18 December 2023

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 10-16 December

1.1. Throughout this week, spot prices mostly ranged between $150-$180/MWh. Instances of price spikes were observed during periods of low wind generation or overestimation of wind forecast, leading to the dispatch of high-priced energy. Two Huntly Rankines continue to run as baseload with Stratford 1 also running continuously. As of December 16, hydro storage was approximately 88% of its historical mean.

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. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range[1] of historic prices, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 10-16 December:

(a) The average wholesale spot price across all nodes was $169/MWh.

(b) 95 percent of prices fell between $68/MWh and $244/MWh.

2.4. Overall, the majority of spot prices are still sitting below $200/MWh and above historic average for this time of year. However, there were also a number of price spikes across the week that saw prices above $300/MWh. Most of these spikes were due to higher priced energy being dispatched to cover wind or demand forecast discrepancies.

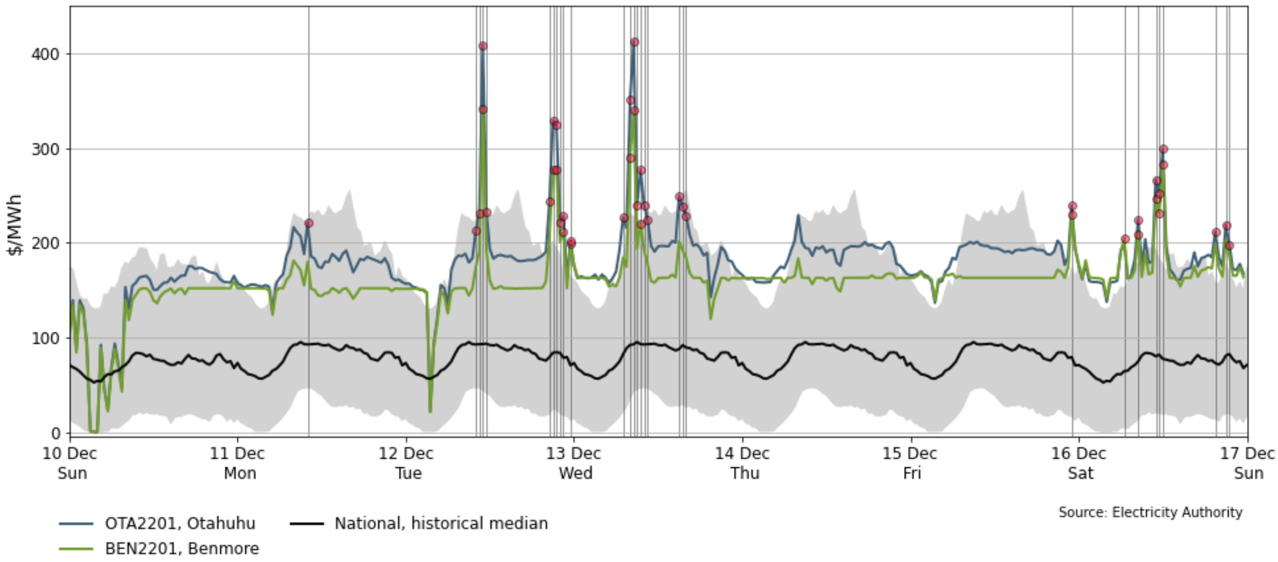
2.5. The first instance of a price above $300/MWh was on Tuesday morning at 11:00am with the prices at Ōtāhuhu being $409/MWh and $342/MWh at Benmore. This happened again between 9:00pm and 9:30pm. The prices at Ōtāhuhu were $329/MWh and $300/MWh and at Benmore were $277/MWh. During the morning price spike, wind was around 60MW less than forecast, and during the evening spikes, wind was around 180MW less than forecast.

2.6. On Wednesday, the price spikes above $300/MWh occurred between 8:00am and 8:30am with Ōtāhuhu prices of $412/MWh and Benmore prices of $340/MWh. During the 8:30am trading period wind was 105MW under-forecasted, also during the evening peak wind was under-forecasted.

[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 $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

2.7. On Saturday, the prices were higher and also above the 90th percentile due to the wind forecast difference and the demand was also higher compared to the previous week.

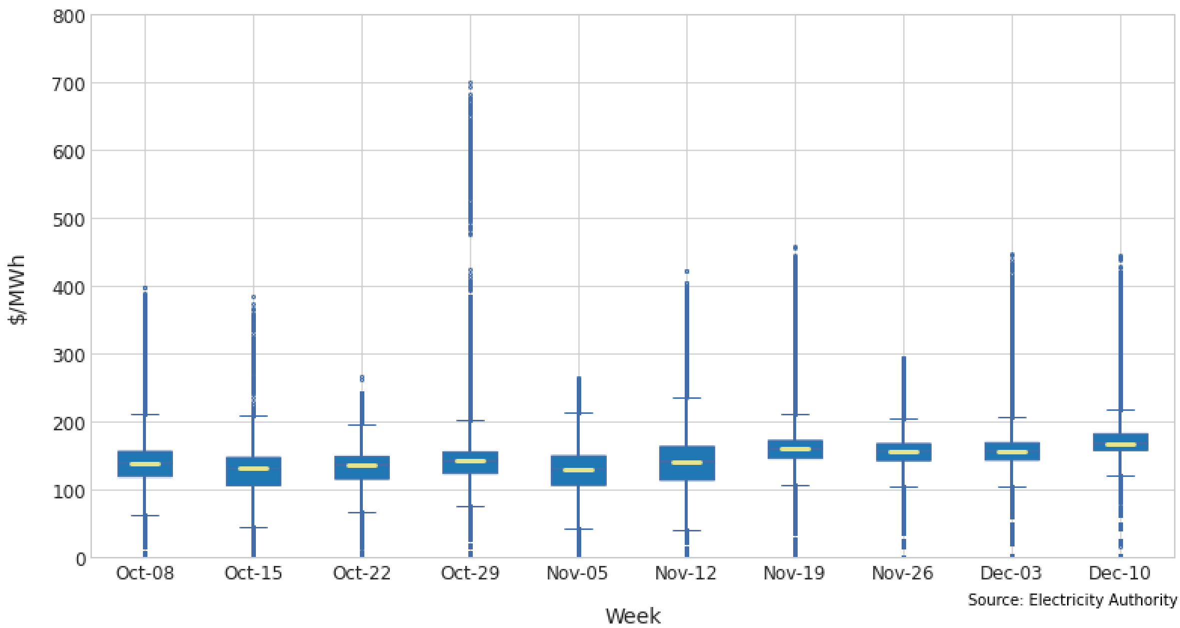
Figure 1: Wholesale spot price at Benmore and Ōtāhuhu between 10-16 December



2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The green 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.

2.9. Distribution of prices was similar to the previous week with the middle 50% of prices lying between $157/MWh and $180/MWh and the median price was $167/MWh. This week saw outlier prices above $300/MWh and some over $400/MWh similar to the previous week.

