Date: 6 June 2023

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 28 May – 3 June 2023

1.1. This week, prices remained low due to high hydro storage and generation, and high wind generation. However, there were minor price spikes during peak times when additional thermal generation was required to meet the high demand in the North Island. HVDC flows were predominantly northward due to the increased hydro generation in the South Island. The majority of energy was cleared in the lower price ranges.

2. Spot Prices

2.1. This report monitors underlying wholesale price drivers to assess whether there are trading periods that require further analysis for the purpose of identifying 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. Prices above the historic 90th percentile are highlighted with a black line. Other notable prices, but which did not breach the 90th percentile, are marked in black dashed lines (if any).

2.2. Between 28 May – 3 June 2023:

(a) The average wholesale spot price across all nodes was $6/MWh.

(b) 95 percent of prices fell between $0/MWh and $58/MWh.

2.3. Figure 1 shows spot prices at Benmore and Ōtāhuhu alongside their historic median and historic 10th - 90th percentiles adjusted for inflation.

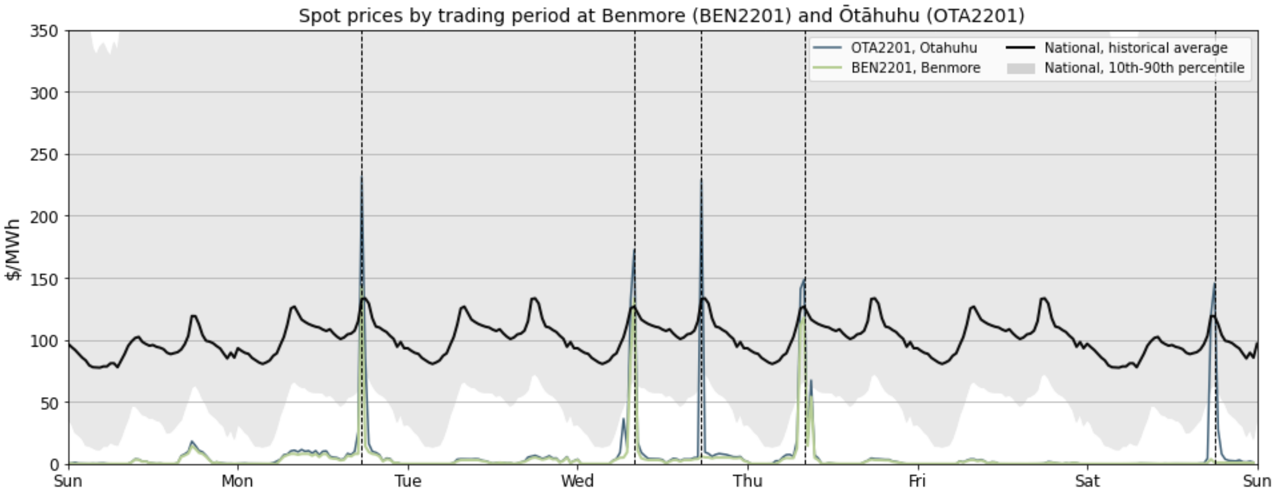
2.4. The majority of prices remained low, falling mostly below the 10th percentile, although there were occasional instances when prices exceeded the historical average during periods of peak demand. These low prices were primarily attributed to high hydro storage and generation. The highest price was observed on Monday, 29 May 2023, reaching $232/MWh at Ōtāhuhu and $143/MWh at Benmore.

2.5. This week price separations have been observed on:

(a) Wednesday, 31 May 2023 at 5:30 pm when prices were $229/MWh at Ōtāhuhu and $6/MWh at Benmore with Sustained Instantaneous Reserve (SIR) prices of $189/MWh for the North Island and $0.01/MWh for the South Island. At that time North Island load was supported by thermal generation.

(b) Saturday, 3 June 2023 between 5:30 pm – 6:00 pm with prices of $146/MWh at Ōtāhuhu and $1/MWh at Benmore with Fast Instantaneous Reserve (FIR) prices of $55/MWh for the North Island and $0/MWh for the South Island. At this time wind generation was low at around 100 MW.

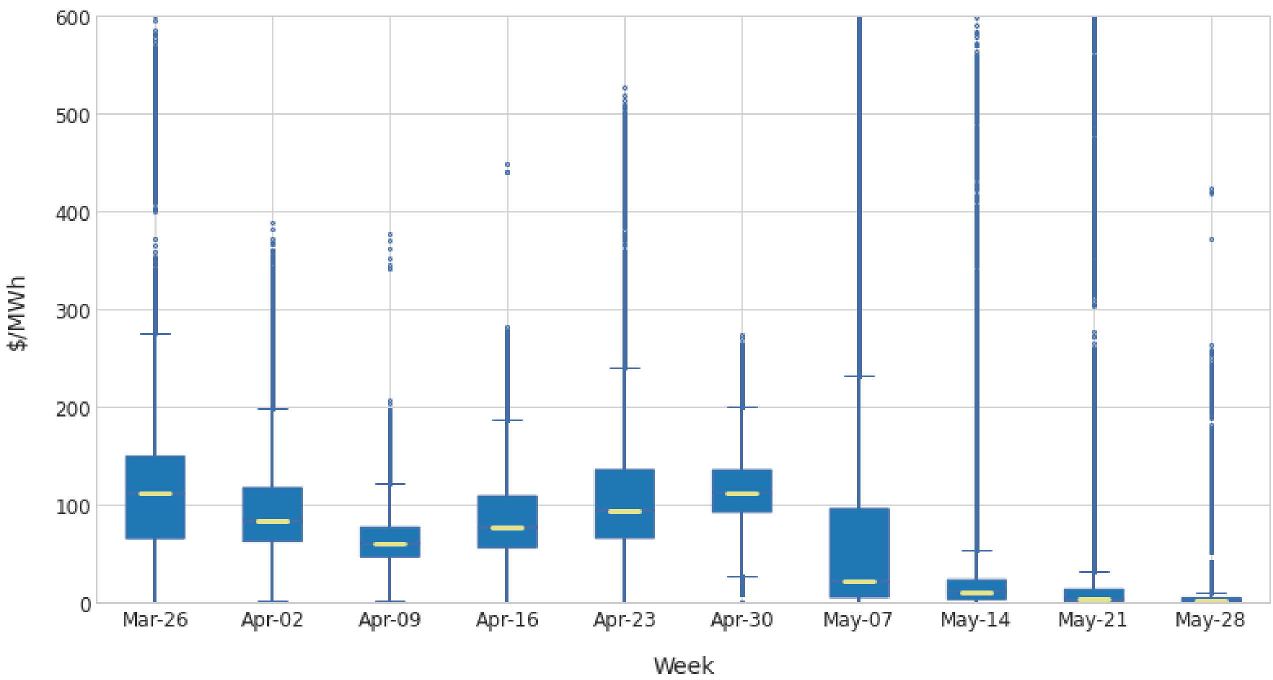
Figure 1: Wholesale Spot Prices between 28 May (Sunday) – 3 June (Saturday) 2023.



