3 January 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for weeks of 17-30 December

1.1. Spot prices were high in the lead up to Christmas with hydro storage still in decline and a number of low wind generation days. There were also a number of days in that week with over 2000MW of generation outages which affected the availability of generation and meant offer stacks were thinner. Most prices in the week before Christmas were above $200/MWh. The following week saw the average price drop to around $169/MWh with a decrease in demand as the holiday season began as well as some good wind generation days and hydro storage increasing again. Hydro is at 69% nominally full as of 1 January 2024.

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, we also single 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. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-90th percentiles adjusted for inflation. There were numerous prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range[1] of historic prices. Significant times where prices were particularly high have been highlighted in the graph below.

2.3. Between 17-30 December:

(a) The average wholesale spot price across all nodes was $200/MWh.

(b) 95 percent of prices fell between $39/MWh and $323/MWh.

2.4. During the week leading up to Christmas, spot prices were generally high and mostly above $200/MWh. A number of days saw periods where prices were above $300/MWh, highlighted by the shaded regions in the graph. From around 2.30pm on 22 December until 10.30pm on 24 December prices were mostly in the $300/MWh region. From 25 December spot prices decreased with most sitting under $200/MWh. The average price for the week of 17-23 December was $237/MWh, dropping to $169/MWh for the week of 24-30 December.

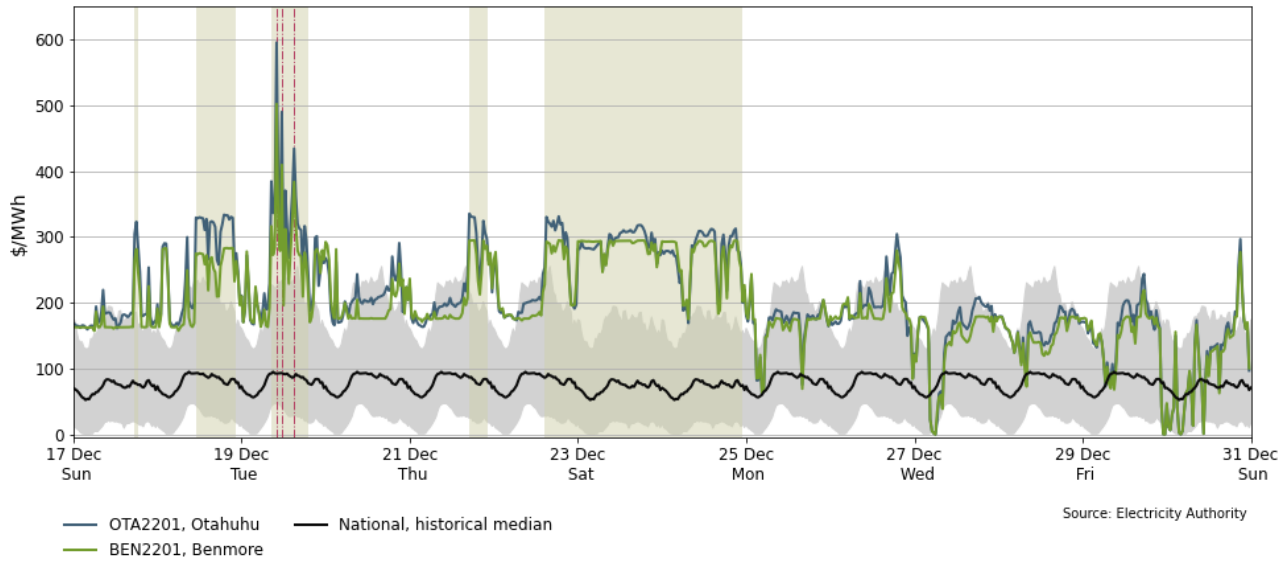
2.5. On 19 December there were significantly high prices throughout the day with three trading periods where prices went above $400/MWh. The 10.00am prices at Benmore and Ōtāhuhu that day were $501/MWh and $595/MWh respectively, with some 5-min prices above $800/MWh. Mercury had 177MW of hydro generation on outage that day, and wind generation was also very low at the start of the day.

2.6. The high prices observed in the lead up to Christmas day were due to a variety of factors. Above average generation outages for this time of year, combined with days of very low

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75th percentile of the distribution. This is using the outlier calculation Q_3+1.5×IQR, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

wind generation and a continued drop in hydro storage all had an impact on the wholesale spot market. From 20-24 December TCC along with two Rankines ran as baseload which may have also contributed to the high prices.

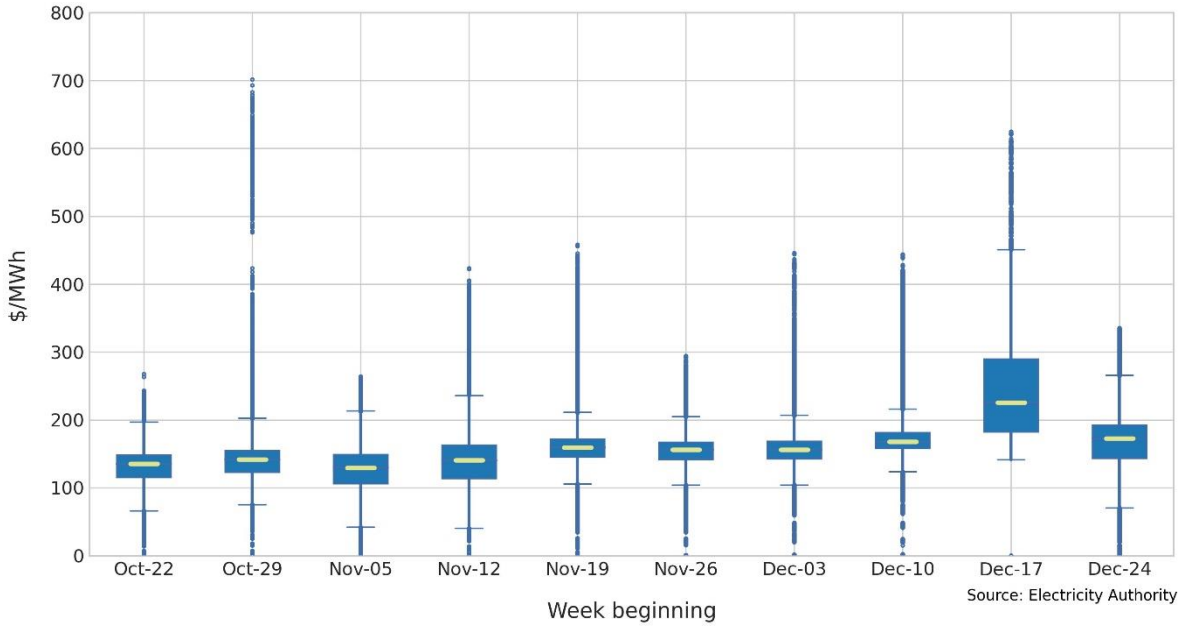
Figure 1: Wholesale spot price at Benmore and Ōtāhuhu between 17-30 December



2.7. Figure 2 shows a box plot with the distribution of spot prices during these two weeks and the previous eight weeks. The yellow line shows each week's median price, while the box part shows the lower and upper quartiles (where 50 percent of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.8. From 17-23 December prices were significantly higher than previous weeks with a median price of $225/MWh and middle 50% of prices within $182-$290/MWh. Prices dropped slightly the following week from 24-30 December with the median at $173/MWh and a smaller IQR with the middle 50% ranging from $143-$192/MWh.

