6 November 2023

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 29 October-4 November

1.1. Weekly average spot prices increased this week with prices sitting above the historic average for most of the week and remaining above that average during overnight periods. There was a significant price spike during the Wednesday morning peak, likely influenced by low and under forecast wind as well as demand being higher than forecast. This was the only day two Rankines were running, and Whirinaki was dispatched for a short period with both Stratford peakers now on outage. A number of large generator outages saw some tight supply towards the end of the week and some high prices during the shoulder period on Friday. Hydro storage remains above average at 106% of historic mean as of 4 November.

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 grey line. Other notable prices that did not exceed the 90th percentile, are marked with black dashed lines.

2.3. Between 29 October – 4 November:

(a) The average wholesale spot price across all nodes was $145/MWh.

(b) 95 percent of prices fell between $68/MWh and $265/MWh.

2.4. Spot prices sat above the historic average for the majority of the week even overnight, with a number of prices sitting around or just above the 90th percentile region. The average spot price increased around $20/MWh compared to the previous week.

2.5. On Monday there was a price spike at 7.00am where the price at Ōtāhuhu was $291/MWh and the price at Benmore was $237/MWh. Wind forecast was ~160MW lower than forecast during this trading period, hydro was running close to 4000MW and three thermal peakers were running.

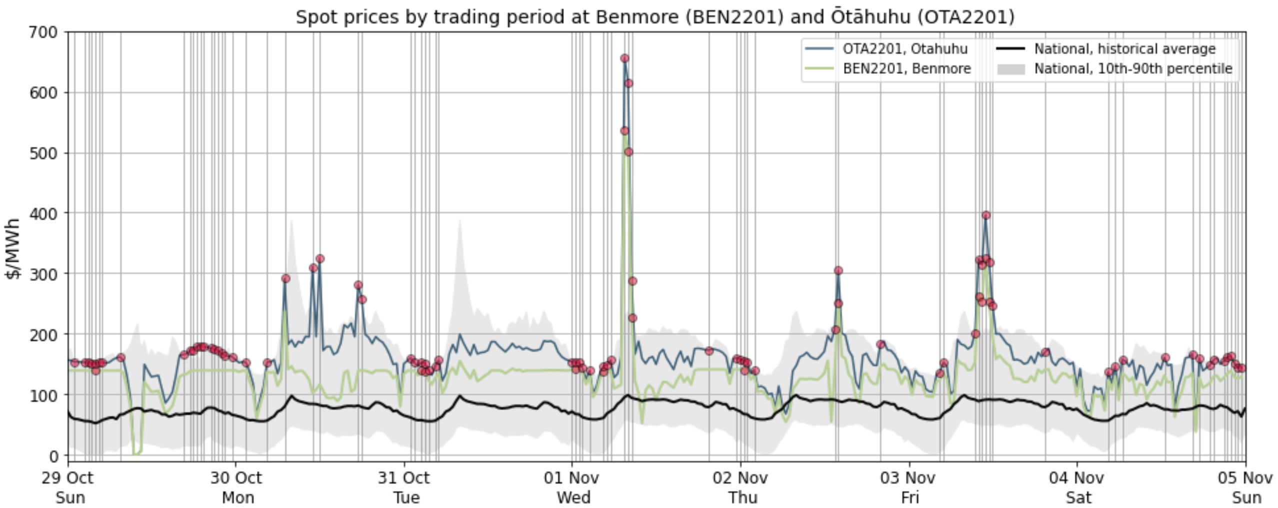
2.6. There was also a period of price separation during the day on Monday due to constraints. Between trading periods 23-25, two Redclyffe Tuai circuits were out, and between trading periods 23-38 a Huntly Stratford circuit was out causing binding constraints at Whakamaru – Tokaanu. At 11.00am and 12.00pm Ōtāhuhu prices spiked to $311/MWh and $325/MWh, around $200/MWh higher than Benmore. The next price spike was at 5.30pm and 6.00pm where Ōtāhuhu prices were $281/MWh and $258/MWh, this time around $120-$140/MWh higher than the prices at Benmore.

2.7. The largest price spikes of the week were on Wednesday morning during the 7.30am and 8.00am trading periods. Prices at Ōtāhuhu were $656/MWh and $614/MWh respectively and $536/MWh and $502/MWh at Benmore. Low wind on Wednesday saw two Rankine units running as well as three thermal peakers, including Whirinaki.

2.8. The next price spike was at 2.00pm on 2 November, with the price at Ōtāhuhu $304/MWh and Benmore $251/MWh Benmore. Demand was around 100MW higher than forecast and also wind was ~120MW lower than forecast. This saw some higher priced hydro offers dispatched.

2.9. During the shoulder period on Friday 3 November from 10.00am-11.30am there were multiple spikes in prices which ranged from $314-$396/MWh at Ōtāhuhu and $252-$324/MWh at Benmore. With a number of large thermal units and hydro units on outage currently as well as low wind, generation balance residuals during Friday's shoulder period were close to 200MW. This meant only higher priced thermal and hydro was available to meet demand requirements.

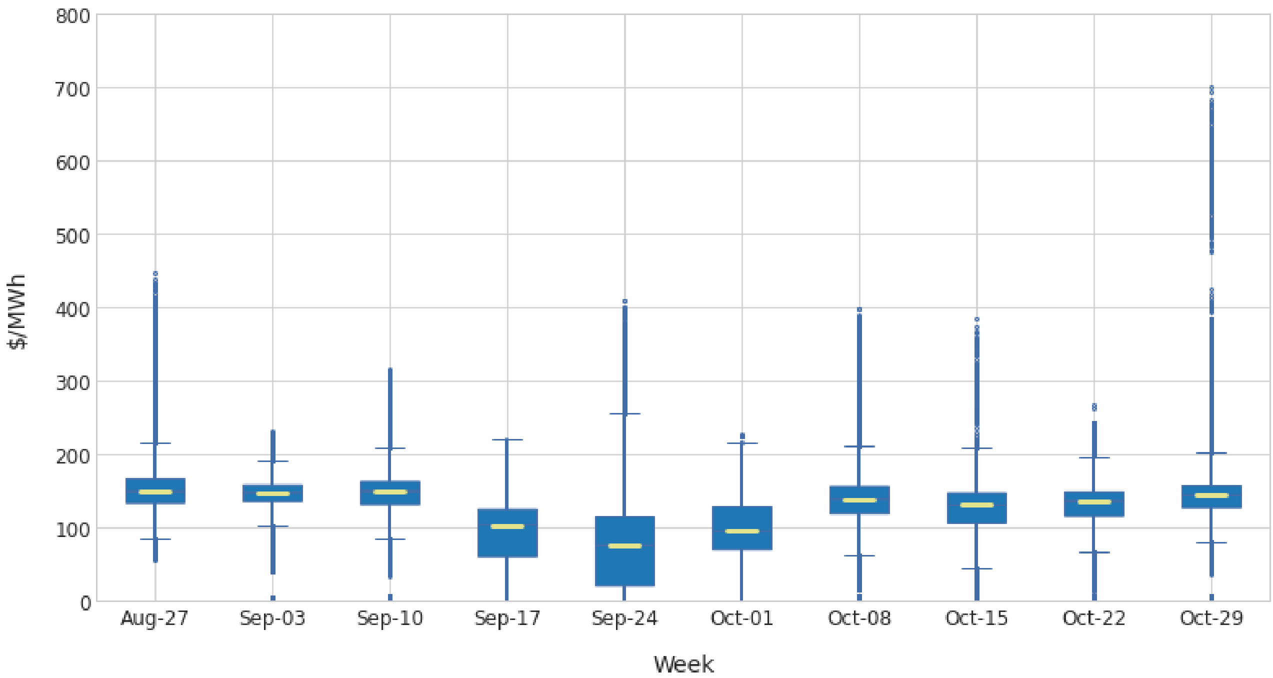
Figure 1: Wholesale spot prices between 29 October (Sunday) and 4 November (Saturday)