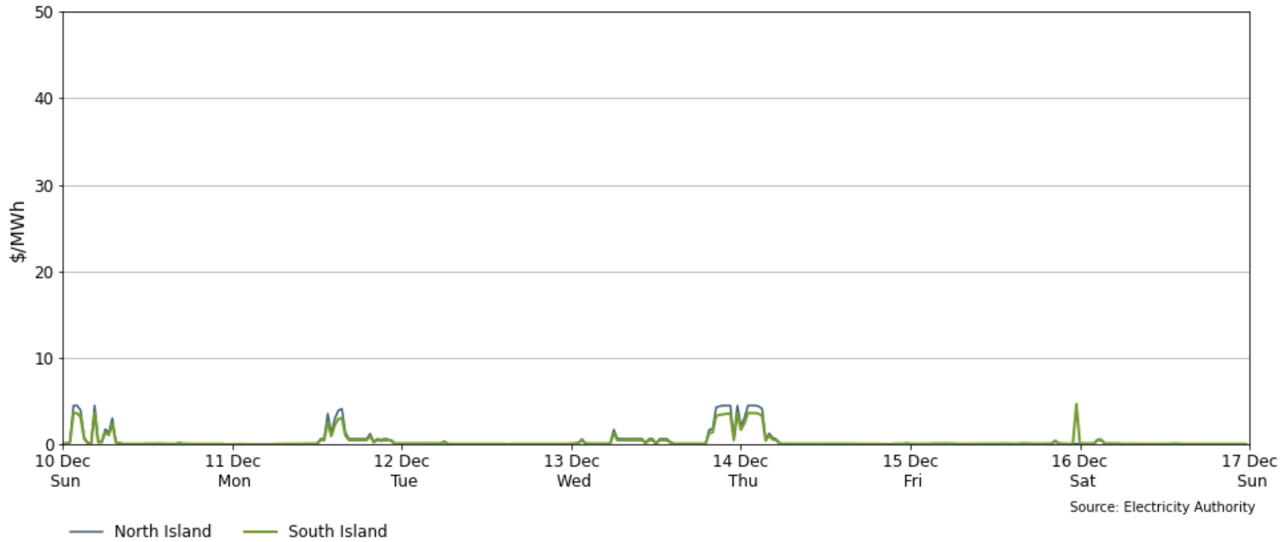
Figure 2: Boxplots showing the distribution of the spot prices this week and the previous nine weeks



3. Reserve prices

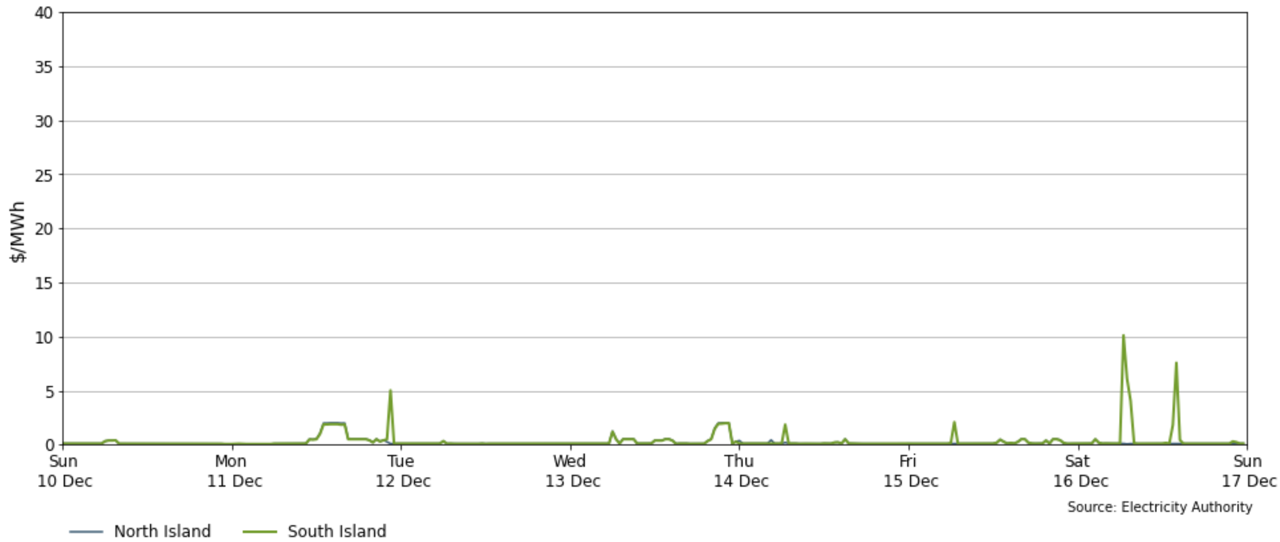
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were all below $5/MWh this week.

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



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were all below $10/MWh this week.

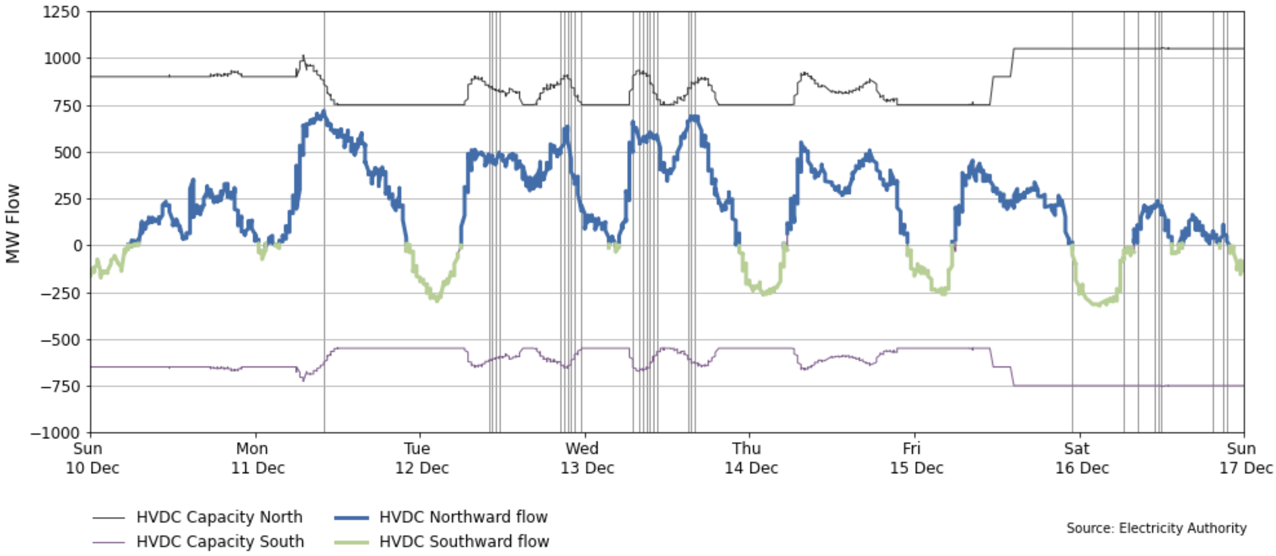
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 10-16 December. HVDC flows were northwards during the day with some southward flow overnight. Northward flow was mostly below 750MW, with the maximum southward flow of around 315MW.

