Date: 12 June 2023

ELECTRICITY AUTHORITY
TE MANA HIKO

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 4 – 10 June 2023

1.1. This week once again saw increased price volatility, with the majority of prices very low due to high hydro storage and generation, but significant price spikes occurring when additional thermal generation was necessary to meet high demand. The highest prices occurred on Tuesday, when demand was particularly high, and two Rankine units were on outage. There were also very high prices on Thursday and Friday, when wind generation was lower, and when less reserve was available, resulting in higher energy prices.

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 with black dashed lines.

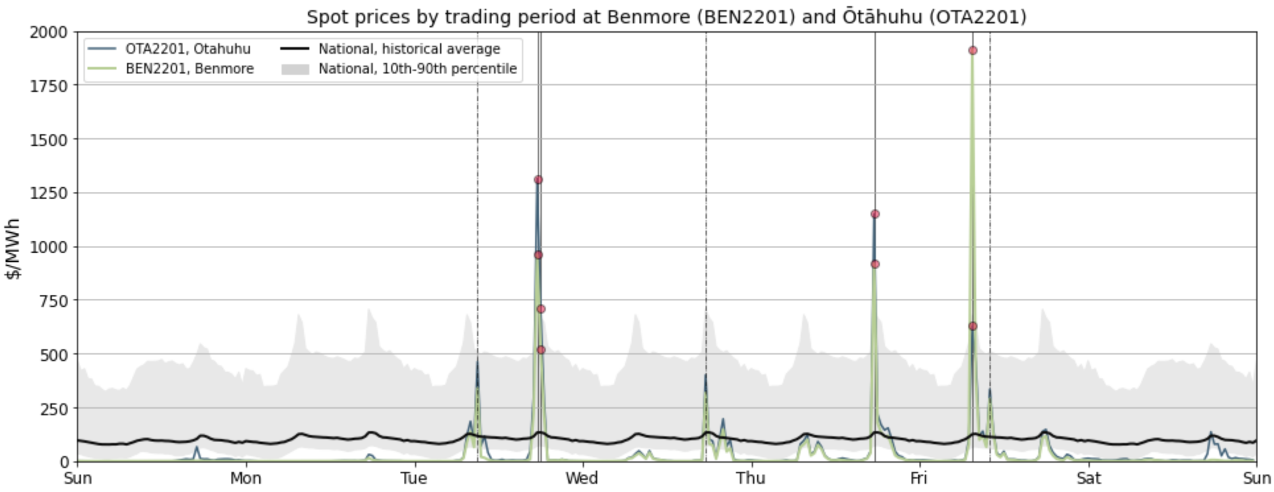
2.2. Between 4 – 10 June:

(a) The average wholesale spot price across all nodes was $31.69/MWh.

(b) 95 percent of prices fell between $0.01/MWh and $277/MWh.

2.3. Overall, most spot prices fell below the historic 10th percentile again with the middle 50% of prices between $0.27/MWh and $9.88/MWh. The average price increased around $26/MWh from $6/MWh, primarily driven by the high price spikes.

Figure 1: Wholesale Spot Prices between 4 (Sunday) – 10 June (Saturday) 2023.



2.4. On 6 June there were two price spikes, the first was at 9.00am during morning peak and was above the historic average but below the 90th percentile. The price at Benmore was $339/MWh and the price at Ōtāhuhu was $462/MWh. At 5.30pm there was a much larger spike that saw the price at Benmore reach $960/MWh and the price at Ōtāhuhu reach

$1,313/MWh. Demand was particularly high, and wind was about 100MW lower than forecast which resulted in additional thermal generation being dispatched. There was also a high price of $522/MWh at Benmore and $708/MWh at Ōtāhuhu at 6.00pm.