2.10. 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.

2.11. Most prices were within $126-$157/MWh this week, although there were multiple outliers due to the price spikes that occurred across the week. The median spot price this week was $143/MWh.

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



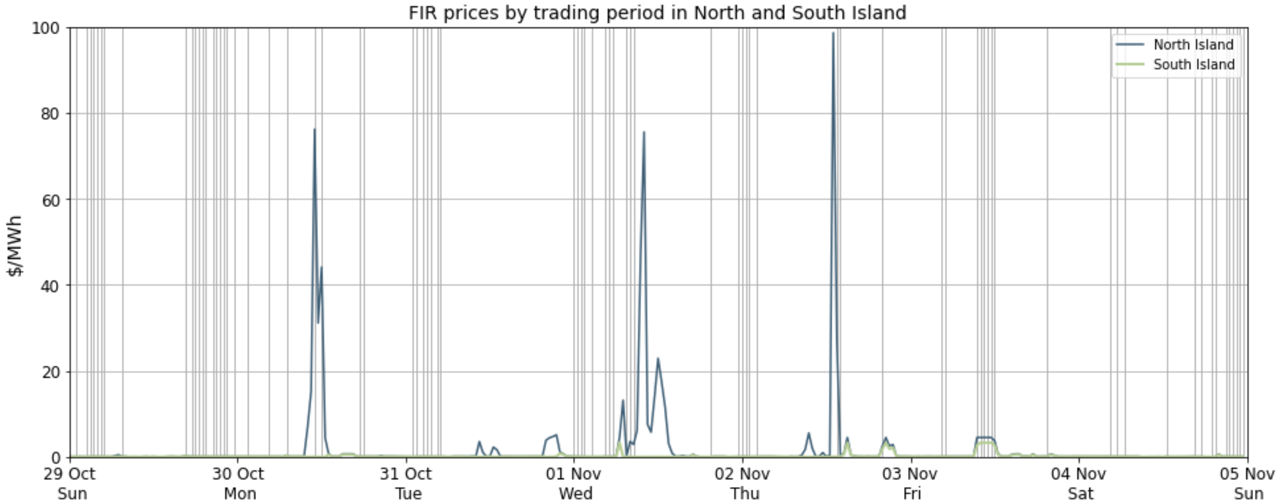
3. Reserve prices

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. However, there were three significant spikes in North Island FIR due to binding constraints on the HVDC[1]. The first spike occurred on Monday at 11.00am in line with the separation and price spikes with the spot prices. North Island FIR was $76/MWh at this time.

3.2. North Island FIR was also close to $76/MWh at 10.00am on Wednesday morning. The highest North Island FIR price occurred on Thursday afternoon at 1.00pm, with the price reaching around $99/MWh.

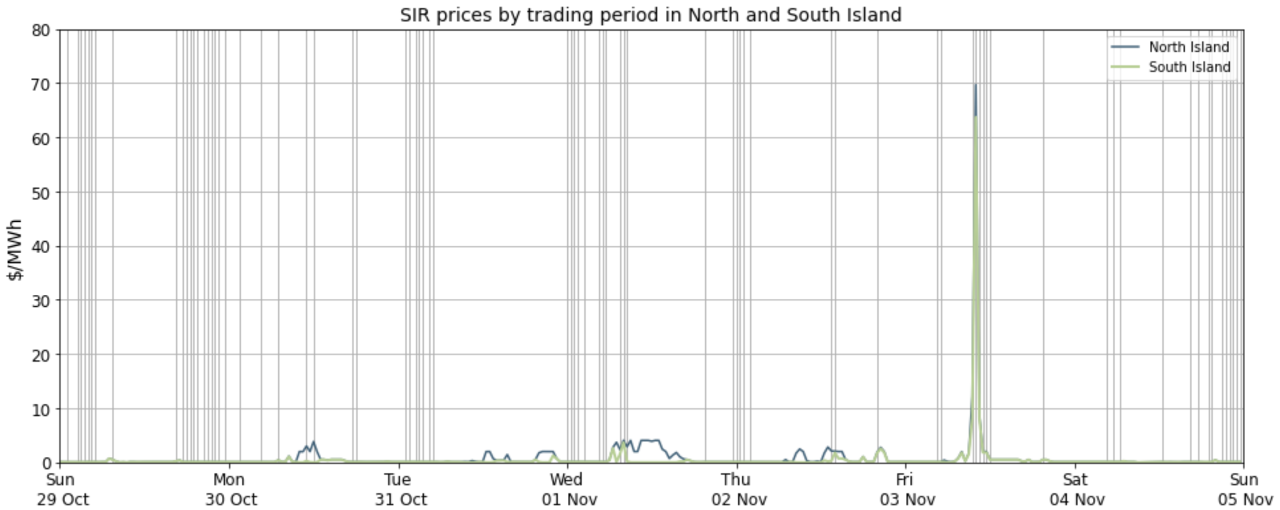
[1] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these—the one that determines the required quantity of instantaneous reserve. Reserve 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 mainly below $5/MWh. There was a significant spike in both North and South Island SIR at 10.00am on Friday. North Island SIR was ~$70/MWh and South Island SIR was ~ $64/MWh. This spike coincided with some high spot prices during the Friday shoulder period and was likely due to tight supply.