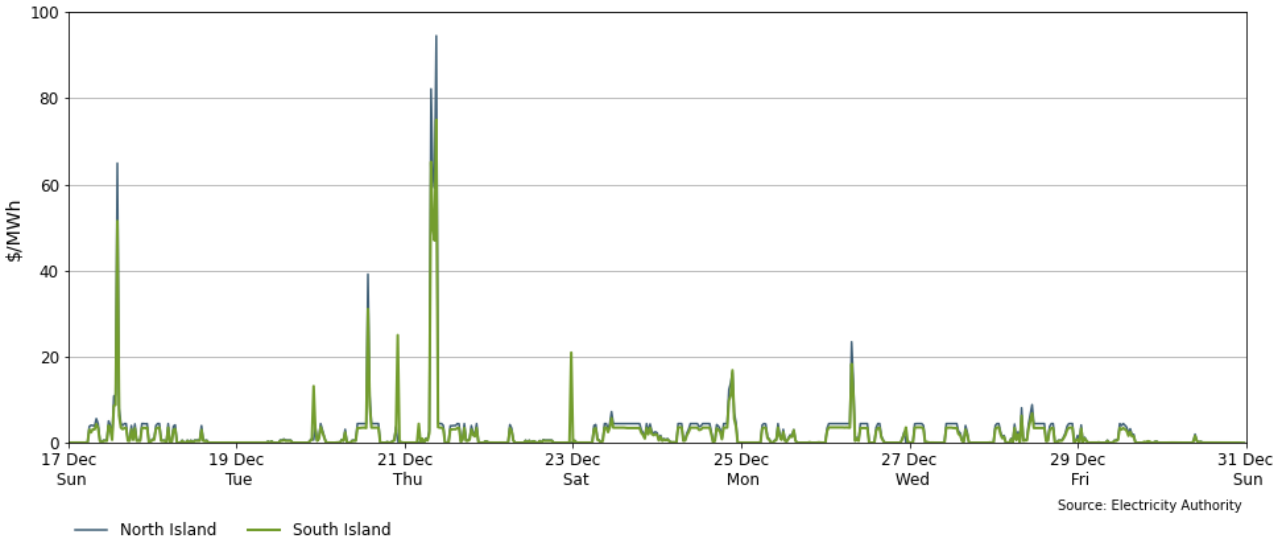
Figure 2: Boxplots showing the distribution of the spot prices for the weeks 17-23 December and the previous nine weeks



3. Reserve prices

3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mostly under $10/MWh. However, there were a few spikes in FIR prices, the highest of those being on 21 December between 7.30am and 9.00am. FIR prices at this time ranged from $47-95/MWh. These spikes were due to covering North Island risk[2] with large generators like TCC running during this morning peak. This increased demand for reserves in the North Island.

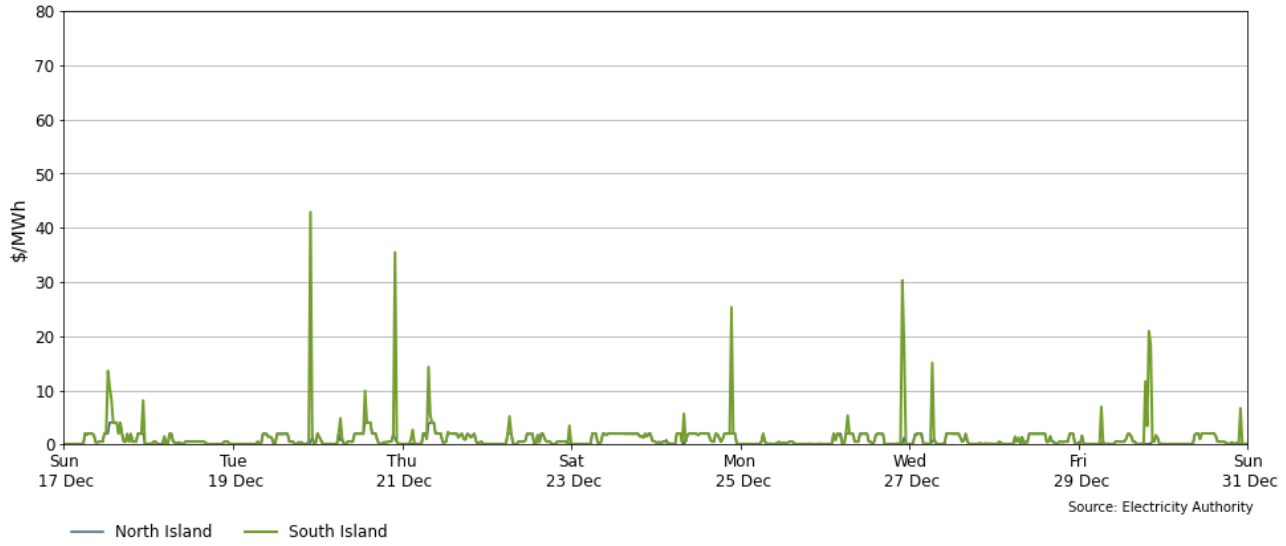
Figure 3: Fast Instantaneous Reserve (FIR) prices by trading period and island



[2] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these—the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South islands.

3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mainly below $10/MWh with a few spikes in South Island SIR prices occurring across the week where prices were within $18-43/MWh. These spikes were mostly in the evening and when the HVDC flow started southwards.

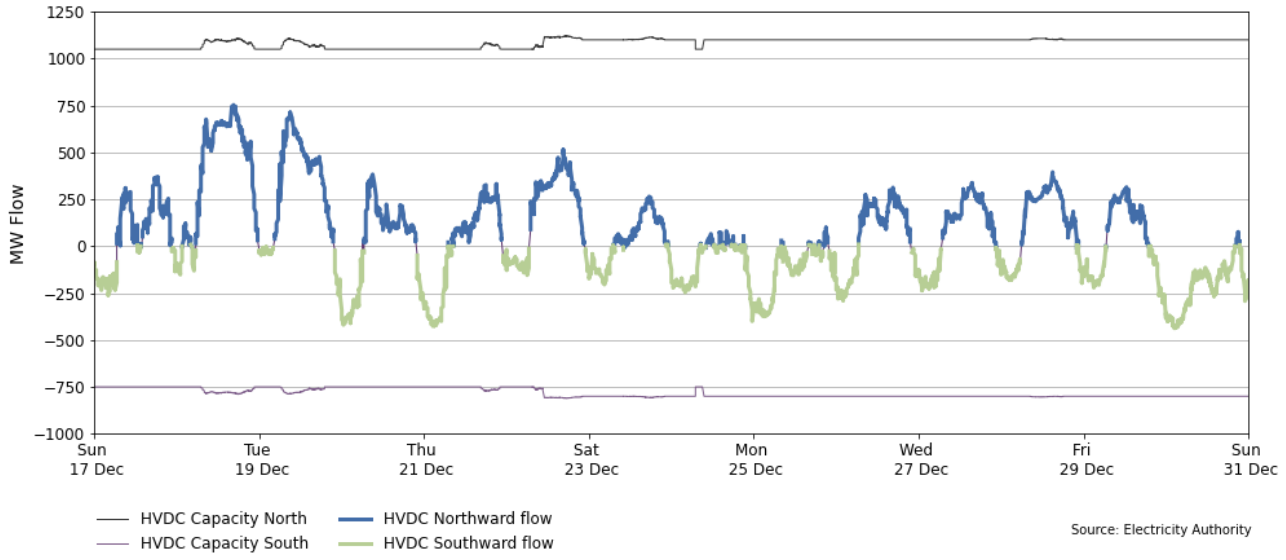
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 17-30 December. HVDC flow reduced northwards as the holiday period approached with more overnight southward flow compared to recent weeks. There was also an increase to southward flow on days where wind generation was higher.

