16 October 2023

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 8-14 October

1.1. Prices sat above historical average this week with most prices in the $119-$157/MWh range. Both Monday and Wednesday's morning peak saw a spike in Ōtāhuhu prices over $300/MWh which was mainly driven by a drop in wind generation and some higher priced thermal or hydro being dispatched to meet demand. Overall, the proportion of thermal generation has reduced with some higher wind generation and an increase in hydro generation over the last week.

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 at any node exceed their historical 90th percentiles.

2.2. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside their historic average and historic 10th-90th percentiles adjusted for inflation. Prices above the historic 90th percentile are highlighted with a vertical black line. Other notable prices that did not exceed the 90th percentile, are marked with black dashed lines.

2.3. Between 8-14 October:

(a) The average wholesale spot price across all nodes was $137/MWh.

(b) 95 percent of prices fell between $56/MWh and $191/MWh.

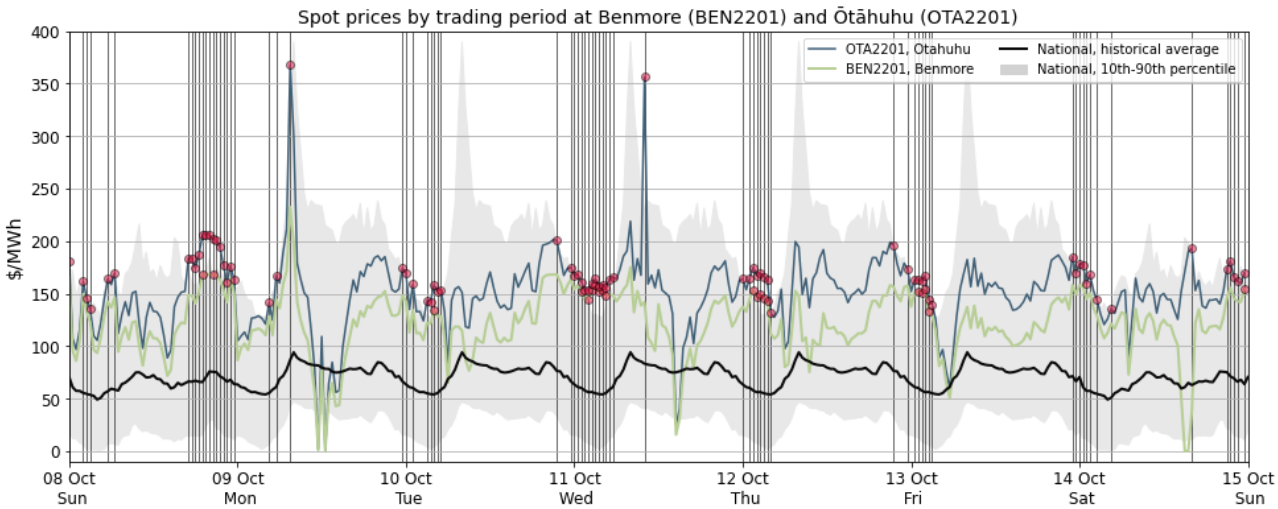
2.4. This week the average spot price increased around $47/MWh compared to the previous week with the majority of prices sitting above the historic average and between $119-$157/MWh. Overnight prices were high at times with peakers supporting baseload generation. Most of the time only one Rankine was running. Low wind and under forecast wind may also have impacted prices, particularly on Sunday afternoon from 3.00pm where prices sat between ~$140/MWh and $200/MWh until midnight.

2.5. The first notable price spike this week occurred during the Monday morning peak at the 7.30am and 8.00am trading periods. Prices at Ōtāhuhu were $368/MWh and $301/MWh respectively and Benmore prices were $232/MWh and $198/MWh. Demand was under forecast by around 100MW during the 7.30am trading period. Wind generation was very low during this time. Two Rankines and all available peakers ran, including Whirinaki.

2.6. On Wednesday at 10.00am there was a price spike at Ōtāhuhu of $356/MWh. At the same time the price at Benmore was $142/MWh. Wind generation was around 100MW as well as lower than forecast. Two Rankines and four peakers were also running. However, high priced hydro appears to have set the price during this trading period. The system operator issued a CAN notice for the 7.30am to 9.30am trading periods, so this price spike occurred immediately after. Possibly some generation was offered that otherwise would not have been due to this tight situation, but we will investigate this trading period more fully.

2.7. On Saturday afternoon there was some price separation of around $100-$190/MWh in the afternoon between 2.00pm and 4.00pm coinciding with an unexpected HVDC pole outage. This was due to high winds causing significant swinging to the conductor on the BEN-HAY 2 circuit (Pole 2), and consequent arcing between the conductor and the transmission towers. The grid owner made several attempts to restart Pole 2 at reduced voltage, before Pole 2 eventually tripped and remained out of service from around 2:40 pm till around 4:25 pm.

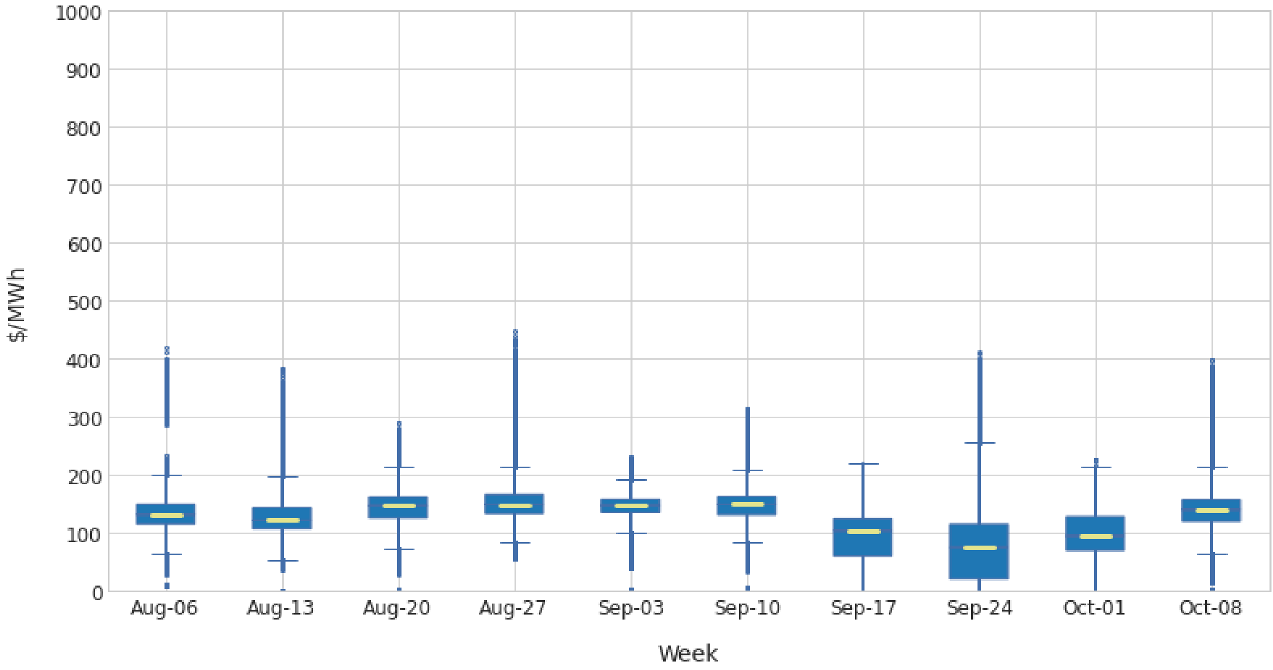
Figure 1: Wholesale spot prices between 8 October (Sunday) and 14 October (Saturday)



