16 December 2024

Trading conduct report 8-14 December 2024

Market monitoring weekly report

Trading conduct report 8-14 December 2024

1. Overview

1.1. Spot prices decreased slightly compared to last week and were mostly below the historical median. Hydro storage increased to ~95% nominally full. Thermal generation remains low. HVDC pole 2 tripped on Thursday morning triggering reserve scarcity and high North Island spot 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 8-14 December 2024:

(a) the average wholesale spot price across all nodes was $45/MWh.

(b) 95% of prices fell between $0.03/MWh and $166/MWh.

2.3. Overall, the majority of spot prices were within $5-$36/MWh and the weekly average price decreased by $3/MWh compared to the previous week.

2.4. Huntly 1 tripped around 5pm on Monday causing the 5.30pm Ōtāhuhu price to spike to $167/MWh while the Benmore price remained low at $52/MWh. Huntly 1 generation resumed from just after 7pm before turning off at midnight.

2.5. Wednesday spot prices peaked at 4.30pm at $121/MWh at Ōtāhuhu and $88/MWh at Benmore when national demand was ~90MW higher than forecast. Prices dropped at 5.00pm to $45/MWh at Ōtāhuhu and $32/MWh at Benmore despite similar demand because the amount of low priced hydro offers increased.

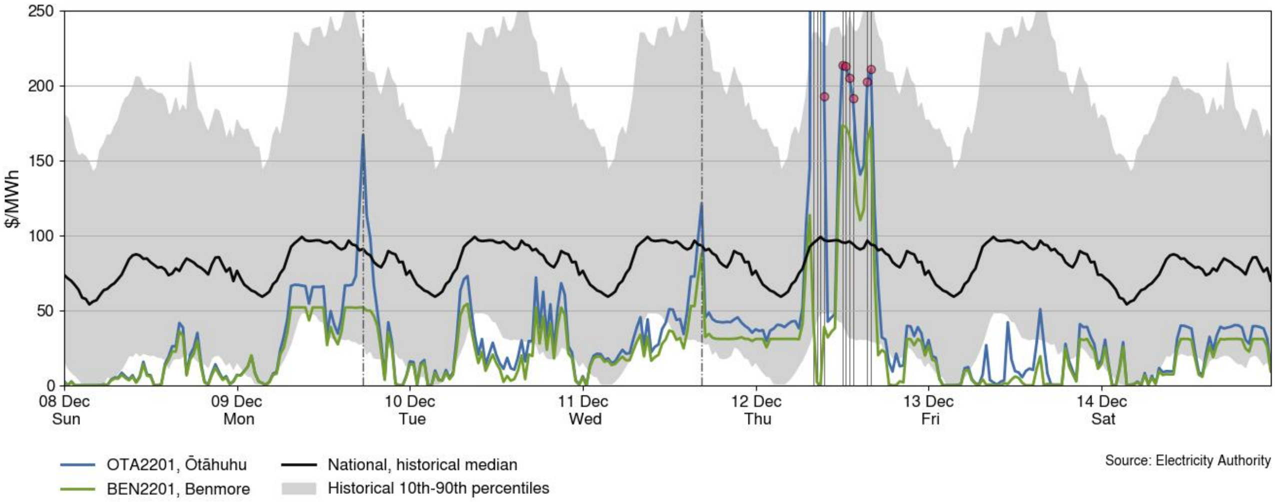
2.6. The highest price at Ōtāhuhu this week was $4,877/MWh at 8:30am on Thursday. This was due to HVDC pole 2 tripping at 8.18am when wind generation was low and lower than forecast by more than 100MW and when demand was at its peak for the week and higher than forecast in the North Island. Reserve scarcity pricing was triggered during three 5-minute trading intervals between 8.20am-8.30am. In response, all available peakers turned on to meet the North Island demand requirements

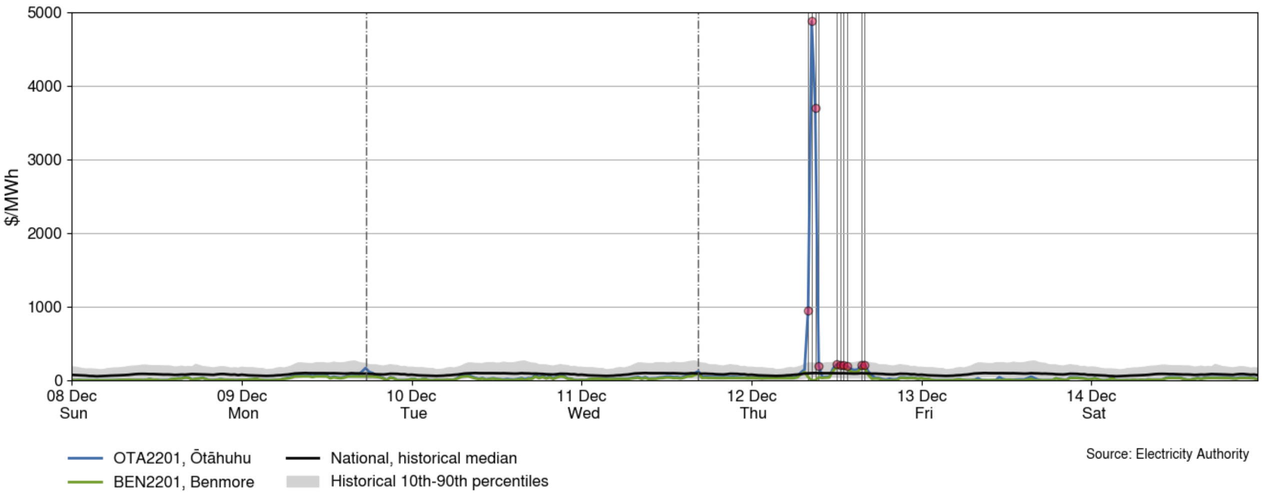
2.7. After HVDC pole 2 returned to service on Thursday around 9.30am, prices were still high compared to the rest of the week, likely because of lower wind and high demand.

2.8. Most other prices this week were below the historical median, with times of higher wind pushing prices below the historic 10th percentile.

2.9. 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, 8-14 December 2024

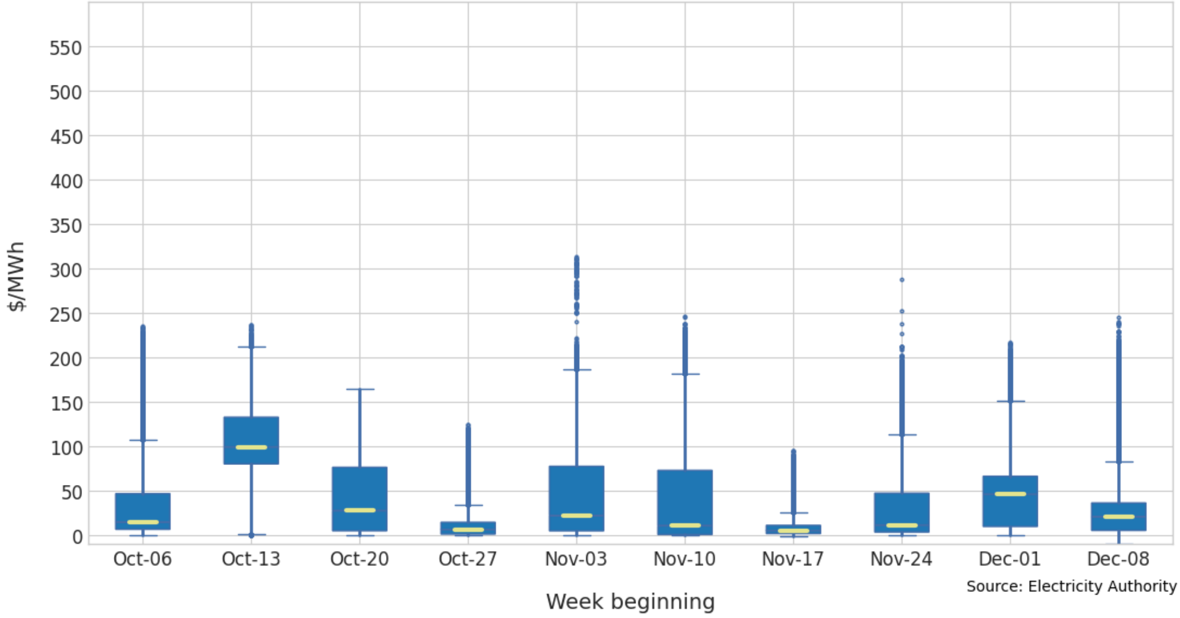




2.10. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.11. The median price reduced to $21/MWh and the middle 50% of prices reduced to between $5-36/MWh. There are more high priced outliers outside of 1.5 times the interquartile range this week, including a number of prices above $1,000/MWh not shown in Figure 2 which are related to the HVDC trip on Thursday morning.