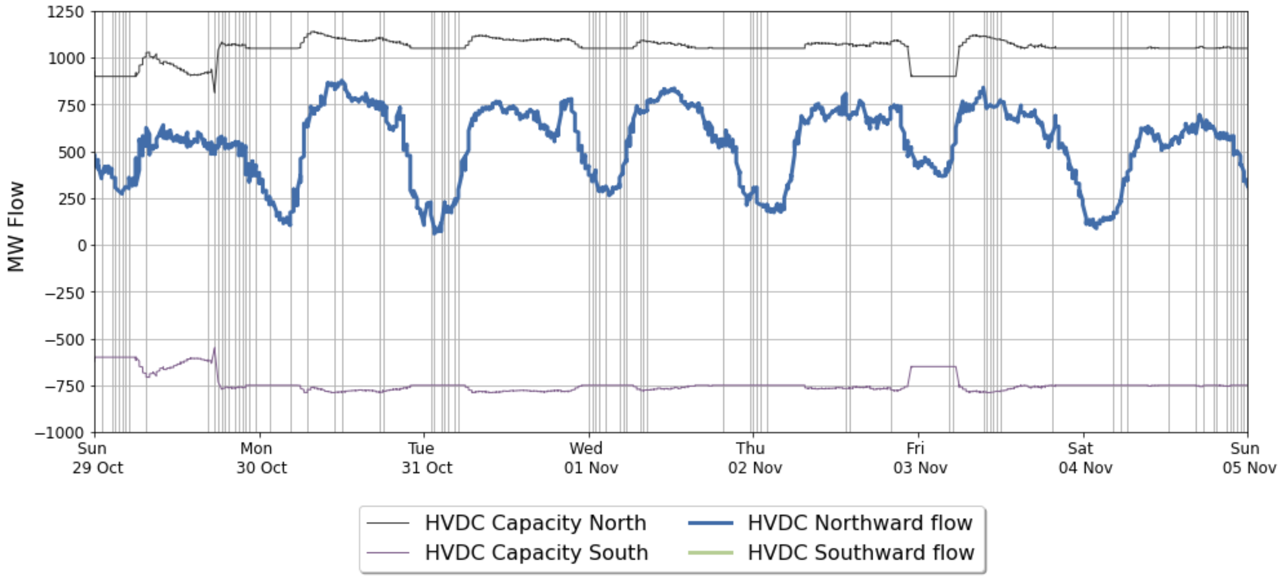
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and Island



4. HVDC

4.1. Figure 5 shows HVDC flow between 29 October-4 November. HVDC flows were northwards the whole week, with maximum flow north of 878MW on Monday at midday.

Figure 5: HVDC flow and capacity

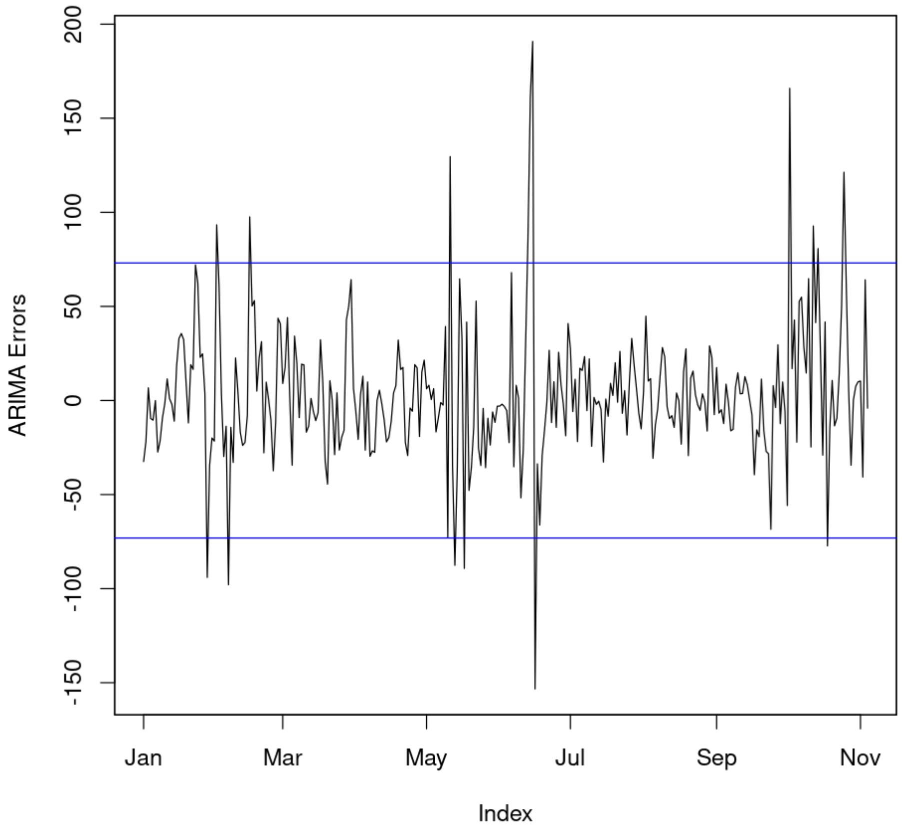


5. Regression residuals

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 there were no residuals above or below two standard deviations of the data.

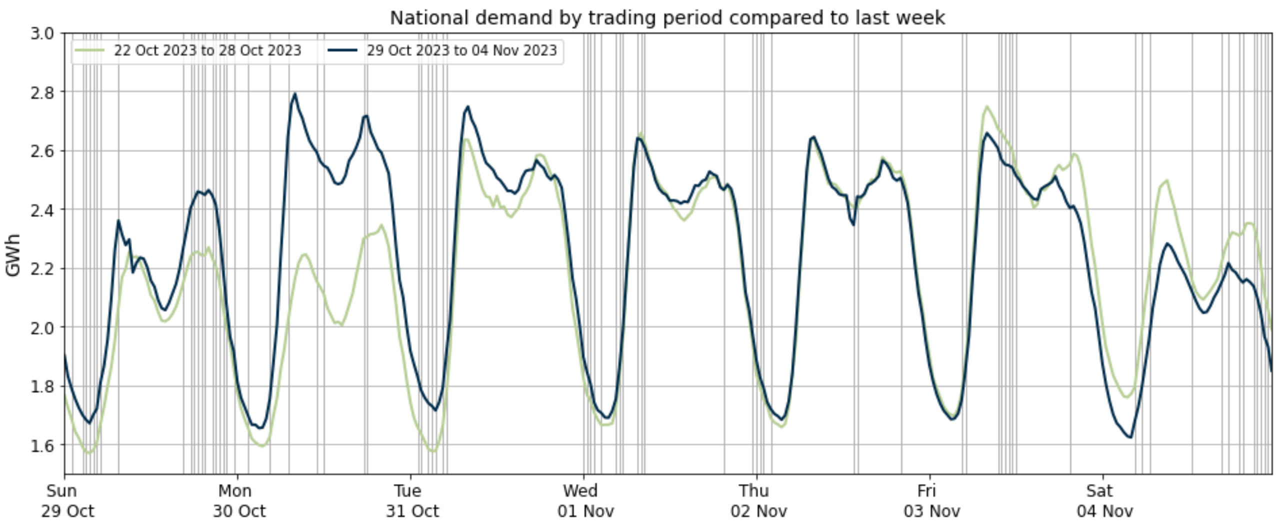
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 4 November 2023