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. There was a bit more volatility this week with some outliers above $200/MWh but below $400/MWh sitting above 1.5 times the IQR. The middle 50% of prices this week was smaller than the previous few weeks. However, most prices were generally higher overall compared to the previous week, in the range of $119-$157/MWh. The median price was $139/MWh.

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



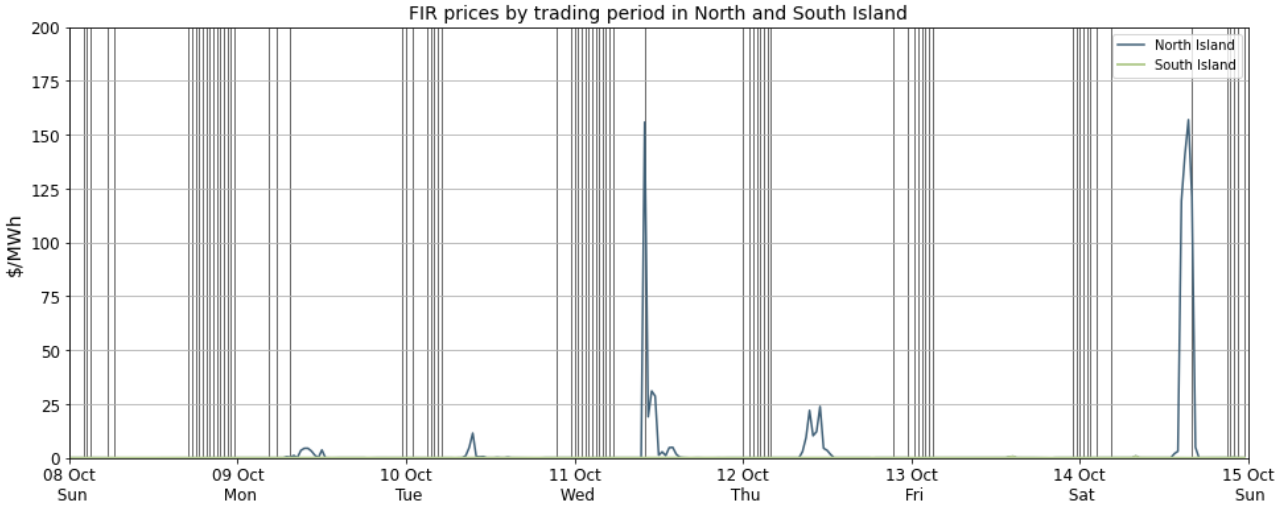
3. Reserve prices

3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mostly below $10/MWh. There were a few spikes in North Island FIR this week due to binding risks on the HVDC.[1] With the Rankine units as the current largest NI generators due to the e3p outage and TCC stopping generating for the spring/summer, this reduces NI generator risk to ~230MW and means it is more likely that the HVDC risk will bind.

3.2. There was a significant spike at 10.00am on Wednesday 11 October where North Island FIR was $156/MWh. This occurred at the same time there was a spike in spot prices. There were also spikes in North Island FIR on Saturday from 2.30pm to 4.00pm, where prices ranged between $119-$157/MWh. This was due to an unplanned pole outage which reduced reserve sharing capacity between islands.

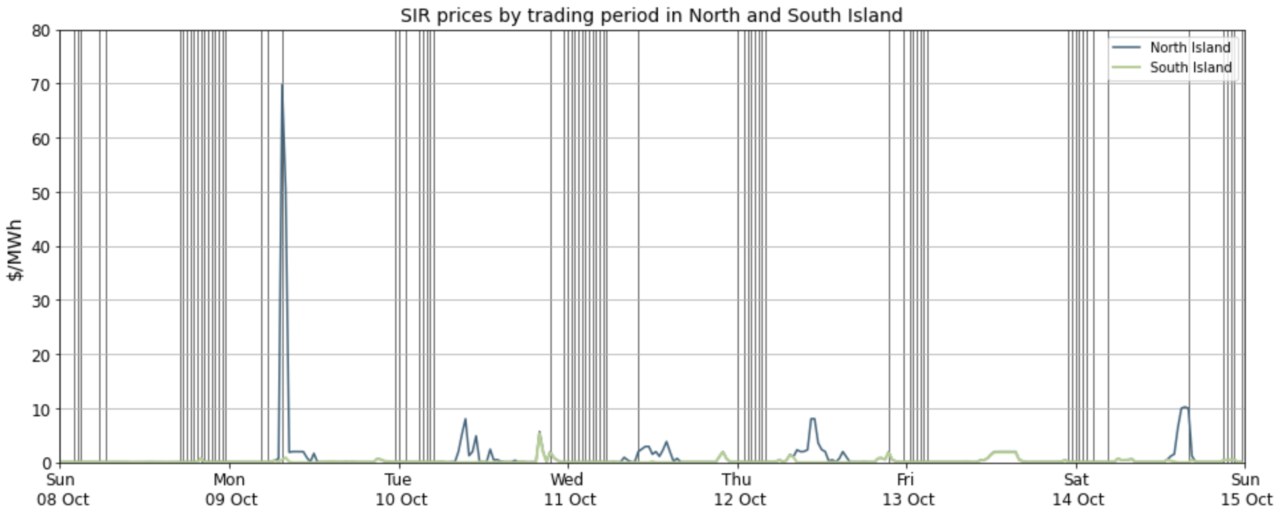
[1] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these—the one that determines the required quantity of instantaneous reserve. Reserve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

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



3.3. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh. There was one significant North Island SIR spike on Monday during the same two trading periods where the spot prices spiked again due to HVDC risks binding. At 7.30am the North Island SIR price was $70/MWh and at 8.00am the price was $50/MWh.