Figure 5: HVDC flow and capacity



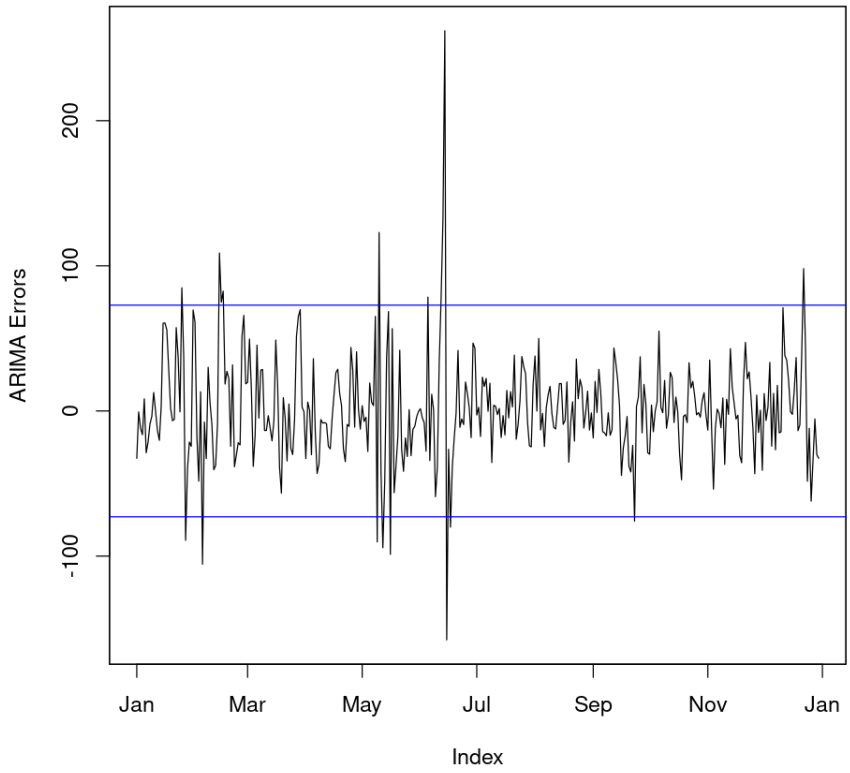
5. Regression residuals

5.1. The Authority's monitoring team uses a regression model to model spot price. The residuals show how close the predicted 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 on the trading conduct webpage.

5.2. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than 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 for in the regression analysis.

5.3. There was one residual 2 standard deviations above the data meaning that actual prices were higher than the model expected.

Figure 6: Residual plot of estimated daily average spot prices from 1 January 2022-30 December 2023



6. Demand

6.1. Figure 7 shows national demand compared to the previous two weeks. Demand significantly dropped off as the holiday period started. Figure 8 shows national demand between 17-30 December, compared to the equivalent trading weeks and days from the previous two years. Overall, demand in the week leading up to Christmas was a lot higher than it was the previous two years.

Figure 7: National demand between 17-30 December compared to the previous two weeks

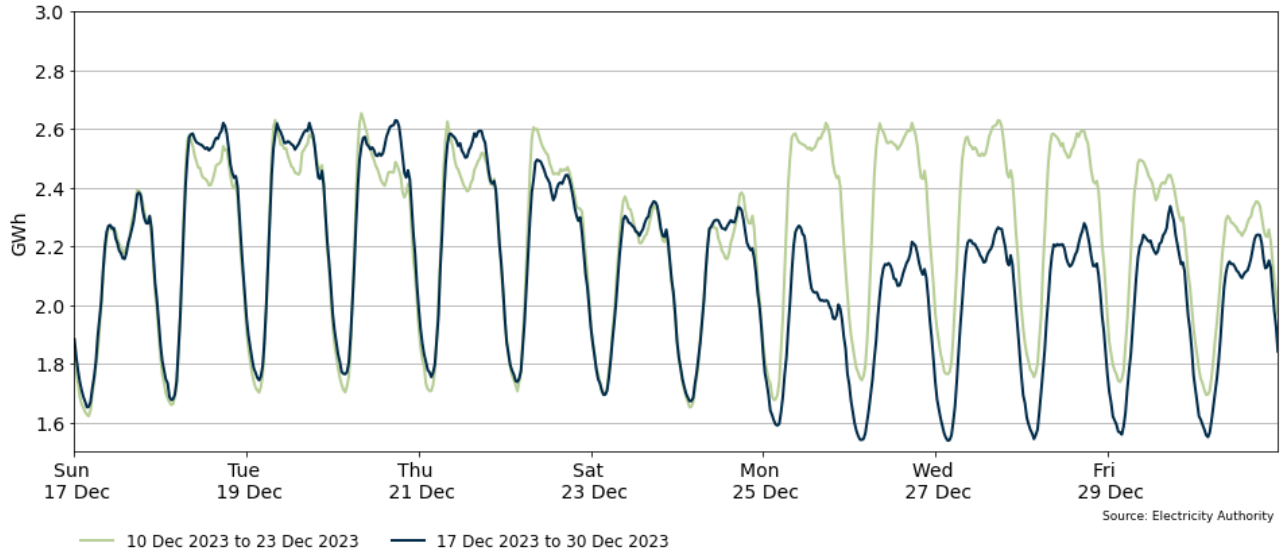
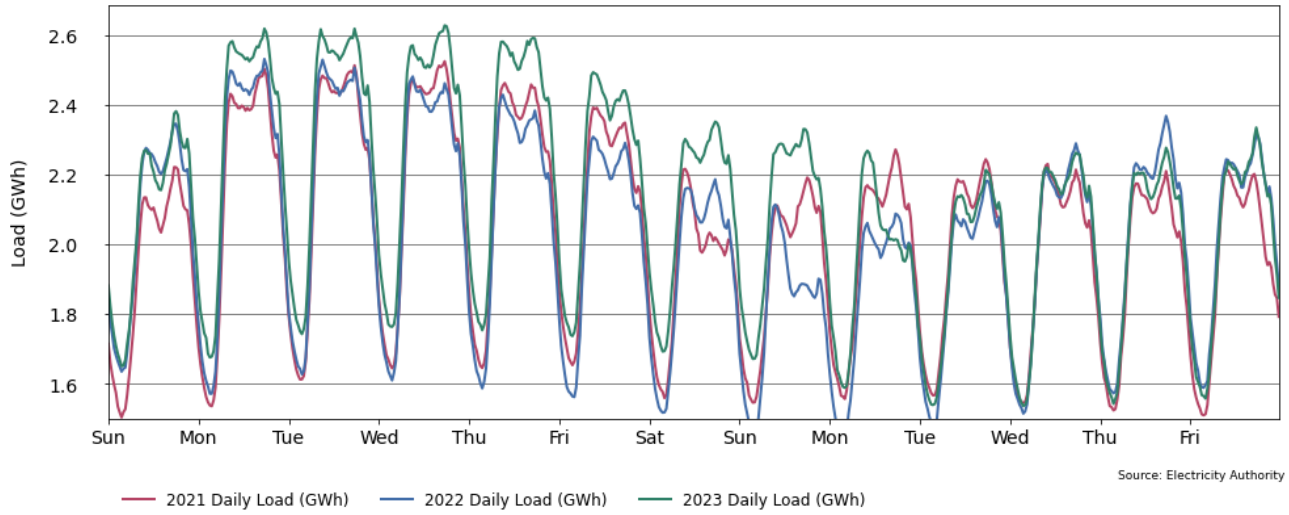


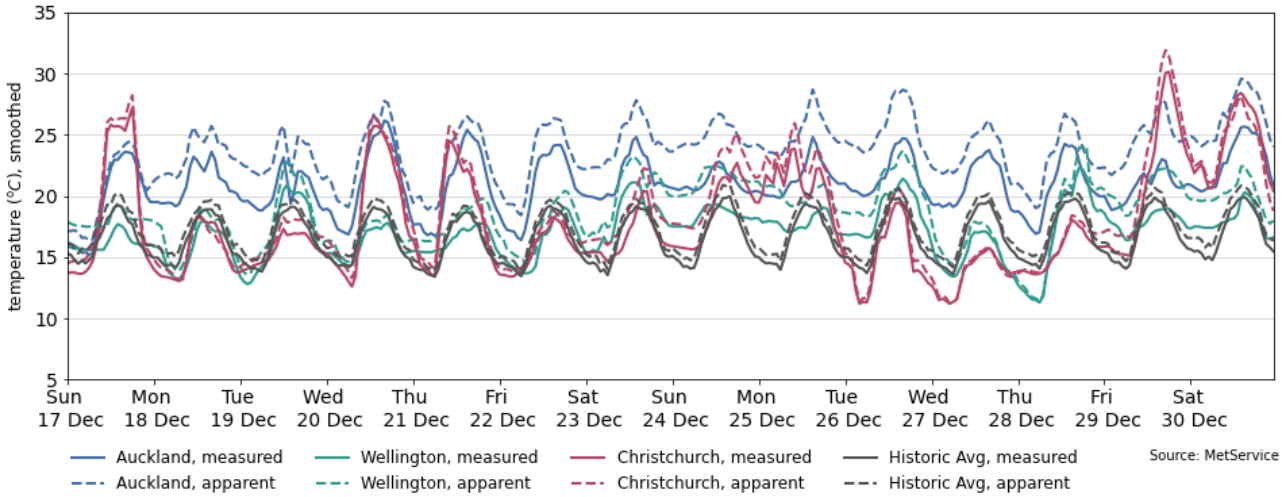
Figure 8: National demand by trading period compared to the previous two years