Figure 5: HVDC flow and capacity



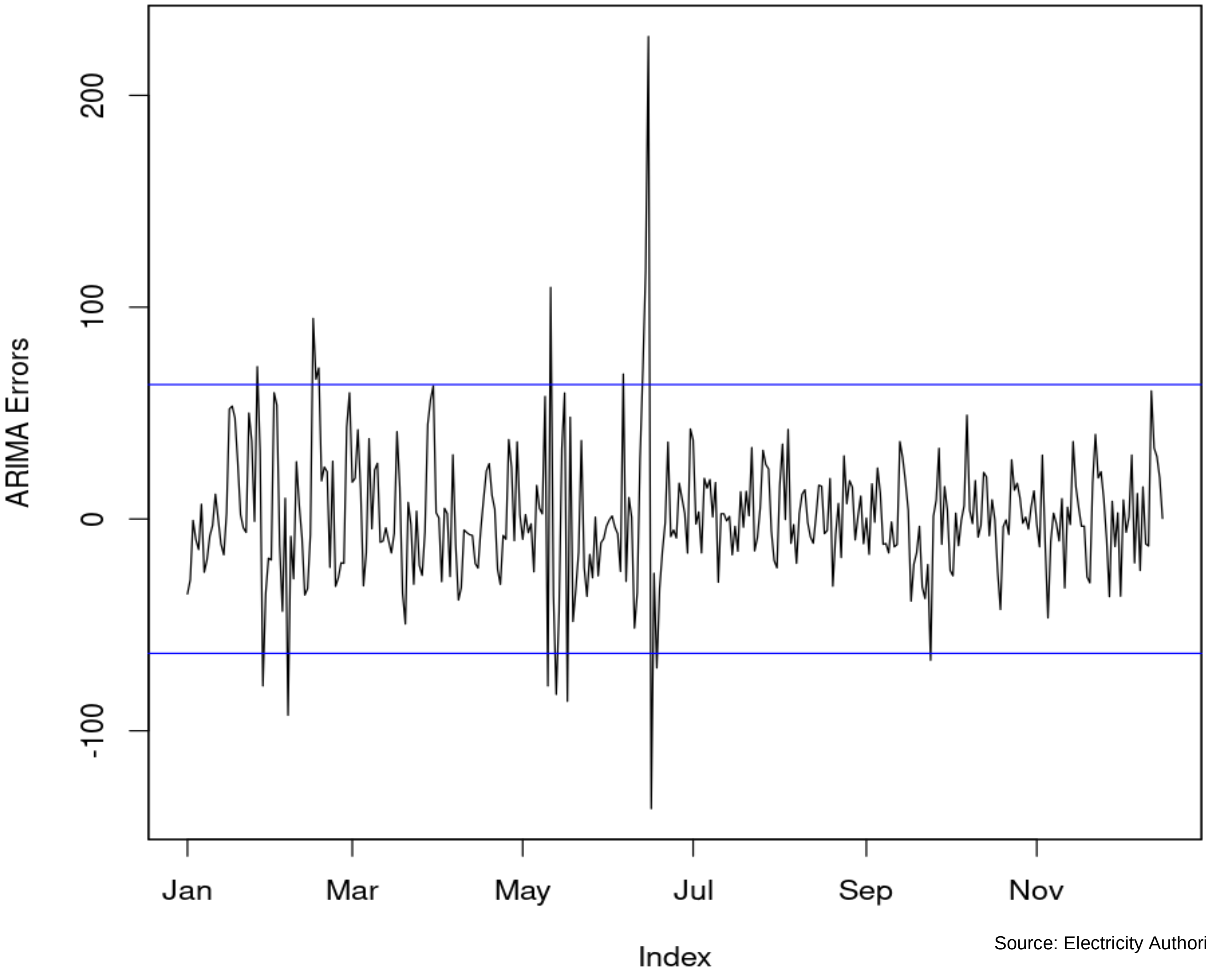
5. Regression residuals

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 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 for in the regression analysis.

5.3. This week no residuals were above or below 2 standard deviations, indicating actual and modelled prices were similar.

Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 16 December 2023

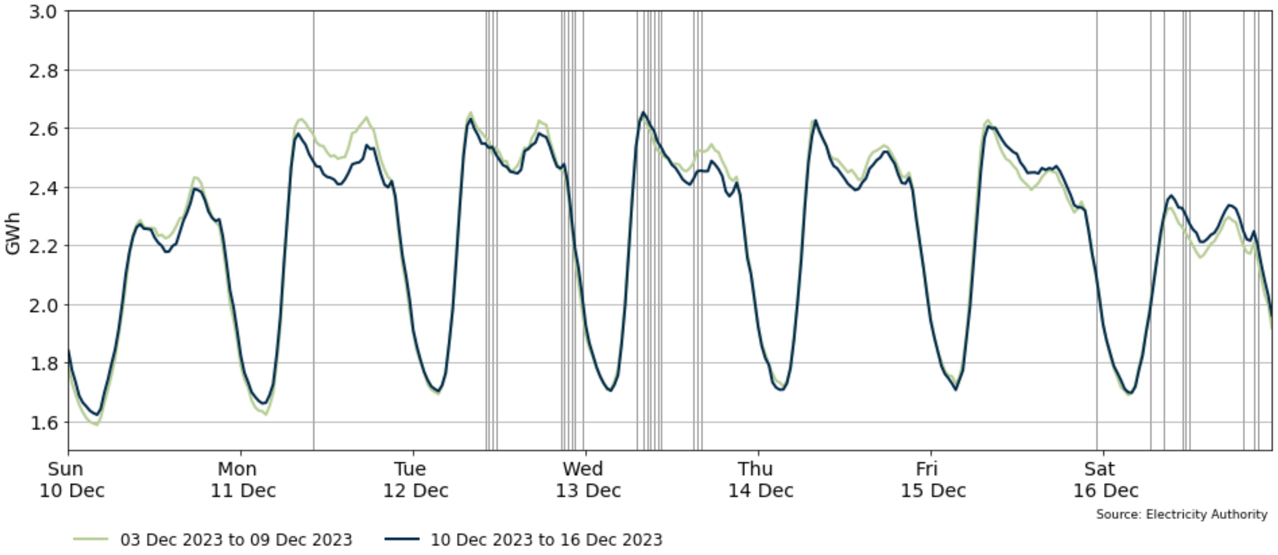


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 10-16 December, compared to the previous week. Overall, demand was similar to the previous week except on Monday when demand was lower compared to the previous week. Also, on Wednesday during the evening peak demand was lower due to mild temperatures.