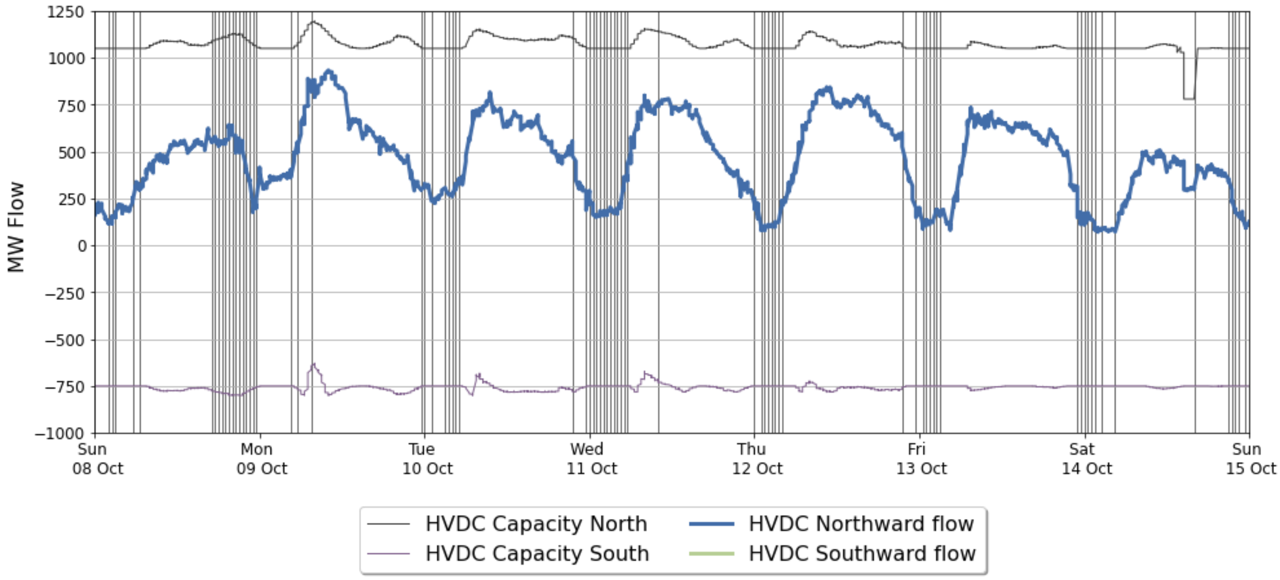
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 8-14 October. HVDC flows were northwards all week and mainly below 750MW except during the weekday morning peaks. There was a drop in HVDC capacity from around 2.43pm until 4.30pm on Saturday afternoon due to an unplanned outage to pole 2.

Figure 5: HVDC flow and capacity

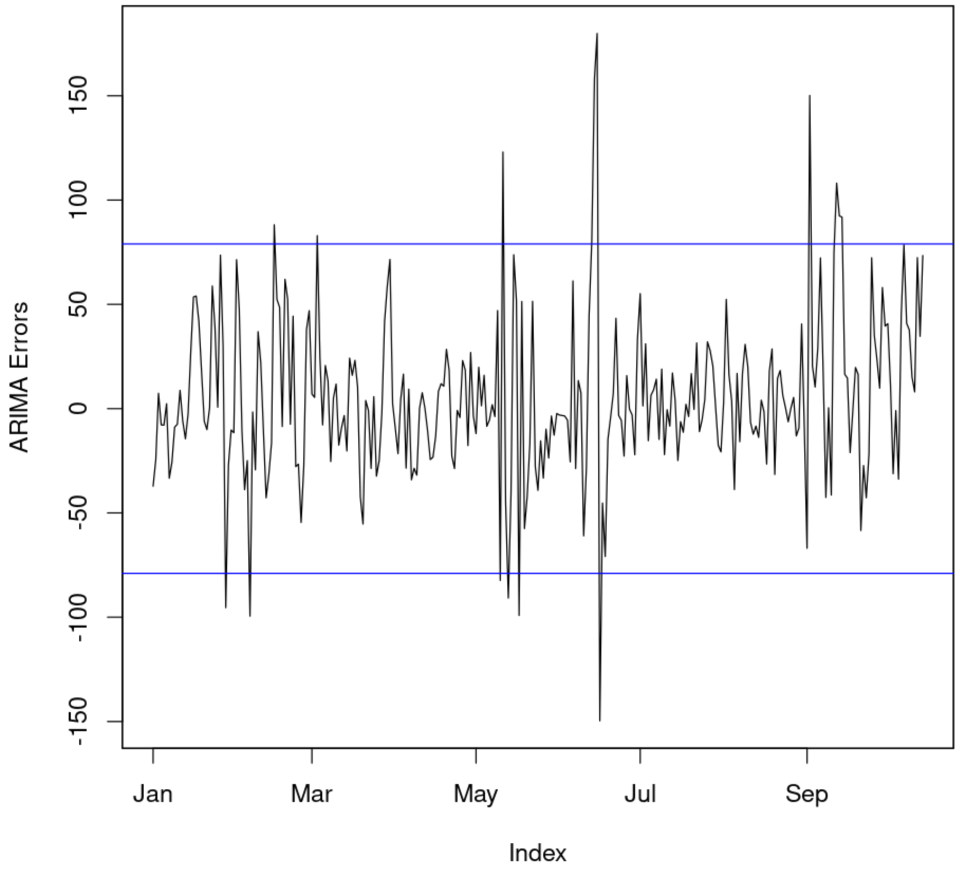


5. Regression residuals

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. This week all prices were within two standard deviations of the data.

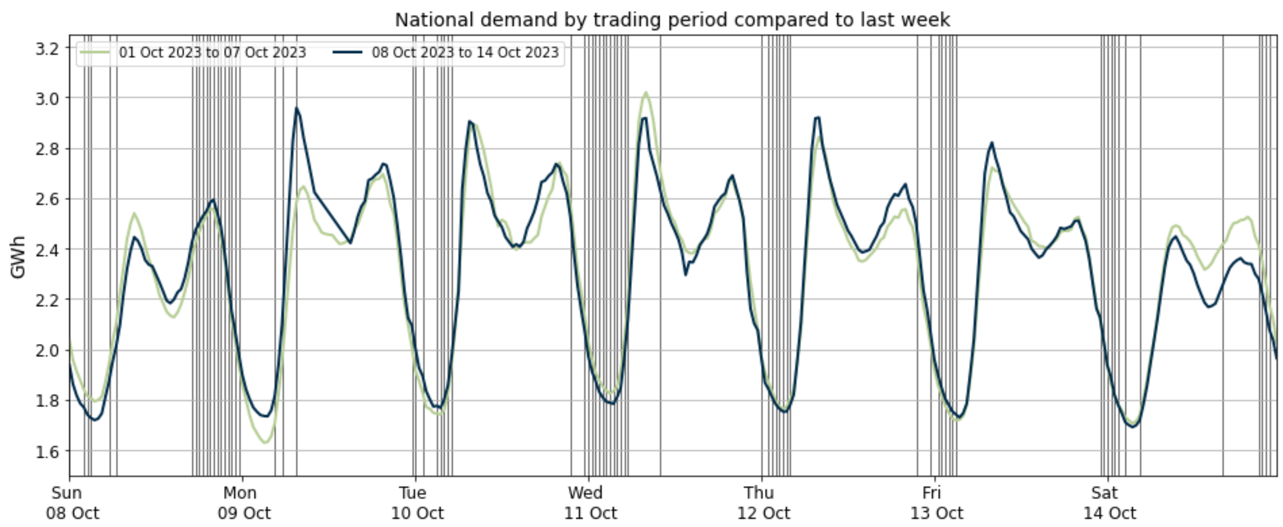
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 14 October 2023



6. Demand

6.1. Figure 7 shows national demand between 8-14 October, compared to the previous week. Demand followed a similar trend to the previous week with higher morning than evening peaks, with a few weekday morning peaks seeing greater demand as school returned.