2.6. 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.

2.7. This week, the median price was much lower compared to the previous week with fewer outliers. The decline in prices was primarily influenced by the substantial hydro storage and generation. In May, prices were lower than prices in April, due to increased hydro generation.

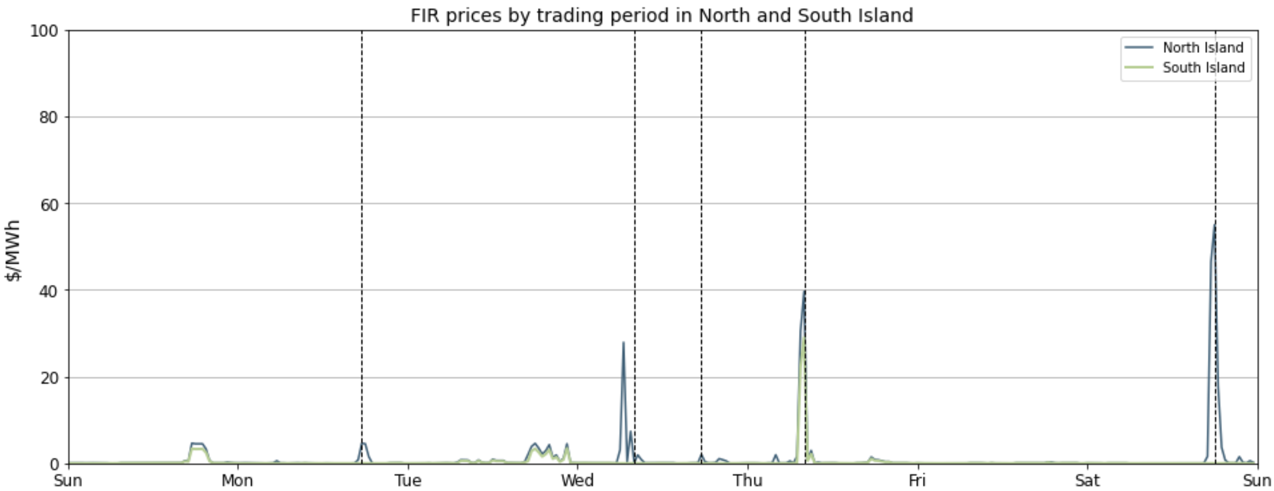
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks.



3. Reserve Prices

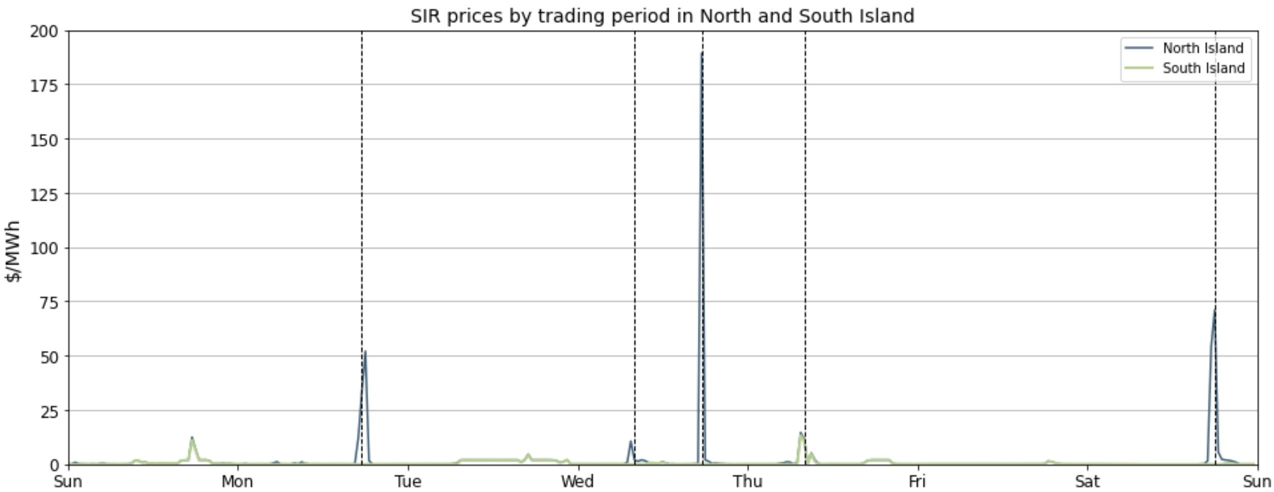
3.1. FIR prices for the North and South Islands are shown below in Figure 3. This week the FIR prices were mostly below $5/MWh for both islands with only a few instances of price spikes that still stayed below $60/MWh. The highest price spike occurred in the North Island on Saturday, 3 June 2023 between 5:30 pm and 6:00 pm, when the HVDC was the risk setter, which increased the requirement for North Island reserve. This contributed to price separation in both energy and reserve prices. During this period, FIR prices in the North Island peaked at $55/MWh, while the South Island experienced prices as low as $0/MWh.

Figure 3: Fast instantaneous reserve (FIR) prices by trading period and Island.



3.2. SIR prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh this week. However, on Wednesday 31 May 2023 at 5:30 pm a notable price spike occurred, when the HVDC was the risk setter, which increased the requirement for North Island reserve. This contributed to price separation in both energy and reserve prices resulting in SIR prices of $189/MWh for the North Island and $0.01/MWh for the South Island.

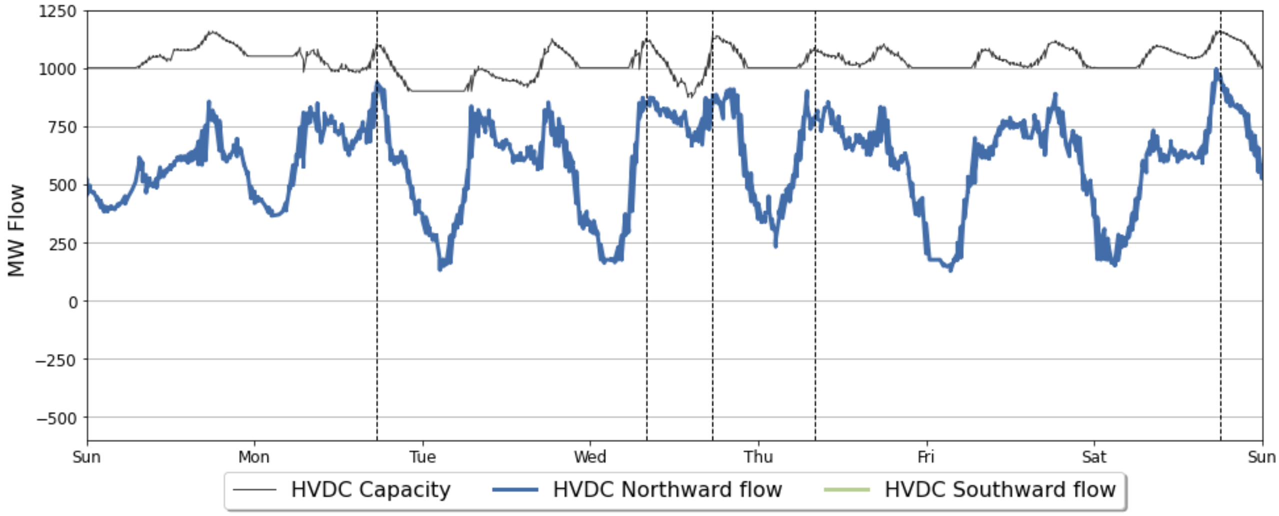
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and Island.



