15 January 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for weeks of 7-13 January 2024

1.1. Spot prices were high across the week, mainly sitting in the $200-$300/MWh range. Demand increased this week as many businesses reopened and many people returned to work after the holiday period. High temperatures and low rainfall also increased demand for air conditioning and irrigation. This saw more hydro and thermal generation across the week. Hydro storage has declined over the week and controlled storage is 67.8% of nominally full as of 13 January.

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 7-13 January:

(a) The average wholesale spot price across all nodes was $228/MWh.

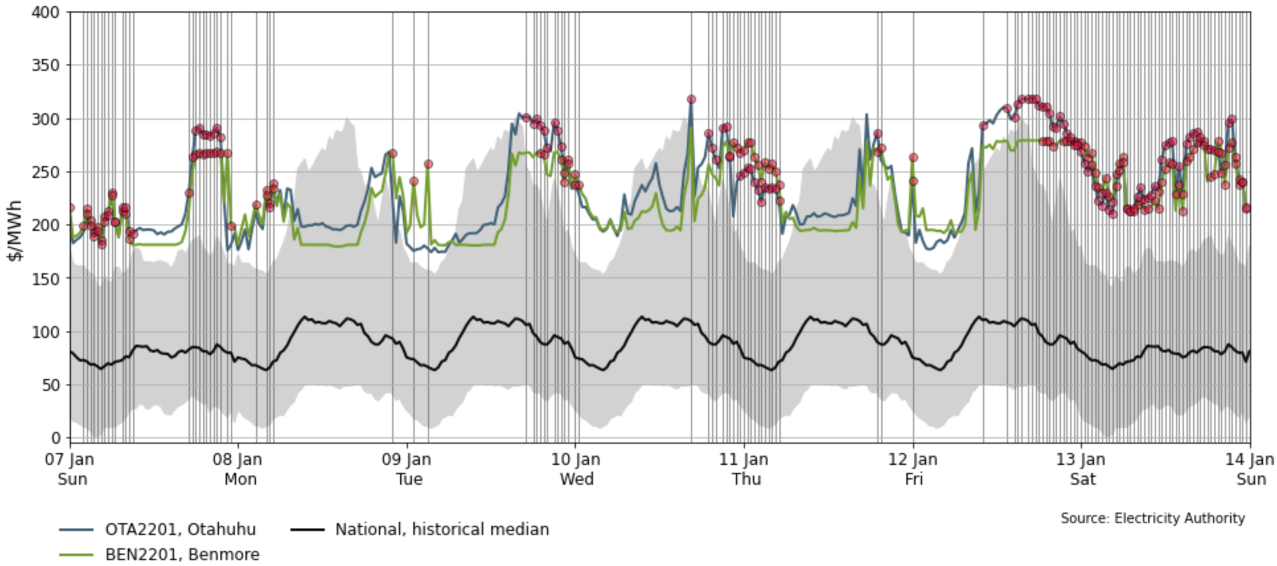
(b) 95 percent of prices fell between $174/MWh and $304/MWh.

2.4. Overall, the majority of spot prices were between $200-$300/MWh across the week. High priced hydro is mainly setting the prices as hydro storage began to decrease again this week. A number of the highlighted prices in the chart below occurred when wind generation was low and hydro generation increased. The majority of prices in the weekend were highlighted as historically prices have been cheaper in the weekend, even though the prices in the weekend were consistent with prices across the week.

2.5. High prices across the day on Saturday occurred mainly due minimal energy being offered in the $50-$200/MWh range. Demand was higher than the previous week and forecast demand was lower than actual demand by between 20-70MW during a number of trading periods.

[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.

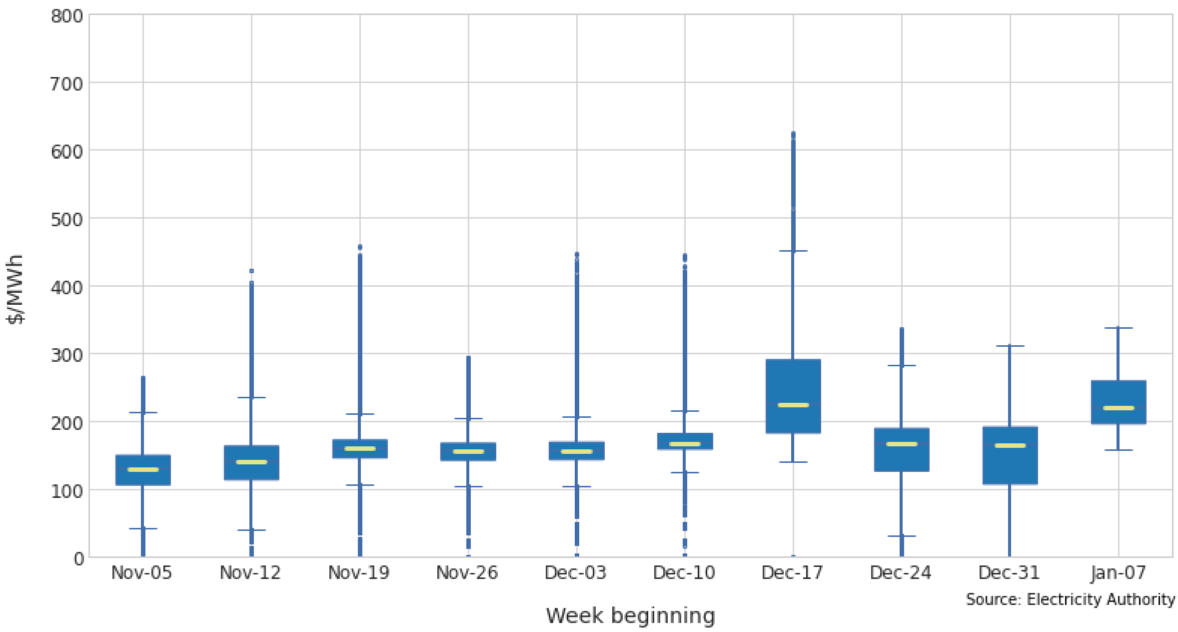
Figure 1: Wholesale spot price at Benmore and Ōtāhuhu between 7-13 January



2.6. 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 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.

2.7. Overall, the distribution of prices was small, however prices sat a lot higher than the previous two weeks. The middle 50% of prices this week were within $196/MWh and $259/MWh, with a median price of $220/MWh.