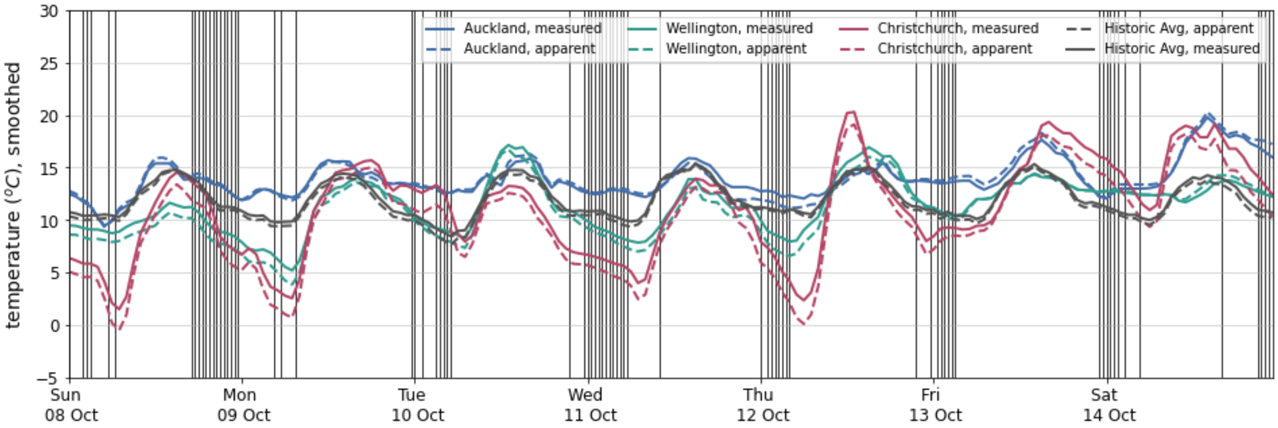
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 8-14 October. 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 generally on or just above average in Auckland. Wellington temperatures mostly sat around the historic average with some cooler temperatures during Sunday and a few weekday mornings. Christchurch temperatures were cooler at the start of the week, with temperatures towards the end of the week going above historic average.

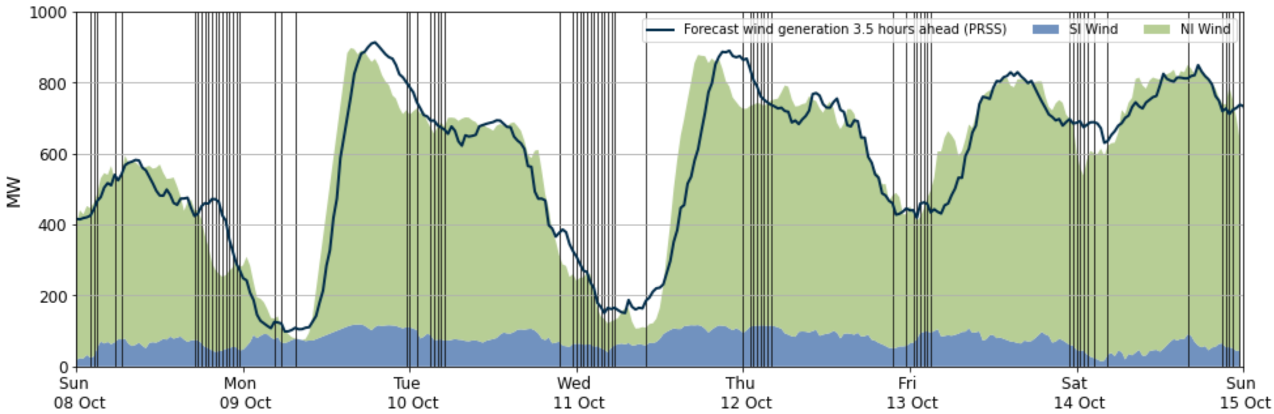
Figure 8: Temperatures across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 8-14 October. Wind generation varied across the week from around 75MW to 897MW. A number of the highlighted prices occurred during times of low wind generation and/or where there was a discrepancy in actual wind compared to what was forecast.

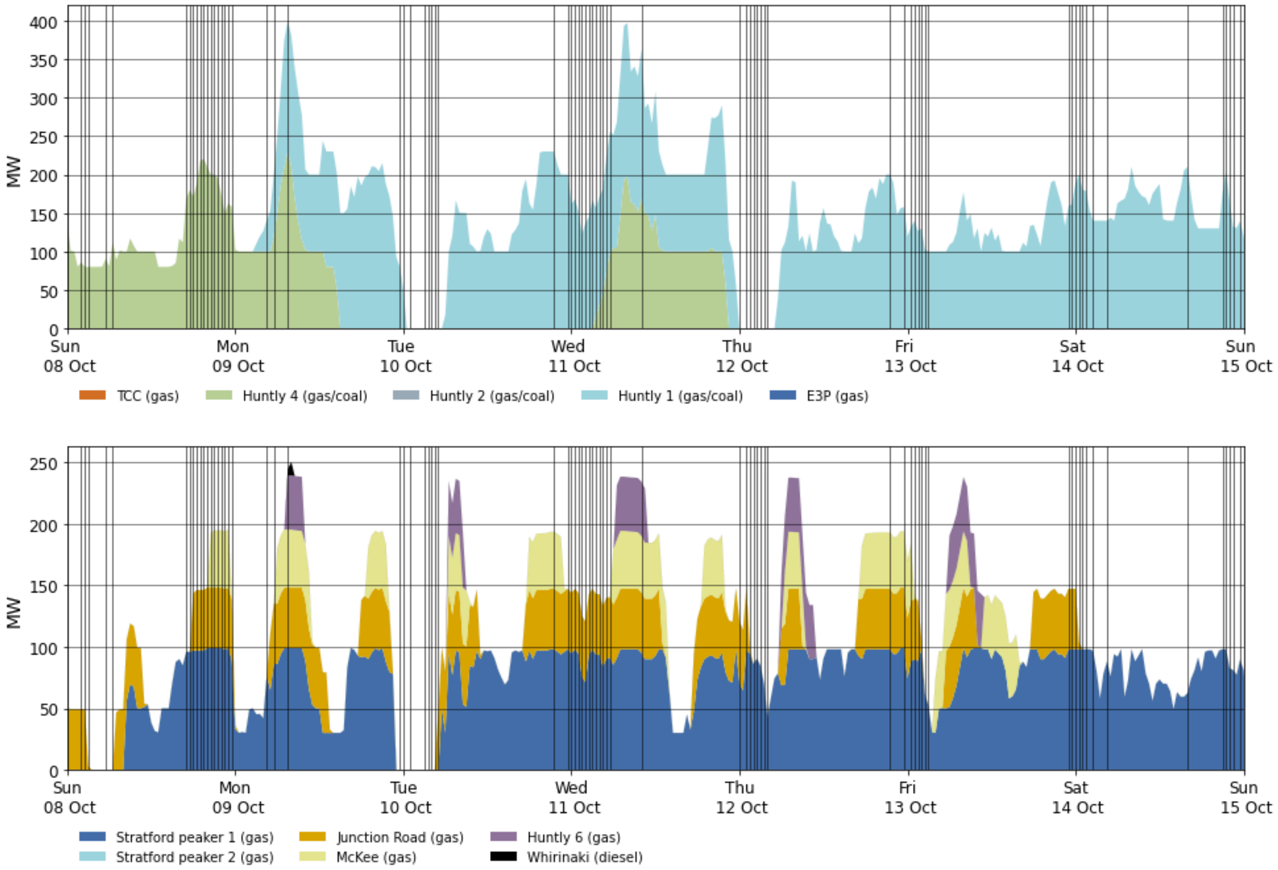
Figure 9: Wind generation and forecast between 8-14 October