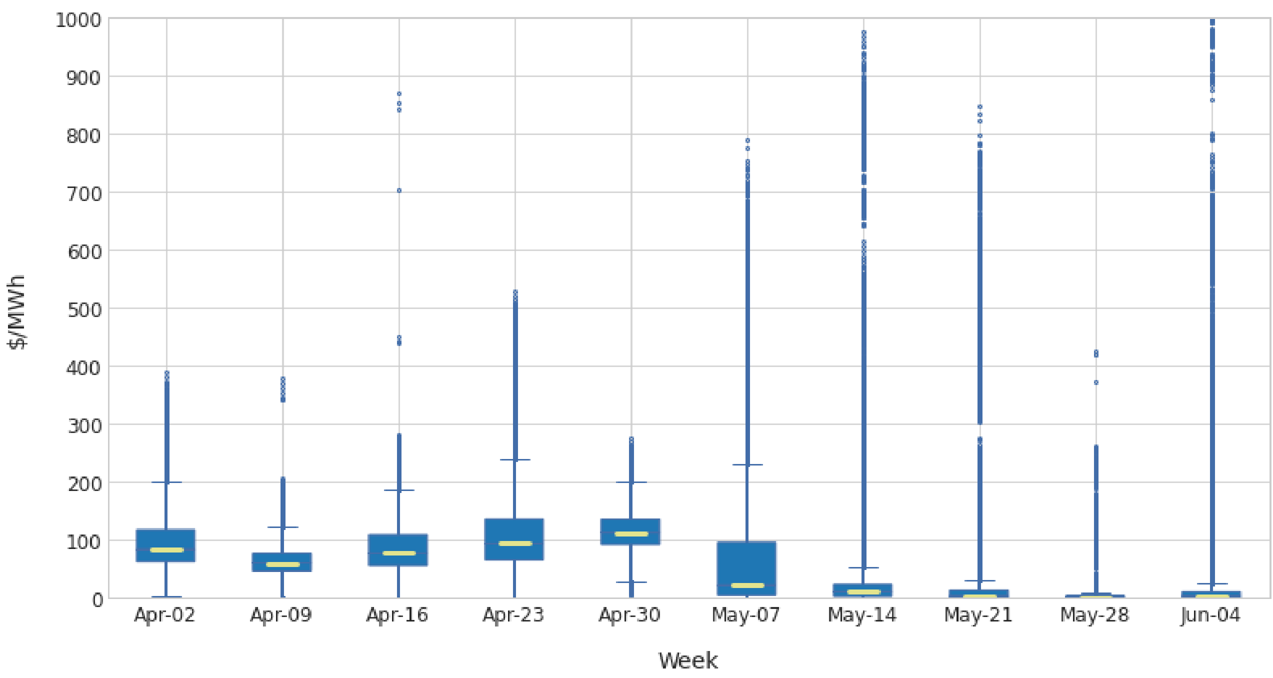
2.5. The next big price spike occurred on 8 June at 5.30pm that saw a price at Benmore of $920/MWh and $1150/MWh at Ōtāhuhu. This coincided with a large ramp down of the HVDC northward flow. Wind generation during this time had dropped below the forecast, meaning more peakers were required to cover demand requirements.

2.6. 9 June saw prices at certain South Island nodes peak at over $10,000/MWh, with a price separation occurring between the islands. At 7.30am the price at Benmore was $1915/MWh and the price at Ōtāhuhu was $630/MWh. This coincided with a large ramp down of the HVDC northward flow, which occurred due to a drop in available North Island reserve. Ramp down constraints then caused temporary scarcity to occur in the South Island. There was also a smaller price spike at around 10:00am where the price at Benmore was $290/MWh and the price at Ōtāhuhu was $335/MWh.

2.7. 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.

2.8. This week, the median and upper quartile prices were higher than last week, but still low compared to most prices seen during April and early May. This decline is primarily due to the substantial hydro storage and generation. Demand was higher this week than last week which resulted in an increase in unusually high prices which was also seen in early May.