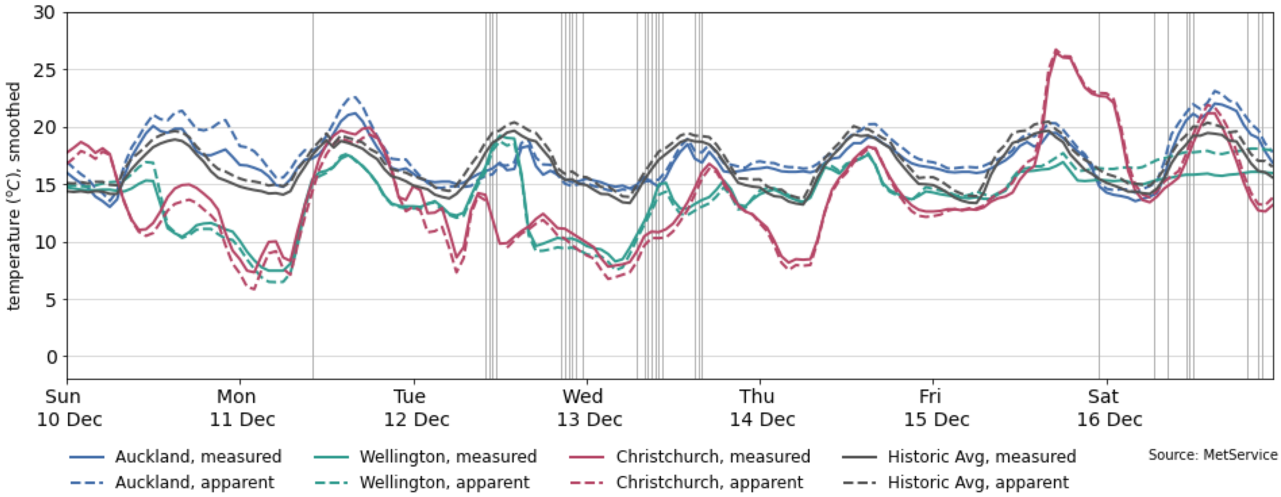
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 10-16 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. Temperatures were mostly above 6℃ at the three main population centres. Auckland temperatures were mostly above or around the historic average, ranging between 14-23℃. However, Wellington temperatures were mostly below average at the start of the week, but were around the historic average from Thursday. Christchurch temperatures usually fell below average, except Friday when temperatures were well above average. Christchurch temperatures ranged between 6-27℃ this week.

Figure 8: Temperatures across main centres

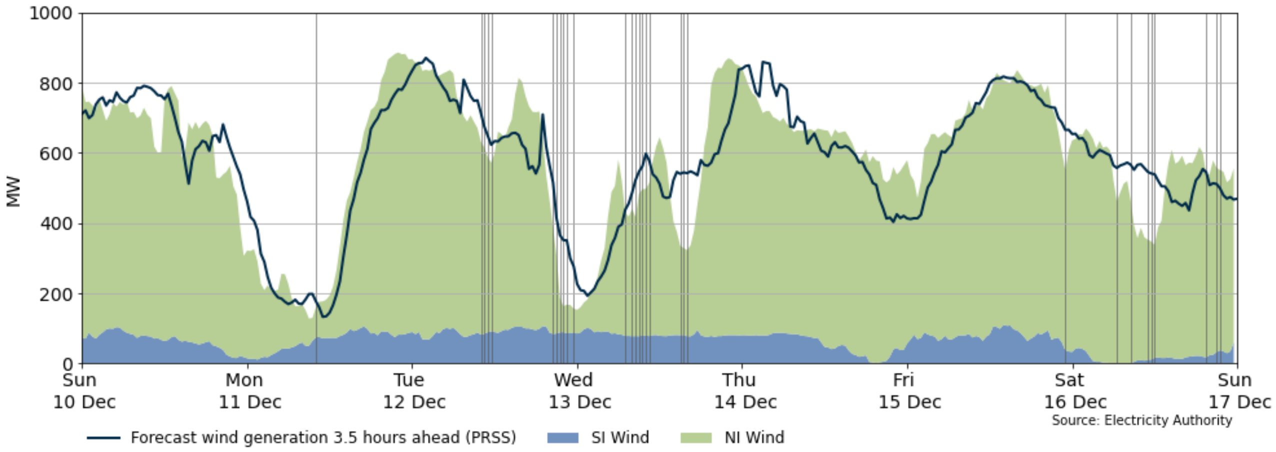


7. Generation

7.1. Figure 9 shows wind generation, from 10-16 December, ranging from ~130MW to 885MW. At the start of the week, wind started high mostly around 700MW but dropped to 180MW till

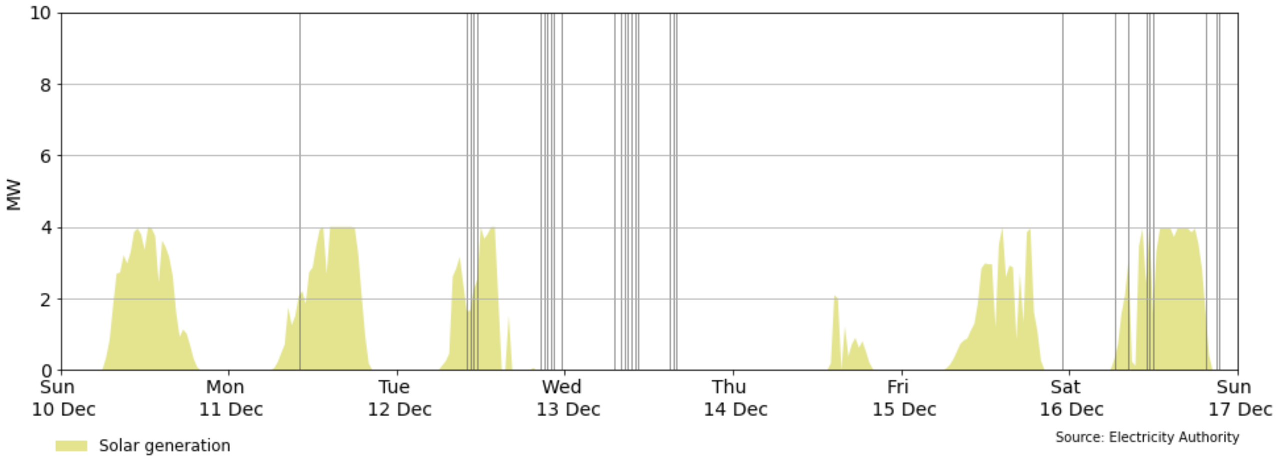
Monday afternoon. On Monday, wind generation gradually increased to around 885 MW until it experienced a notable drop again on Tuesday night. During Thursday and Friday, wind was mostly above 600MW. On Saturday, there was a big difference between the forecast and actual wind generation. This week again both low wind generation and over forecast wind had an effect on spot prices.