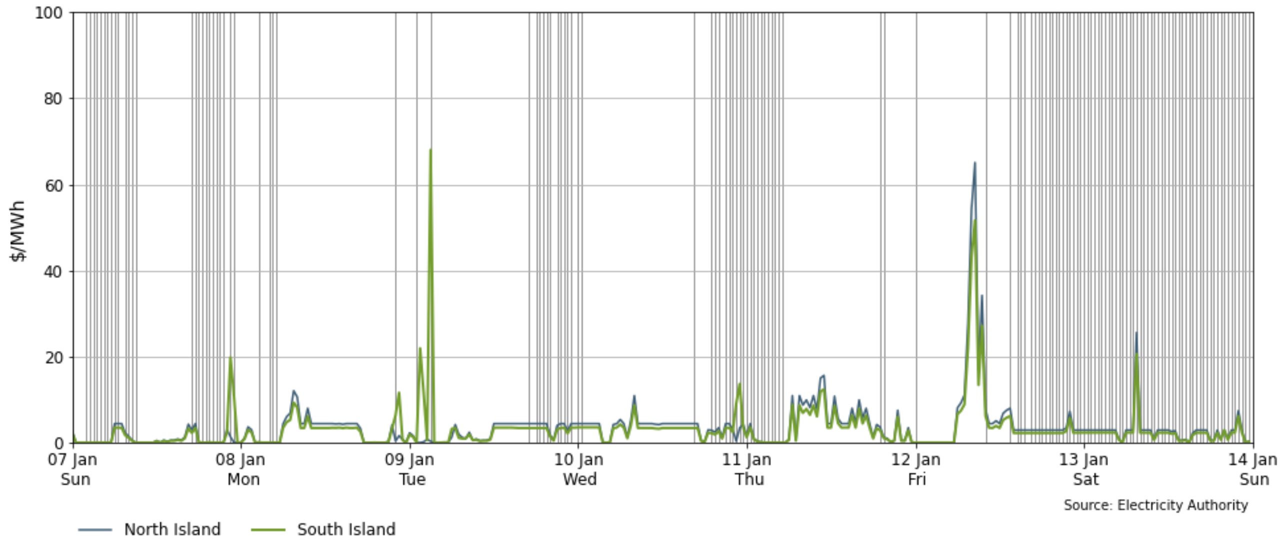
Figure 2: Boxplots showing the distribution of the spot prices this week and the previous nine weeks



3. Reserve prices

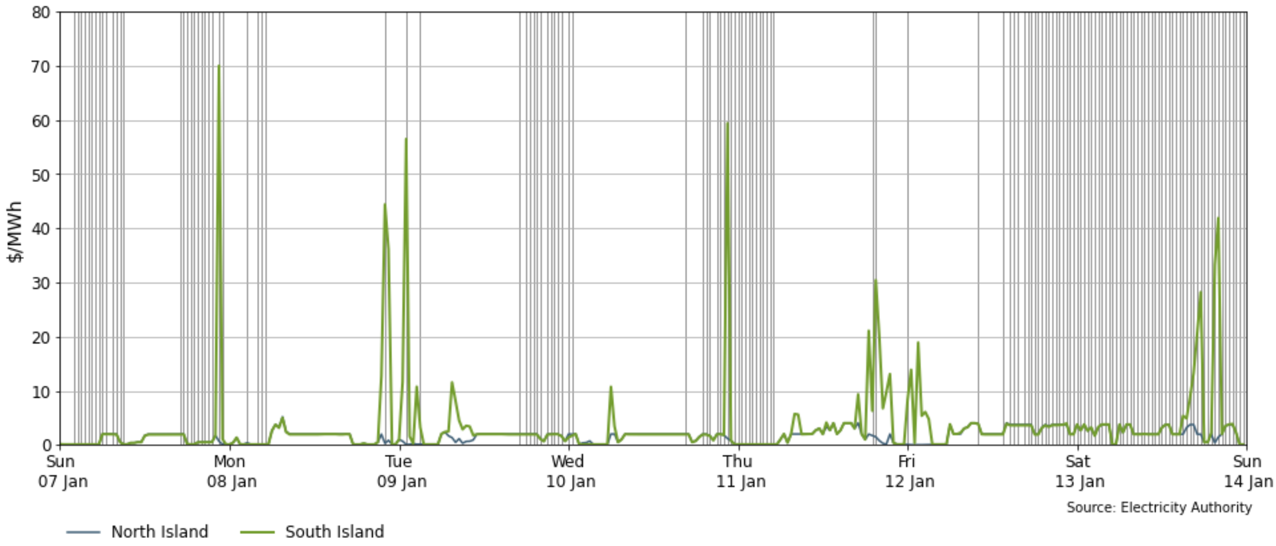
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mostly below $10/MWh, however, there were a few spikes during the week. South Island FIR was $68/MWh on Tuesday at 3.00am and was $43/MWh and $52/MWh on Friday at 8.00am and 8.30am. North Island FIR also spiked on Friday and was $54/MWh and $65/MW at those same times. The spike on Tuesday was due to the binding risk on the HVDC as explained below for the SIR spikes that also occurred at this time. Friday morning spikes were likely due to tightening supply, related to the decreasing and over forecast wind generation and higher than forecast demand.

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. North Island SIR prices were nearly all below $5/MWh. South Island SIR prices were mainly below $5/MWh, although there were multiple spikes across the week. The highest of those was $70/MWh and occurred on Sunday at 10.30pm. There were a few other times over the week where South Island SIR went above $40/MWh. Most of these spikes occurred when the HVDC flow was changing direction. When the HVDC flow changes direction, for a short period of time only one pole will be operating creating a binding risk in the event it tripped off. As a result, more reserve is required, which can increase prices.

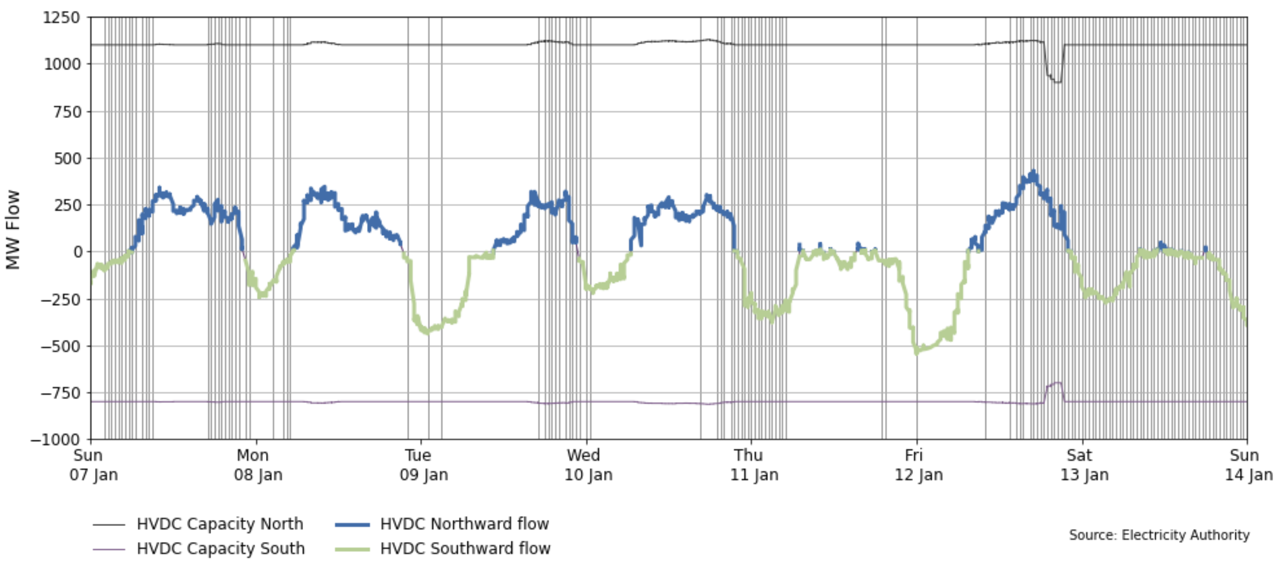
Figure 4: Sustained instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC[2] flow between 7-13 January. Most days flow was northward during the day with overnight southward flow. Maximum flow southward was around 545MW at midnight on 12 January, with maximum northward flow this week of 429MW. High southward flow is consistent with decreasing hydro storage in the South Island