6. Demand

6.1. Figure 7 shows national demand between 29 October-4 November, compared to the previous week. Overall, demand was higher at the beginning of the week, with Wednesday and Thursday showing a similar demand profile to the previous week. Warmer weather at the end of the week saw a drop in demand compared to the previous week.

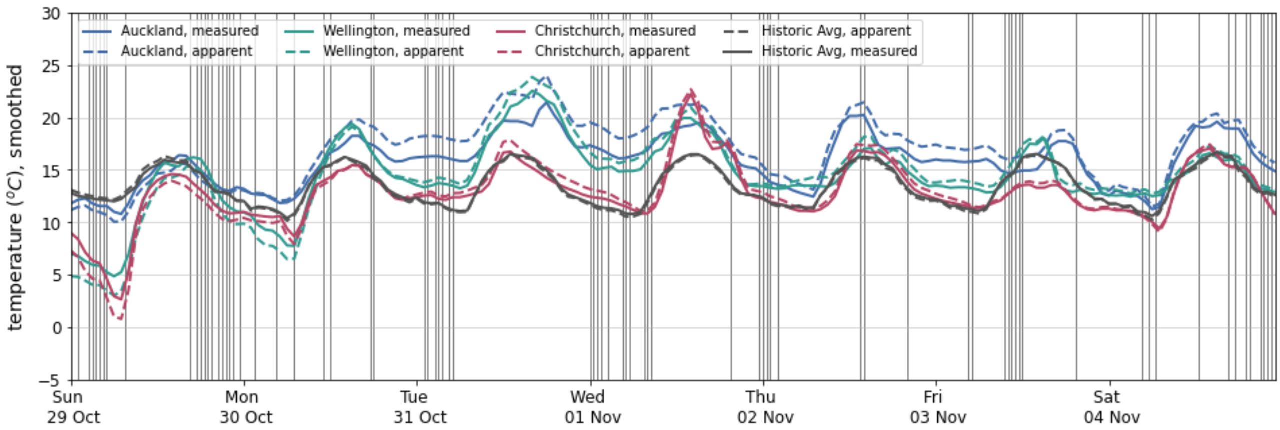
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 29 October-4 November. 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 in Auckland were on or above average across the week. Wellington and Christchurch saw some cooler temperatures on Sunday and Monday morning with the rest of the week seeing temperatures on or above average.

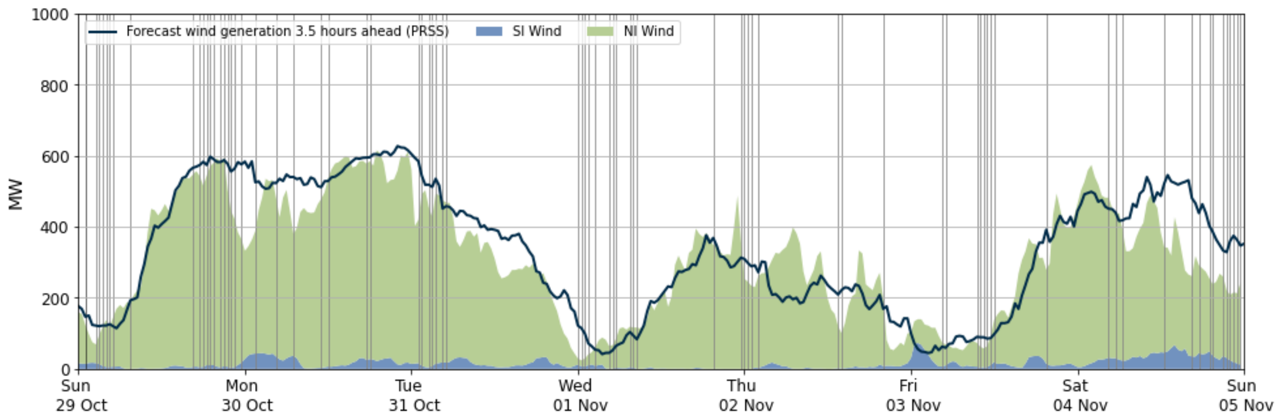
Figure 8: Temperature across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 29 October – 4 November. Overall, this week saw much lower wind generation than we have had in recent weeks with generation ranging between 24MW and 615MW across the week. There were also discrepancies in forecast and actual wind generation across the week, often coinciding with high prices.