Figure 9: Wind generation and forecast between 10-16 December



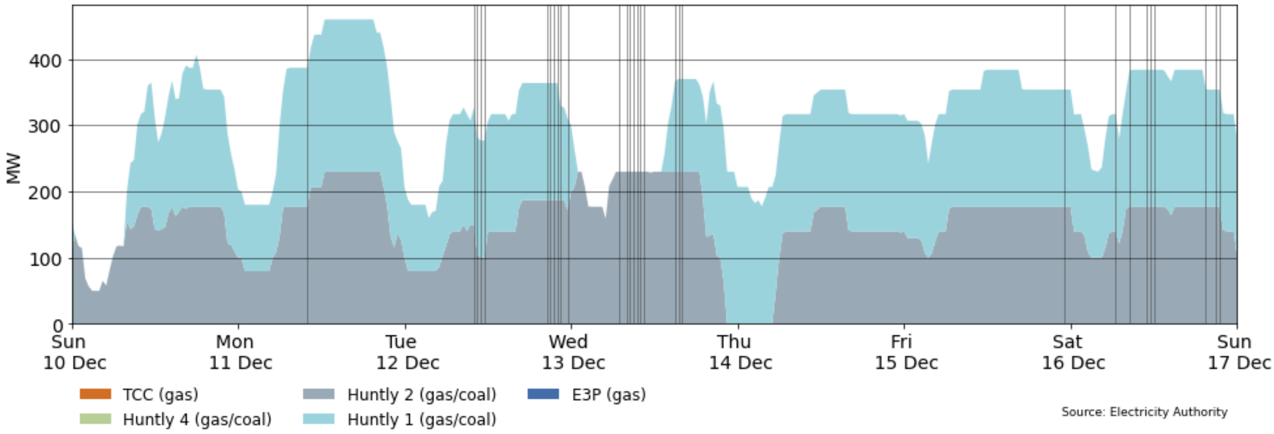
7.2. Up to 4MW of solar generation also occurred this week as the commissioning process continues at Kaitaia Solar Farm.

Figure 10: Solar generation between 10-16 December



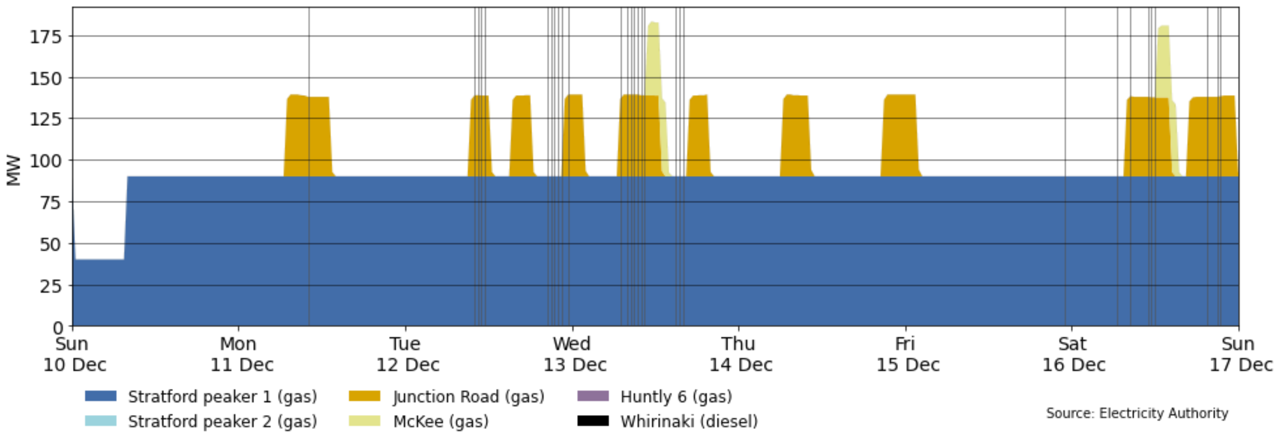
7.3. Figure 11 shows the generation of thermal baseload and thermal peaker plants between 10-16 December. Both Huntly 1 and 2 mostly ran continuously as baseload this week.

Figure 11: Thermal baseload generation between 10-16 December



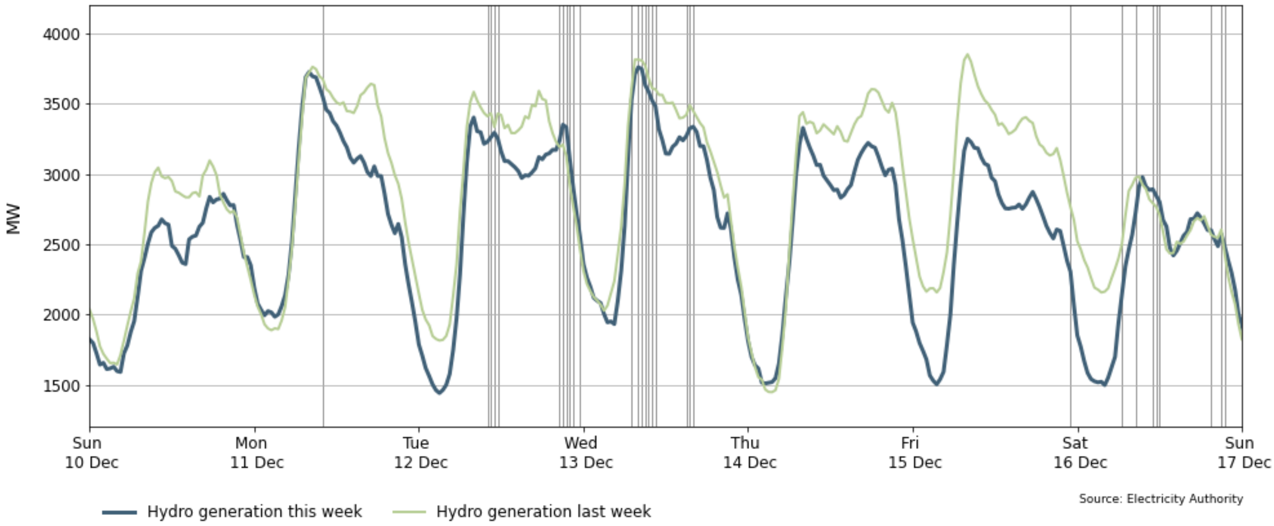
7.4. Stratford 1 ran continuously at 90MW for the week apart from a short period on Sunday morning where it ran at around 40MW as seen in Figure 12. Junction Road ran from Monday to Thursday, and on Saturday. McKee was the only other peaker to run during Wednesday and Saturday.

Figure 12: Thermal peakers generation between 10-16 December



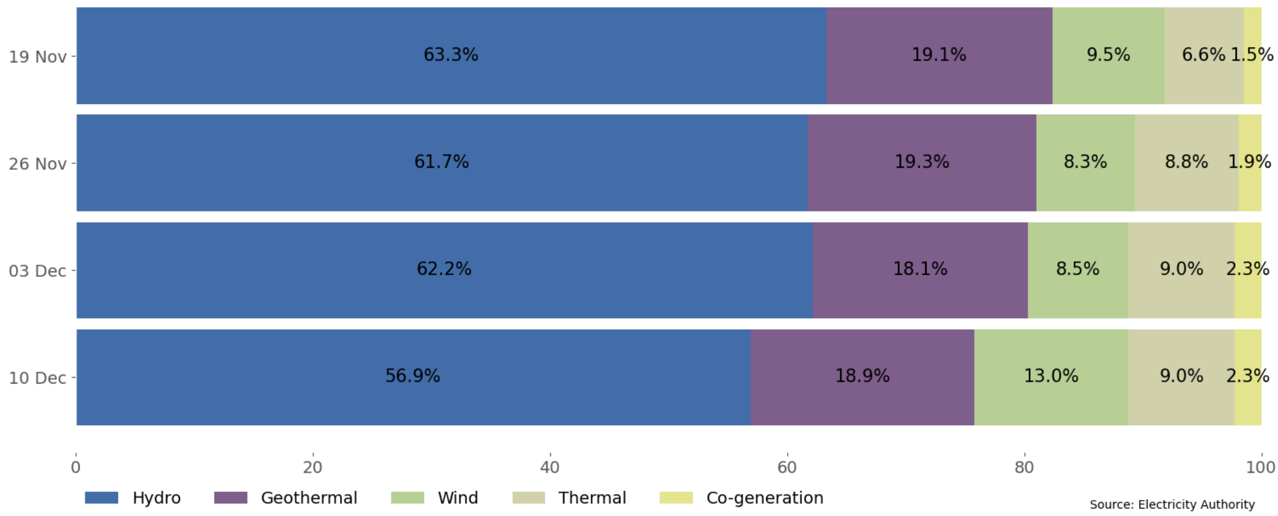
7.5. Figure 13 shows hydro generation between 10-16 December. Most days saw a decrease in hydro generation compared to the previous week, ramping up during peak periods to meet demand requirements.