Figure 5: HVDC flow and capacity



[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. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

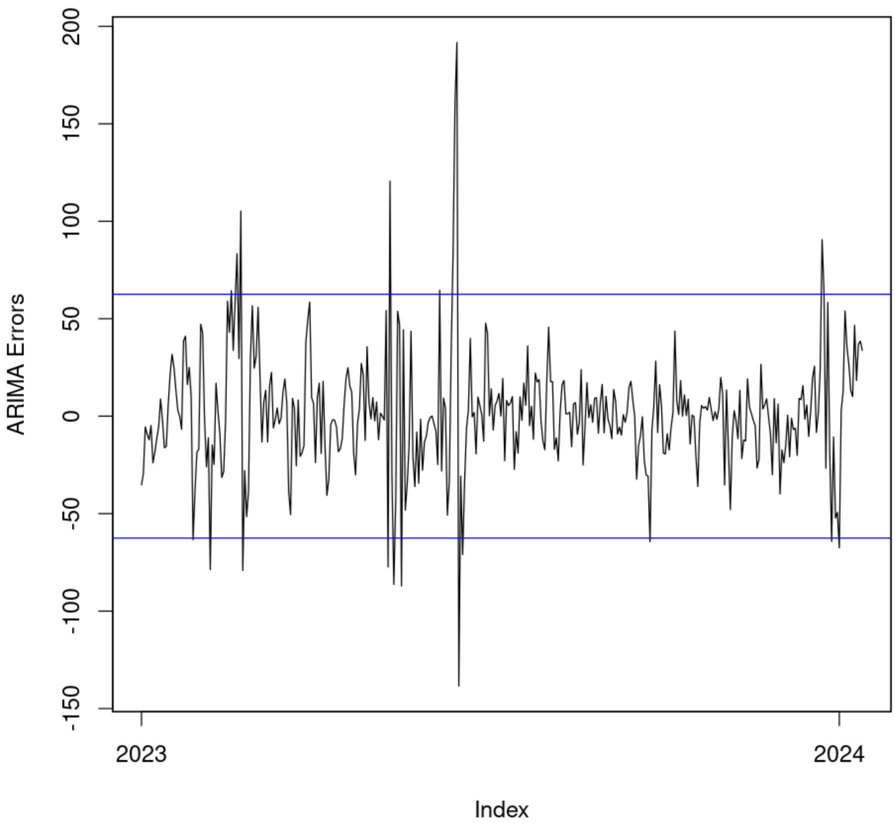
5. Regression residuals

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. This week there were no residuals above or below two standard deviations of the data, indicating actual and modelled prices were similar.

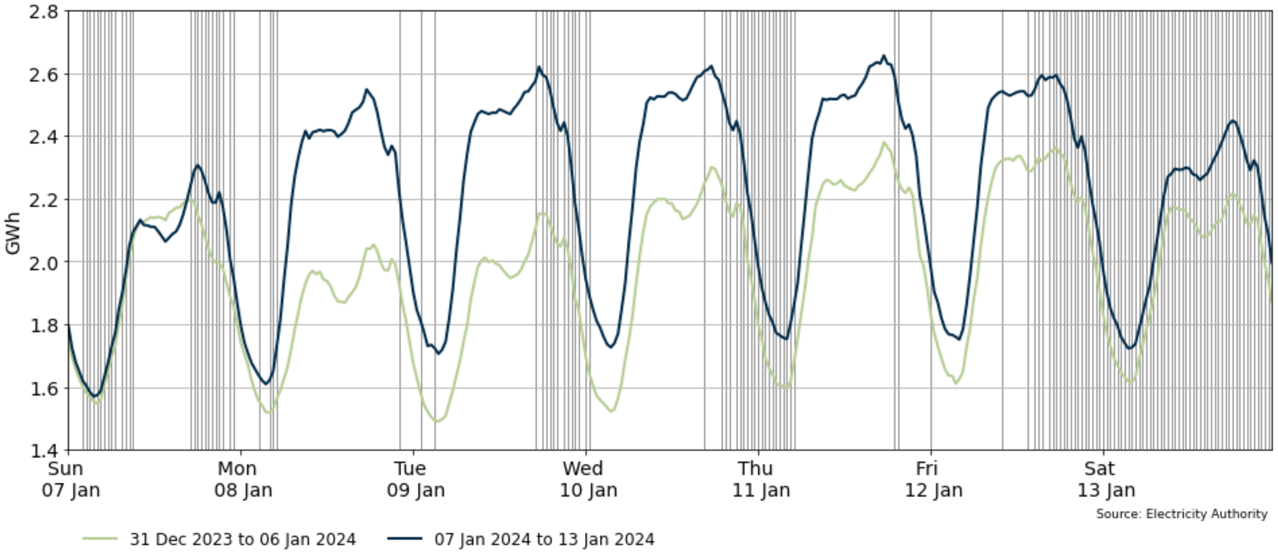
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 6 January 2024



6. Demand

6.1. Figure 7 shows national demand between 7-13 January, compared to the previous week. Overall, demand has increased as businesses reopened with most people heading back to work as well as due to high irrigation load. Weekday afternoon demand was particularly high, likely due to high temperatures which increased the use of air conditioning.

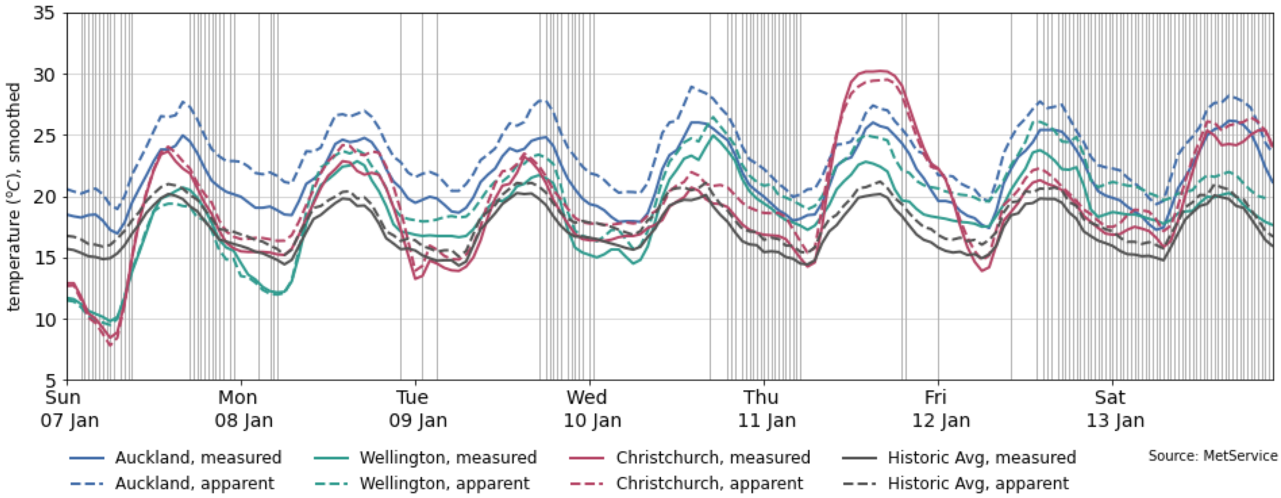
Figure 7: National demand between 7-13 January compared to the previous two weeks