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

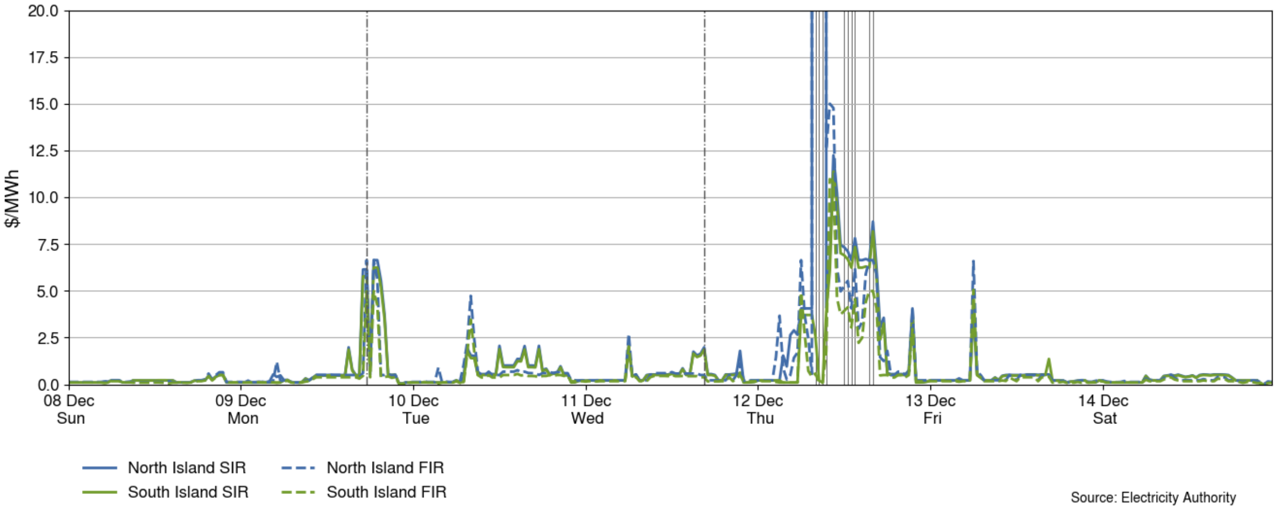


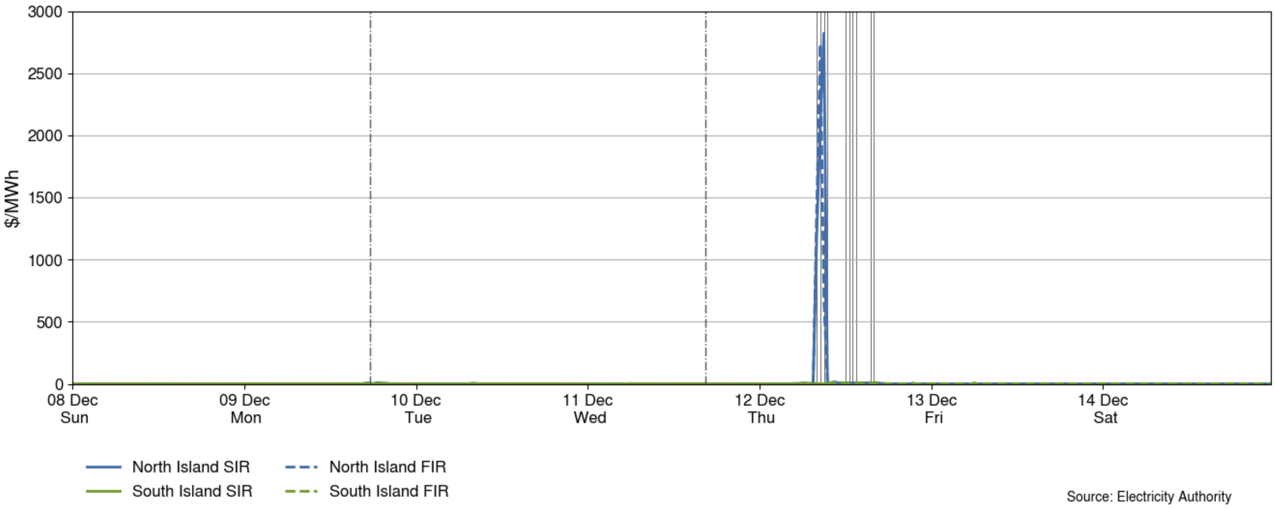
3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices and sustained instantaneous reserve (SIR) prices for the North and South Islands are shown below in Figure 3.

3.2. Reserve prices were mostly below $3/MWh this week. Half hourly North Island FIR and SIR prices spiked to over $2,500/MWh at 8.30am on Thursday when the HVDC tripped, and reserve scarcity pricing was triggered during three 5-minute trading intervals between 8.20am-8.30am.

Figure 3: Fast and sustained instantaneous reserve price by trading period and island, 8-14 December 2024





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.

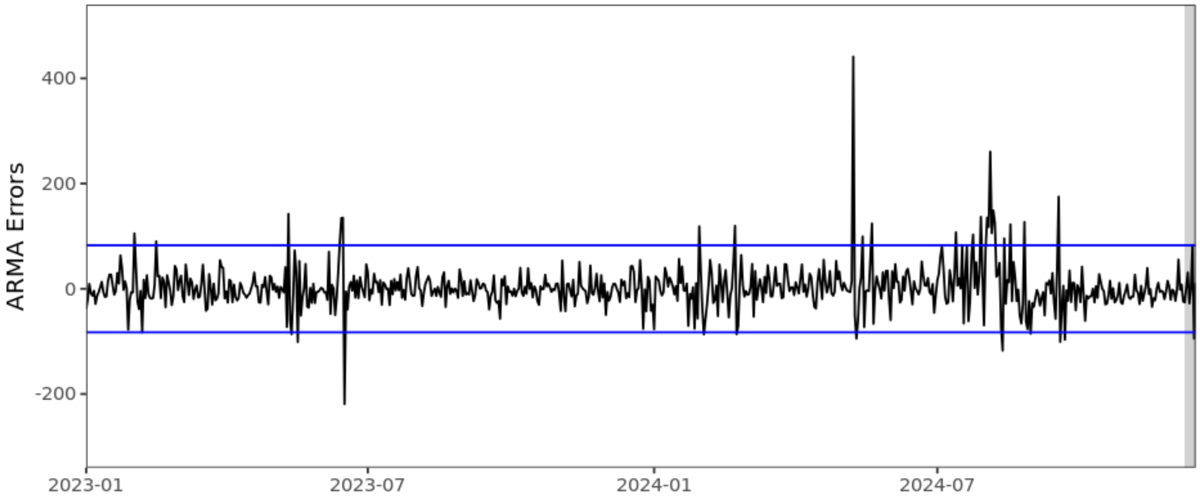
4.2. Figure 4 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled in the regression analysis.

4.3. Prices on Thursday were above two standard deviations of the model because of the HVDC trip increasing prices for a short time, which pushed up the daily average price.

4.4. Prices on Friday were below two standard deviations of the model, this is likely the model carrying over the higher prices from the previous day, but in reality, prices were lower.

4.5. Prices on other days were within two standard deviations of the model, indicating that prices on these days were similar to those predicted by the model.