4. HVDC

4.1. Figure 5 shows HVDC flow between 28 May – 3 June. HVDC flows were northward during both daytime and night-time, reaching up to 880 MW during the daytime. Northward flows were particularly high when demand was high and may have contributed to higher prices and price separation as the risk of losing an HVDC pole increased the reserve required in the North Island. This week again no southward HVDC flow was observed.

Figure 5: HVDC northward flow and capacity.

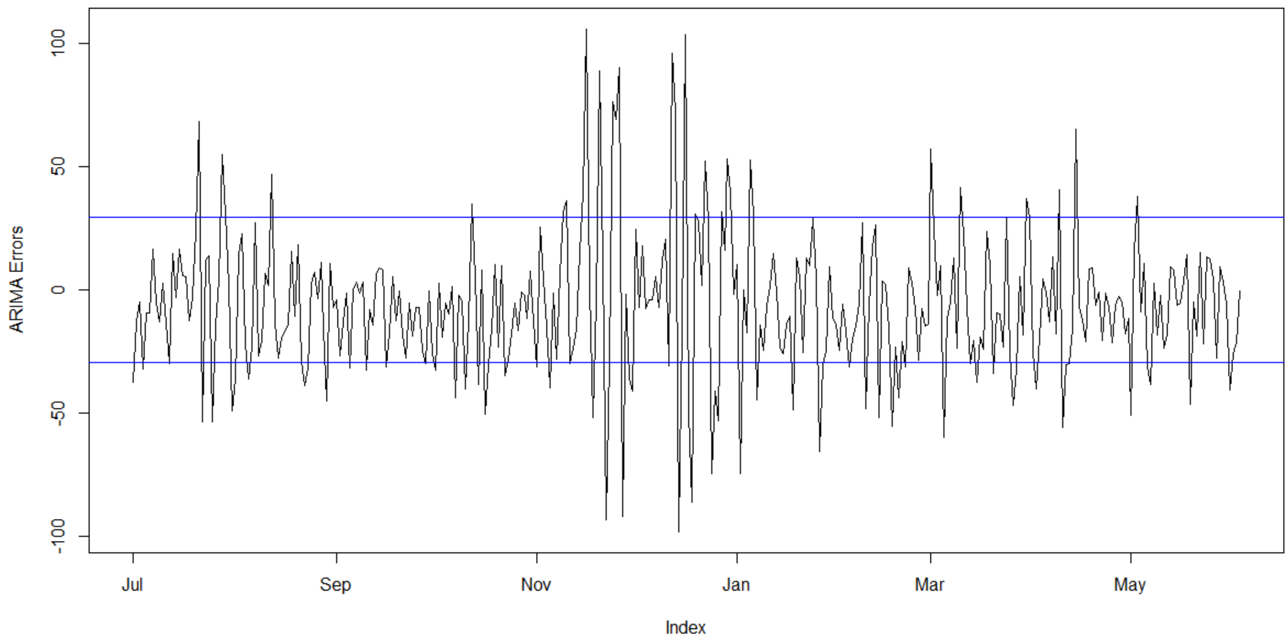


5. Regression Residuals

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. Residuals were mostly relatively small, suggesting that average daily prices on those dates appear to be largely aligned with market conditions. These small deviations reflect market variations that may not be controlled for in the regression analysis. This week, there was one residual below the one standard deviation of the data on Friday. On Friday the average daily price was below $1/MWh. This negative residual indicates that the modelled price was higher than the actual prices.

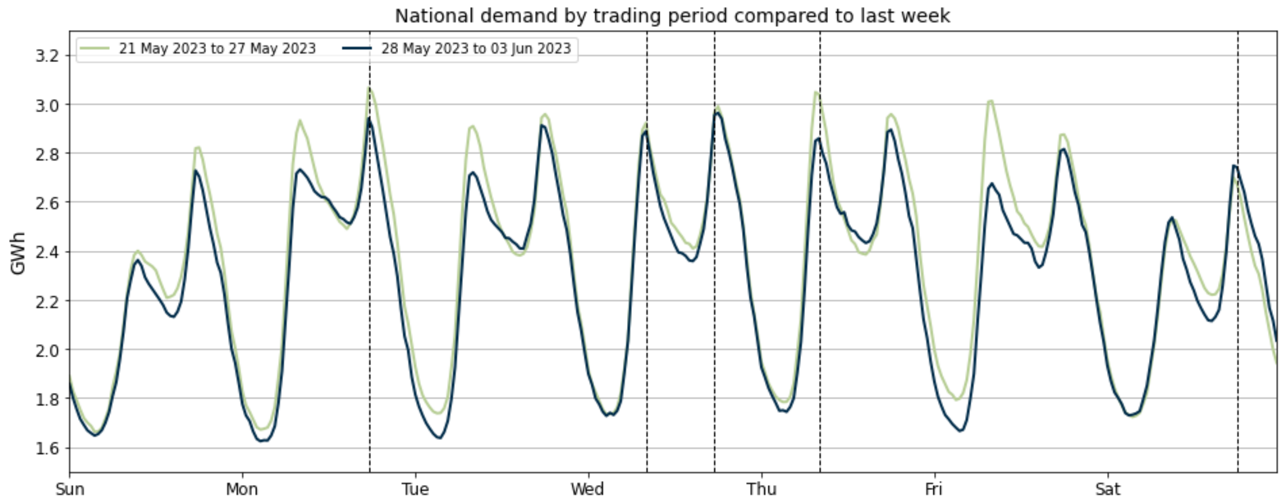
Figure 6: Residual plot of estimated daily average spot prices from 1 July 2022 – 3 June 2023. The blue lines show two standard deviations of the ARMA errors.



6. Demand

6.1. Figure 7 shows national grid demand between 28 May – 3 June, compared to the previous week. Overall, demand was lower than the previous week, particularly during the morning peaks. Wednesday was the only day with a similar demand pattern to the previous week. Saturday evening saw a slightly higher demand during the evening peak. The high prices this week all occurred during peak periods.