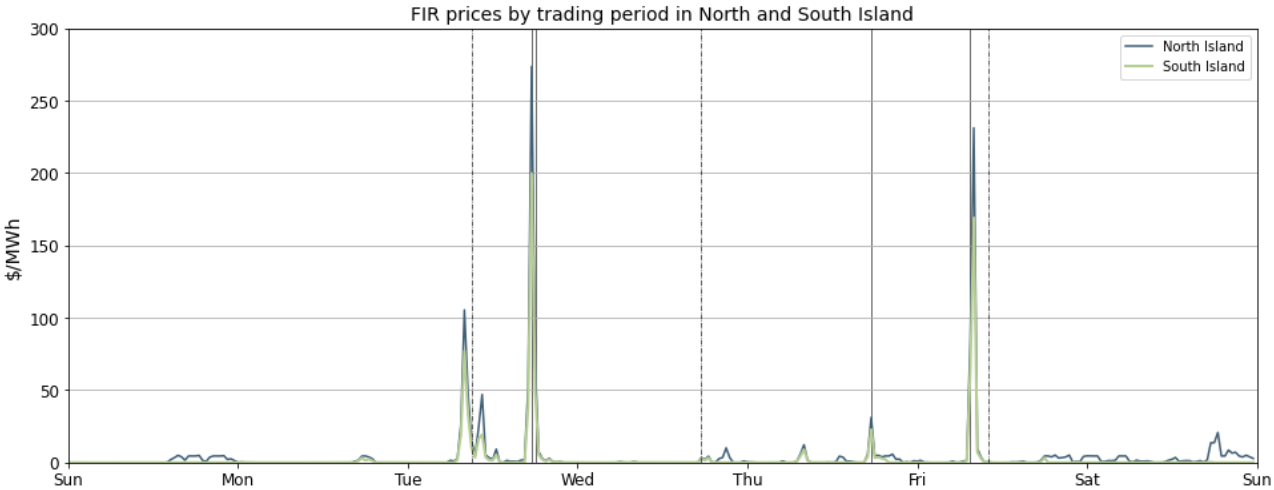
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks.



3. Reserve Prices

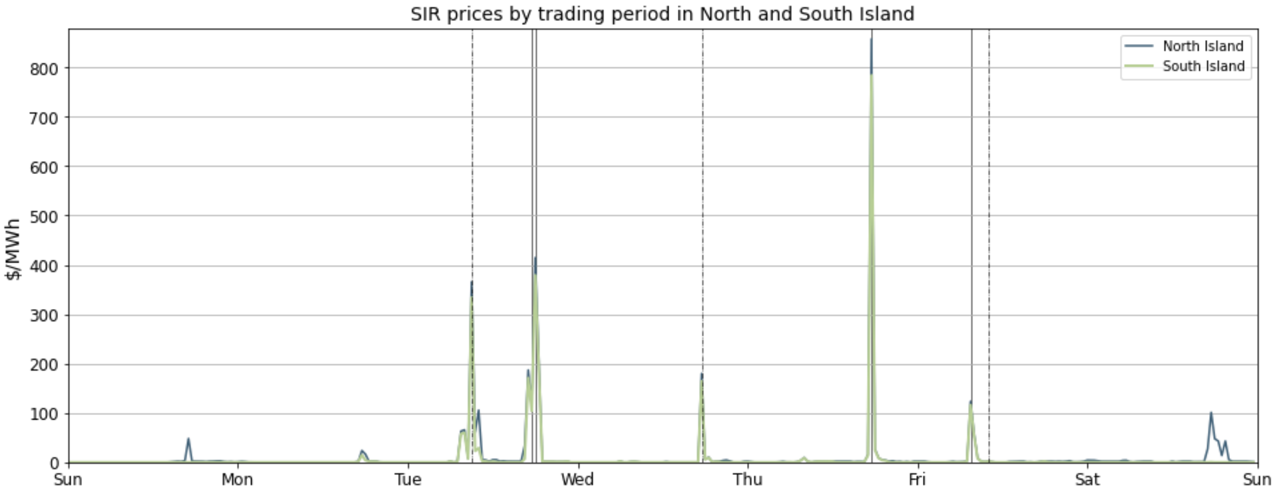
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week the FIR prices were mostly below $5/MWh for both islands with a few instances of price spikes. The highest FIR price occurred on 6 June 2023 at 5:30pm, with the price reaching $274/MWh in the North Island and $200/MWh in the South Island. This coincided with high energy prices and was caused by a tight market. There was also a high FIR price on Friday morning, reaching $231/MWh in the North Island and $169/MWh. This was due to a drop in available interruptible load, which required additional reserve to be acquired from generators.