Figure 4: Residual plot of estimated daily average spot prices, 1 January 2023 – 14 December 2024



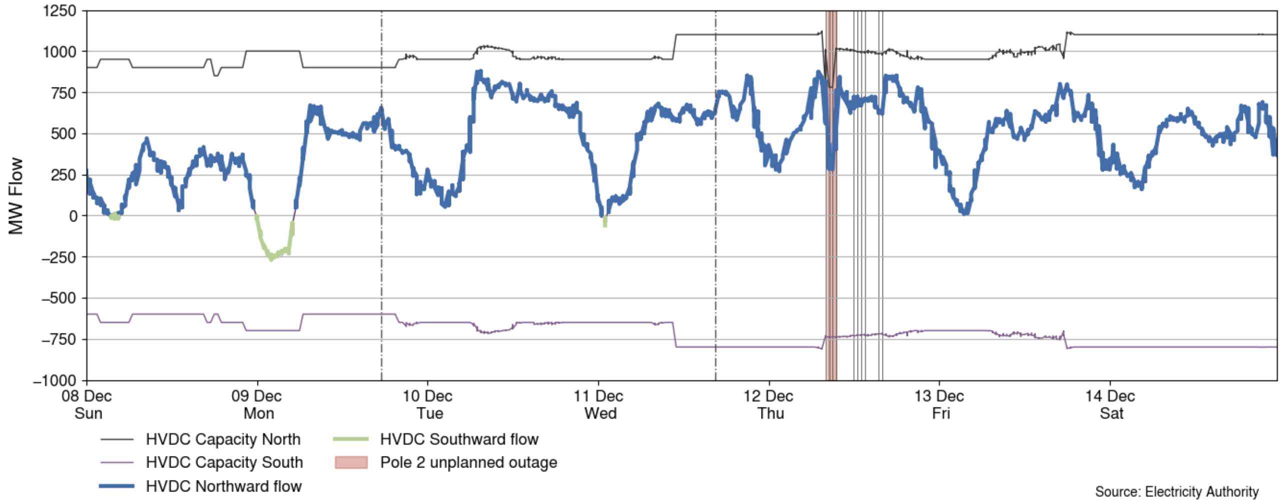
Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 5 shows the HVDC flow between 8-14 December 2024. HVDC flows were mostly northward this week, with some overnight southward flow on Sunday when wind generation was high.

5.2. HVDC pole 2 tripped at 8.18am on Thursday morning caused a sharp drop in northward flow and capacity, before pole 2 was returned to service around 9.30am.

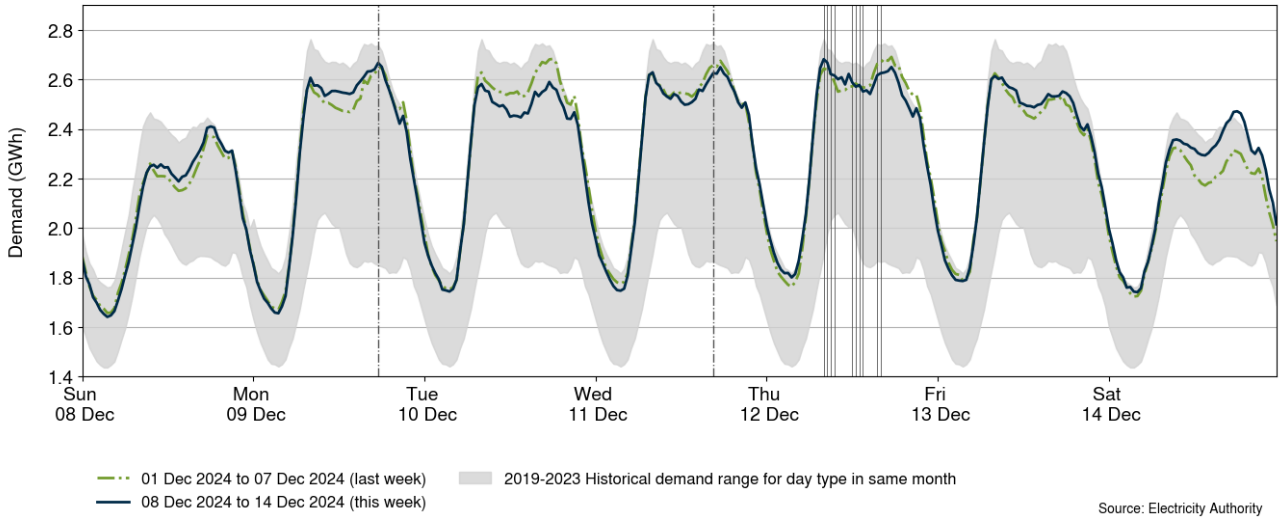
Figure 5: HVDC flow and capacity, 8-14 December 2024



6. Demand

6.1. Figure 6 shows national demand between 8-14 December 2024, compared to the historic range and the demand of the previous week. The maximum demand this week was around 2.68GWh (5.36GW) at 8:00am on Thursday. Demand was mostly similar to last week and near the upper end of the historical range. Demand increased above the historical range on Saturday afternoon when national temperatures were well above average for this time of year.

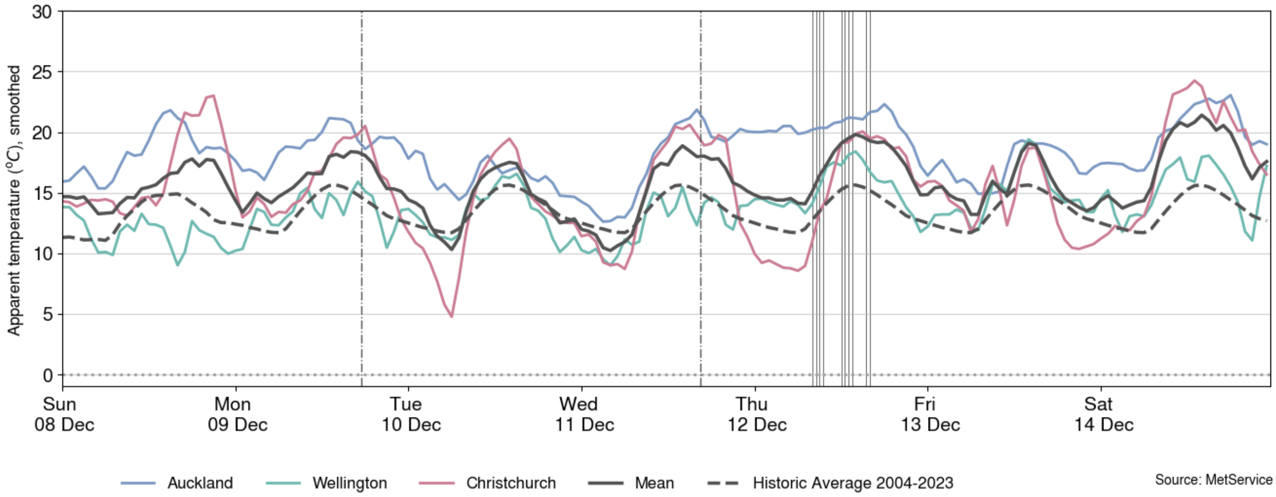
Figure 6: National demand, 8-14 December 2024 compared to the previous week



6.2. Figure 7 shows the hourly apparent temperature at main population centres from 8-14 December 2024. 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 above average this week and ranged from 12°C to 23°C in Auckland, 7°C to 20°C in Wellington, and 4°C to 24°C in Christchurch.

Figure 7: Temperatures across main centres, 8-14 December 2024

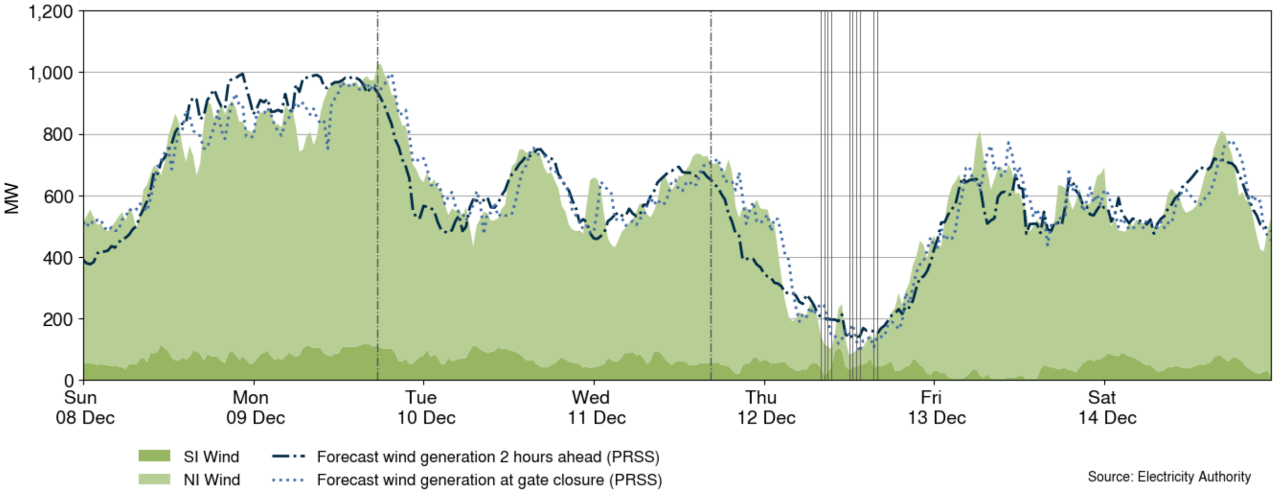


7. Generation

7.1. Figure 8 shows wind generation and forecast from 8-14 December 2024. This week wind generation varied between 82MW and 1,026MW, with a weekly average of 601MW. Wind generation was strong for most of the week but very low on Thursday.