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

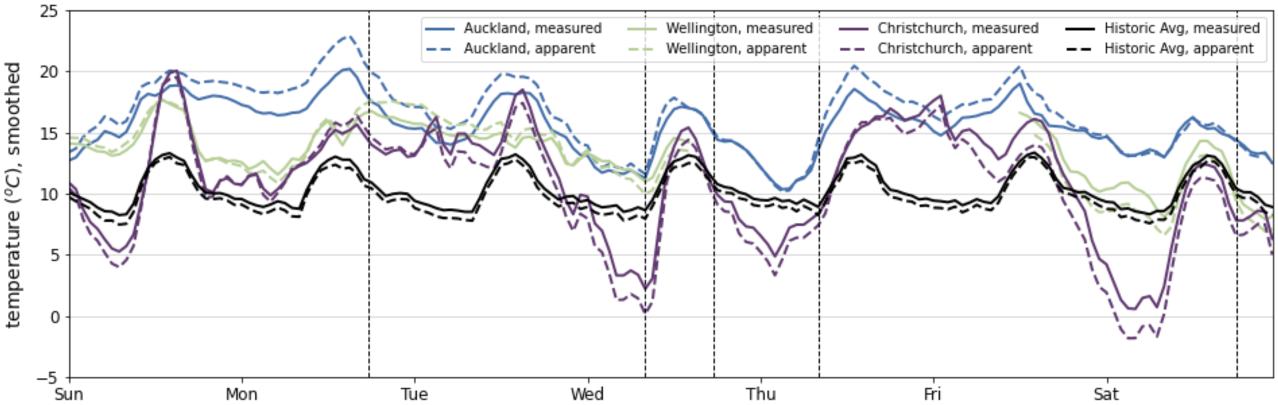


6.2. Figure 8 shows hourly temperatures at the three main population centres between 28 May – 3 June. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels.

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 mainly above historic average (around 8-13 degrees) in Auckland with temperatures mostly above 15 degrees with a few instances of apparent temperatures reaching around 20 degrees. Wellington temperatures were mainly above historic average, however, some Wellington data from around Wednesday midday to Friday midday is missing. Christchurch had the most varied apparent temperatures, ranging from around -2 to 20 degrees.

Figure 8: Temperatures across main centres.



7. Outages

7.1. Figure 9 shows generation capacity on outage. Total capacity on outage between 28 May – 3 June ranged between ~700 – 1,300 MW.

7.2. Notable outages include:

(a) Huntly 1 came back from outage on Wednesday.

(b) Huntly 4 went on outage from 3 June to 11 June.

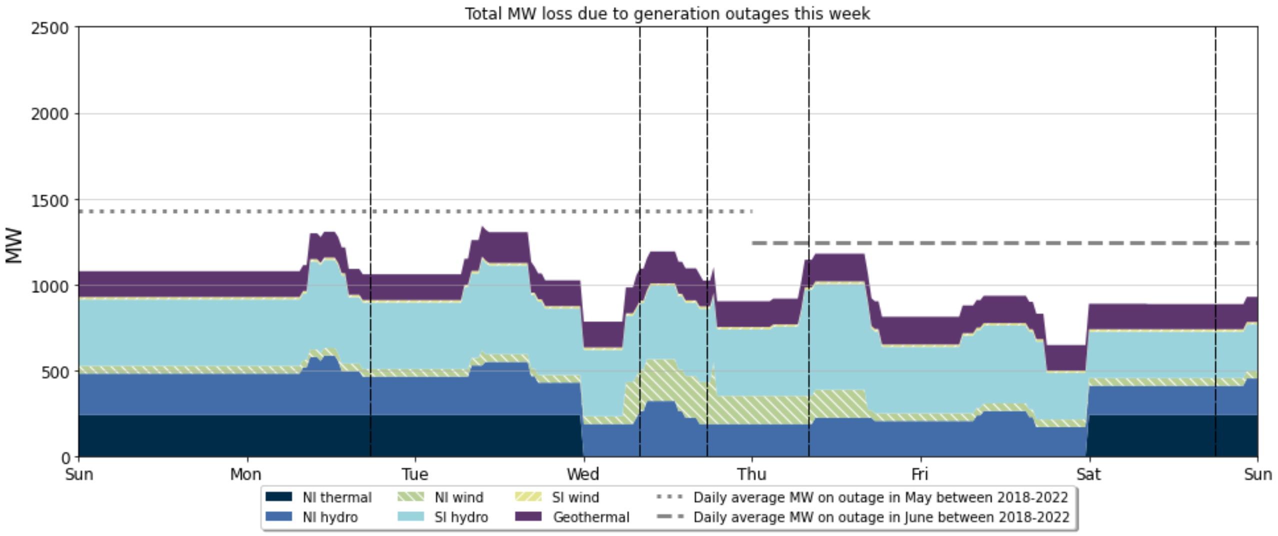
(c) The Geothermal plant Kawerau extend outage until 14 June.

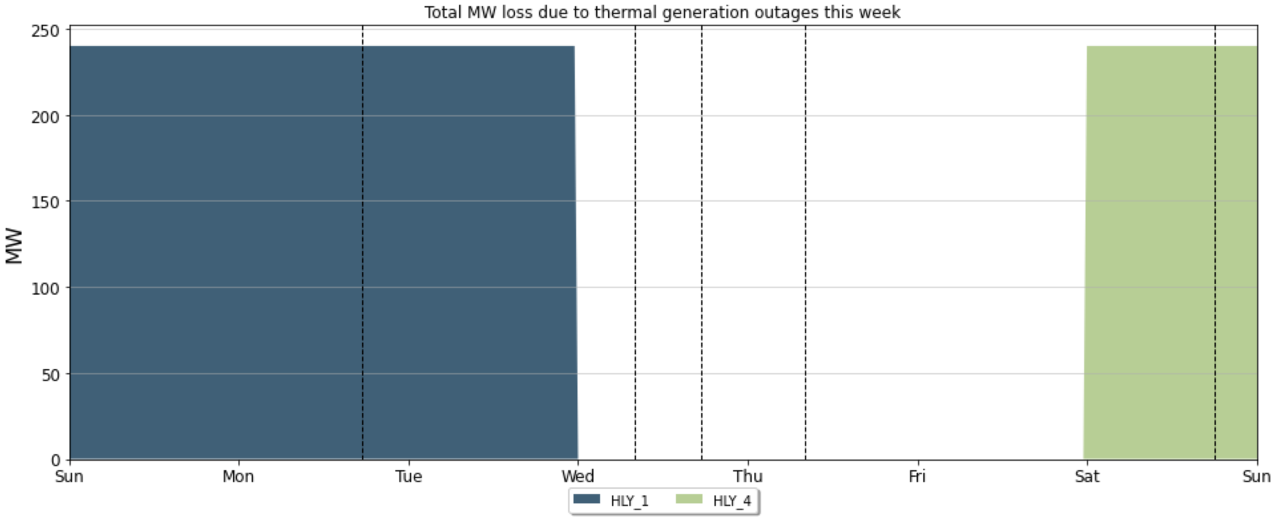
(d) West wind farm has a partial outage until November.