7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 8-14 October. Huntly 1 was the main Rankine used for baseload with TCC having turned off last week and e3p still on outage until January. Huntly 4 ran from Sunday until after the Monday morning peak and then again on Wednesday over the peak and shoulder periods.

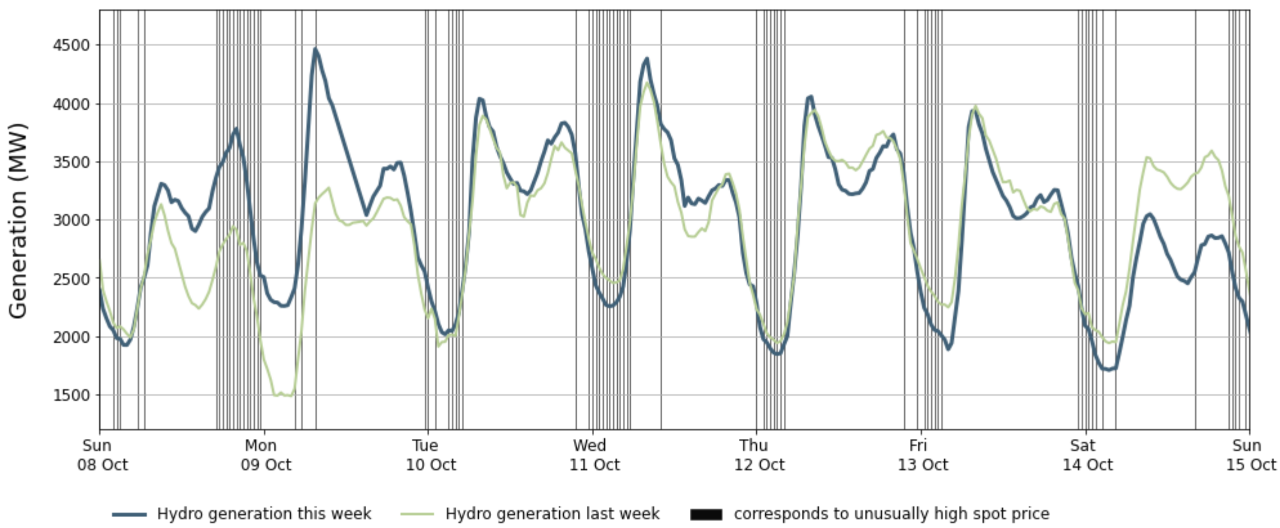
7.3. There were more thermal peakers generating this week with most morning peaks seeing at least four out of the five available peakers running. Evening peaks mainly saw Stratford 1, Junction Road and McKee running, with Stratford 1 running continuously for a lot of the week. Whirinaki also ran during the two trading periods on Monday morning where we saw the prices spike.

Figure 10: Thermal generation between 8- 14 October



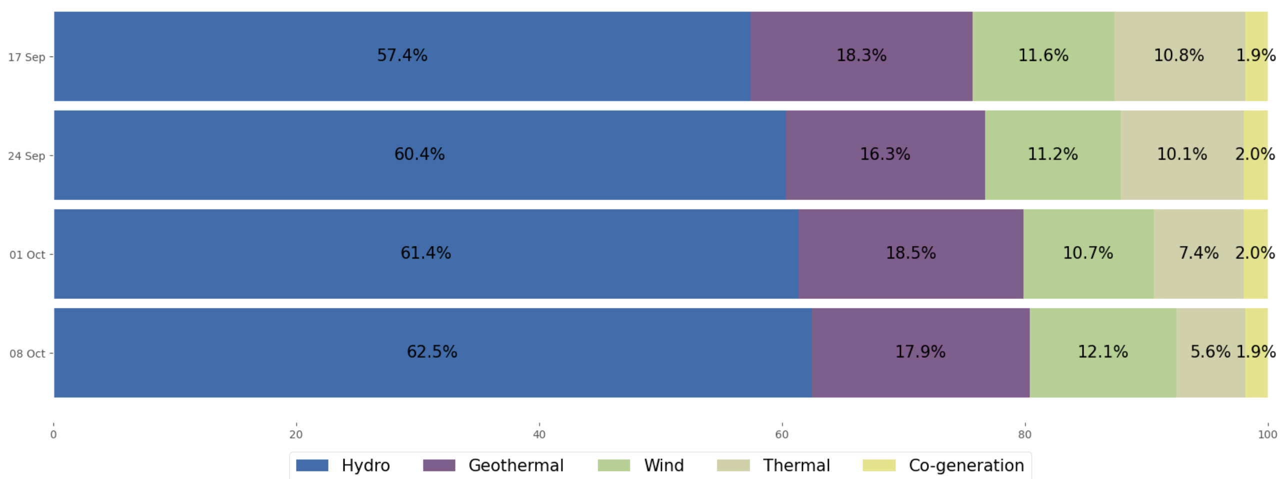
7.4. Figure 11 shows hydro generation between 8-14 October. Sunday and Monday saw much higher hydro generation than the previous week with the Monday high demand morning peak seeing a significant ramp up of hydro generation. Most of the rest of the week saw similar generation profile to the previous week, with only Saturday seeing an overall reduction in hydro generation.

Figure 11: Hydro generation between 8-14 October compared to the previous week



7.5. As a percentage of total generation, between 8-14 October, total weekly hydro generation was 62.5%, geothermal 17.9%, wind 12.1%, thermal 5.6%, and co-generation 1.9%. There has been a significant decrease in the proportion of generation from thermal over the last couple of weeks generally due to hydro generation beginning to increase again and the significant increase in wind generation.