7.2. The largest negative gate closure forecast discrepancy of 184MW was at 3.30am on Thursday morning when wind generation was reducing quickly.

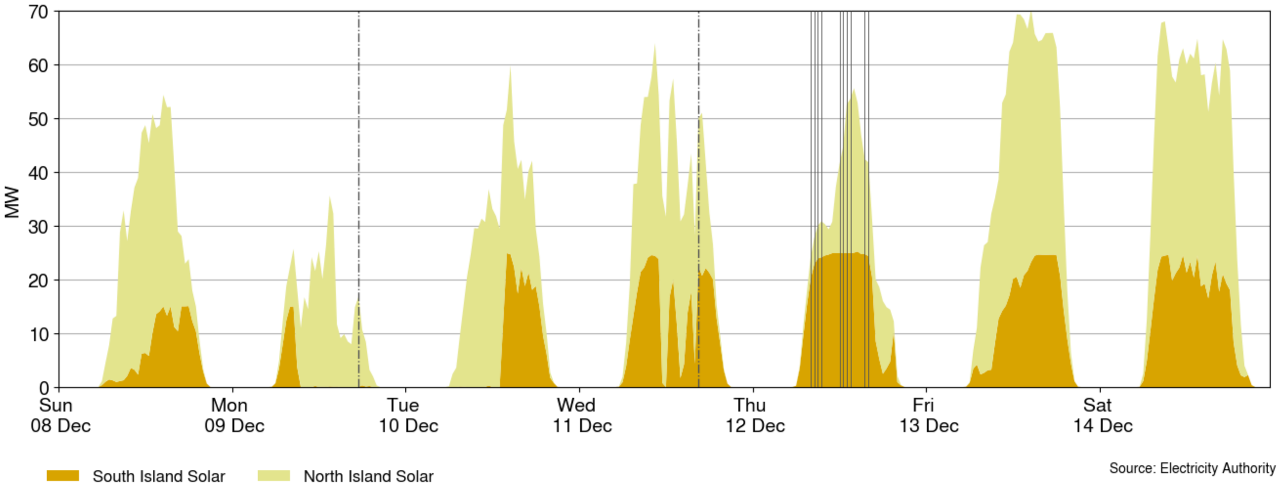
Figure 8: Wind generation and forecast, 8-14 December 2024



7.3. Figure 9 shows solar generation from 8-14 December 2024. Solar generation was lowest on Monday when conditions around the North Island farms were overcast. Solar generation was strongest on Friday and Saturday peaking above 60MW.

7.4. The Lauriston solar farm in the South Island reached a new maximum of 25MW this week as it continues to be commissioned.

Figure 9: Solar generation, 8-14 December 2024



7.5. Figure 10 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.

7.6. The most significant marginal price differences this week were $58-$143/MWh on Thursday morning when the HVDC tripped. Figure 11 shows the individual Ōtāhuhu and Benmore price differences on Thursday to highlight how the HVDC trip led to a large difference of over $4,500/MWh in the forecast versus final Ōtāhuhu price.

7.7. There was also a marginal price difference of $99/MWh on Thursday at 11.30am and on Wednesday at 4.30pm of $67/MWh when national demand was 75MW and 90MW higher than forecast respectively.

Figure 10: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 8-14 December 2024

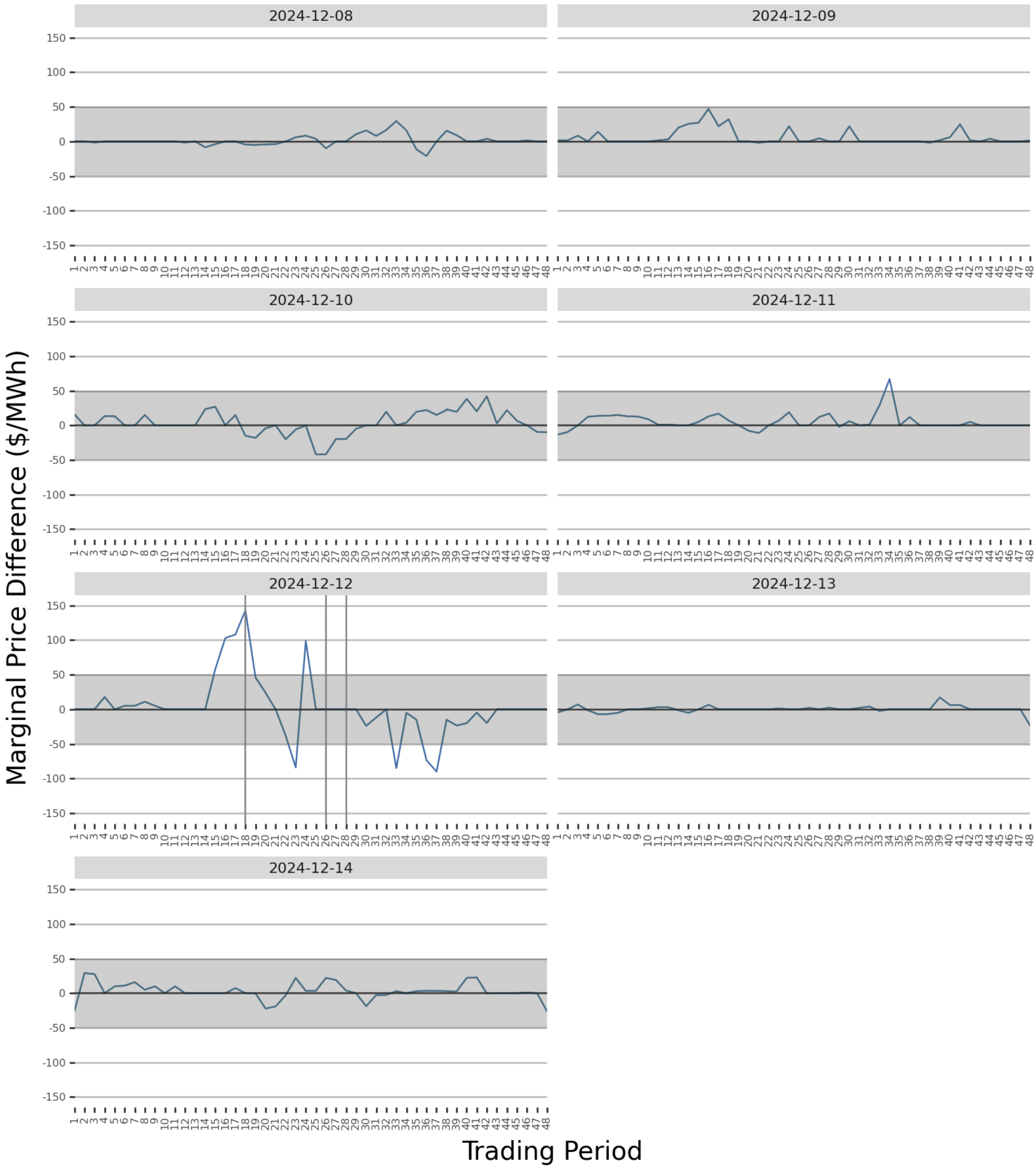
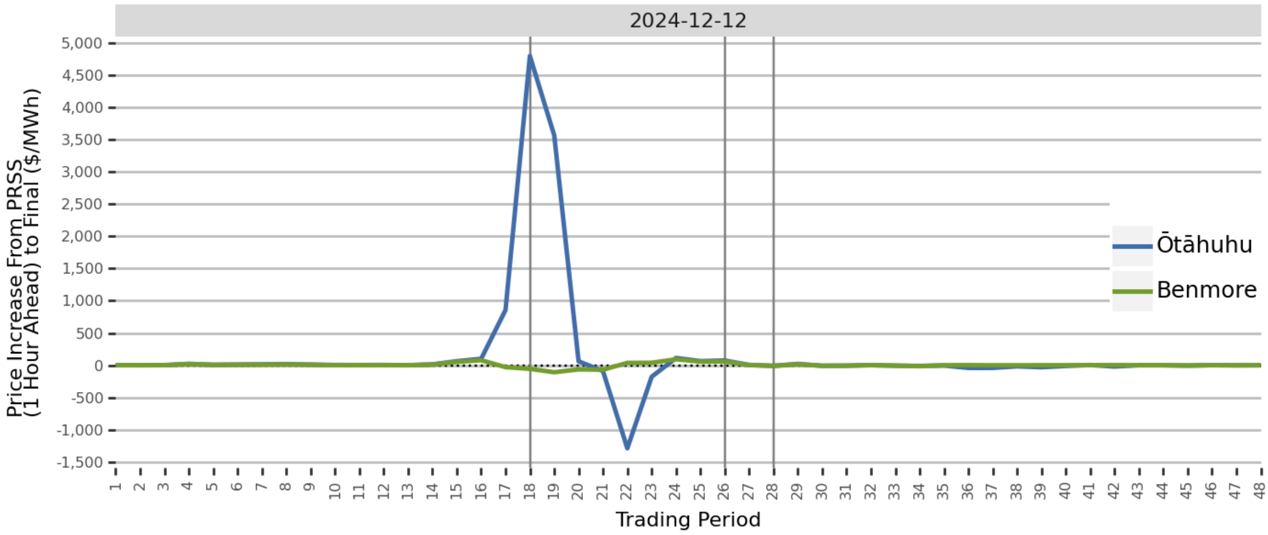
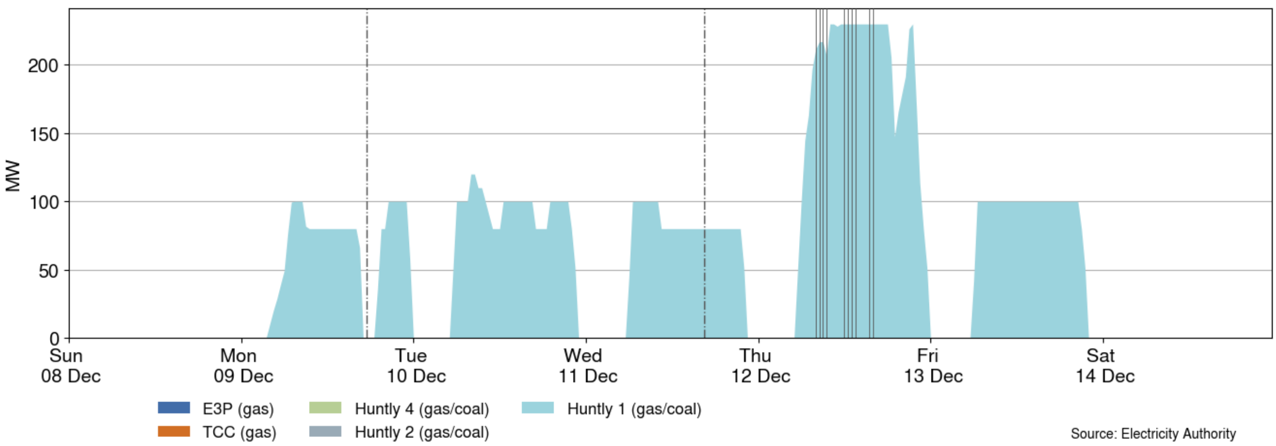