(e) Linton wind was on outage between Wednesday and Thursday.

(f) Various North and South Island hydro units were on outage this week.

Figure 9: Total MW loss due to generation outages.

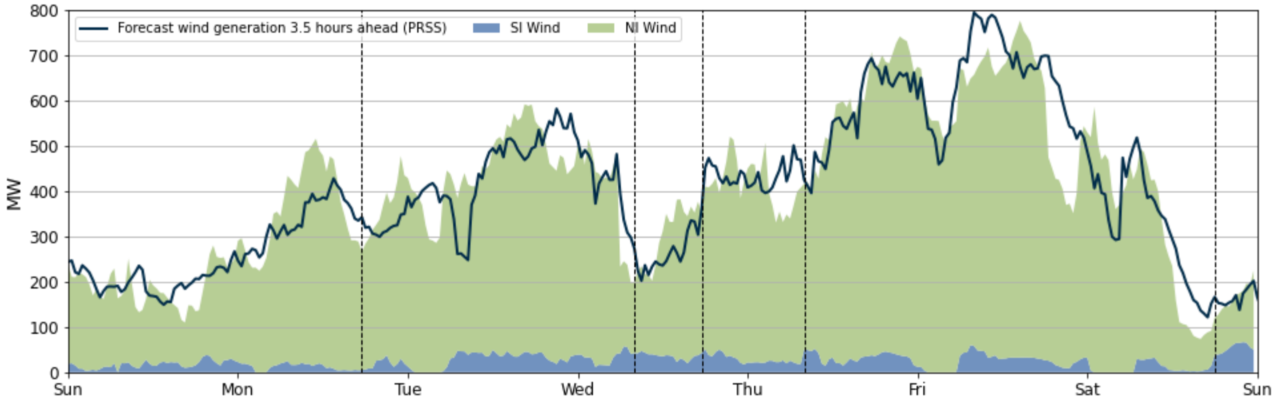




8. Generation

8.1. Wind generation, between 28 May – 3 June, varied between 75-775 MW (Figure 10). Wind generation was around 200 MW at the start of the week and increased to around 500 MW on Monday and peaked to 600 MW on Tuesday. West Wind farm had a partial outage and Linton wind was on outage between Wednesday and Thursday which contributed to lower wind generation. Wind started low around 200 MW on Wednesday and increased steadily, peaking at 775 MW on Friday. Wind dropped on Saturday to below 100 MW in the evening. Several of the price spikes this week occurred when wind generation had dropped by over 100MW.

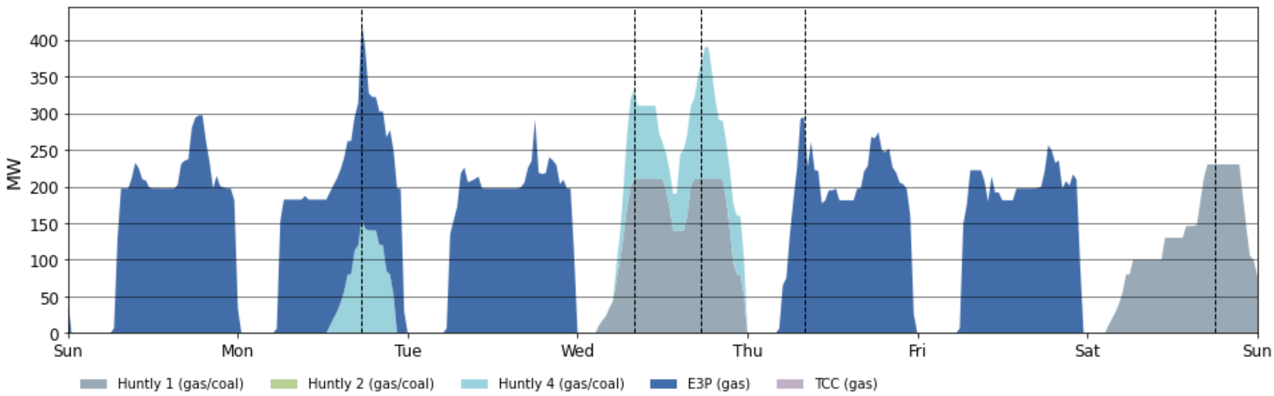
Figure 10: Wind Generation and forecast.

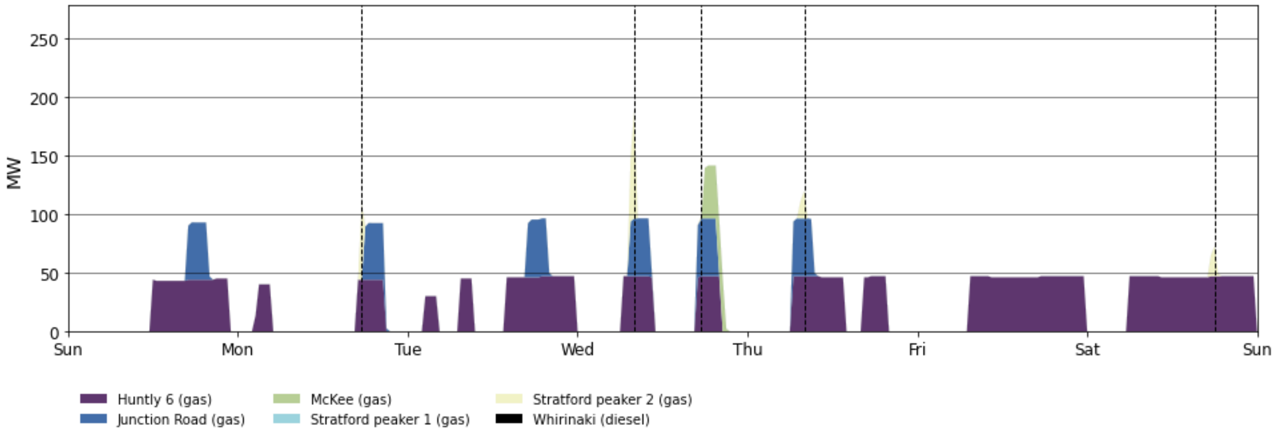


8.2. Figure 11 shows generation of thermal baseload and thermal peaker plants between 28 May – 3 June. E3P (Huntly 5) ran from Sunday to Tuesday, and on Thursday and Friday as baseload but did not run continuously through the night. Huntly 1, and 4 ran on Wednesday, and Huntly 1 ran on Saturday when E3P wasn't running. Huntly 4 also ran on Monday during the evening peak demand period.