6.2. Figure 9 shows the hourly temperature at main population centres from 17-30 December. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Auckland temperatures remained above 15℃ for the two weeks with a maximum of ~30℃, whereas temperatures in Wellington ranged from 11℃ to 24℃. Christchurch saw the largest variation in temperatures ranging from 11℃ to 30℃.

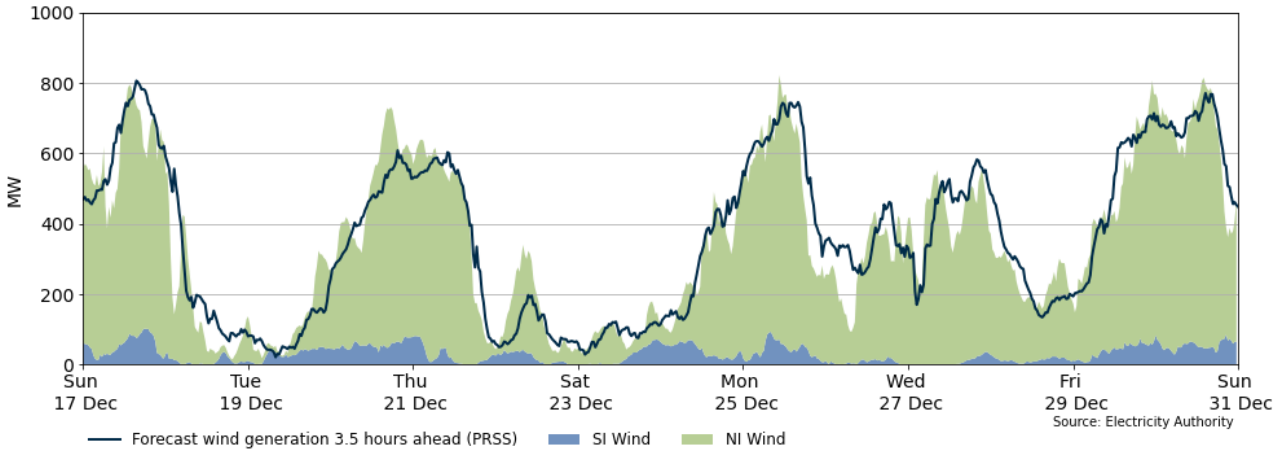
Figure 9: Temperatures across main centres



7. Generation

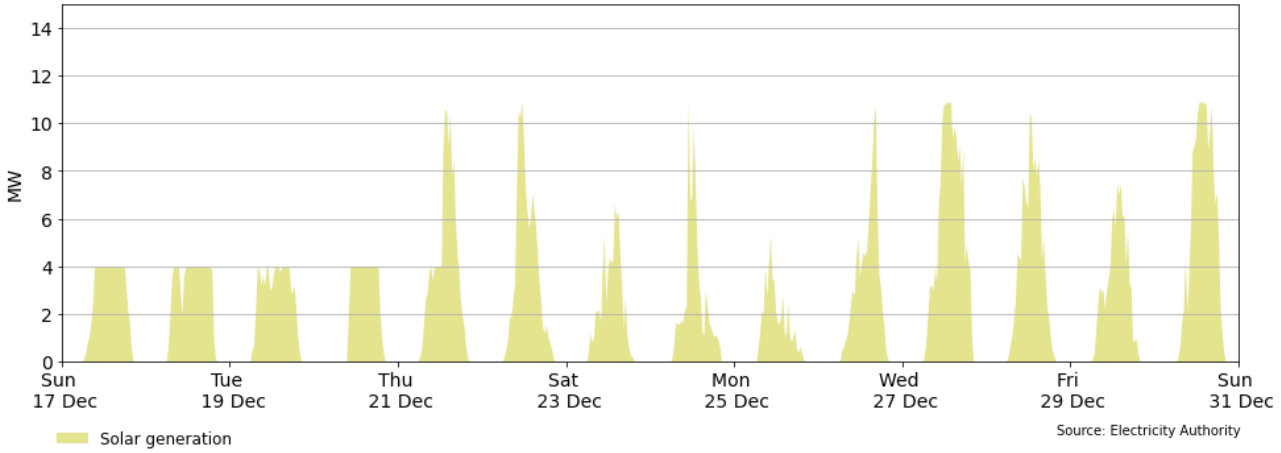
7.1. Figure 10 shows wind generation, from 17-30 December. Wind generation ranged between 15MW and ~822MW. Low wind generation periods are in line with the days where prices were high, in particular on 19 December and from 22-24 December.

Figure 10: Wind generation and forecast between 17-30 December



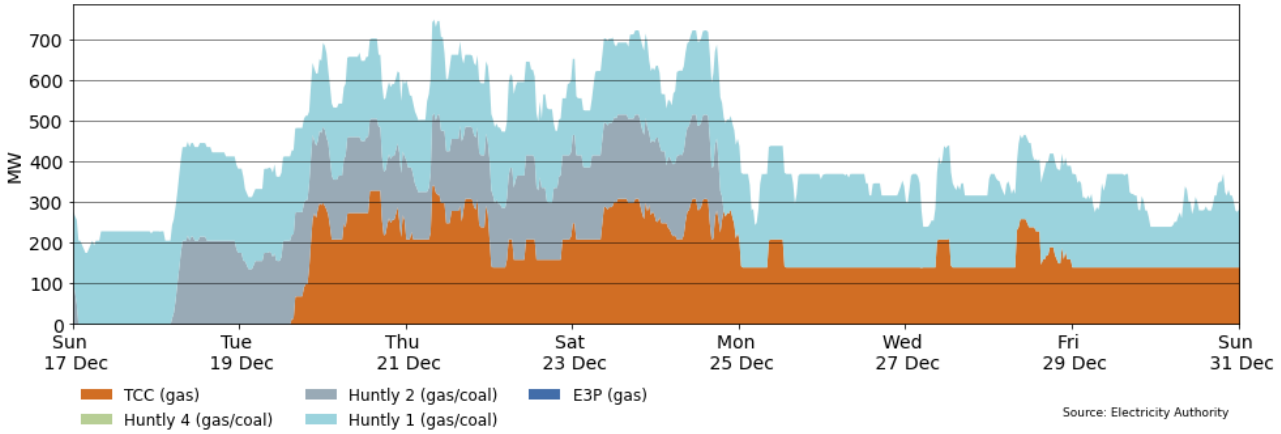
7.2. Figure 11 shows solar generation from 17-30 December. There has been some increased solar generation over the last week of December with some trading periods reaching ~11MW as Kaitaia's solar farm continues the commissioning process.