6.2. Figure 8 shows the hourly temperature at main population centres from 7-13 January. 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 mostly sat above 15℃ during the week. Auckland saw apparent temperatures between 19-29℃. Wellington apparent temperatures reached around 26℃ on a couple of occasions, with Christchurch recording a high of around 30℃ on Thursday.

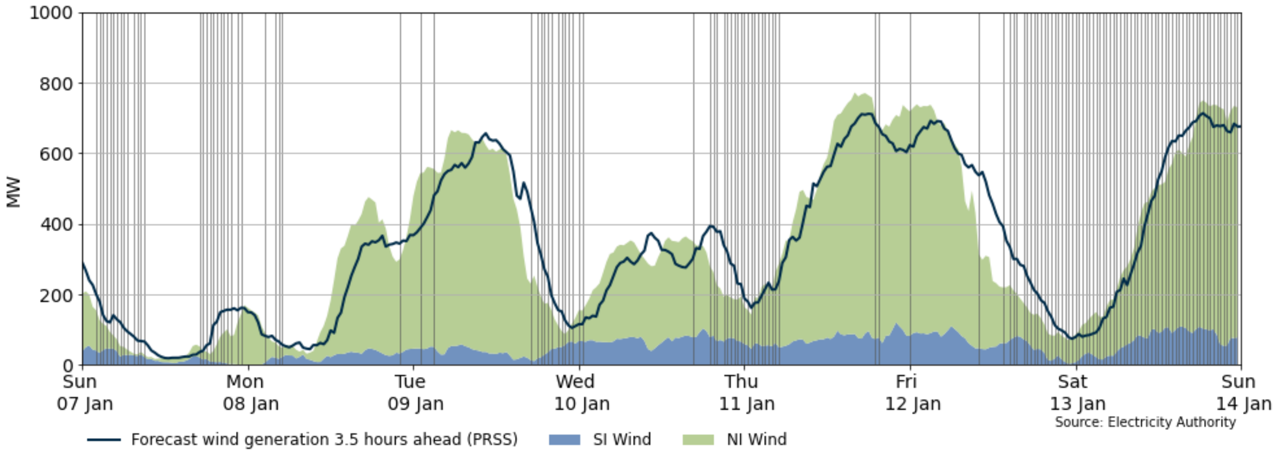
Figure 8: Temperatures across main centres



7. Generation

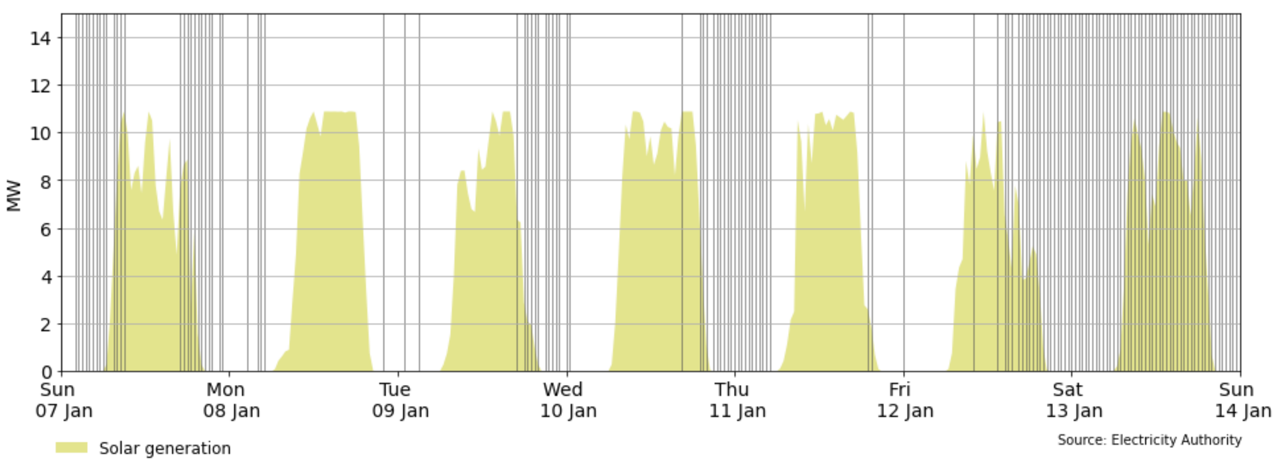
7.1. Figure 9 shows wind generation, from 7-13 January. Wind was again variable, with generation ranging between 17MW and 772MW. A number of the high prices occurred when wind generation was low. There were also a number of trading periods where wind generation was lower than forecast. Tuesday, Thursday, and Friday all saw trading periods where the forecast discrepancy was over 100MW.

Figure 9: Wind generation and forecast between 7-13 January



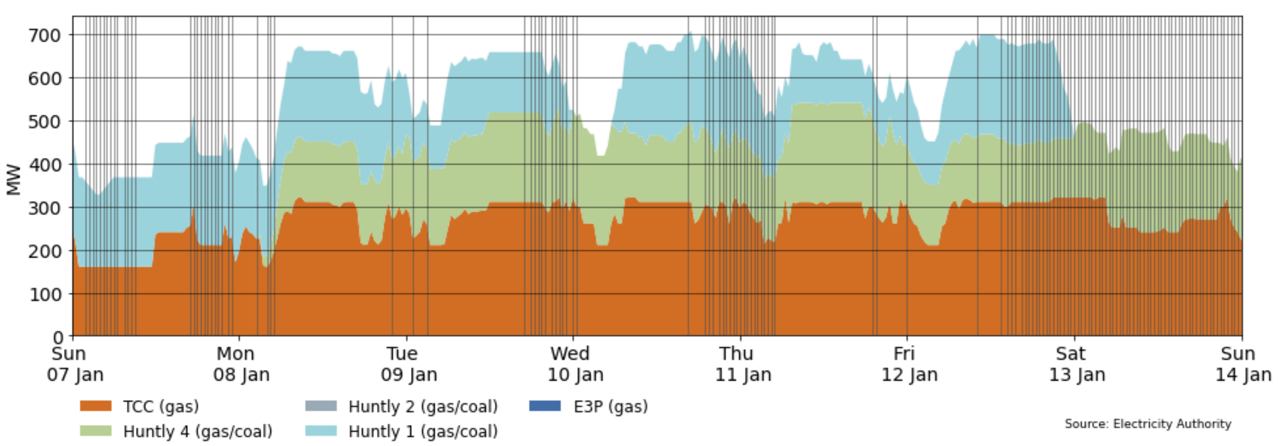
7.2. Figure 10 shows solar generation between 7-13 January. Most days saw between 8-11MW of solar generation over the daytime trading periods, with any dips likely due to cloud cover. Maximum output remains around 11MW.