8.3. Generation from thermal peakers was low this week, never reaching above 150 MW. Huntly 6 ran frequently this week, especially during peak and some shoulder periods. Junction Road ran during some peak periods between Sunday to Thursday. Stratford peaker 2 ran during Wednesday and Thursday morning peak and McKee only ran during the Wednesday evening peak.

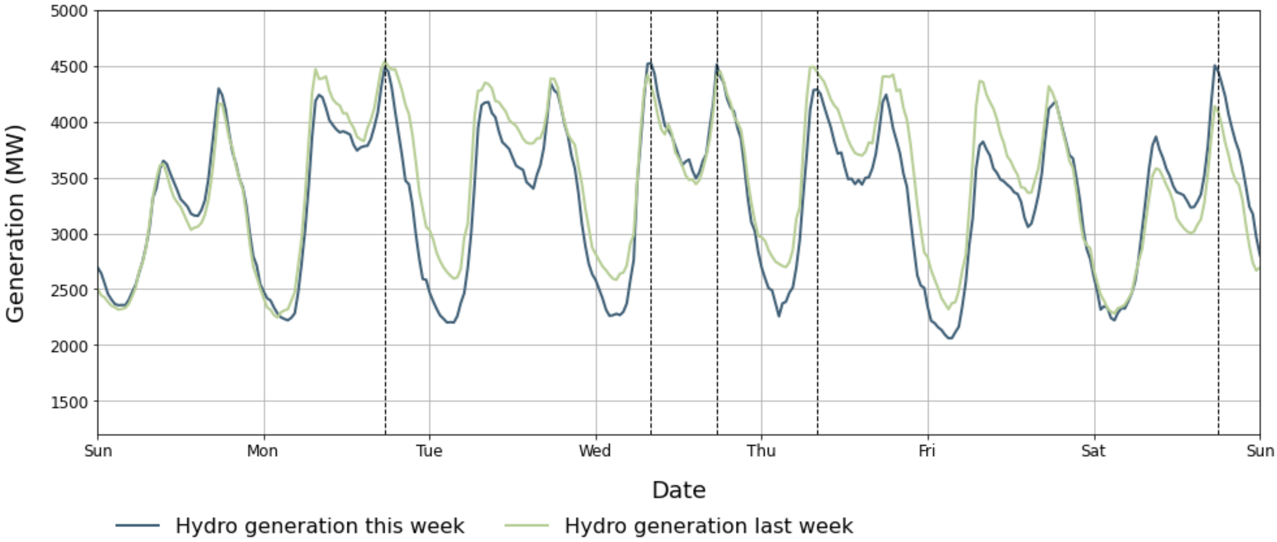
Figure 11: Thermal Generation.





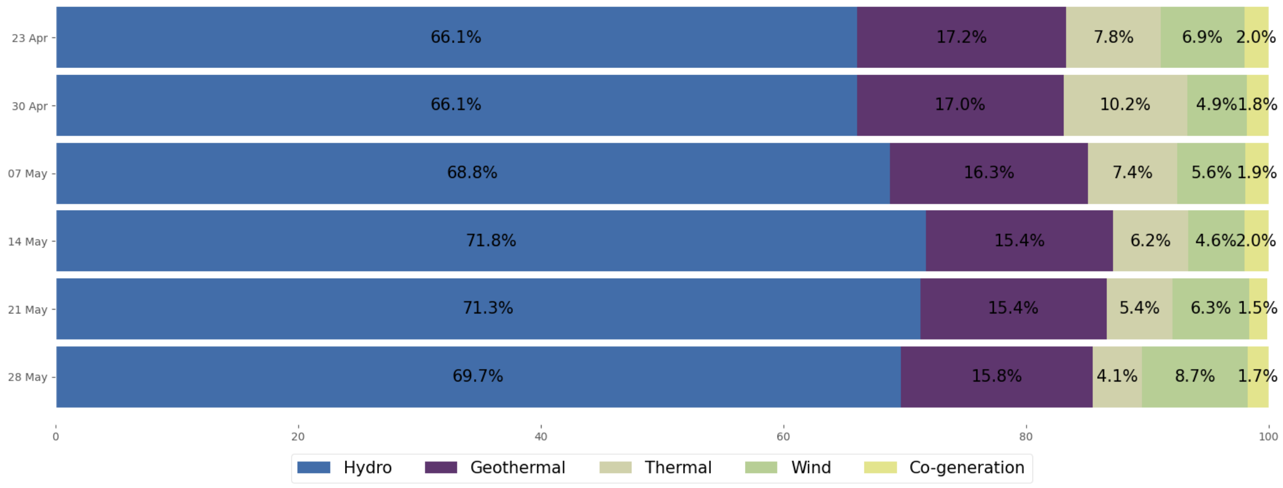
8.4. Figure 12 shows total hydro generation in MW produced each trading period, compared to the same time in the previous week. Hydro generation was slightly lower compared to the previous week, primarily driven by slightly lower demand. But in general hydro generation was high due to high lake levels.

Figure 12: Hydro generation between 28 May – 3 June compared to the previous week.



8.5. As a percentage of total generation, between 28 May – 3 June, total weekly hydro generation totalled 69.7 percent, geothermal 15.8 percent, thermal 4.1 percent, wind 8.7 percent, and co-generation 1.7 percent.

Figure 13: Total generation as a percentage each week between 23 April and 3 June 2023.