Figure 11: Difference between national marginal RTD price and simulated RTD price at Benmore and Ōtāhuhu, with the difference due to one-hour ahead wind and demand forecast inaccuracies, Thursday 12 December 2024



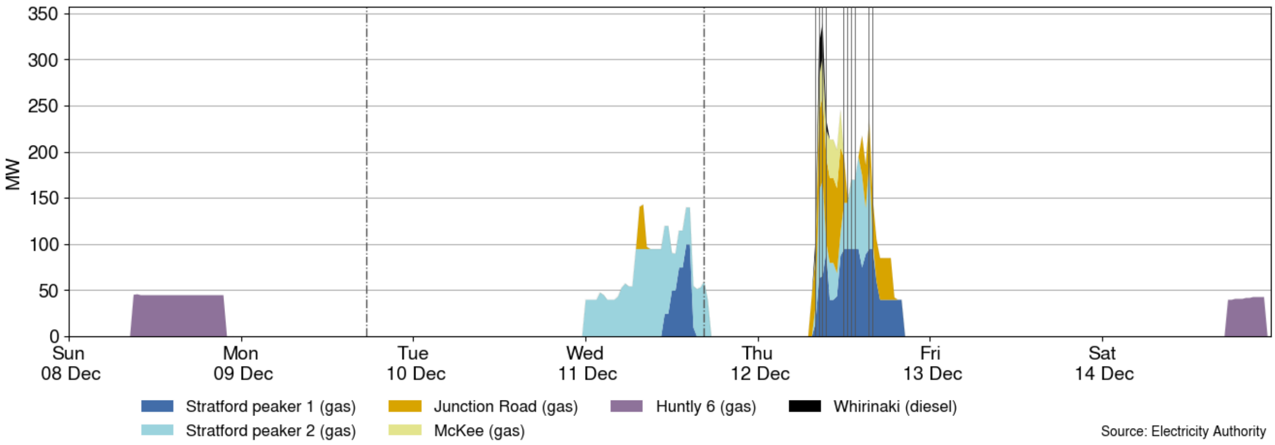
7.8. Figure 12 shows the generation of thermal baseload between 8-14 December 2024. Baseload generation was provided by Huntly 1 this week and was greatest on Thursday when wind generation was low.

Figure 12: Thermal baseload generation, 8-14 December 2024



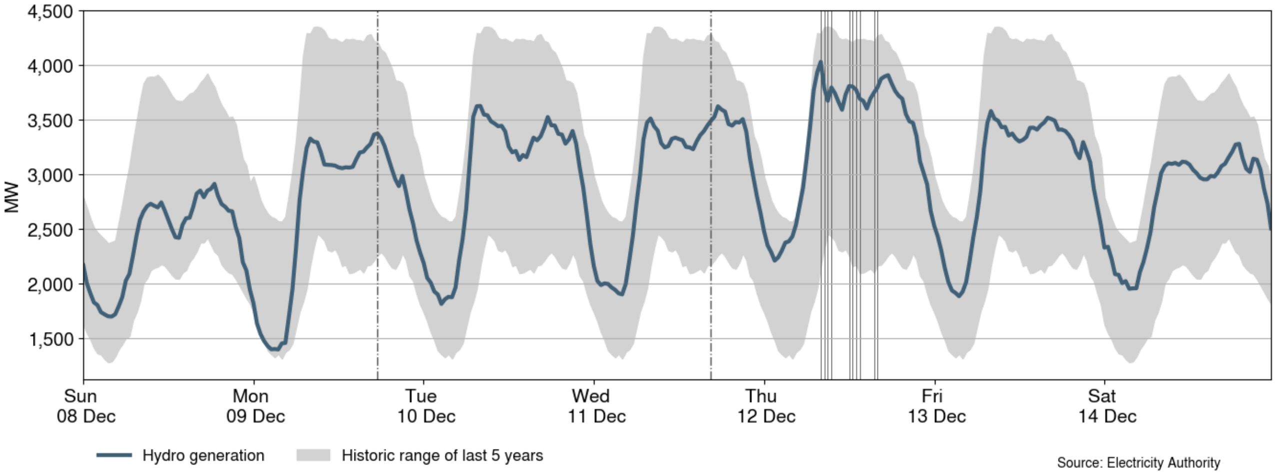
7.9. Figure 13 shows the generation of thermal peaker plants between 8-14 December 2024. Peaker generation was highest on Thursday morning when all peakers were running after the HVDC tripped (except Huntly 6 and one Whirinaki unit which were both on outage). Huntly 6 generated over the weekend and Stratford peakers ran on Wednesday, with Junction Road generating briefly in the morning.