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 mostly below $5/MWh this week, with occasional price spikes. The highest SIR price occurred on 8 June at 17:30, which the North Island price reached $858/MWh in the North Island and $784/MWh in the South Island and coincided with the highest energy prices. During this trading period the 5-minute price reached $3000/MWh in the North Island, indicating reserve scarcity.

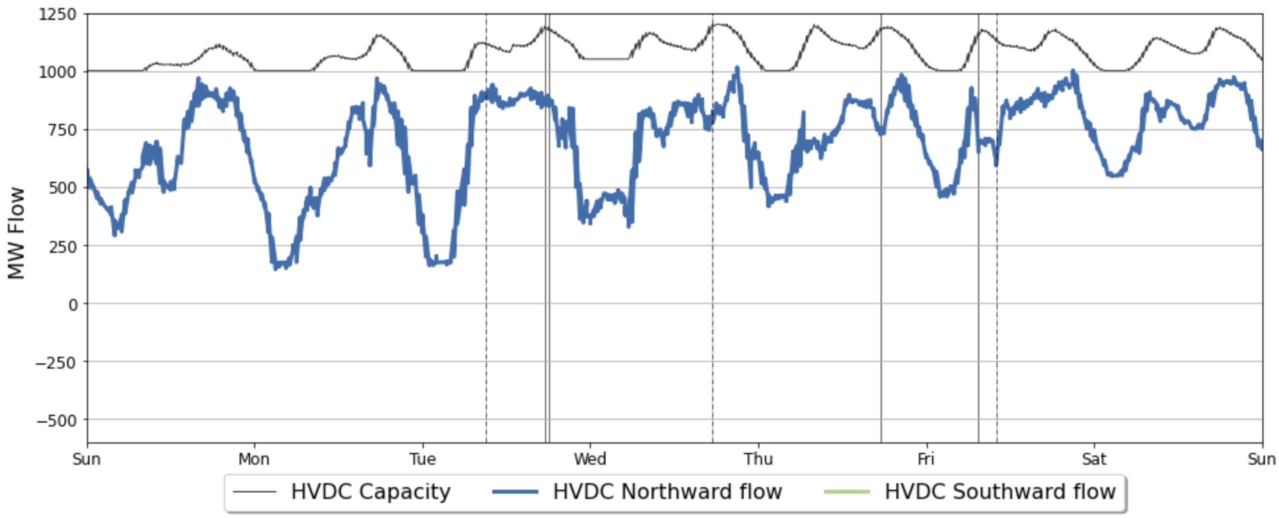
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and Island.



4. HVDC

4.1. Figure 5 shows HVDC flow between 4 – 10 June, which were northwards for the whole week. HVDC flows were relatively high during the day, due to high hydro generation in the South Island. The high prices on 8 and 9 June both coincided with a drop in the northward flow across the HVDC. This was due to a drop in available reserve in the North Island, which required additional North Island generation to be dispatched to meet reserve requirement and therefore less generation was required from the South Island

Figure 5: HVDC northward flow and capacity.