Figure 12: Total generation by type as a percentage each week between 17 September and 14 October 2023



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 8-14 October ranged between ~1400MW and 1900MW.

8.2. Notable outages include:

(a) Huntly 5 on outage until 31 January 2024.

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

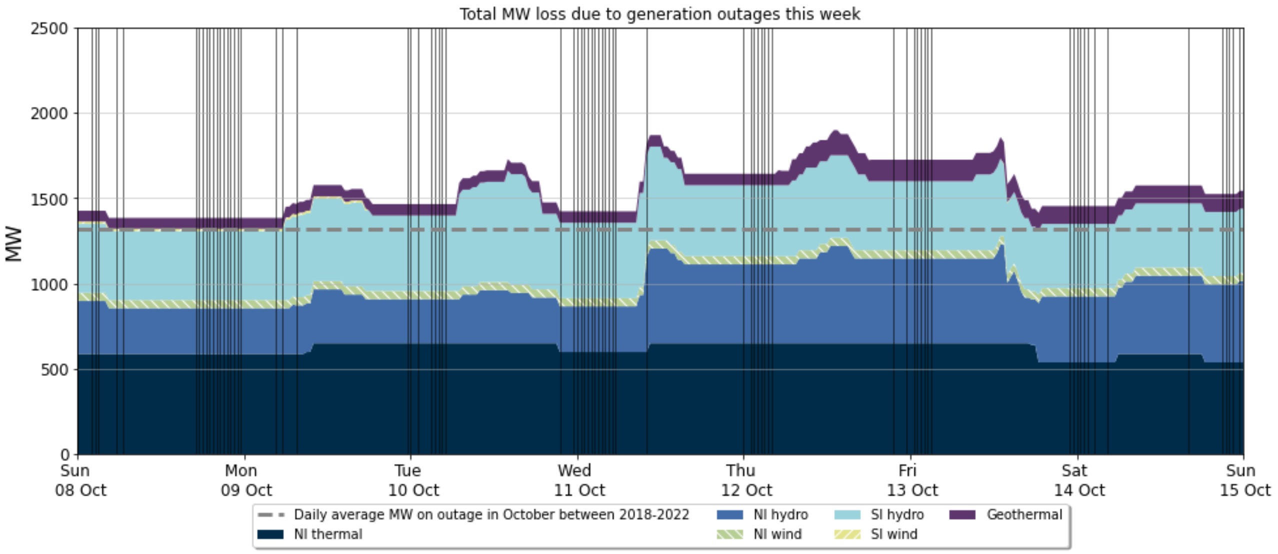
(c) A Whirinaki unit was on outage 9-13 October.

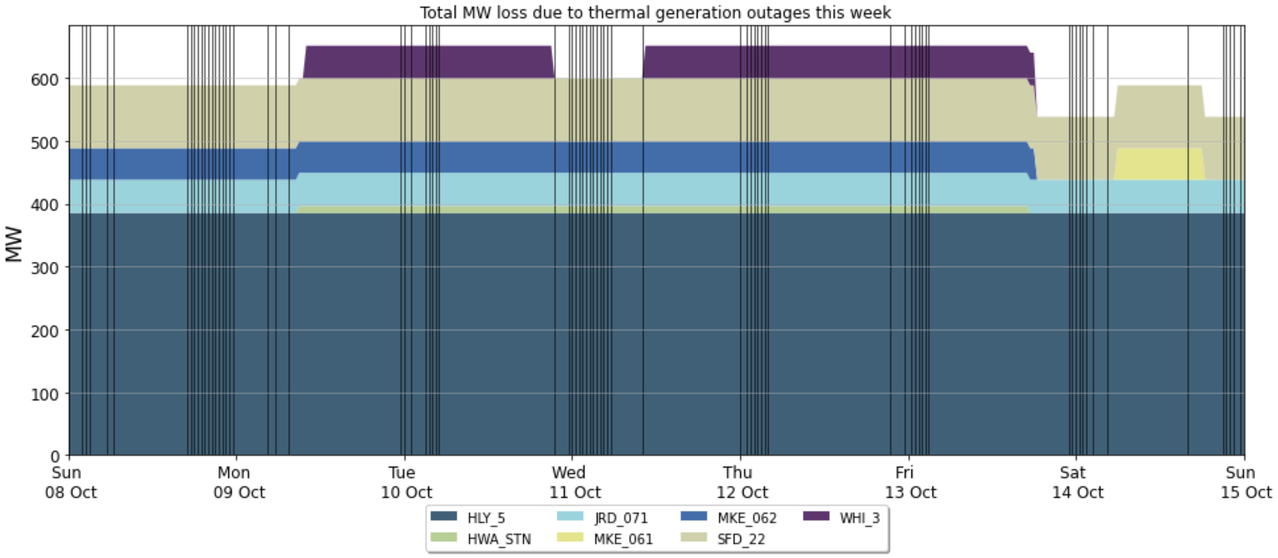
(d) A Junction Road unit is on outage until 31 October.

(e) McKee units were on outage from 3-13 October and 14 October.

(f) Various North and South Island hydro are on outage.