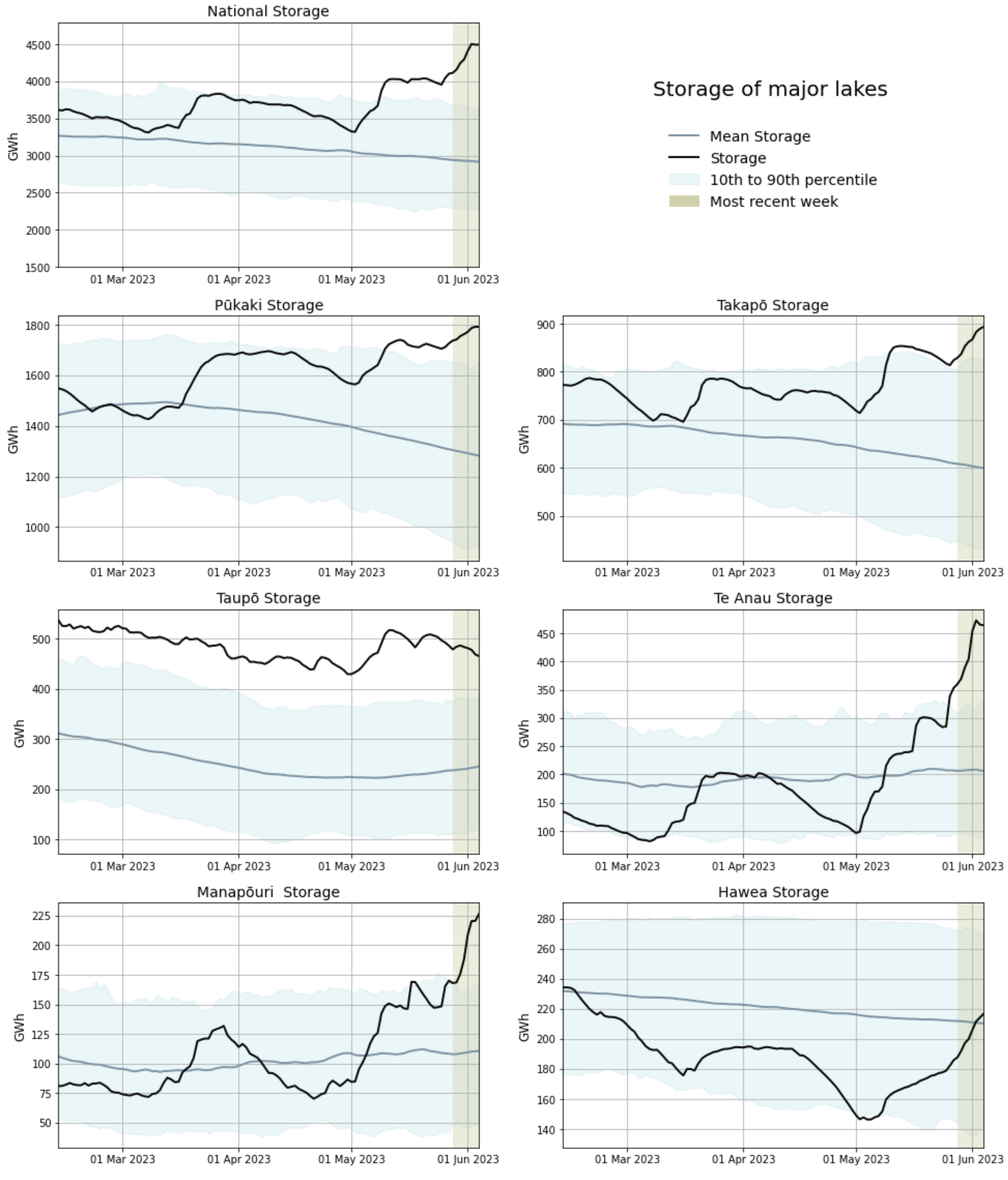
9. Storage/Fuel Supply

9.1. Figure 14 shows 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. Overall, national hydro storage increased over the week and is well above its historic 90th percentile. Total national storage is around 103.4 percent of nominal full as of 3 June.

9.3. All lakes are showing a significant increase in storage levels. Storage at lakes Pūkaki, Takapō and Taupō are above their respective historic 90th percentile. Lakes Te Anau and Manapōuri storage significantly increased with both also above its historic 90th percentile. High lake levels resulted in spill at lakes Pūkaki, and Manapōuri. Hawea storage also increased to slightly above its historic mean.

Figure 14: Hydro Storage.

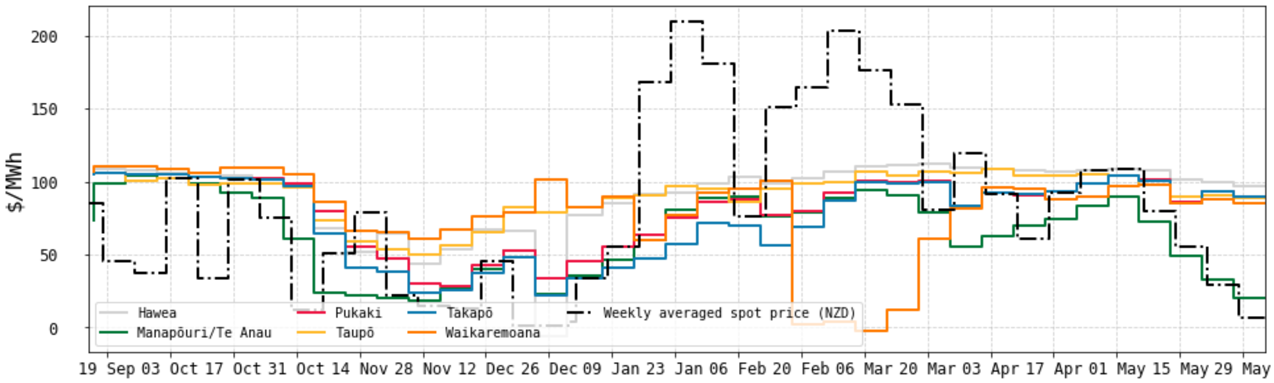


10. JADE Water Values

10.1. The JADE[1] 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 3 June 2023 using values obtained from JADE. 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. Since the beginning of February, the water values at most lakes have been relatively steady, with a small drop in March as lake levels rose. During the previous week, water levels in all lakes remained stable following a substantial increase in storage levels over the past couple of weeks. However, the water values at Te Anau and Manapōuri experienced a drastic drop following the recent increase in storage as both are above the 90th historic percentile.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 3 June 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 June 2023. The SRMC of diesel plants has significantly decreased from March, and the SRMC of gas-fuelled and coal plants has also slightly decreased. A reduction in carbon prices has contributed to the decline in SRMCs.

11.4. In early June, Indonesian coal stayed at around ~$466/tonne (NZD) putting the latest SRMC of coal-fuelled Huntly generation at ~$260/MWh.

11.5. The SRMC of Whirinaki has decreased to ~$508/MWh.

11.6. The SRMC of gas fuelled thermal plants decreased and is between $53/MWh and $80/MWh, likely due to a decrease in gas demand as well as carbon prices.