Figure 11: Solar generation between 17-30 December



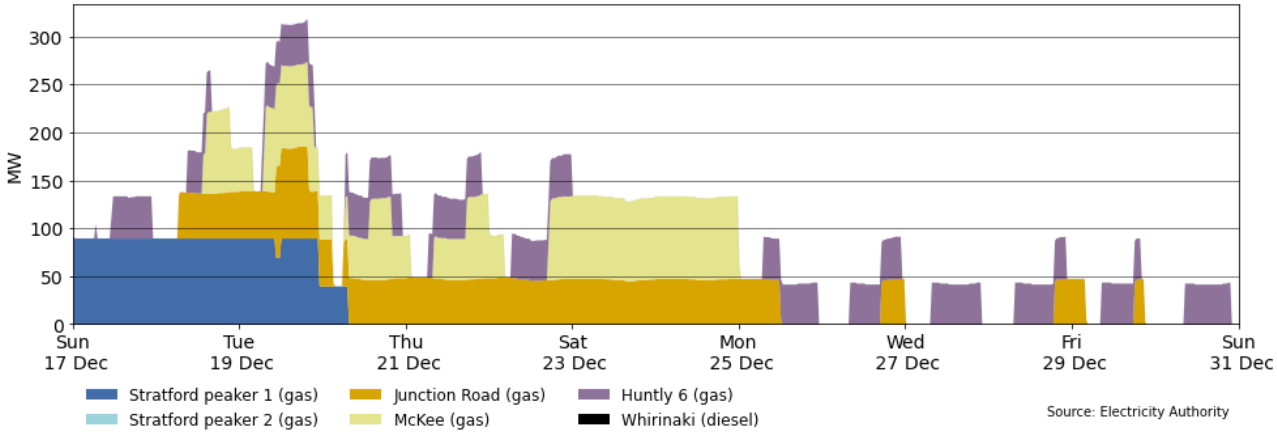
7.3. Figure 12 shows the generation of thermal baseload between 17- 30 December. Huntly 1 ran as baseload with Huntly 2 in support from 18-24 December. TCC also started generating again on 19 December. This was possibly to replace Stratford 1 which Contact had been running continuously, as it went on a short outage.

Figure 12: Thermal baseload generation between 17-30 December



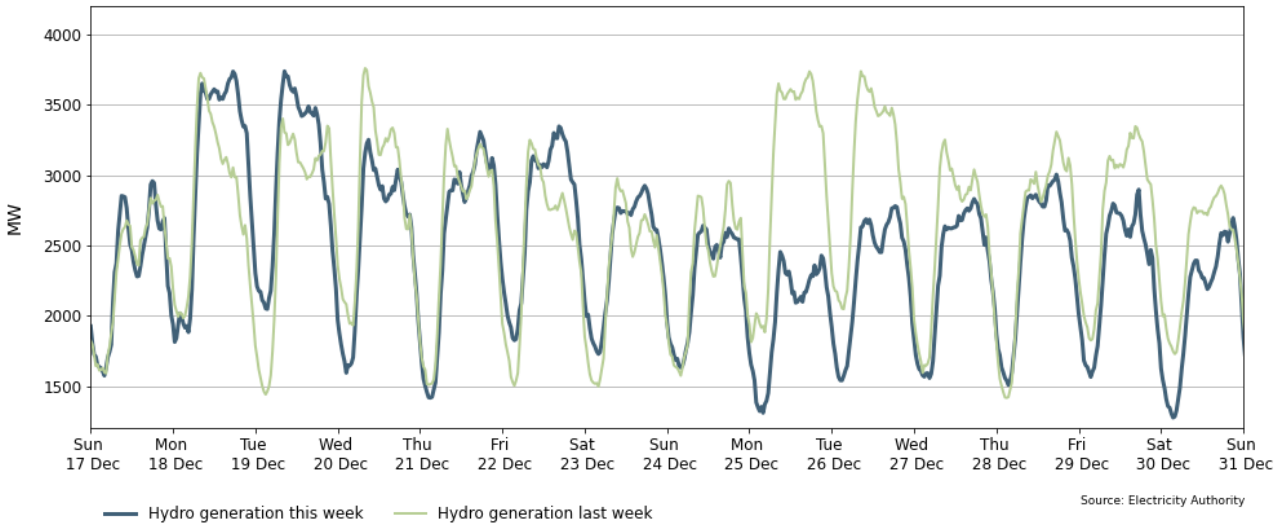
7.4. Figure 13 shows thermal peaker generation from 17-30 December. Stratford 1 ran until 20 December. All other available gas peakers ran at various times across the two weeks, with less peakers required between Christmas and New Year's Eve as demand dropped due to the holidays. On 19 December when prices spiked, all 4 available gas peakers were running along with two Rankine units.

Figure 13: Thermal peaker generation between 17-30 December



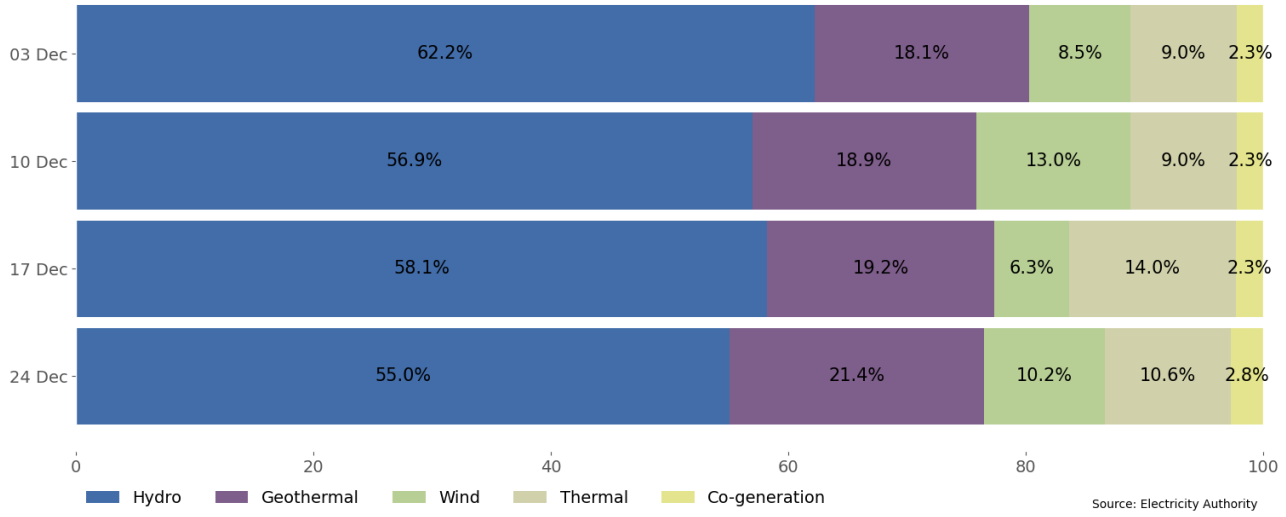
7.5. Figure 14 shows hydro generation between 17-30 December. Hydro generation generally decreased across the two weeks along with the drop in demand as the holiday period approached. The highest hydro generation was on 18 and 19 December in line with a period of low wind generation and high demand. Prices were also high during this period with hydro units generally setting the price. This was also prior to any storage increases to hydro schemes across the country.

Figure 14: Hydro generation between the 17-30 December compared to the previous week



7.6. As a percentage of total generation, between 24-30 December, total weekly hydro generation was 55%, geothermal 21.4%, wind 10.2%, thermal 10.6%, and co-generation 2.8%.

Figure 15: Total generation by type as a percentage each week between 3-30 December



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 17-30 December ranged from 1300MW to ~2320MW.