Figure 13: Total MW loss due to generation outages





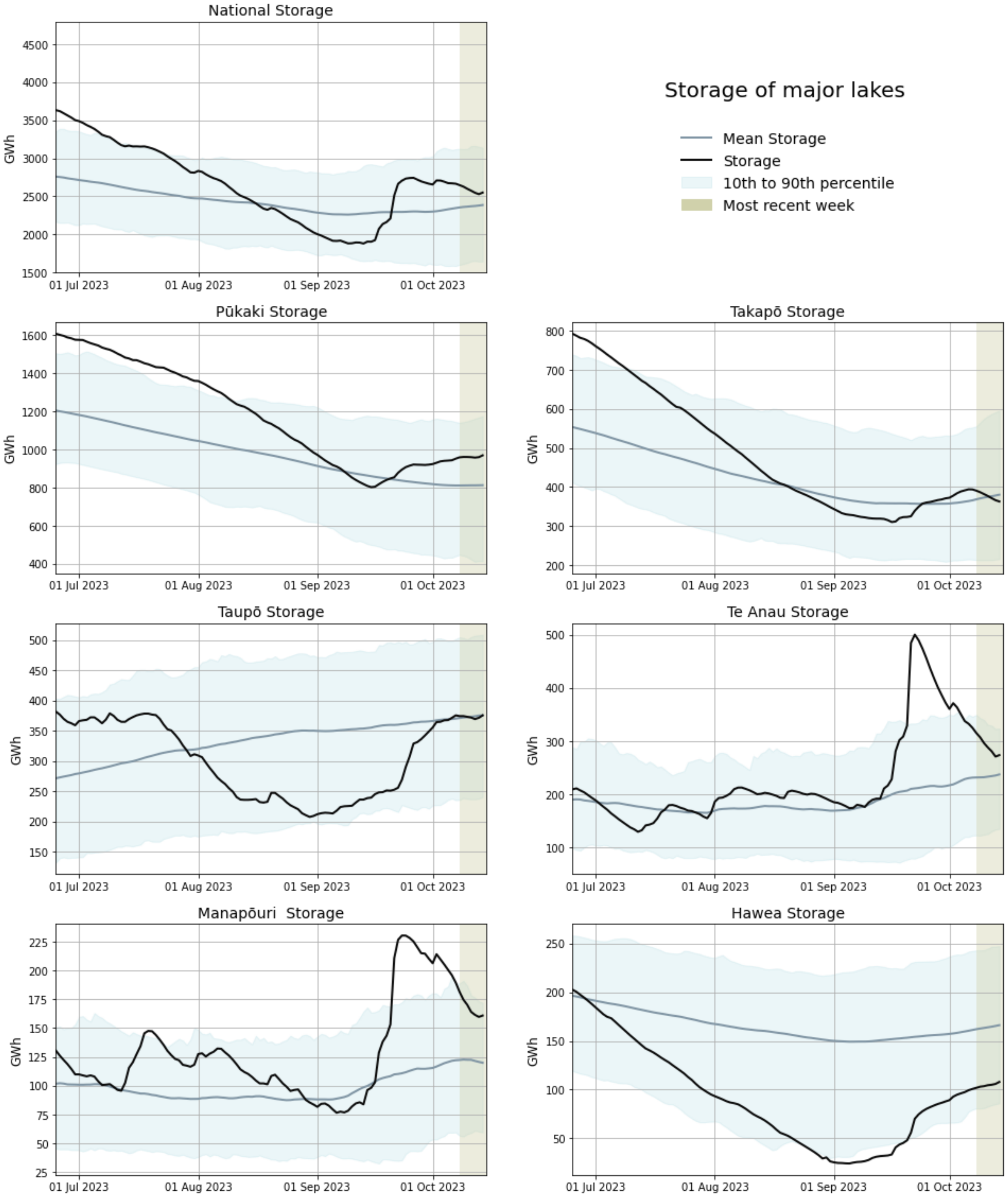
9. Storage/fuel supply

9.1. Figure 14 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 controlled hydro storage levels have decreased slightly over the week with storage at 2855GWh as of 14 October, 64.7% nominally full and 106% of historic mean.

9.3. Storage at Taupō remained steadily around its historic mean. Pūkaki levels were generally steady across the week. Takapō storage steadily declined and is now just below its historic mean. Both Manapōuri and Te Anau have decreased, although both lakes remain close to their high operating level. The South Island lakes will be expecting more rain with some strong fronts forecast to cross this part of the country. Hawea levels are still steadily increasing, and its storage remains above its historic 10th percentile.

Figure 14: Hydro storage

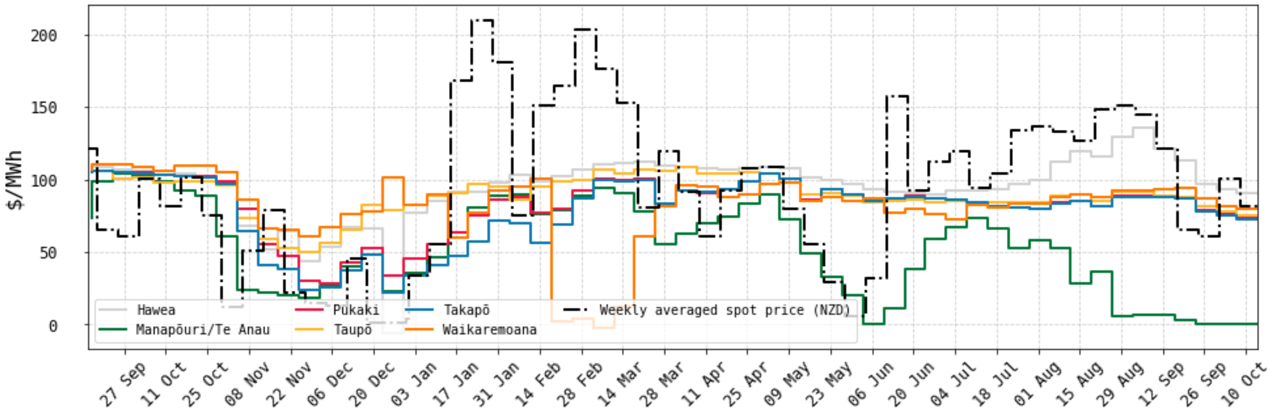


10. JADE water values

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 15 shows the national water values between 15 September 2022 and 14 October 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. Significant inflows over the last couple of weeks have seen water values at Manapōuri and Te Anau of around $0.07/MWh and all other lakes have seen a decrease of around $3/MWh.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 14 October 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 16 shows an estimate of thermal SRMCs as a monthly average up to 1 October 2023. The SRMC of diesel plants has been increasing since May, and the SRMC of coal-fuelled plants and gas-fuelled plants has decreased slightly. While an increase in carbon prices has contributed to the increase in the diesel fired plant SRMC, this has been more than offset by a reduction in the underlying fuel prices in the case of gas and coal plant SRMCs.