Figure 13: Thermal peaker generation, 8-14 December 2024



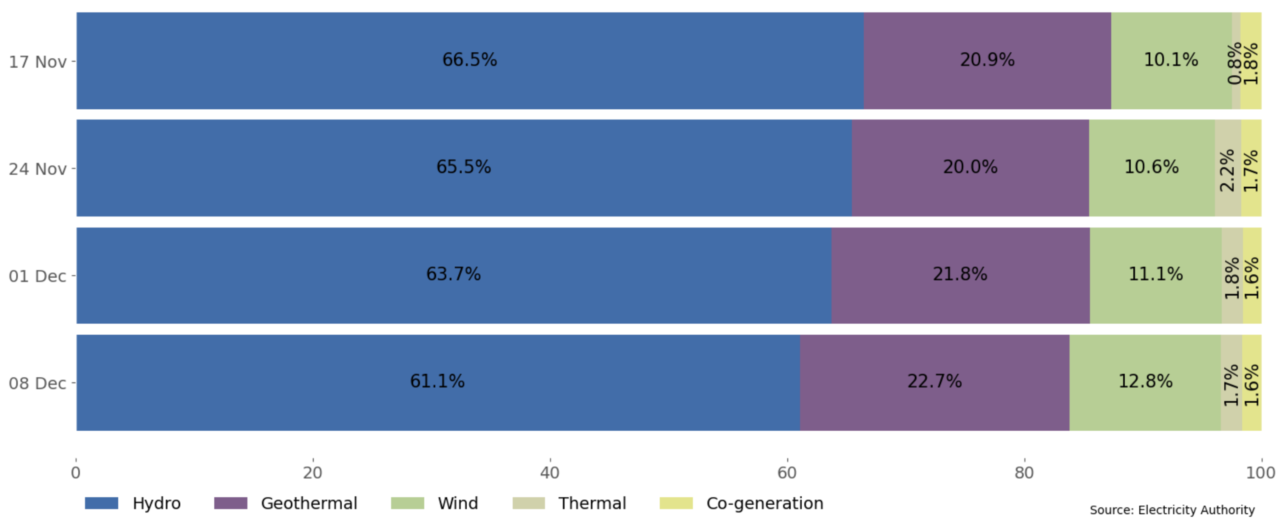
7.10. Figure 14 shows hydro generation between 8-14 December 2024. Hydro generation was within the historic range this week and was highest on Thursday morning when wind generation was low. Hydro generation also dropped sharply on Thursday morning when the HVDC tripped.

Figure 14: Hydro generation, 8-14 December 2024



7.11. As a percentage of total generation, between 8-14 December 2024, total weekly hydro generation was 61.1%, geothermal 22.7%, wind 12.8%, thermal 1.7%, and co-generation 1.6%, as shown in Figure 15. Geothermal and wind generation increased this week, while hydro generation reduced and thermal generation remained steady.

Figure 15: Total generation by type as a percentage each week, 17 November – 14 December 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 8-14 December 2024 ranged between ~1,150MW and ~2,480MW. 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 5 is on outage from 9-17 December.

(c) Several large hydro units are on outage.

Figure 16: Total MW loss from generation outages, 8-14 December 2024

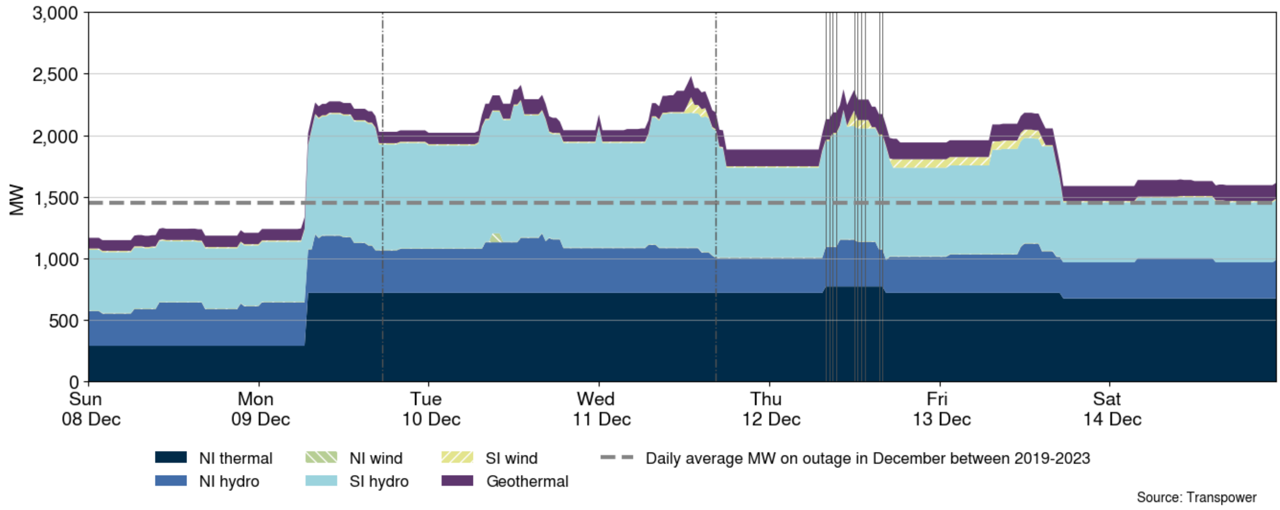
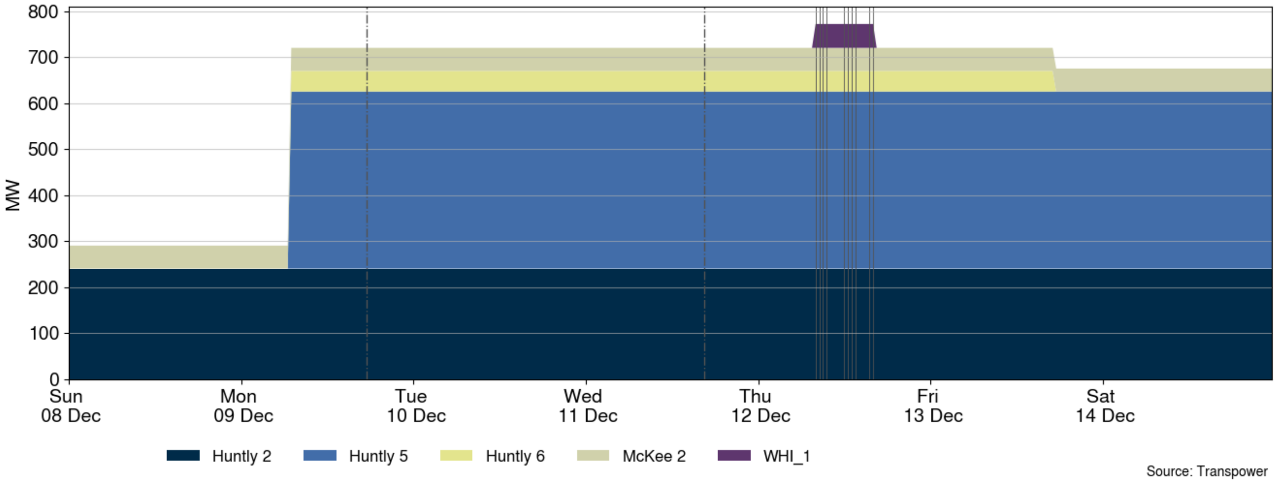


Figure 17: Total MW loss from thermal outages, 8-14 December 2024

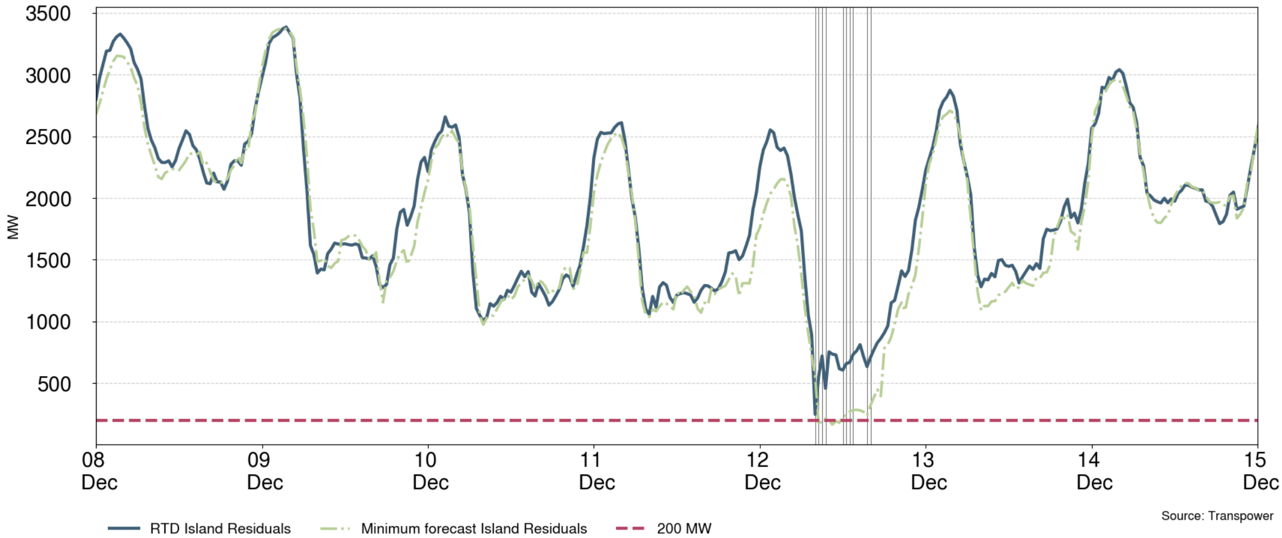


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 8-14 December 2024. 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 ~60MW at 8.30am on Thursday when wind generation was low and the HVDC tripped, causing North Island generation to ramp up – reducing the amount of North Island residual generation.