Figure 10: Solar generation between 7-13 January



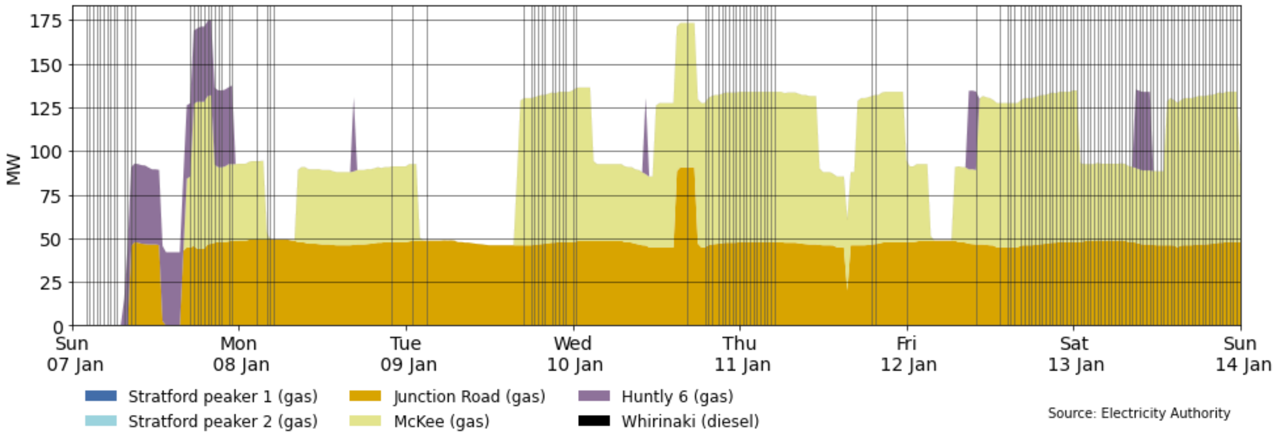
7.3. Figure 11 shows the generation of thermal baseload plants between 7-13 January. TCC ran all week as baseload with Huntly 1 and 4 in support. Weekdays saw both Rankines running along with TCC with only 1 Rankine generating at the weekend.

Figure 11: Thermal baseload generation between 7-13 January



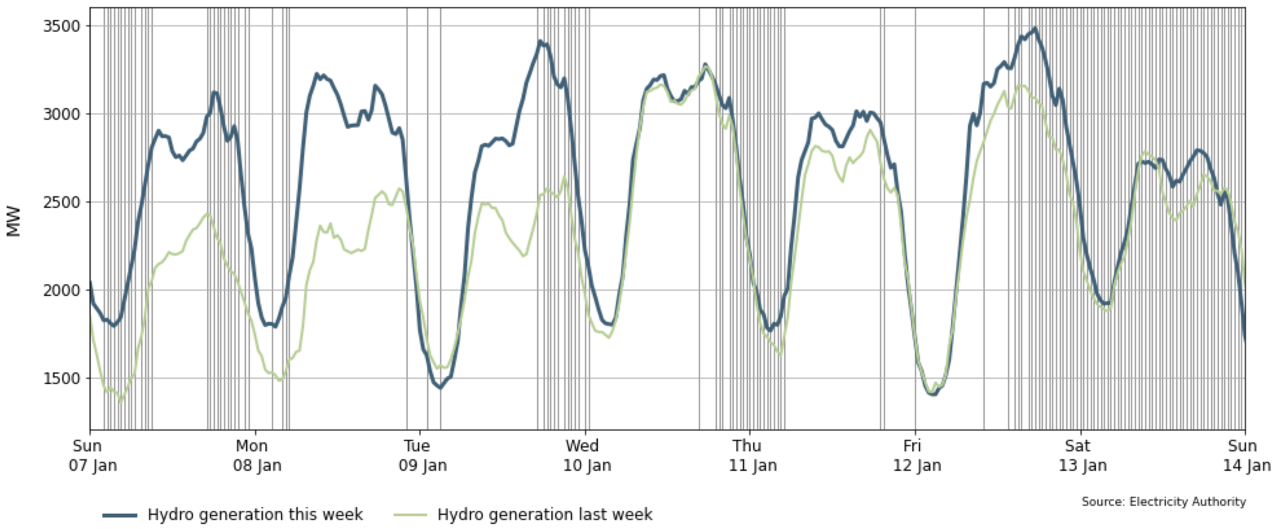
7.4. Figure 12 shows the generation of thermal peaker plants 7-13 January. Junction Road ran continuously from Sunday afternoon with McKee also running on most days. Huntly 6 ran from the morning peak to late evening on Sunday, as well as running for a few trading periods on Friday and Saturday.

Figure 12: Thermal peaker generation between 7-13 January



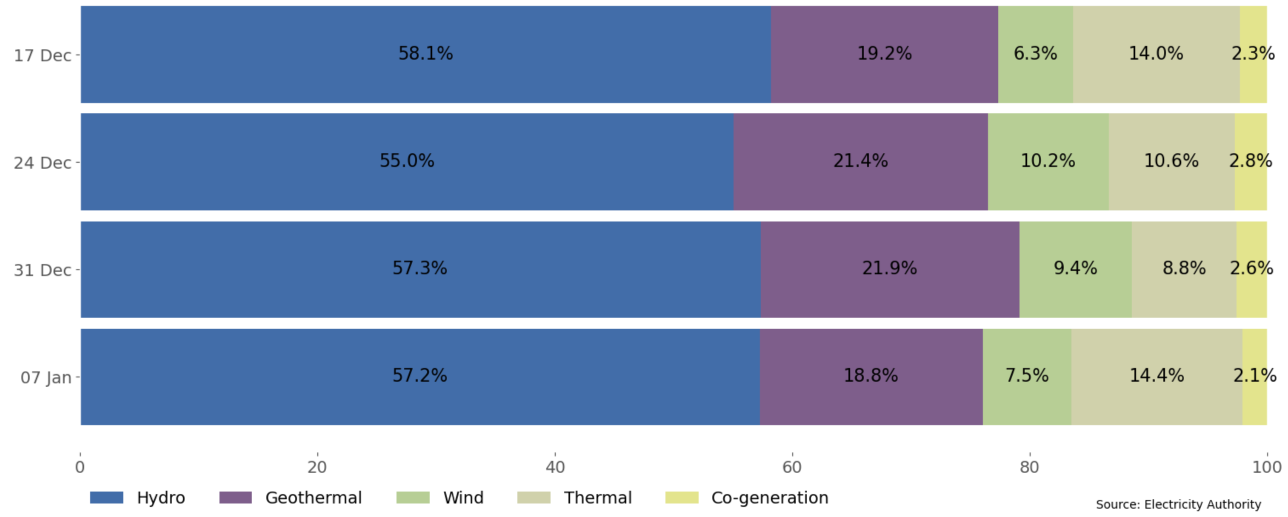
7.5. Figure 13 shows hydro generation between 7-13 January. With increased demand this week hydro generation was noticeably higher the start of the week. Sunday, Tuesday and Friday evening peaks saw hydro ramping up in line with very low wind generation.