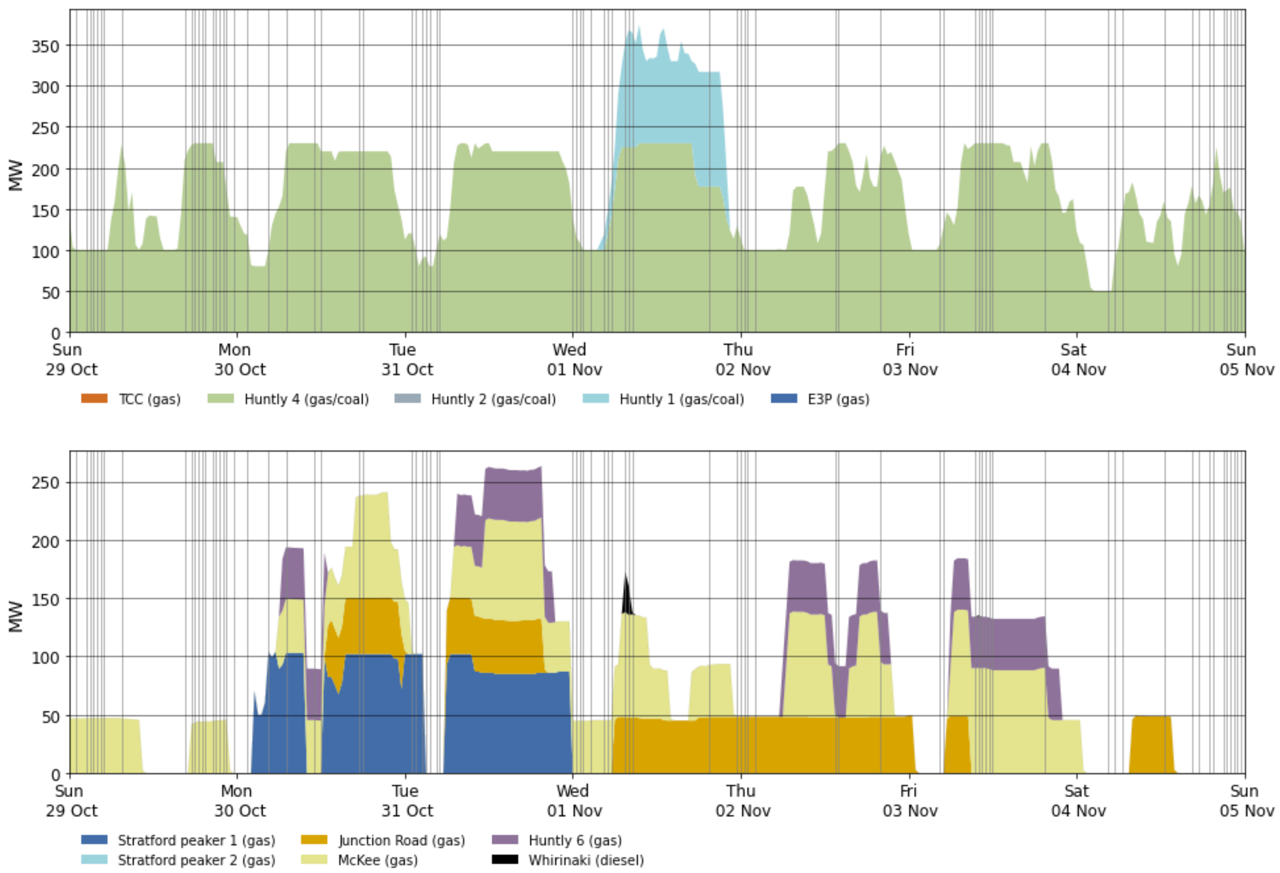
Figure 9: Wind generation and forecast between 29 October - 4 November



7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 29 October–4 November. Huntly 4 ran all week as baseload with support from Huntly 1 on Wednesday.

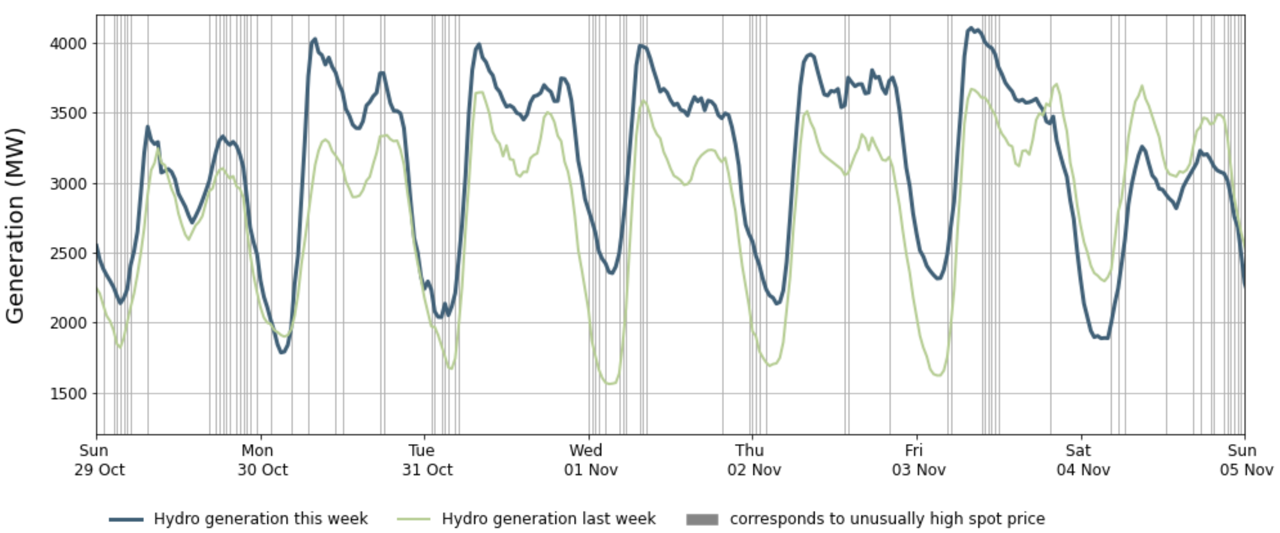
7.3. Stratford 1 ran on Monday and Tuesday but went on outage on 1 November, which was then extended to run until 20 November. Junction Road and McKee were dispatched most days this week, and Huntly 6 only ran on four days, likely due to the outage at Kupe which limited gas availability. Instead, Whirinaki was dispatched during Wednesday morning when prices spiked to over $600/MWh.

Figure 10: Thermal generation between 29 October - 4 November



7.4. Figure 11 shows hydro generation between 29 October and 4 November. Hydro generation increased compared to the previous week with weekday morning peak periods seeing generation close to 4000MW.

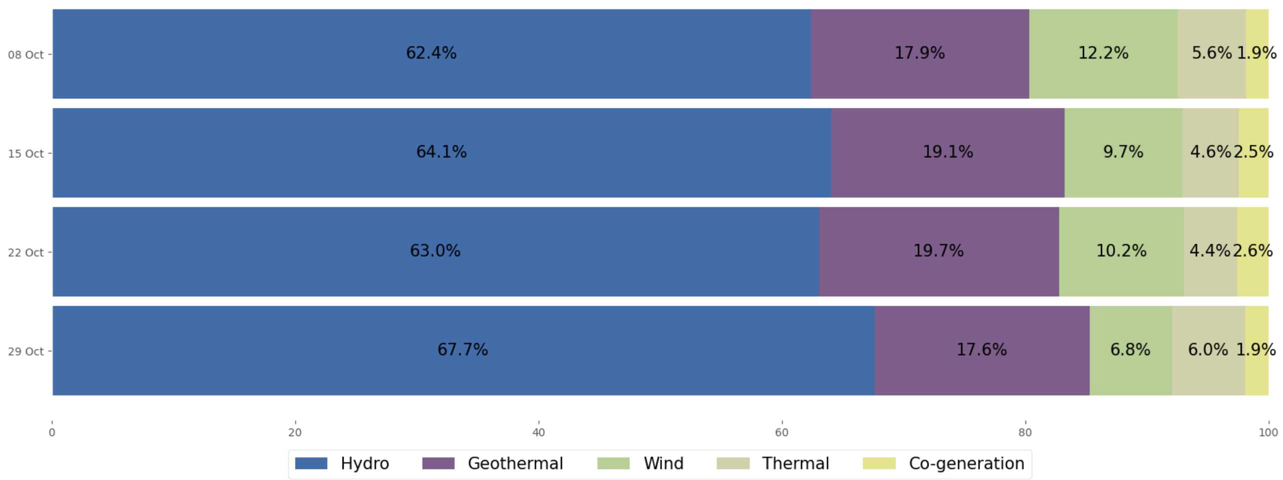
Figure 11: Hydro generation between 29 October - 4 November compared to the previous week



7.5. As a percentage of total generation, between 29 October-4 November, total weekly hydro generation was 67.7%, geothermal 17.6%, wind 6.8%, thermal 6%, and co-generation

1.9%. With less wind generation this week there was an increase to hydro and thermal generation compared to the previous week.