Figure 13: Hydro generation between 10-16 December compared to the previous week



7.6. As a percentage of total generation, between 10-16 December, total weekly hydro generation was 56.9%, geothermal 18.9%, wind 13%, thermal 9%, and co-generation 2.3%.

Figure 14: Total generation by type as a percentage each week between 19 November and 16 December



8. Outages

8.1. Figure 15 shows generation capacity on outage. Total capacity on outage between 10-16 December ranged from 2100MW to 2850MW and was particularly high from Tuesday and Thursday.

8.2. Notable outages include:

(a) Huntly 5 on outage until 20 January 2024

(b) TCC on outage until 18 December

(c) Huntly 4 on extended outage until 22 December

(d) Stratford 2 outage until 28 February 2025

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

Figure 15: Total MW loss due to generation outages

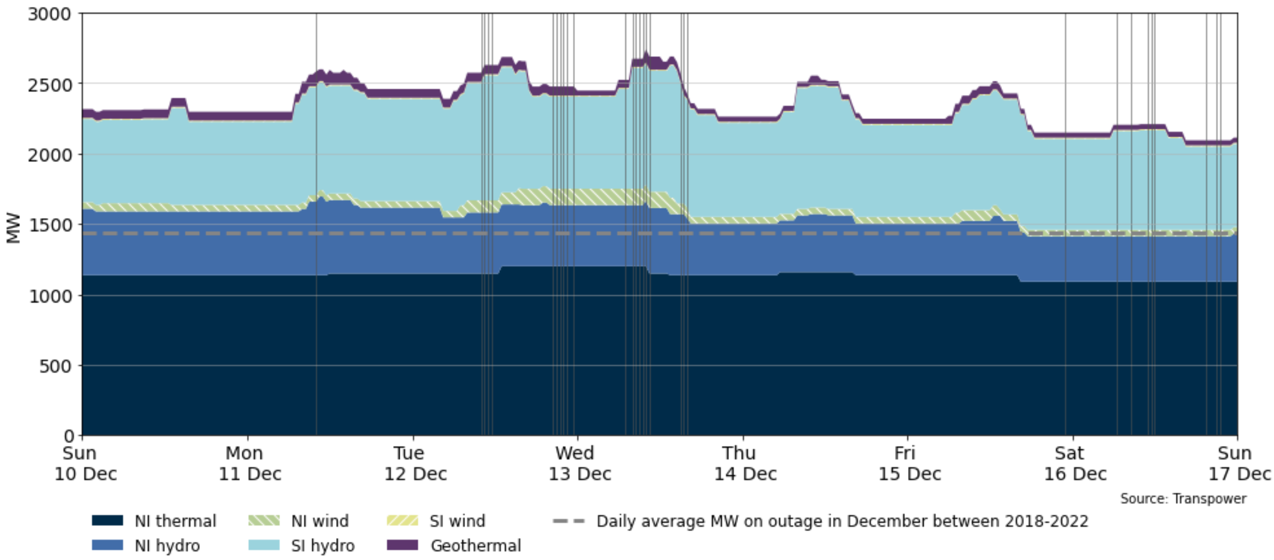
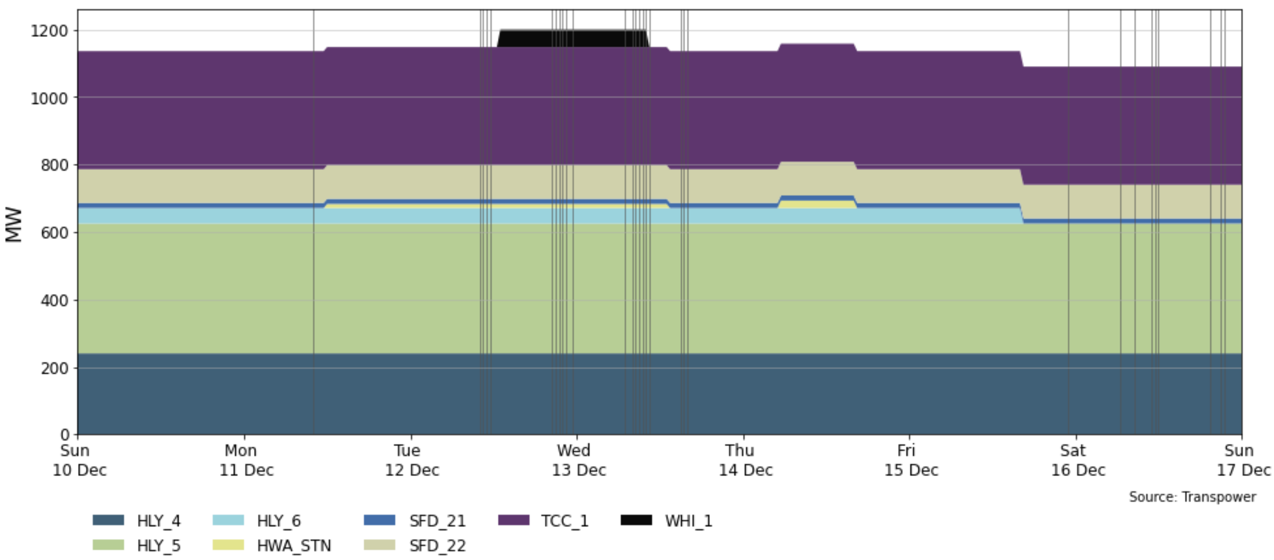