Figure 13: Hydro generation between 7-13 January



7.6. As a percentage of total generation, between 7-13 January, total weekly hydro generation was 57.2%, geothermal 18.8%, wind 7.5%, thermal 14.4%, and co-generation 2.1%. Increased demand saw more hydro and thermal generation this week. Compared to the previous week, hydro generation made up a similar portion of the generation mix. However, because there was a significant increase in demand this week, total hydro generation was higher in MW terms. The increase in demand also resulted in thermal generation significantly increasing this week.

Figure 14: Total generation by type as a percentage each week between 7-13 January



8. Outages

8.1. Figure 15 shows generation capacity on outage. Total capacity on outage between 7-13 January ranged from ~1300MW to ~2000MW. Outages were generally close to average for this time of year.

8.2. Notable outages include:

(a) Huntly 5 is on outage until 20 January

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

(c) Various North and South Island hydro units were on outage

Figure 15: Total MW loss due to generation outages

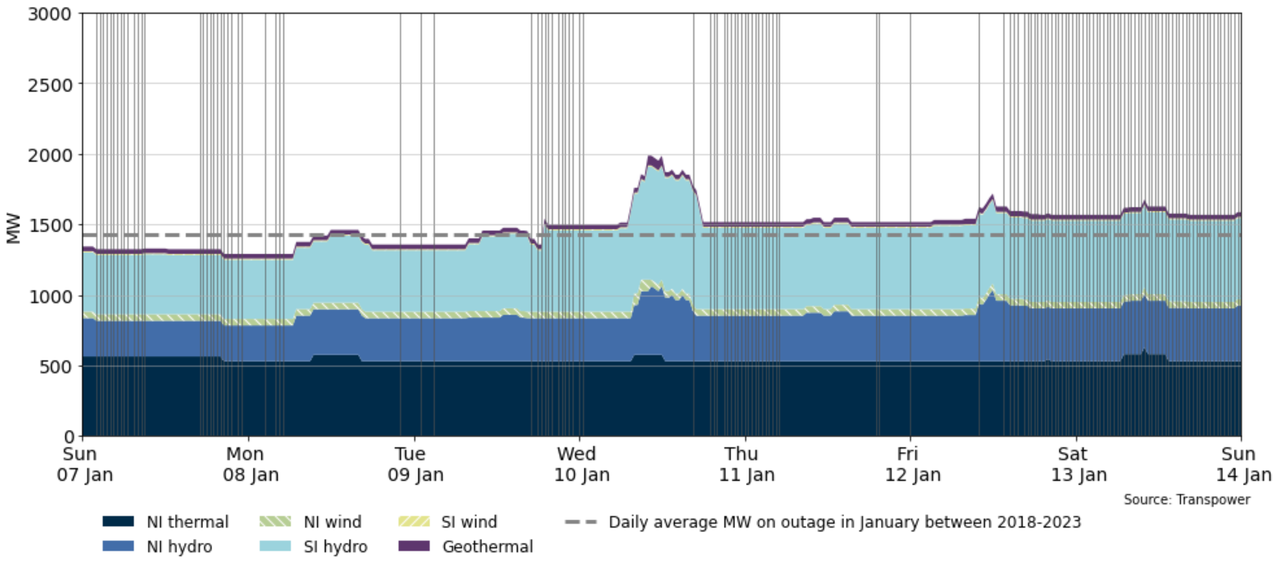
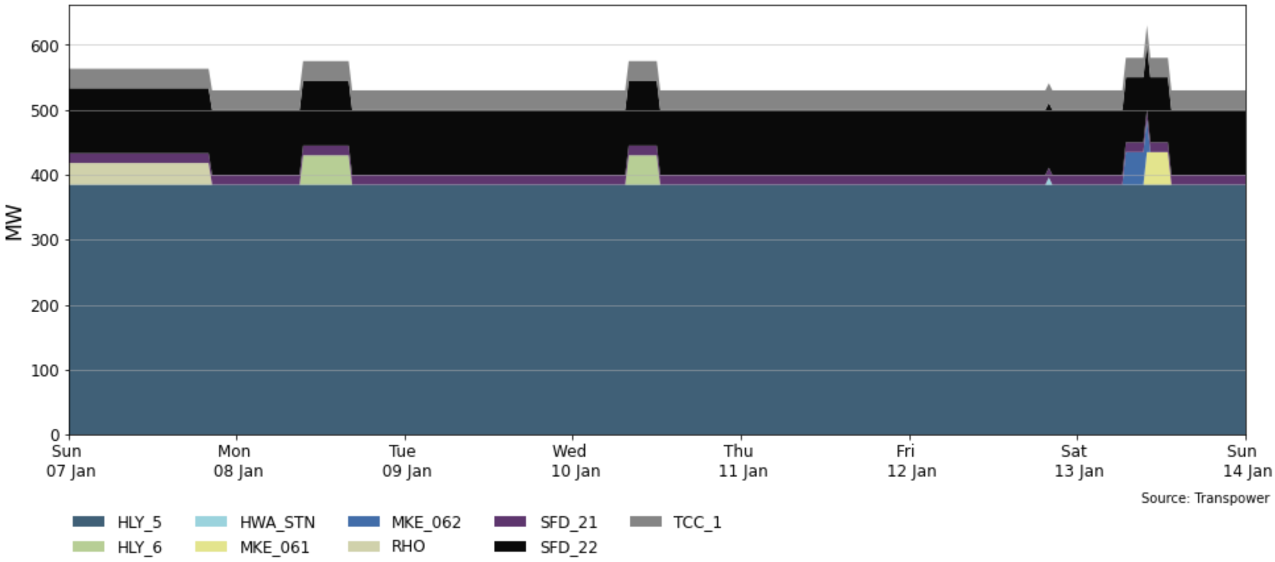