8.2. Notable outages include:

(a) Huntly 5 is on outage until 20 January 2024

(b) Huntly 4 was on outage from 24 November to 22 December

(c) TCC was on outage from 23 October to 18 December

(d) Stratford 1 was on outage during 20 December

(e) Stratford 2 is on outage until 28 February 2025

(f) Various North and South Island hydro units on outage

Figure 16: Total MW loss due to generation outages

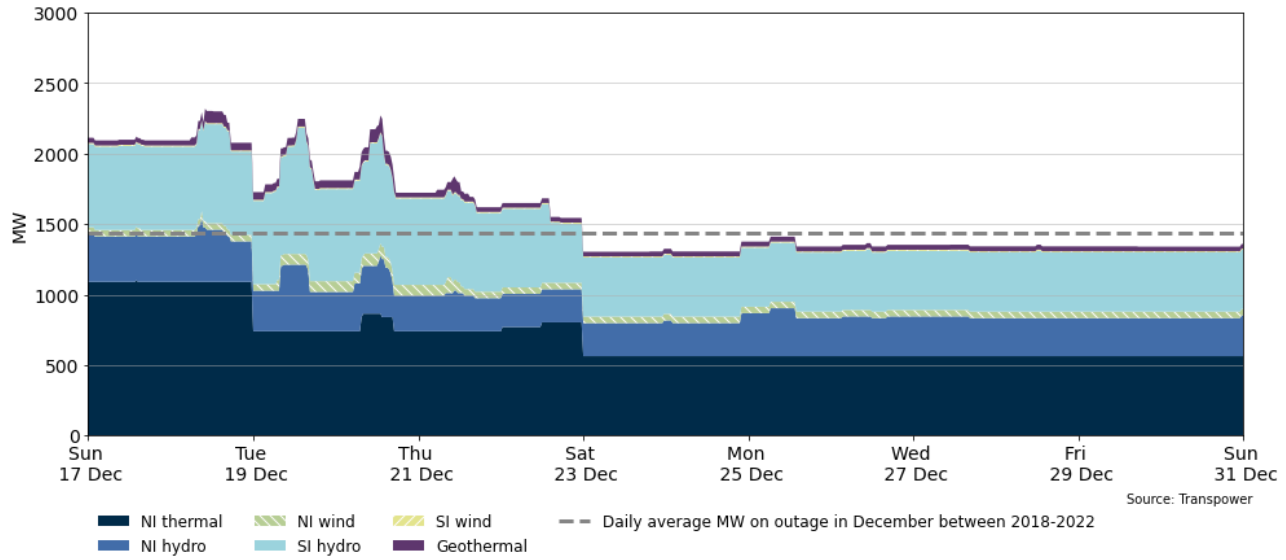
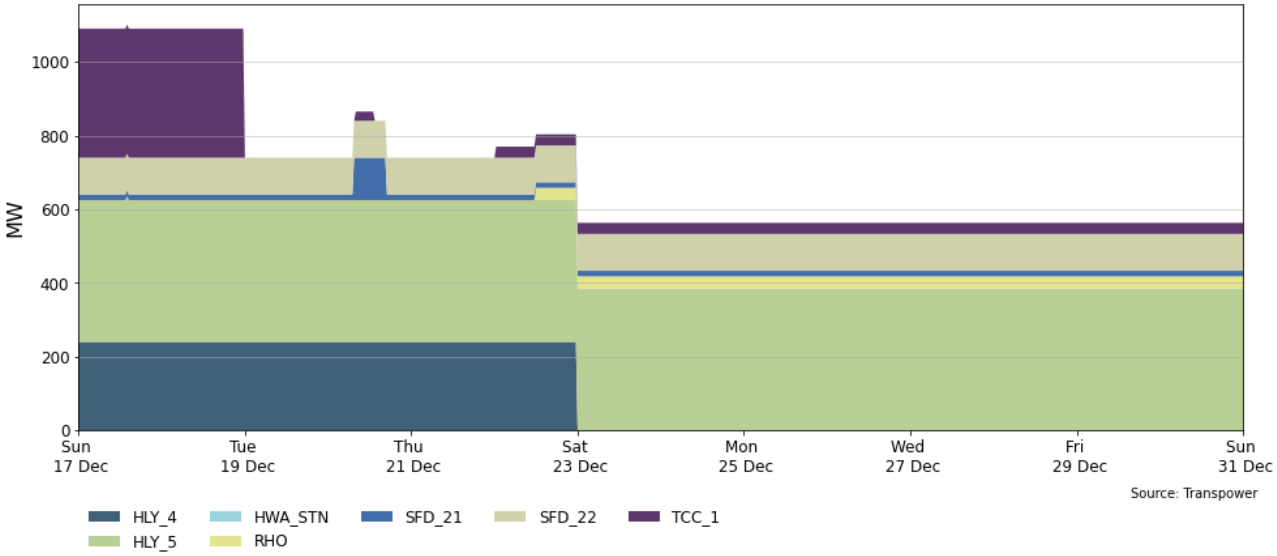


Figure 17: MW loss from thermal outages



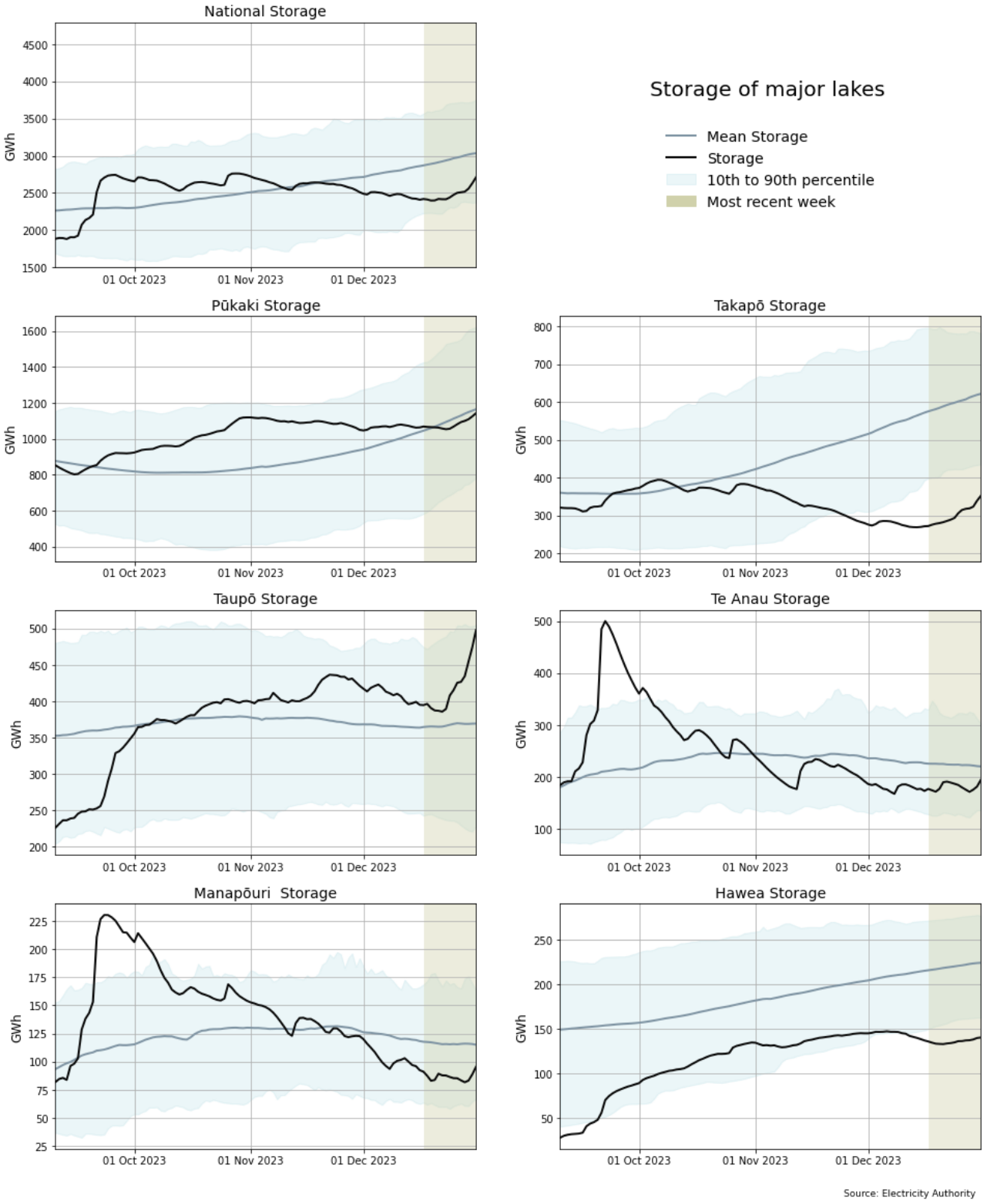
9. Storage/fuel supply

9.1. Figure 18 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.

9.2. National hydro storage levels were still in decline until 20 December where they dropped to 2733GWh. Since then, controlled storage has been increasing and now sits at around 3056GWh as of 1 January. This is 91% of mean and 69% nominally full.