Figure 16: MW loss from thermal outages



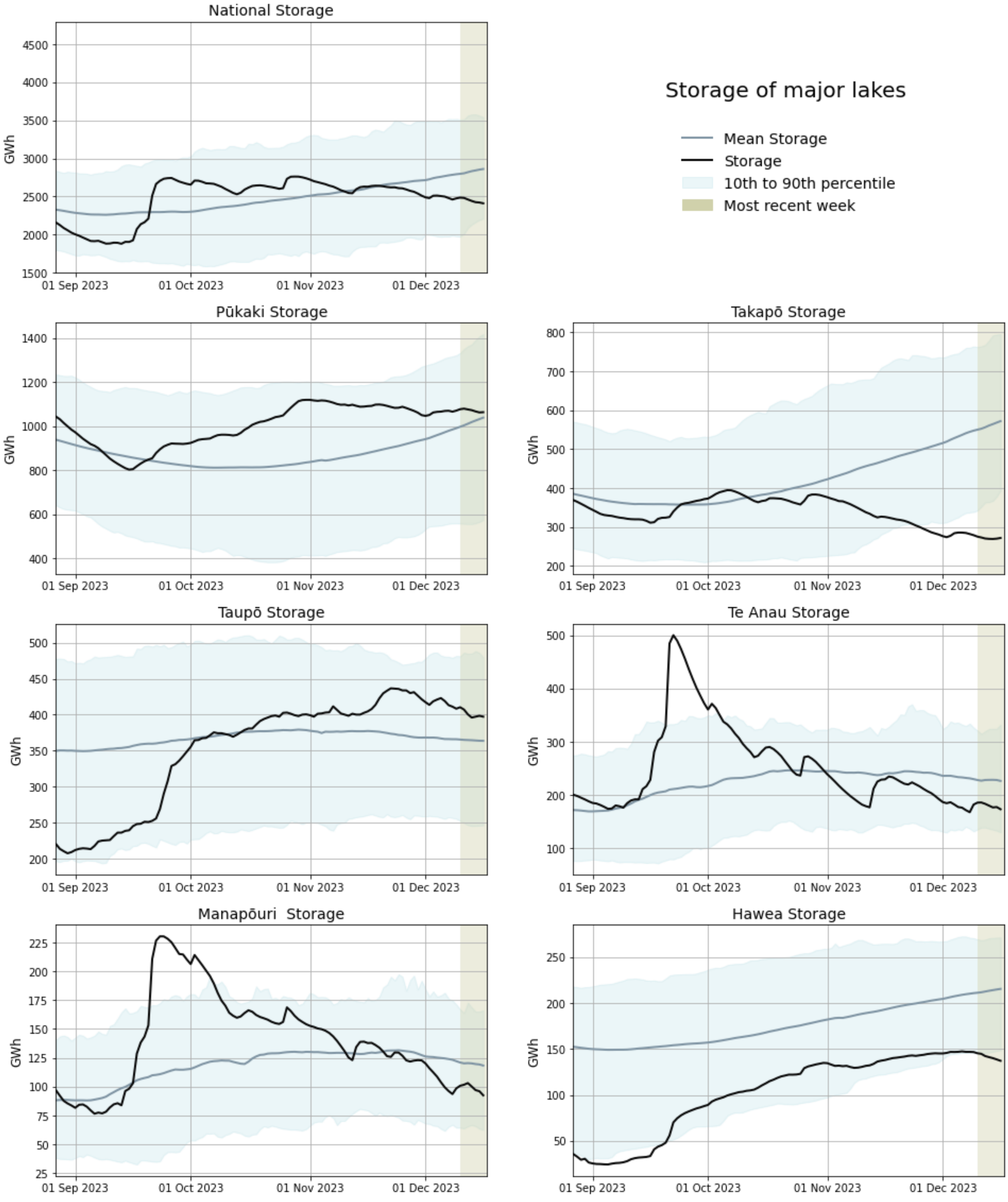
9. Storage/fuel supply

9.1. Figure 17 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 continue to decrease with controlled storage as of 16 December at 87.5% of historic mean and 62.4% nominally full.

9.3. During this week, all lake levels experienced a decline. Pūkaki storage decreased slightly this week, touching its historic mean, while Takapō storage has continued to decline, remaining below its historic 10th percentile. Taupō storage dipped again, although remains above its historic mean storage. Moreover, Manapōuri and Te Anau storage also decreased and both lakes remain below the historic mean for this time of year but above their 10th percentile ranges. Hawea storage is below its 10th percentile range.

Figure 17: Hydro storage



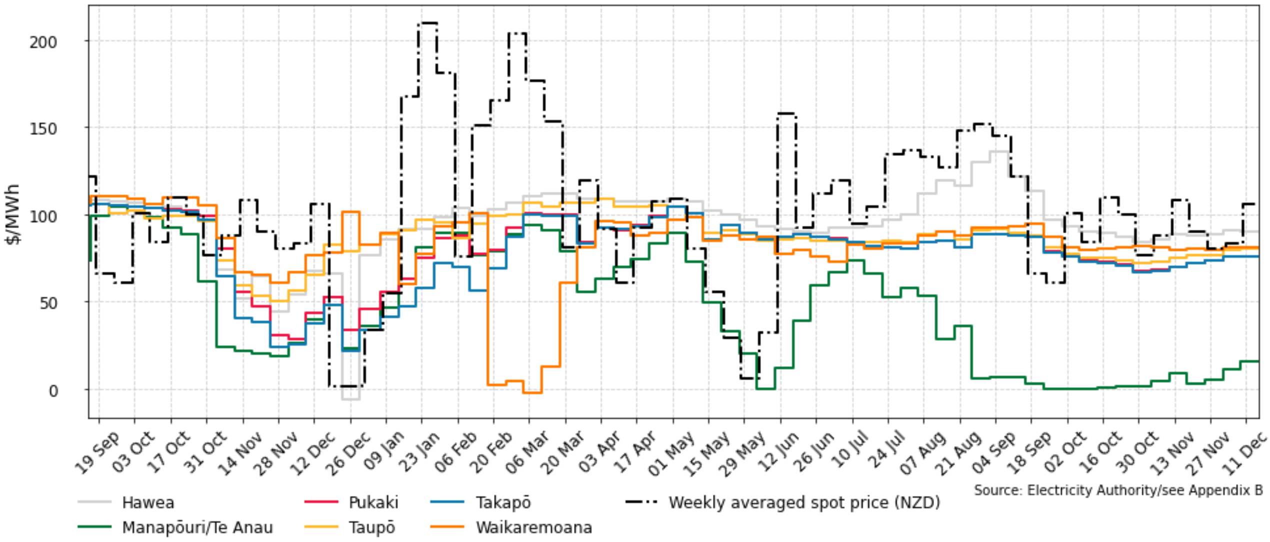
Source: Electricity Authority

10. JADE water values

10.1. The JADE[2] 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 18 shows the national water values between 15 September 2022 and 16 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.

10.2. The water values of most lakes remained steady, apart from Manapōuri/Te Anau whose water value increased to ~$4/MWh.

Figure 18: JADE water values across various reservoirs between 15 September 2022 and 16 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 19 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

[2] 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.