Figure 16: MW loss from thermal outages



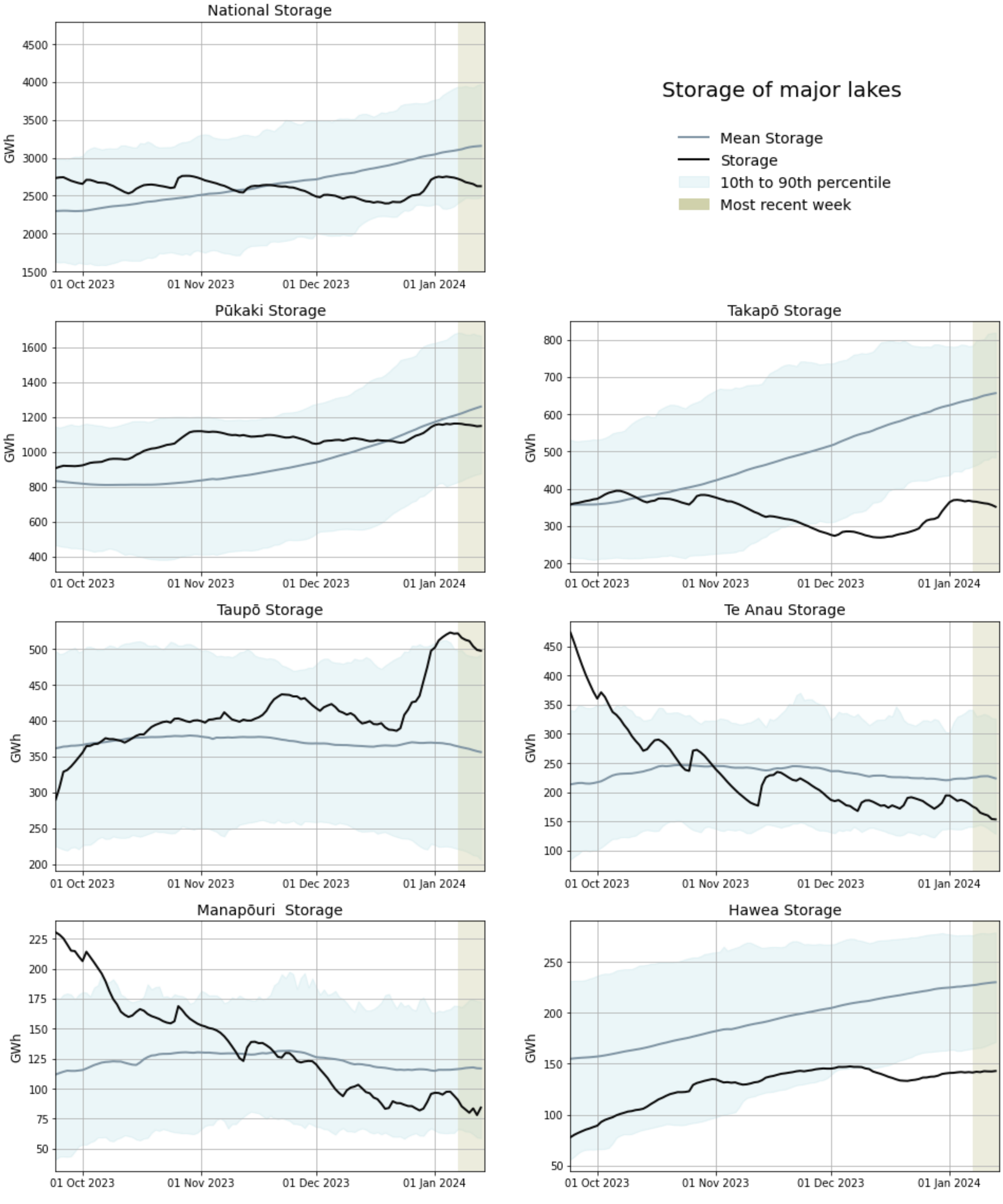
9. Storage/fuel supply

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 decreased over the week with current controlled storage at 86.6% of mean and 67.8% nominally full as of 13 January.

9.3. Taupō is the only lake currently sitting above its historic mean, with current levels close to 500GWh (above its historic 90th percentile region). Pūkaki levels were steady across the week and sitting below mean. Takapō levels dropped slightly with the lake level currently below its historic 10th percentile region. Te Anau storage is in decline and approaching its 10th percentile region. Manapōuri storage has mainly declined although saw a small uptick towards then end of the week.

Figure 17: Hydro storage



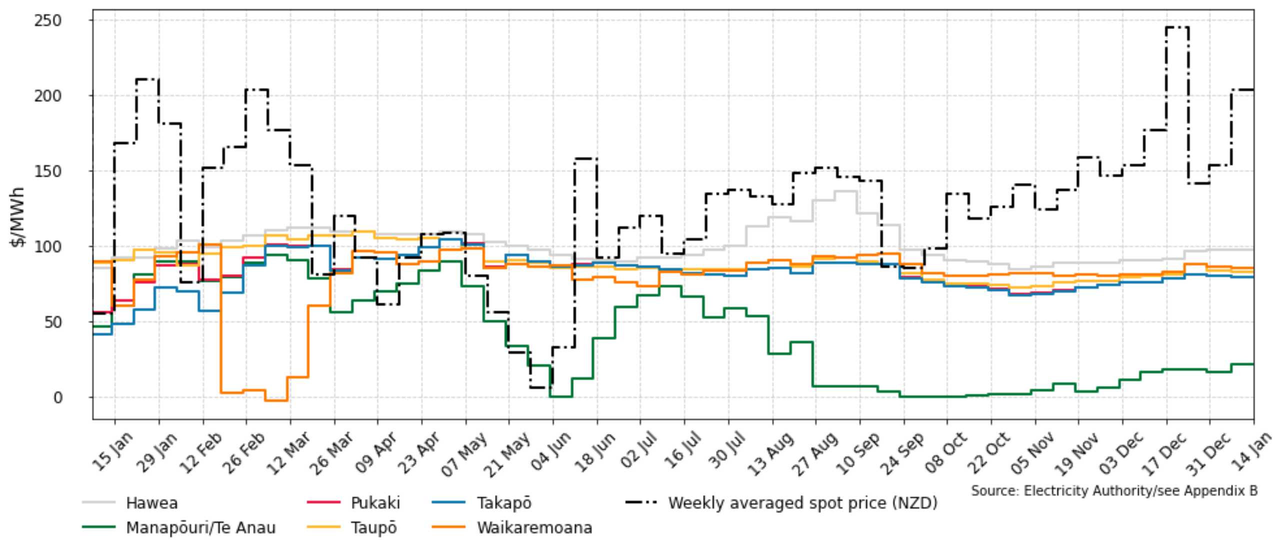
Source: Electricity Authority

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 18 shows the national water values between 8 January 2023 and 13 January 2024 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. Most water values remained similar to the previous week. Manapōuri/Te Anau's water value increased by $4/MWh to $21/MWh.

Figure 18: JADE water values across various reservoirs between 8 January 2023 and 13 January 2024



Source: Electricity Authority/see Appendix B

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 January 2024. The SRMC for diesel decreased slightly compared to the previous month. The coal SRMC also continued its slightly decreasing trend, while the gas SRMC continued to slightly increase.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$154/MWh. This is now lower than the cost of running the Rankines on gas at ~$168/MWh.