9.3. All lakes have seen an increase to storage with Taupō seeing the steepest incline and storage now at its 90th percentile region. Pūkaki storage remains just below its mean but is increasing. Takapō remains below its 10th percentile region, although has seen a steady increase over the last week. Manapōuri and Te Anau both saw small increases to storage towards the end of the week but remain below their respective means. Hawea has had a steady increase to its storage, although its storage is still below the historical 10th percentile region.

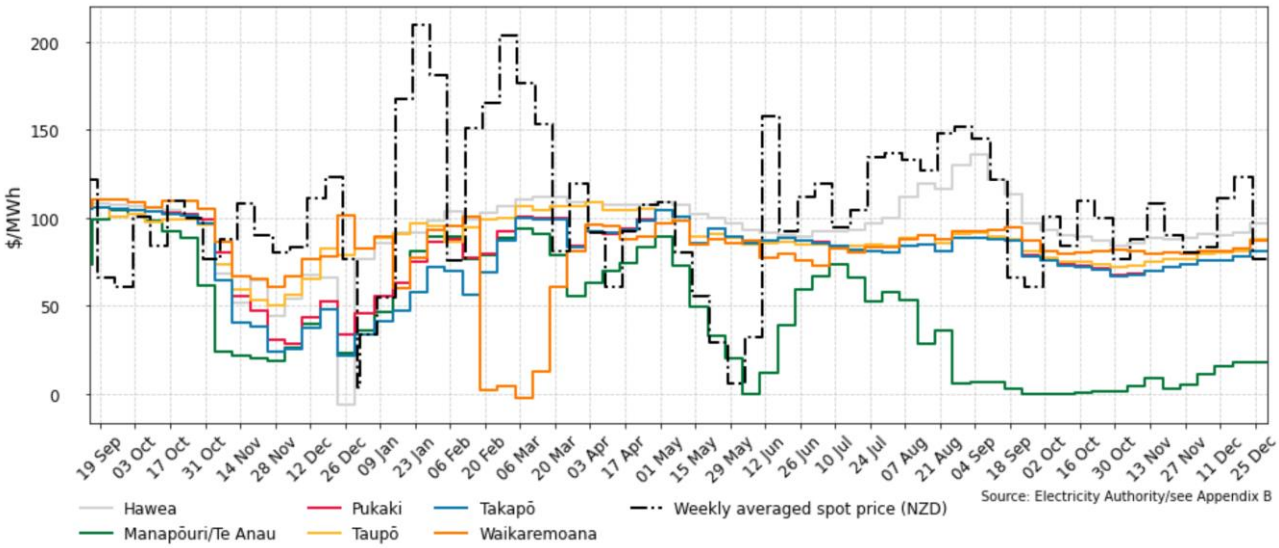
Figure 18: Hydro storage



10. JADE water values

10.1. The JADE[3] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 19 shows the national water values between 15 September 2022 and 30 December 2023 obtained from JADE calculated as at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B. The water values of most lakes slightly increased.

Figure 19: JADE water values across various reservoirs between 15 September 2022 and 30 December 2023



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 2023. After increasing since May, the SRMC for diesel has now started to decrease. Coal SRMC has increased slightly on the previous month, with gas SRMC rising due to outages which reduced supply, the most significant being a full outage at Kupe.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$162/MWh. This is now lower than the cost of running the Rankines on gas at ~$176/MWh. It appears that the Rankines were predominantly fuelled by coal during the Kupe outage, and Enerlytica estimated that the fuel mix was 30% gas when the outage started.

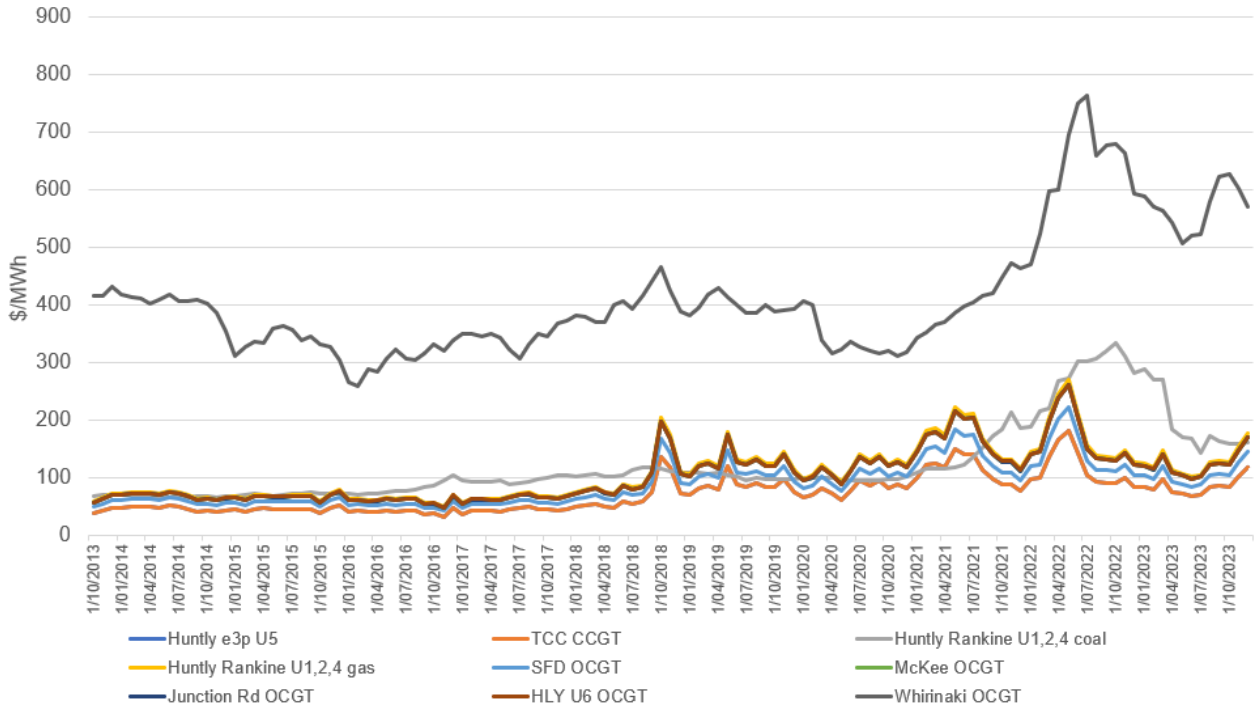
[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

11.5. The SRMC of gas fuelled thermal plants is currently between $118/MWh and $176/MWh.

11.6. The SRMC of Whirinaki has decreased to ~$570/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C on the trading conduct webpage.