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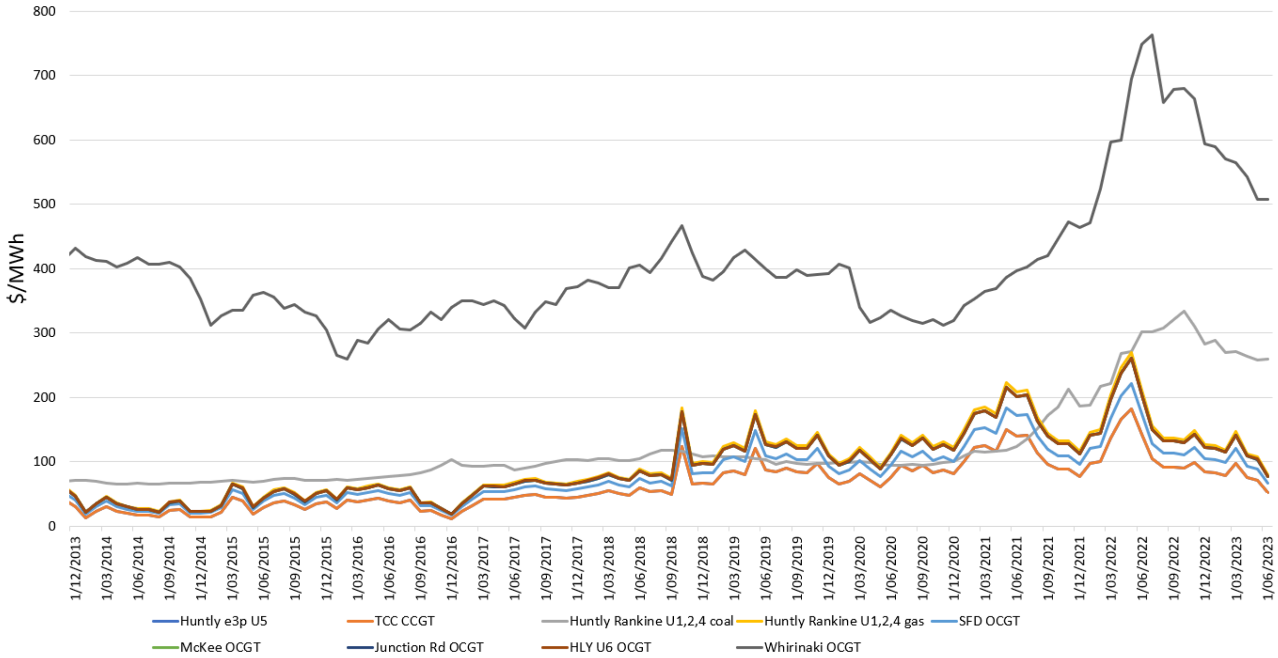
[1] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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

Figure 16: Estimated monthly SRMC for thermal fuels.

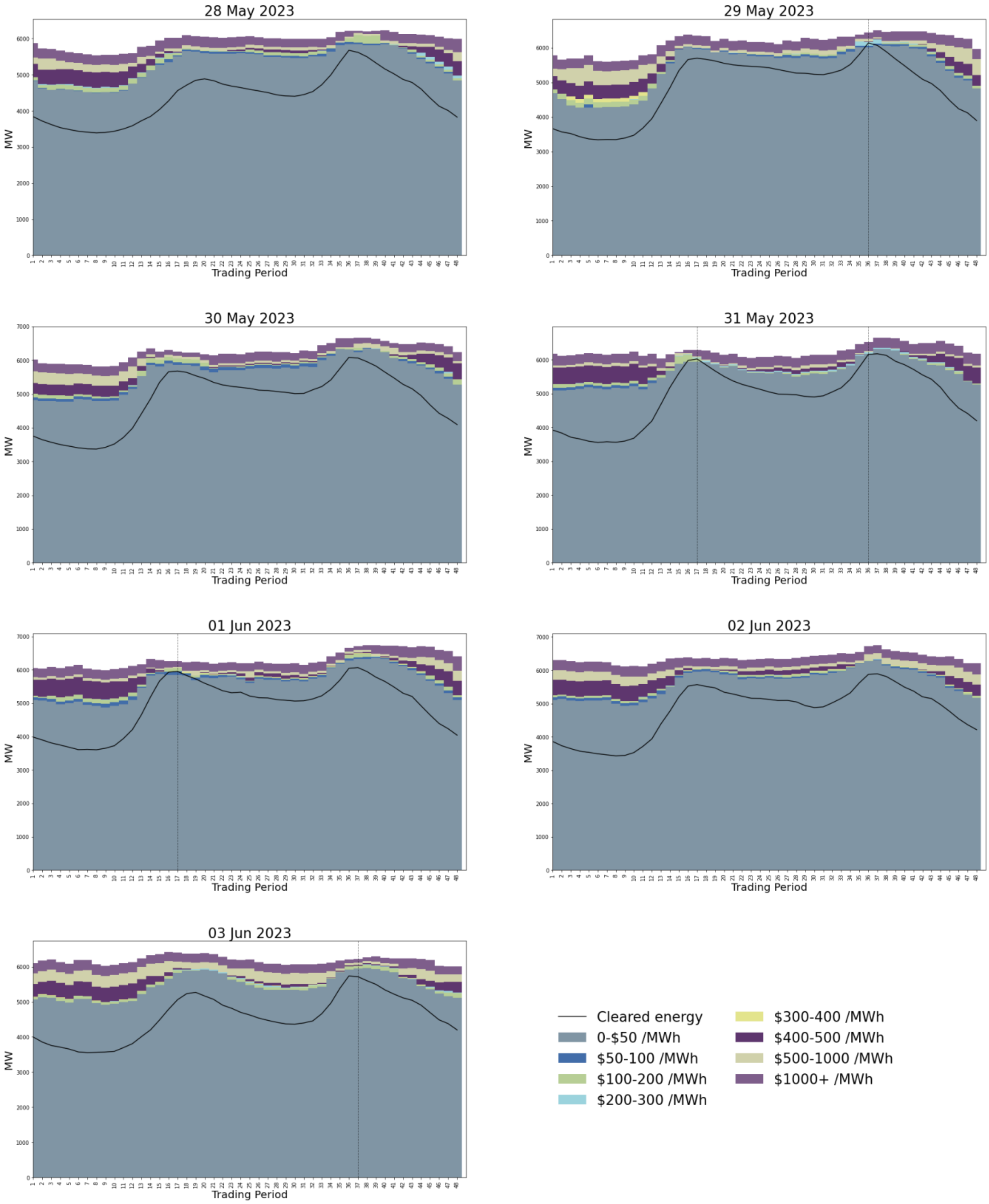


12. Offer Behaviour

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. There was a high quantity of generation offered between $0 and $50/MWh due to high hydro generation. As a result, the majority of cleared energy fell in this band. There was an increase in offers during the peak demand periods but the stack remained thin above $100/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. However, there appear to be offer changes/market conditions in the previous weeks which may have resulted in instances of higher prices. These are being looked into 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	Further analysis	N.A.	Multiple	High energy prices associated with high hydro offers.
17/4/2023	48	Further analysis	Contact	Clyde and Roxburgh.	Offer changes.
19/4/2023	27	Further analysis	Contact	Clyde and Roxburgh.	Offer changes.
11/5/2023	37-40	Further analysis	Genesis	Huntly 4	Offer changes.
15/5/2023	36-37	Further Analysis	Genesis	Huntly 2,4,5	Offer changes.
18/05/2023	Several	Further Analysis	N.A.	Multiple	Market conditions which led to higher off-peak prices.
22/05/2023	36	Further Analysis	System Operator	McKee	Grid configuration which resulted in McKee not being dispatched.