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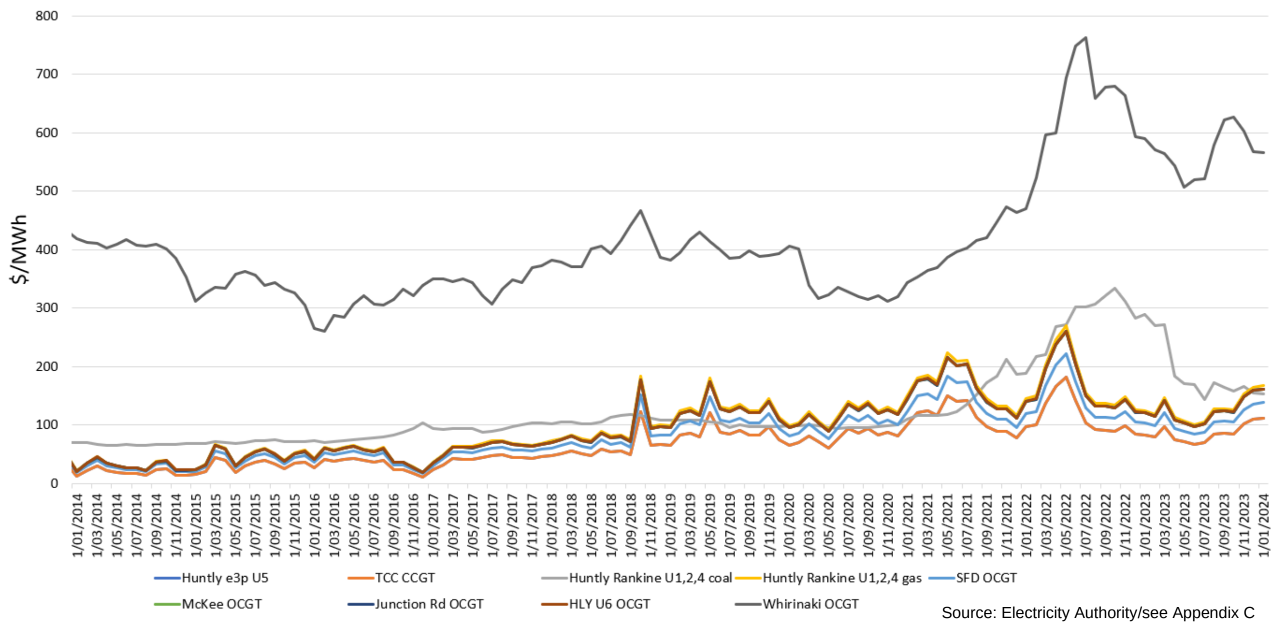
[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

11.5. The SRMC of gas fuelled thermal plants is currently between $112/MWh and $168/MWh.

11.6. The SRMC of Whirinaki has decreased to ~$566/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

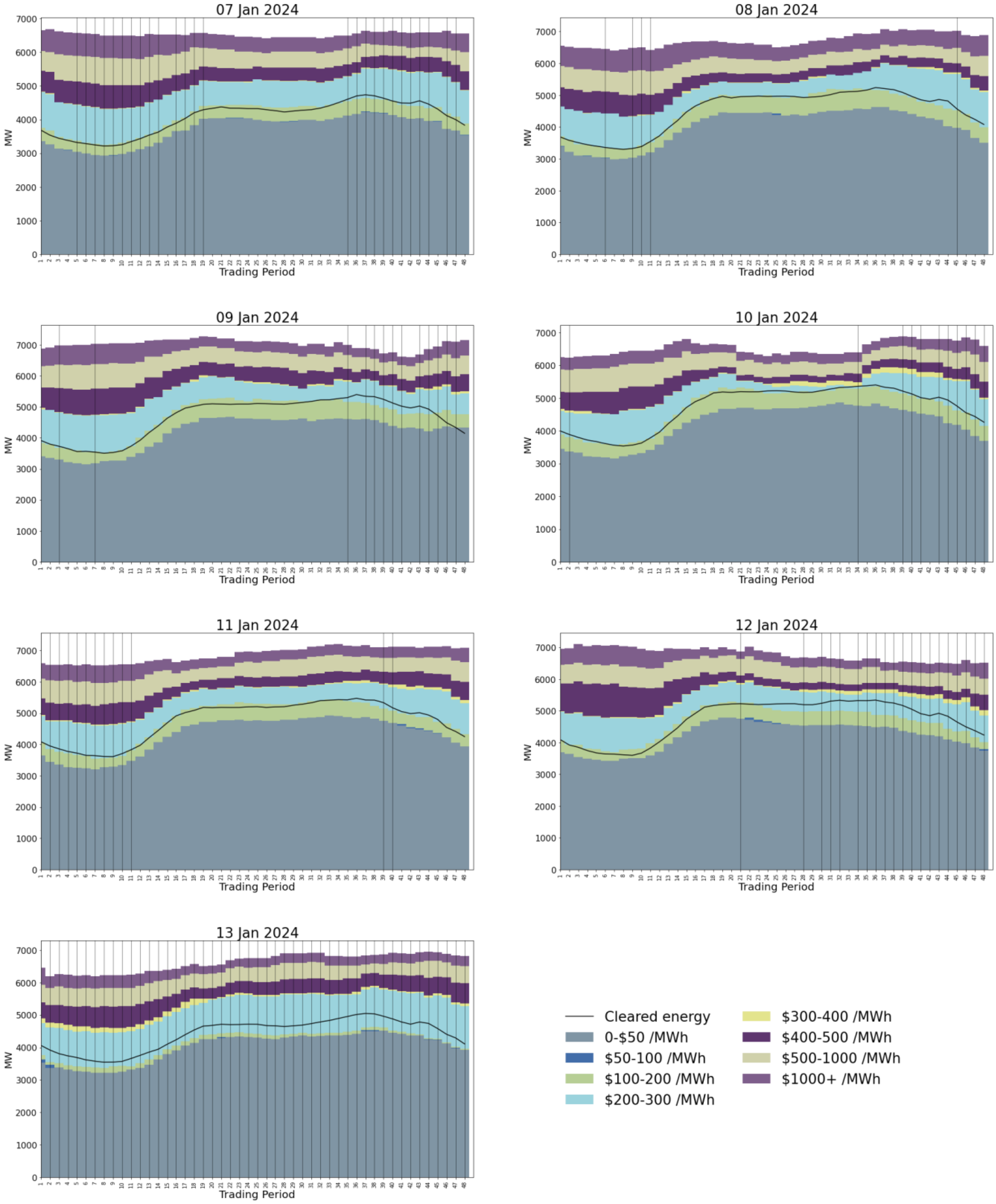
12. Offer behaviour

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. Offers mainly cleared within the $200-$400/MWh region this week. There continues to be only occasional offers in the $50-$100/MWh range.

12.3. Most of the highlighted prices occurred towards the end of this week. The offer chart below highlights that the $50-$100/MWh and $100-200/MWh offer bands were very thin.

Figure 20: Daily offer stacks[4]



Source: Electricity Authority

[4] Offer stacks 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.