Figure 12: Total generation by type as a percentage each week between 8 October and 4 November



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 29 October-4 November ranged from 2000MW to ~2800MW. Outages are siting above average with recent increased thermal outages listed below as well as multiple hydro outages.

8.2. Notable outages include:

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

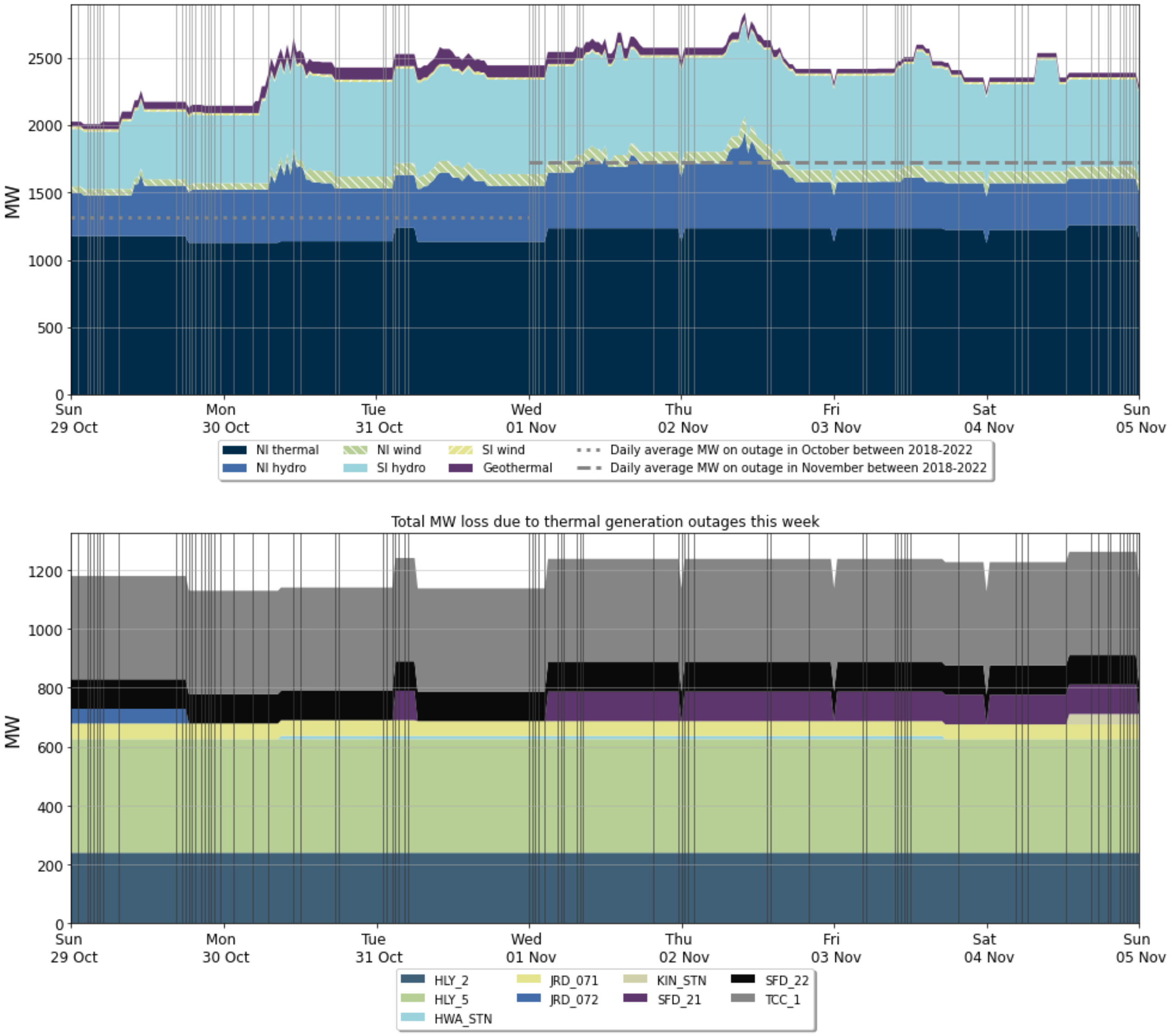
(b) Huntly 2 is on outage 27 October – 13 November

(c) As well as the long term Stratford 2 outage (28 February 2025), Stratford 1 is on outage from 1 November - 20 November 2023.