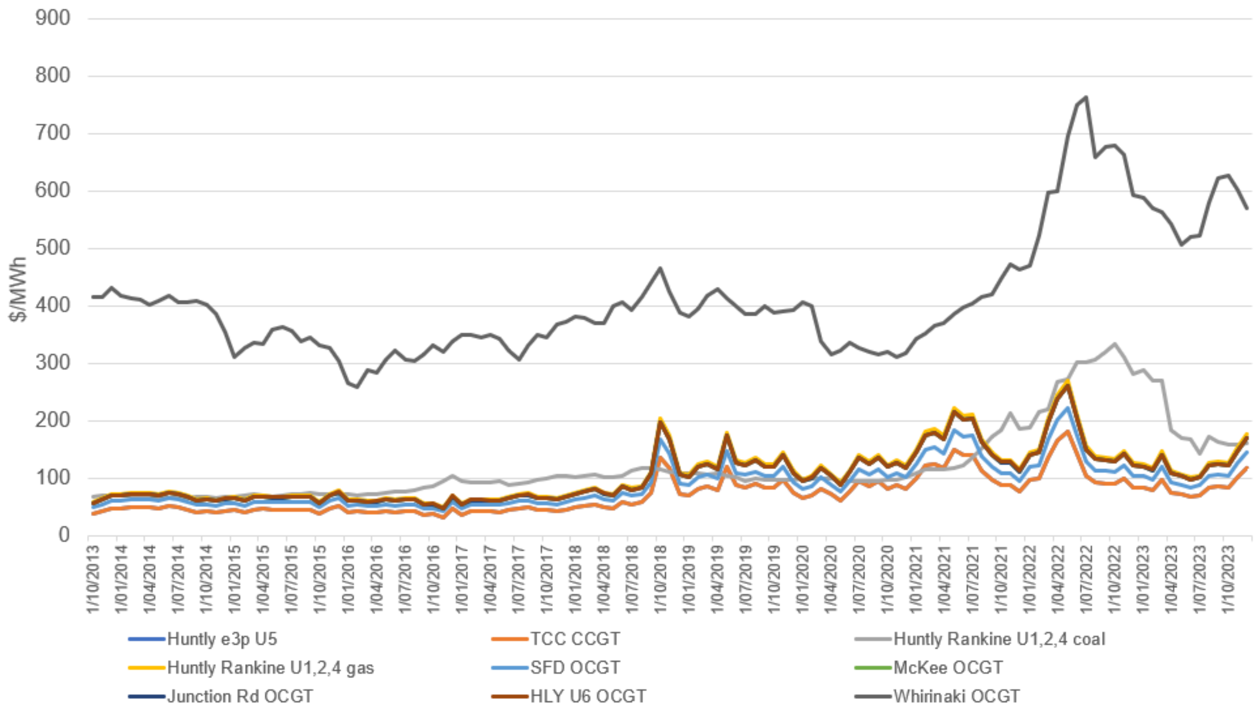
predominantly fuelled by coal during the Kupe outage, and Enerlytica estimated that the fuel mix was 30% gas when the outage started.

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 19: Estimated monthly SRMC for thermal fuels



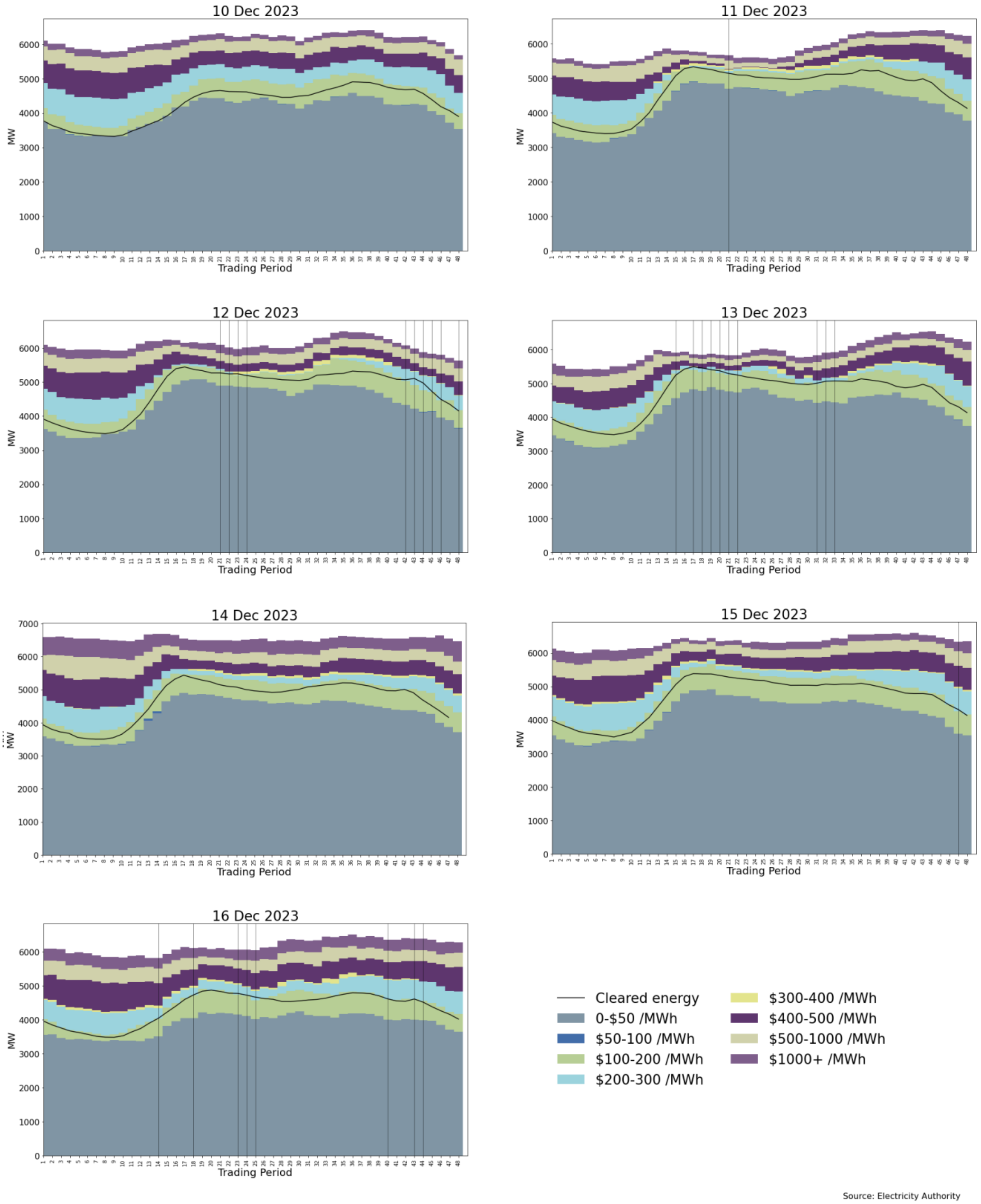
Source: Electricity Authority/see Appendix C

12. Offer behaviour

12.1. Figure 20 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 cleared in the $100-$200/MWh price band this week. Almost no energy was offered between $50-$100/MWh band. There continues to be a thin offer stack between $200-$400/MWh during peak demand periods and total generation offered remains low due to generation outages. As a result, small changes in conditions can result in large price spikes, especially when demand is high.

Figure 20: Daily offer stacks[3]



[3] Offer stacks for 14 Dec 2023 created using PRSS data 30 minutes before gate closure due to unavailable RTD data.

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	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.
11/10/2023	21	Resolved	Genesis	Tokaanu	No trading conduct issue was identified.