Figure 20: Estimated monthly SRMC for thermal fuels



Source: Electricity Authority/see Appendix C

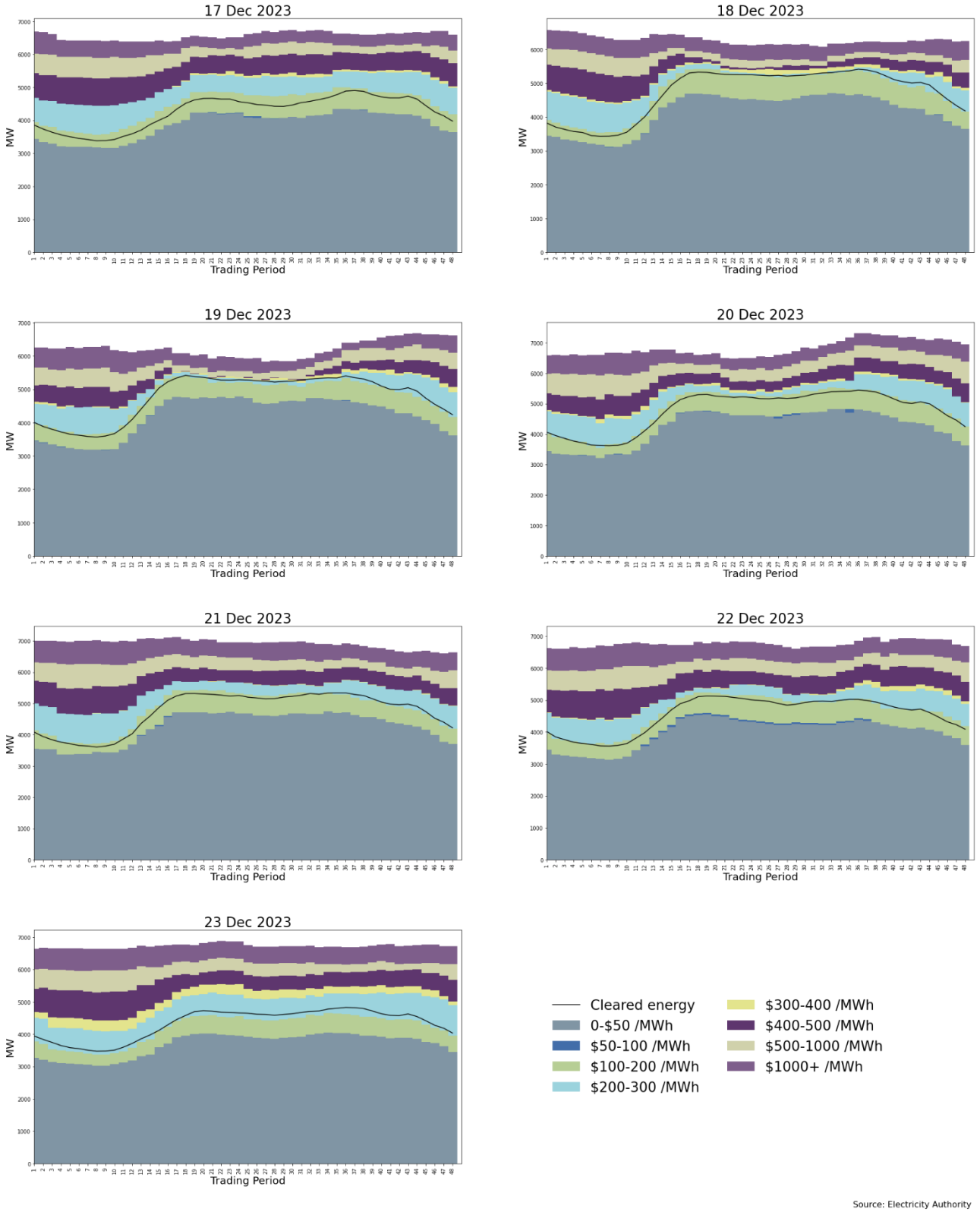
12. Offer behaviour

12.1. Figure 21 and Figure 22 shows the two week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. There were minimal offers in the $50-$100/MWh region as well as the $100-$200/MW offers being thinner on some days. Most offers cleared within the $100-$300/MWh price region.

12.3. On 19 December where there were some very high prices, the offer stacks where thin between $200-$400/MWh, likely due to a large number of generators on outage and total stack was also down compared to some other days. As a result, small changes in conditions can result in large price spikes.

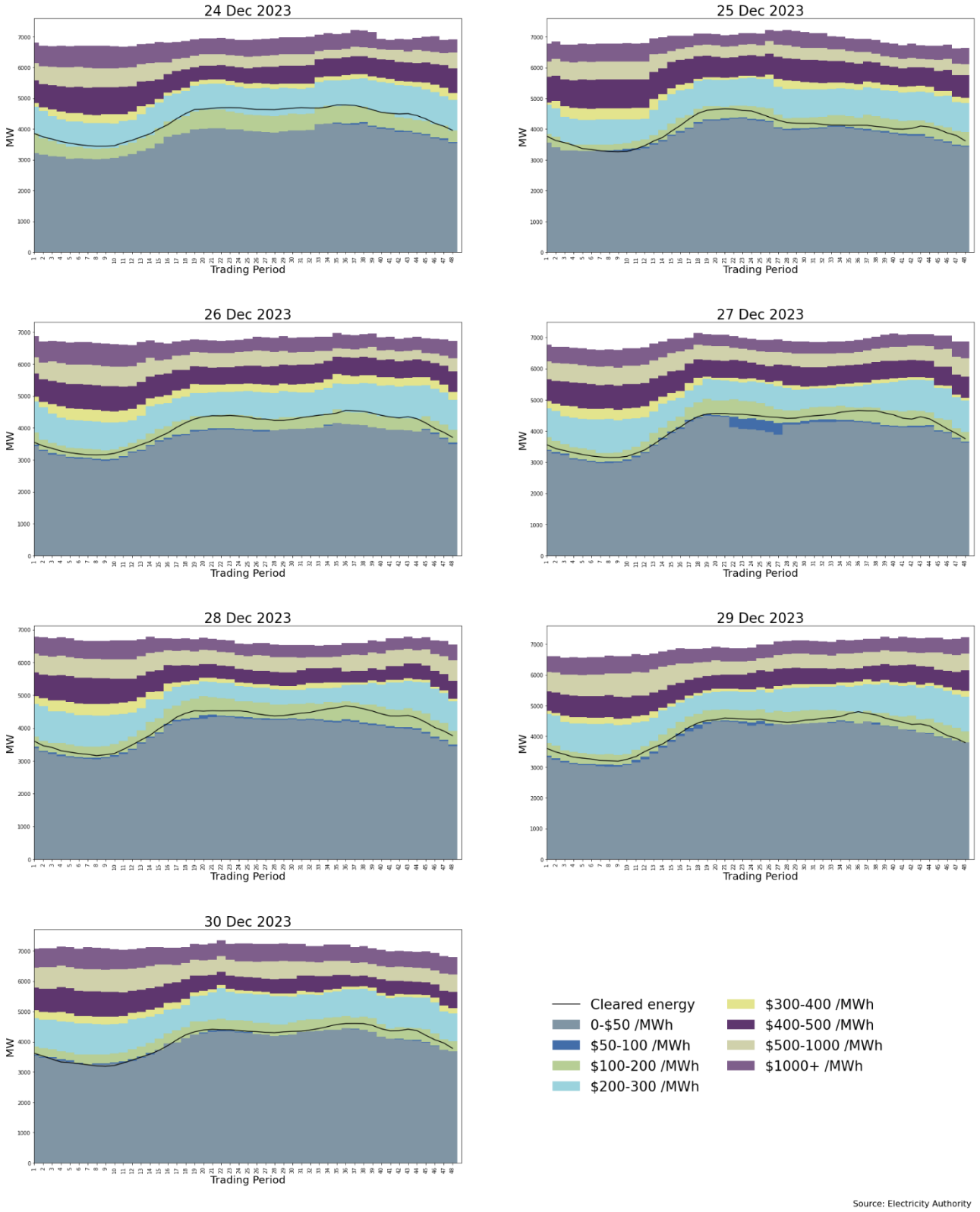
Figure 21: Daily offer stacks[4] 17-23 December



Source: Electricity Authority

[4] Offer stacks created using PRSS data 30 minutes before gate closure due to unavailable RTD data

Figure 22: Daily offer stacks[5] 24-30 December



Source: Electricity Authority

[5] Offer stacks created using PRSS data 30 minutes before gate closure due to unavailable RTD data

13. Ongoing work in trading conduct

13.1. Over the two weeks analysed, 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	TP	Status	Participant	Location	Enquiry topic
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers.
22/09/2023-30/09/2023	Several	Further analysis	Contact	Multiple	High hydro offers.