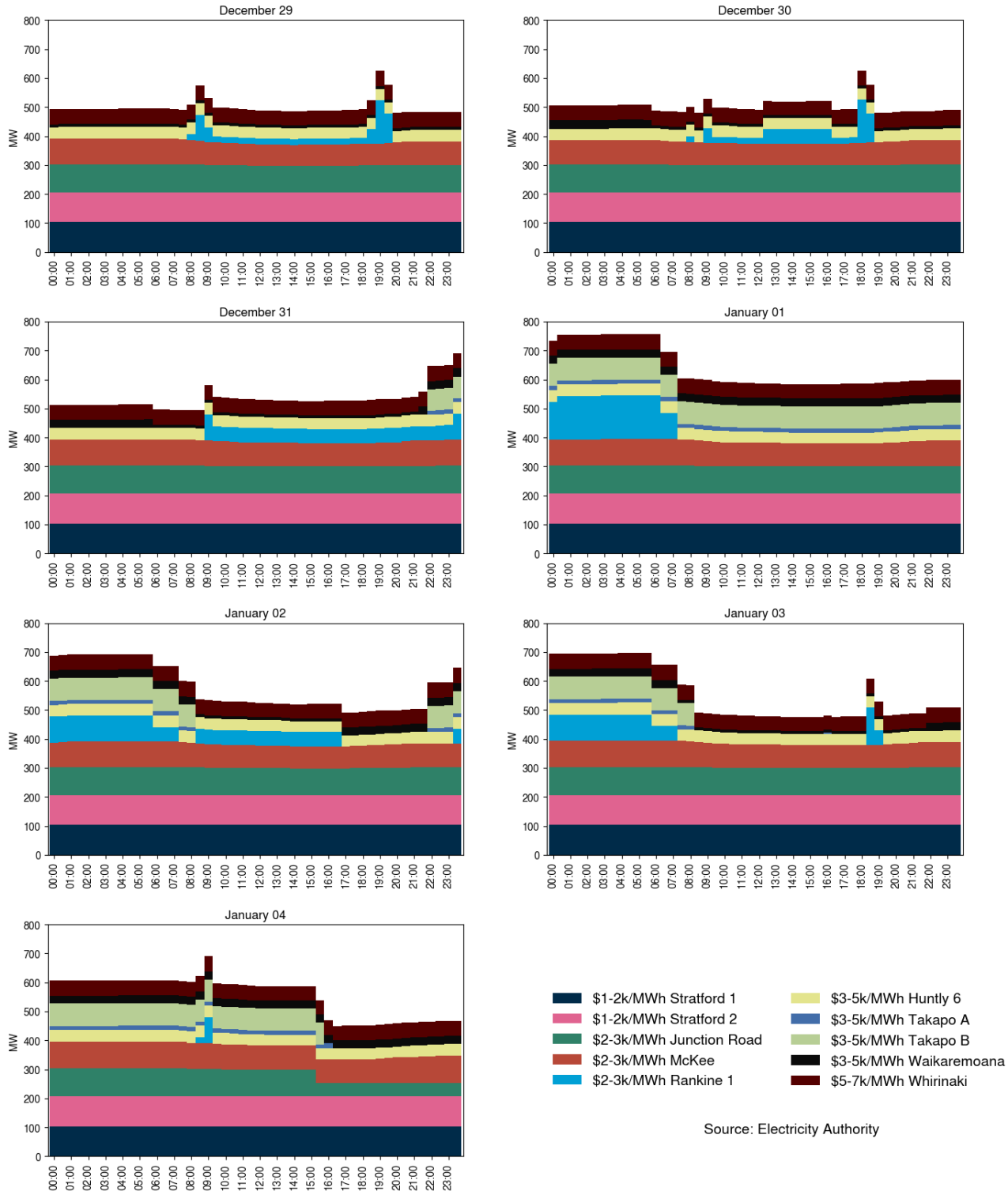


Figure 24: High priced offers from 29 December 2024 - 4 January 2025



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
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers
8-14/12/2024	Several	Further analysis	Genesis	Waikaremoana	Hydro offers