(d) TCC is on outage until 22 December 2023

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

Figure 13: Total MW loss due to generation outages



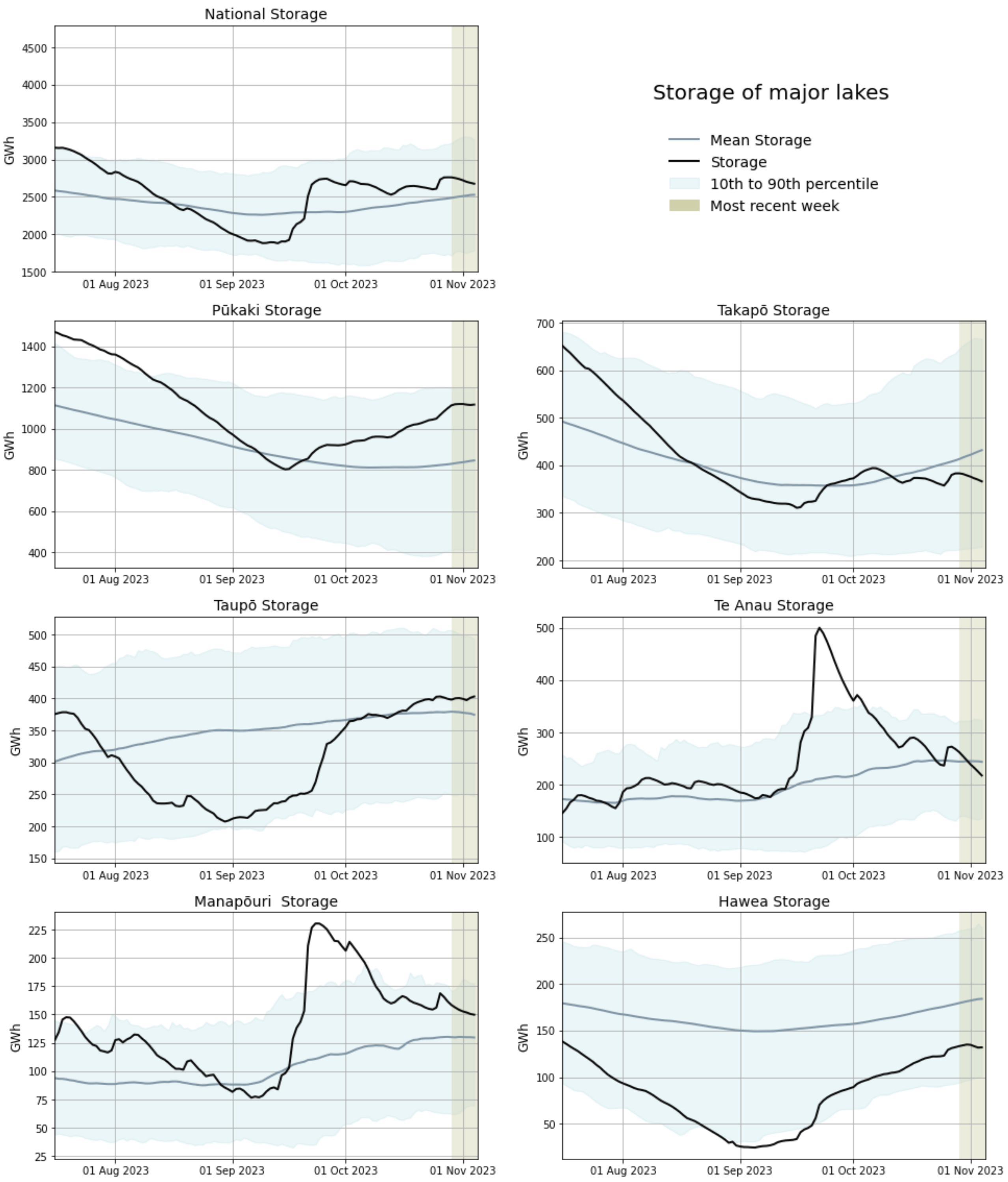
9. Storage/fuel supply

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 hydro storage levels decreased slightly this week, with controlled storage levels at 68% nominally full and 106% of historic mean as of 4 November.

9.3. Taupō storage remained steady and close to 400GWh across the week, still sitting above its historic mean storage levels. Pūkaki storage remains close to its historic 90th percentile with storage levels staying steady this week. Takapō storage declined slightly as its storage levels remain below its historic mean. Manapōuri and Te Anau storage both decreased this week, with Te Anau storage now below its historic mean. Manapōuri storage is currently above its mean. Hawea storage decreased a bit in the latter half of the week but still remains above its historic 10th percentile.

Figure 14: Hydro storage



10. JADE water values

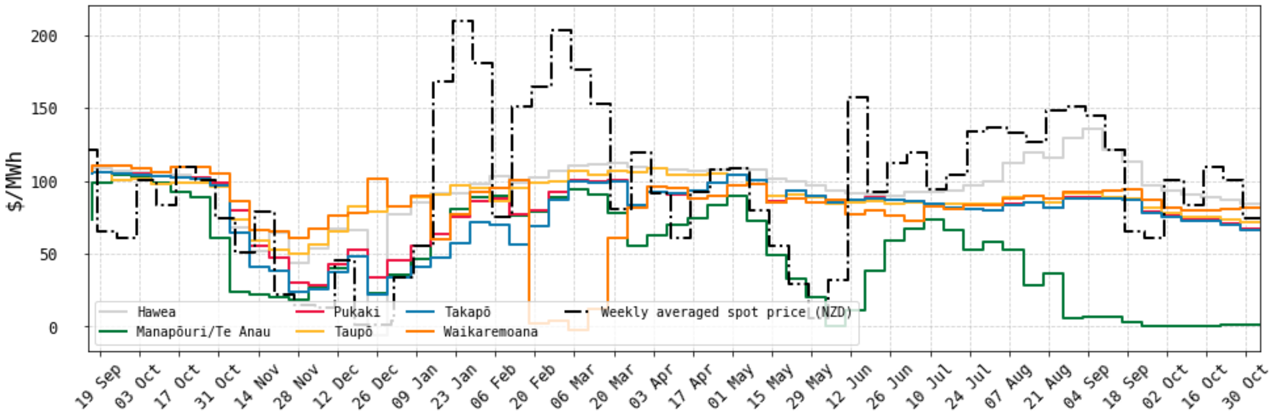
10.1. The JADE[2] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and

[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.

provides an estimate of water values at a range of storage levels. Figure 15 shows the national water values between 15 September 2022 and 4 November 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. Pūkaki and Takapō saw a small decrease of around $4/MWh to water values this week in line with Pūkaki storage remaining high. Increases to Hawea storage has also seen a small decrease to its water values. Most other lake water values have seen little change compared to previous weeks.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 4 November 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 November 2023. The SRMC of diesel plants has been increasing since May, and the SRMC of coal-fuelled and gas-fuelled plants has started to increase again. The recent increase in the SRMC of gas likely reflects increased production at Methanex, as well as gas production outages.