Figure 18: National generation balance residuals, 8-14 December 2024



10. Storage/fuel supply

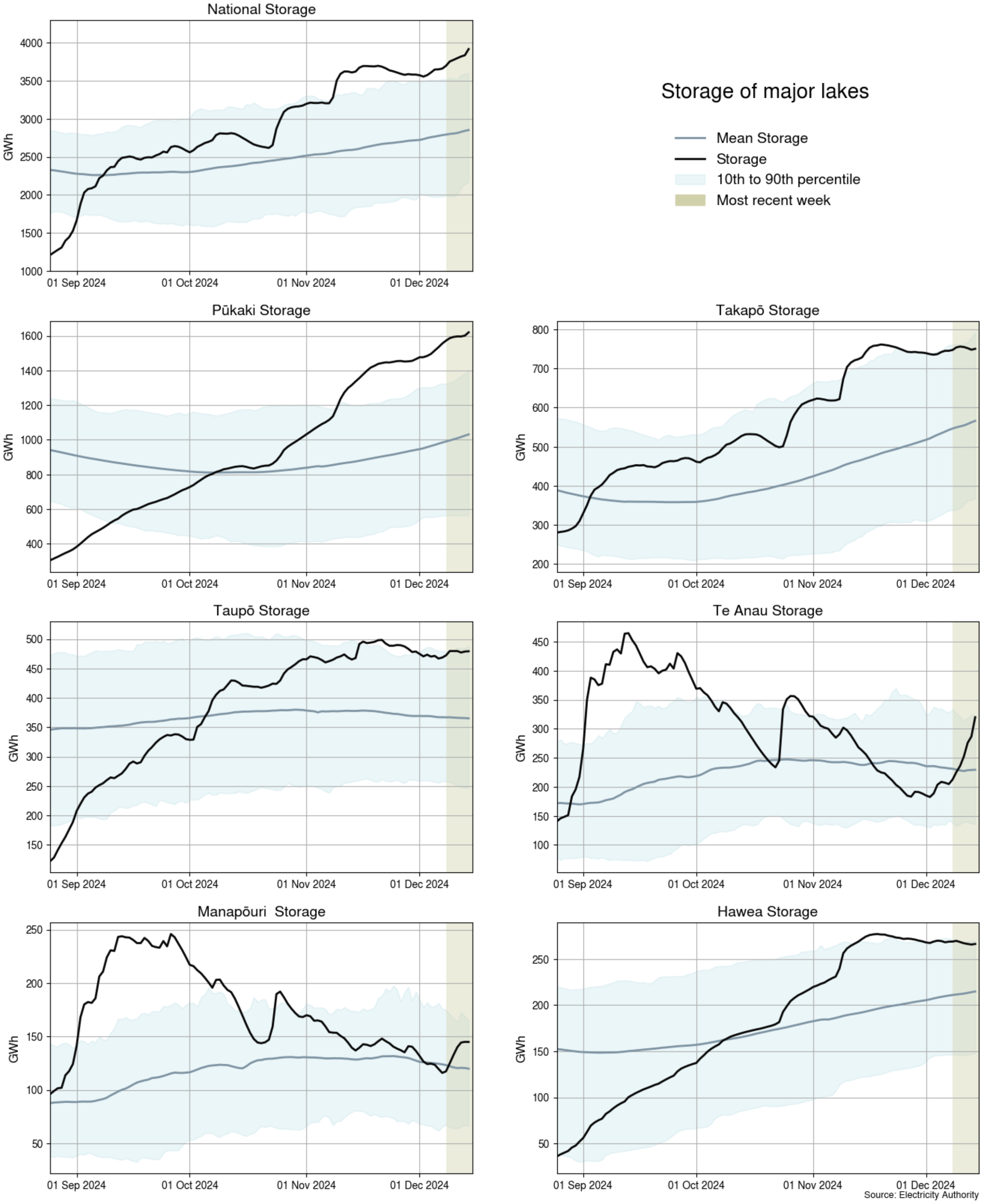
10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National controlled storage increased this week. As at 14 December, storage was ~95% nominally full and ~133% of the historical average for this time of the year.

10.3. Lake Pūkaki continued to increase above its historic 90th percentile and is now ~95% full. Lakes Takapō (~98% full), Hawea (~94% full) and Taupō (~84% full) remained steady just below their historic 90th percentiles.

10.4. Lakes Te Anau and Manapōuri increased above their historic means this week, with Lake Te Anau near its 90th 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 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.

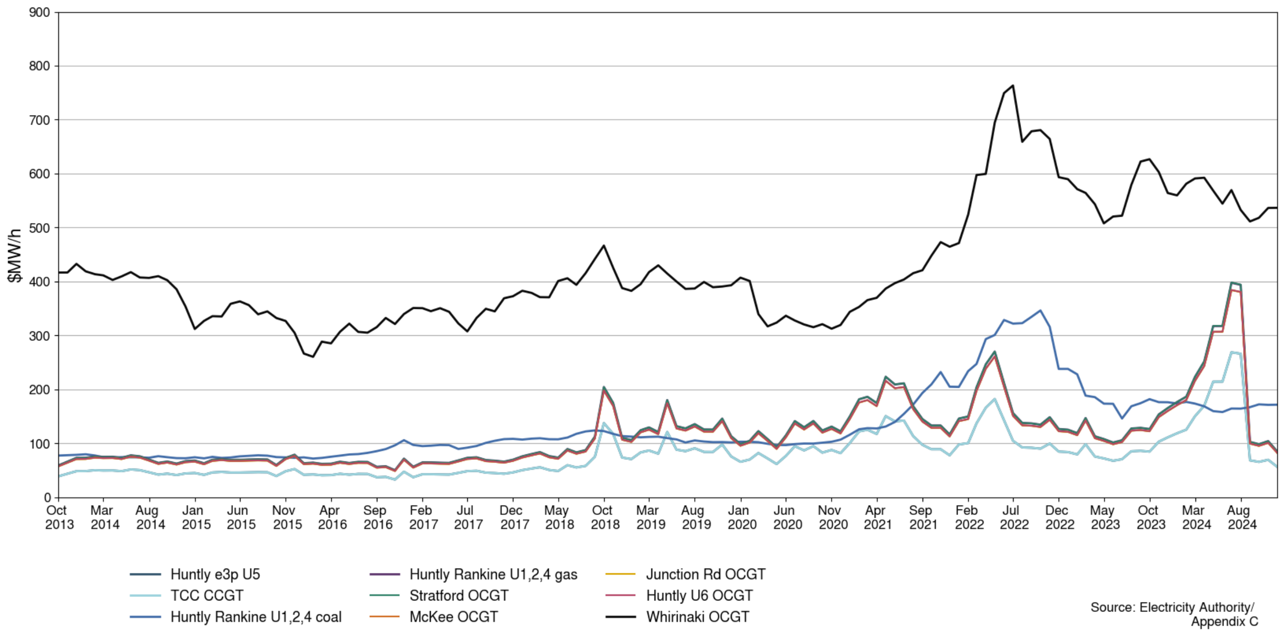
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$171/MWh, with the cost of running the Rankines on gas remaining lower at ~$85/MWh.