11.4. The latest SRMC of coal-fuelled Huntly generation is ~$160/MWh.

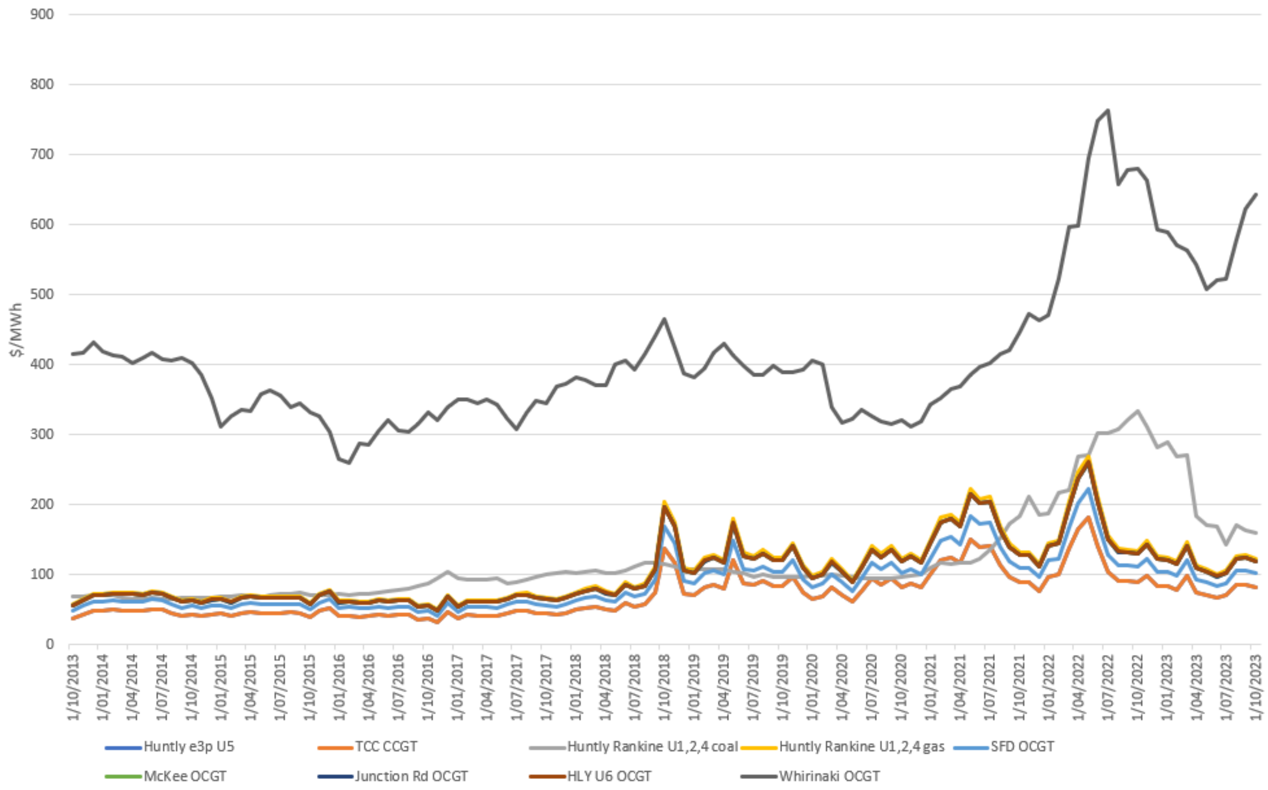
11.5. The SRMC of Whirinaki has increased to ~$643/MWh.

[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.

11.6. The SRMC of gas fuelled thermal plants is currently between $82/MWh and $123/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. This appendix was recently updated to reflect the changes made to coal price indices by the Indonesian government. These changes have had the effect of decreasing the coal SRMC from April 2023.

Figure 16: Estimated monthly SRMC for thermal fuels

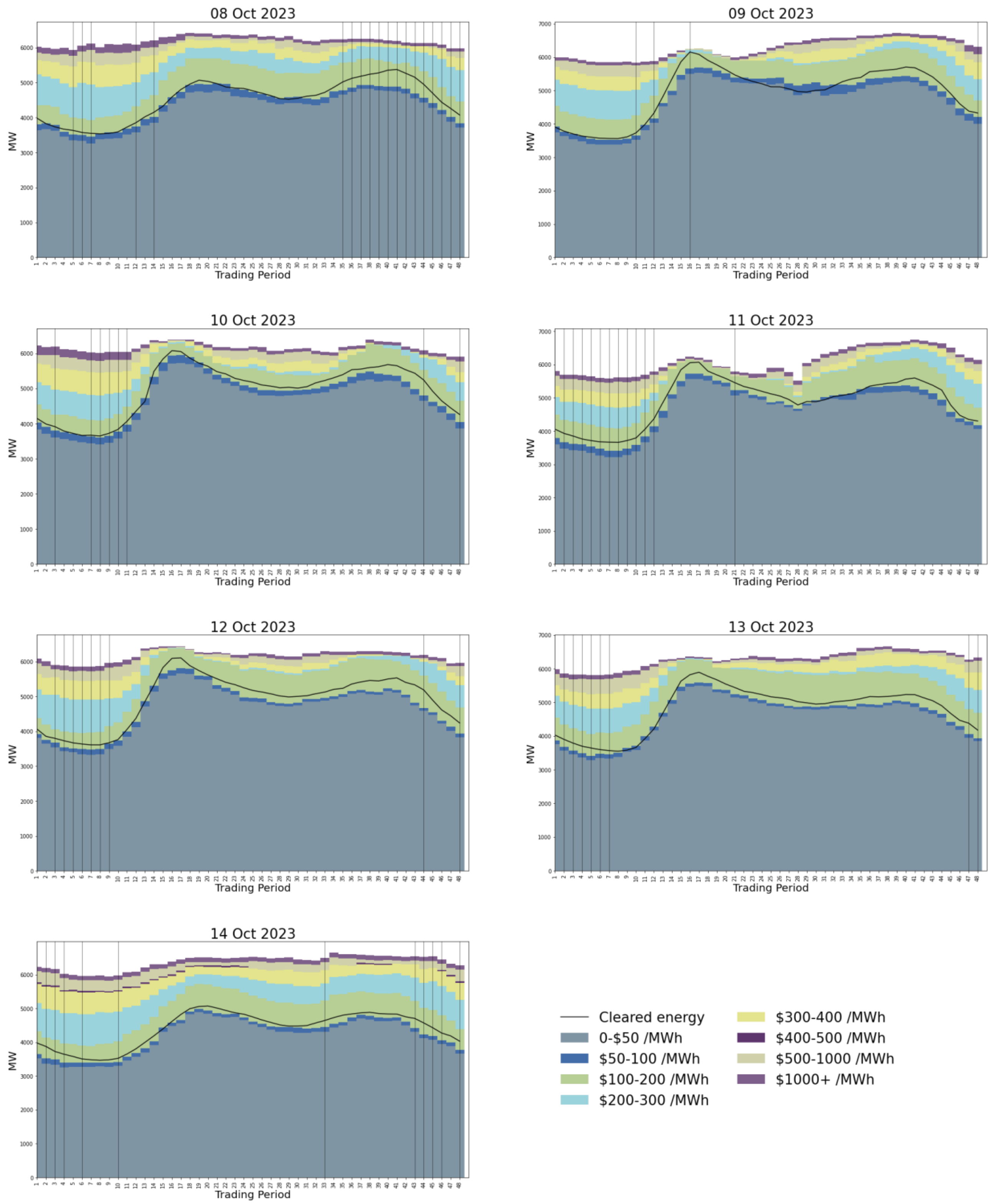


12. Offer behaviour

12.1. Figure 17 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 region with only a few instances of high prices taking cleared offers within $200-$400/MWh.

Figure 17: Daily offer stacks



13. Ongoing work in trading conduct

13.1. This week, prices generally appeared to be consistent with supply and demand conditions, except for one instance immediately after the low residual CAN period (7.30am -9.30am 11 October) which we will investigate further.

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
07/10/2022	15-16	Further analysis	Genesis	Huntly 5	Prices change for final energy tranche.
15/1/2023 - 4/2/2023	Several	Resolved	N.A.	Multiple	No trading conduct issue was found.
13/06/2023	14-16	Resolved	Genesis	Takapō	Offer change was consistent with the trading conduct provisions.
14/06/2023	15-17	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers.
15/06/2023	15-19	Passed to Compliance	Genesis and Contact	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	Further Analysis	Genesis	Tokaanu	High prices during off-peak time.