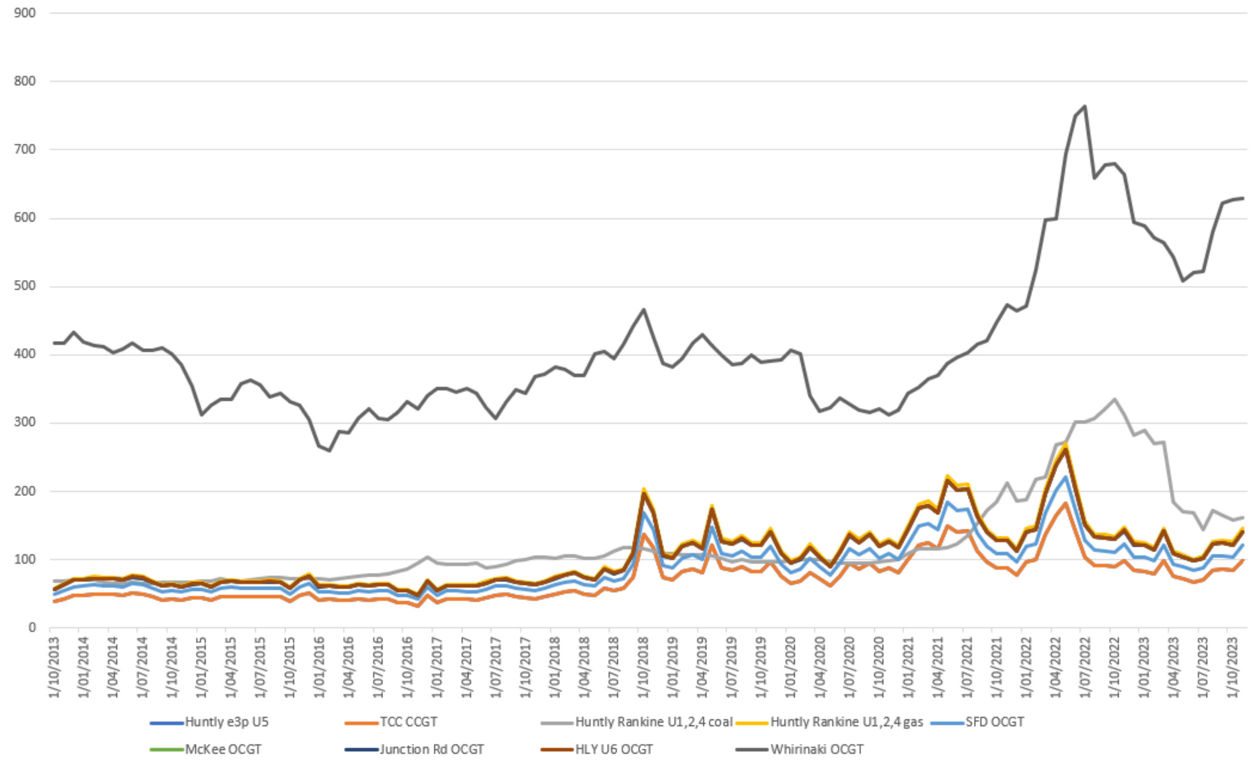
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$161/MWh. This is now only slightly higher than the cost of running the Rankines on gas at $141/MWh, with Genesis continuing to run the Rankines on a combination of both fuels.

11.5. The SRMC of gas fuelled thermal plants is currently between $98/MWh and $141/MWh.

11.6. The SRMC of Whirinaki has increased to ~$629/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



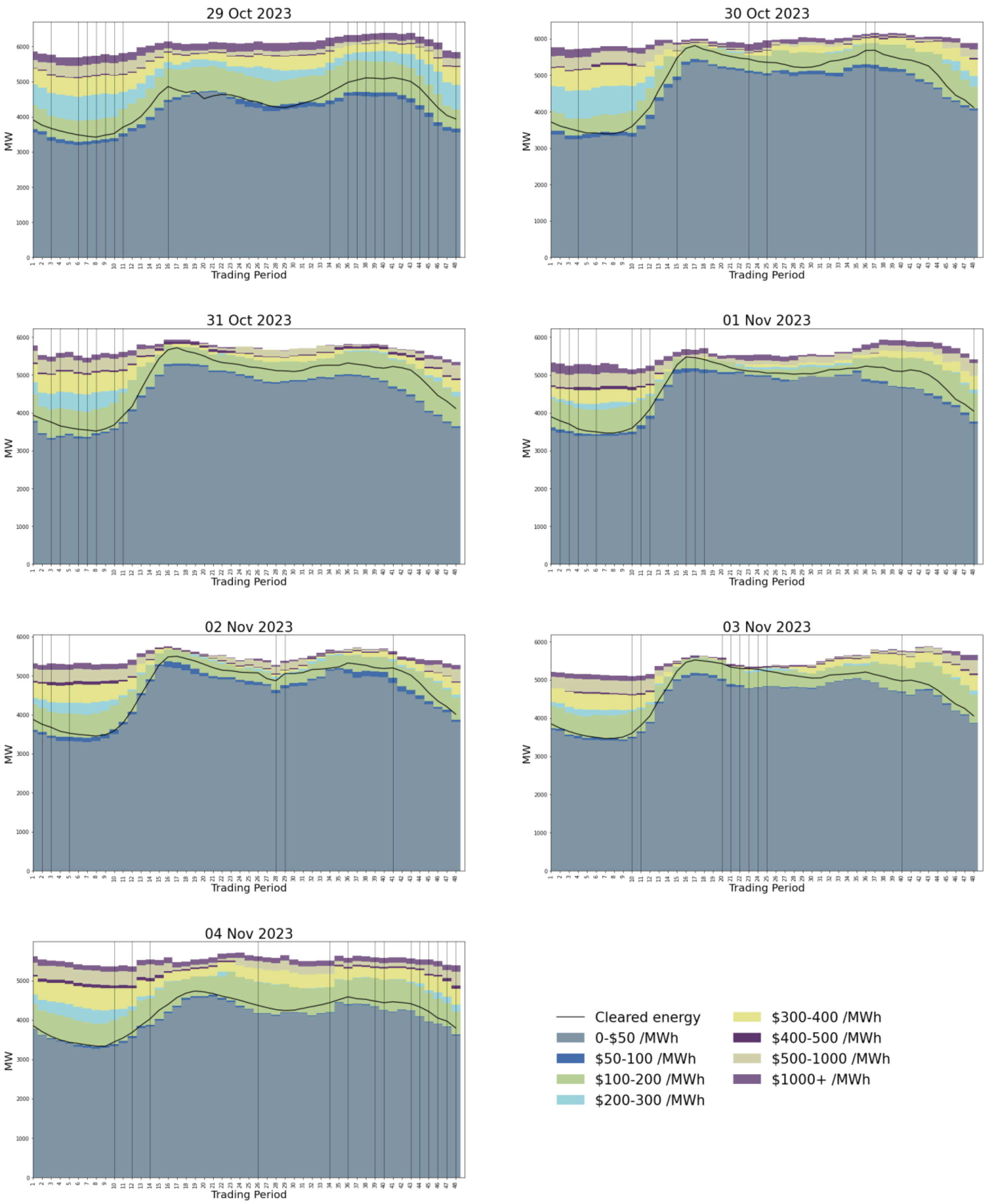
12. Offer behaviour

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 range including overnight offers. The $50-$100/MWh offer band remains thin.

12.3. Multiple price spikes this week saw prices over $300/MWh and a few over $500/MWh. The offer bands in these price regions have been thin.

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.

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.
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.