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

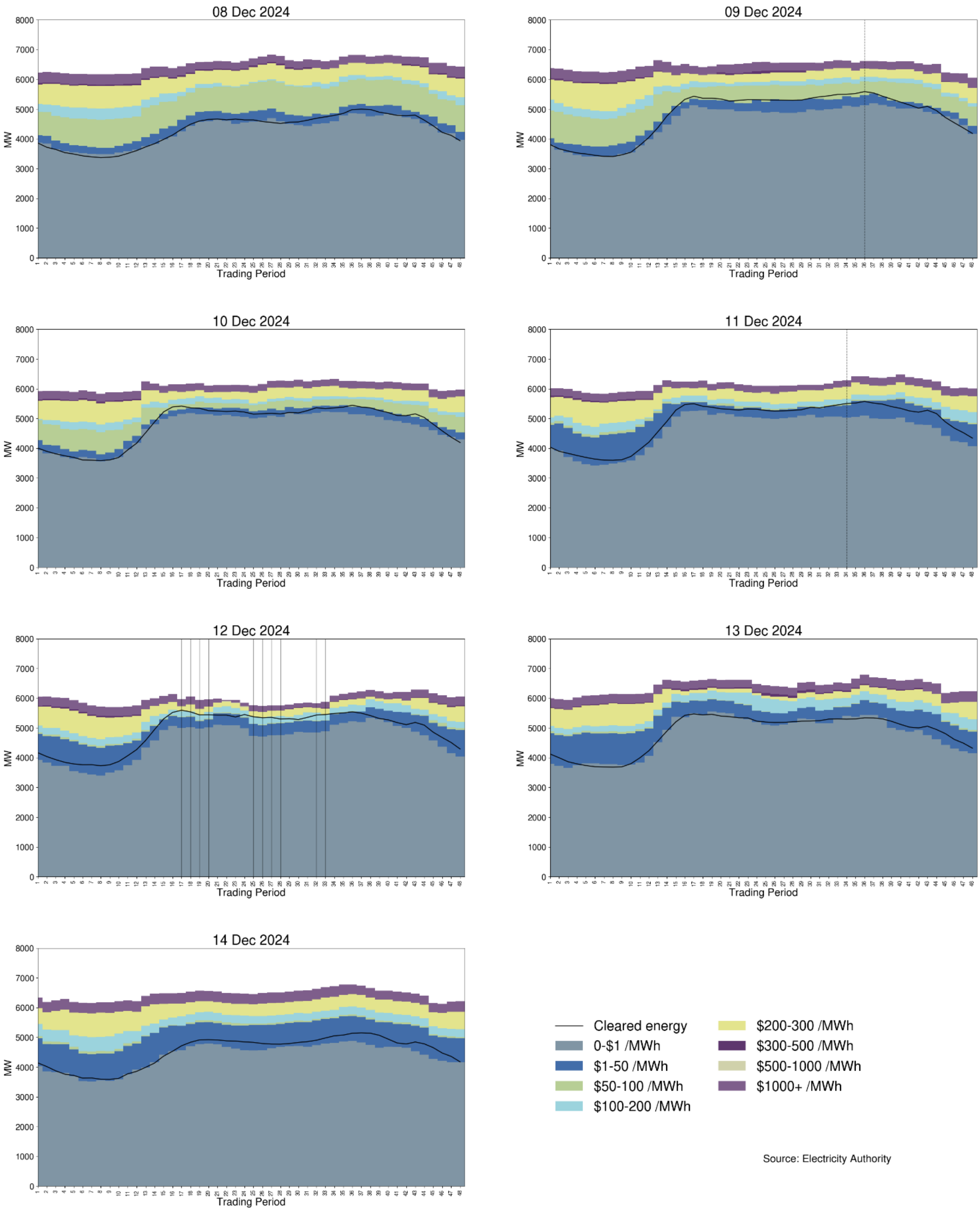


12. Offer behaviour

12.1. Figure 21 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 prices cleared under $50/MWh this week, with higher price tranches clearing on Thursday during low wind and after the HVDC trip. The amount of offers in the $1-50/MWh band increased sharply between 4.30pm and 5.00pm on Wednesday which led to the spot price reducing from its peak before peak demand. The increase in low price offers was a result of hydro offers being lowered.

Figure 21: Daily offer stacks



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.

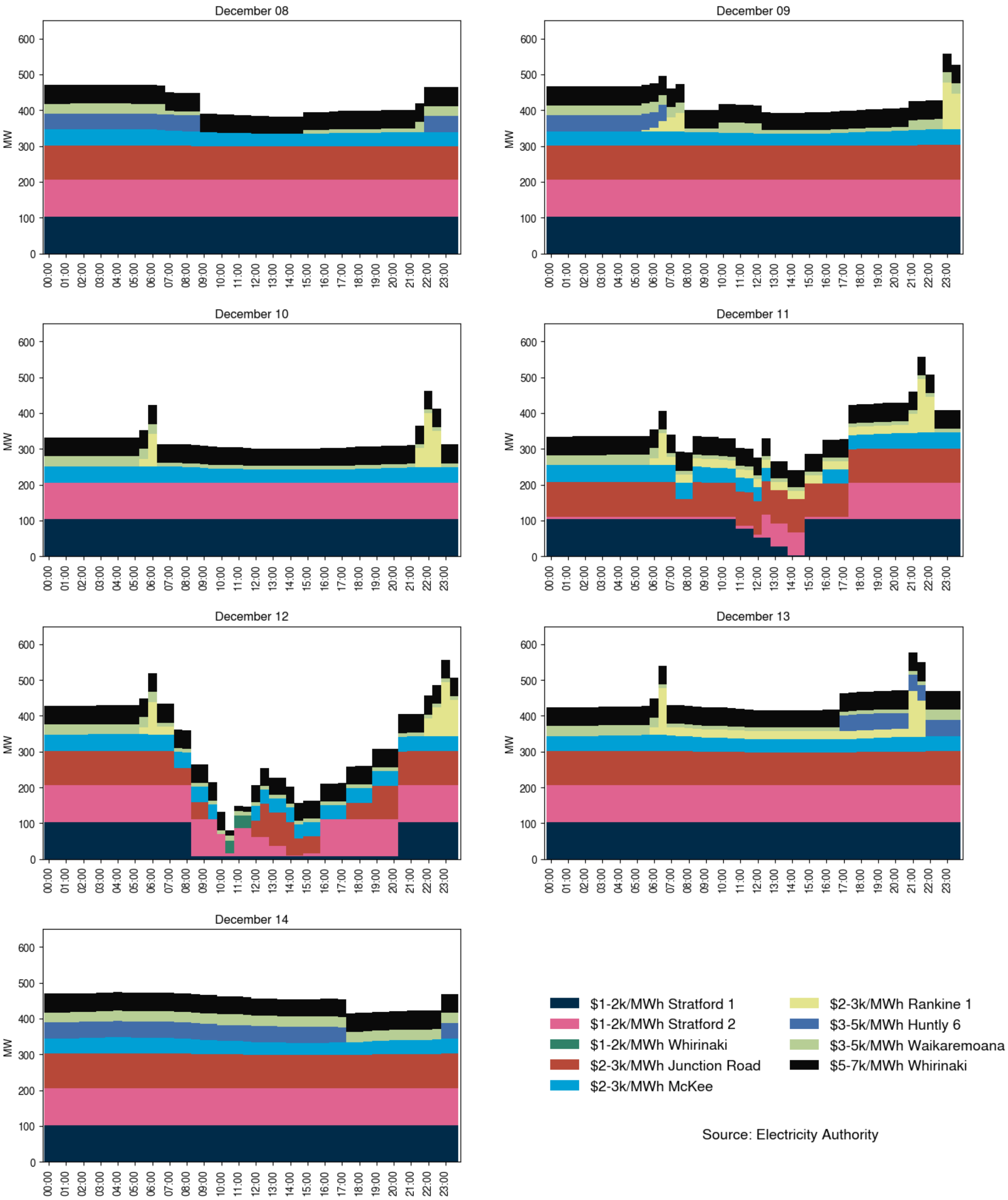
12.4. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren’t expecting to run. These high prices reflects increased operating costs of running for 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 400MW per trading period was above $1,000/MWh this week, which is roughly 7% of the total energy available.

12.6. On Thursday morning, some high prices were priced down after thermal peaker units were dispatched after the HVDC tripped.

12.7. The monitoring team is looking further into high priced offers at Waikaremoana.

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.

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
2-7/12/2024	Several	Further analysis	Mercury	Waikato	Hydro offers
8-14/12/2024	Several	Further analysis	Genesis	Waikaremoana	Hydro offers