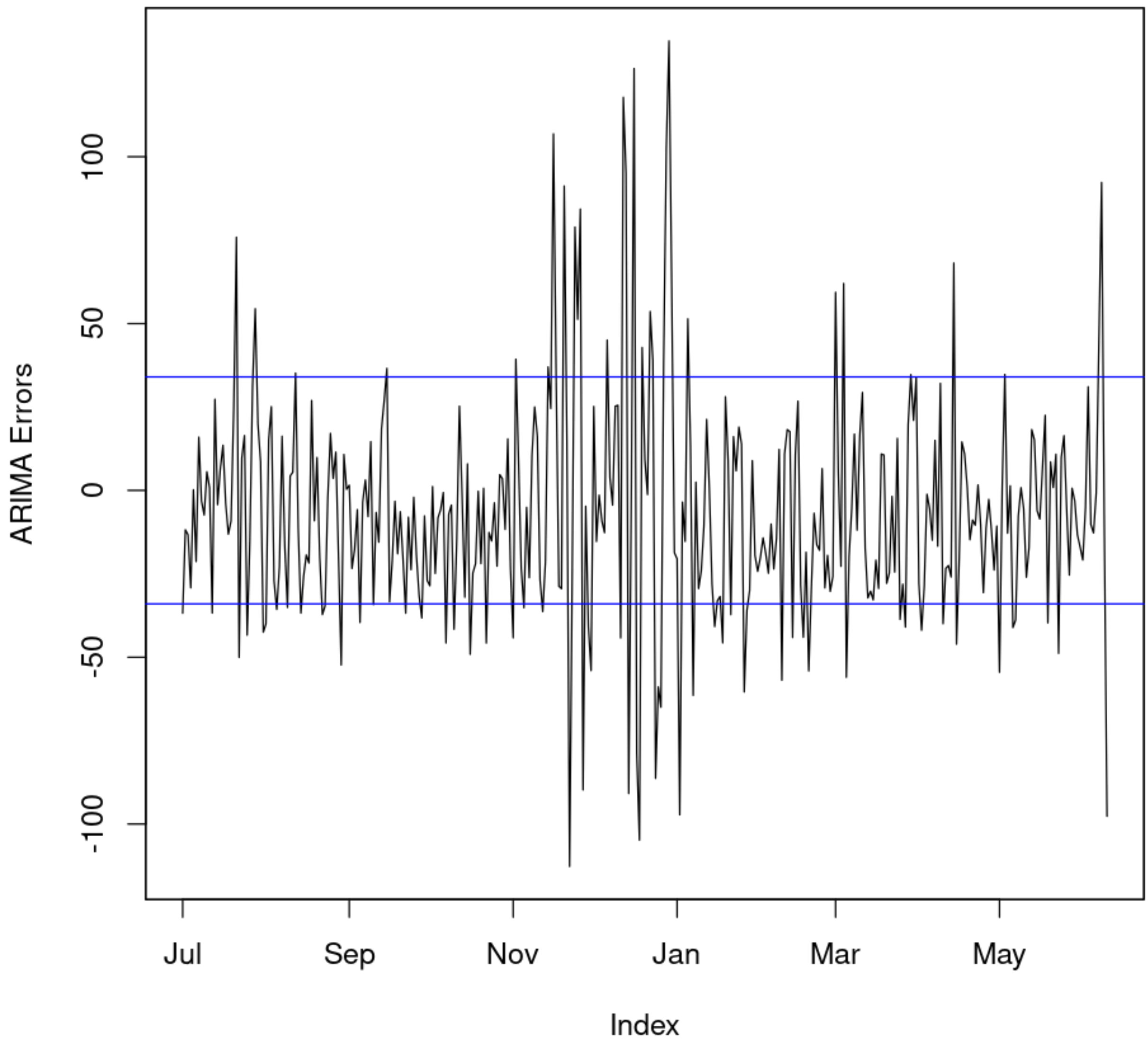


Regression Residuals

4.2. 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.

4.3. 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 above and one below one standard deviation of the data on Thursday and Saturday respectively. The large residual on Thursday was due to the price spikes which increased the average daily price above the model's estimate, while in comparison prices remained low all day on Saturday, leading the model to overestimate prices.

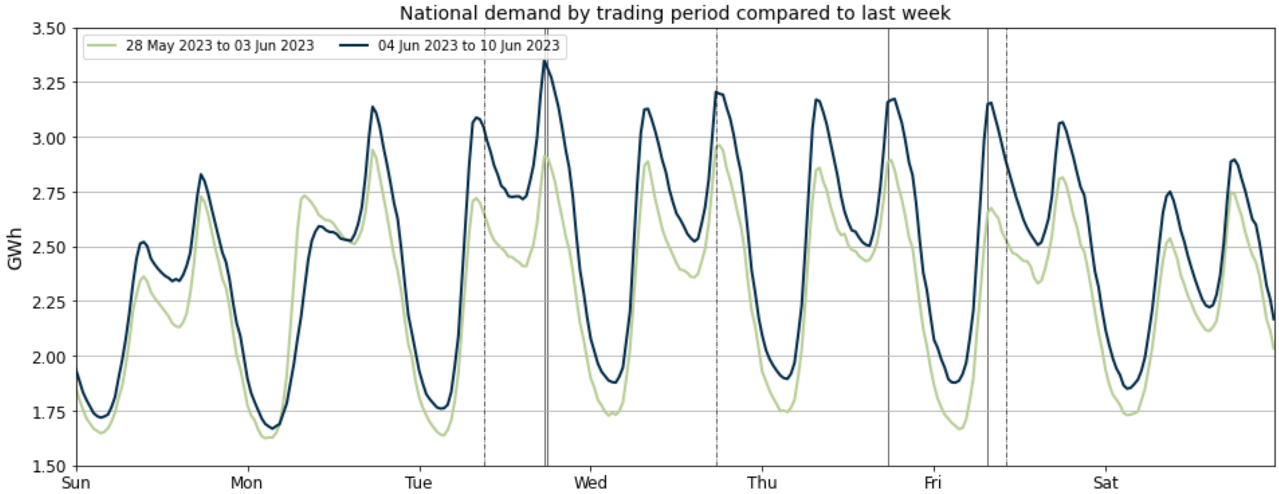
Figure 6: Residual plot of estimated daily average spot prices from 1 July 2022 – 10 June 2023. The blue lines show two standard deviations of the ARMA errors.



5. Demand

5.1. Figure 7 shows national grid demand between 4 – 10 June, compared to the previous week. Overall, demand increased compared to the previous week as temperatures dipped across the country. Weekday morning and afternoon peaks were above 3GWh with the highest evening peak on Tuesday of around 3.35GWh in line with the price spike at 5.30pm.

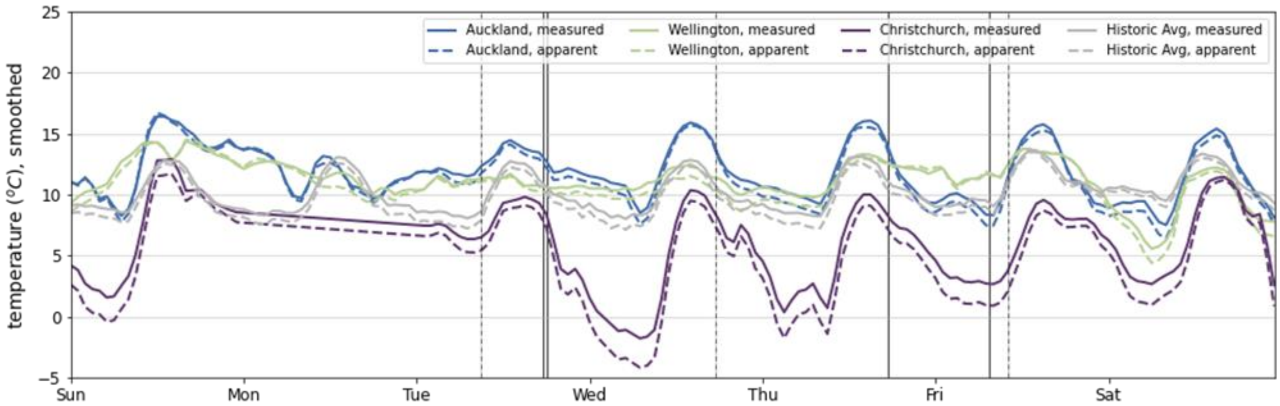
Figure 7: National demand by trading period compared to the previous week.



5.1. Figure 8 shows hourly temperatures at the three main population centres between 4 – 10 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.

5.2. Temperatures have begun to drop across the country with winter officially arriving. In Auckland temperatures were around or above average, ranging from around 6 to 17 degrees across the week. Wellington was similar with temperatures around the average, with the highest temperature of the week around 13 degrees. Christchurch saw the coldest temperatures ranging between -4 degrees and 11 degrees. Note that Monday's temperature data is missing for Christchurch.

Figure 8: Temperatures across main centres.



6. Outages

6.1. Figure 9 shows generation capacity on outage. Total capacity on outage between 4 – 10 June 2023 ranged between ~900MW and 1300MW.

6.2. Notable outages include:

(a) Huntly 4 was on outage from 3 – 11 June.

(b) Huntly 1 had various outages over the week; 4 - 5 June, 5 – 6 June, 7 June.

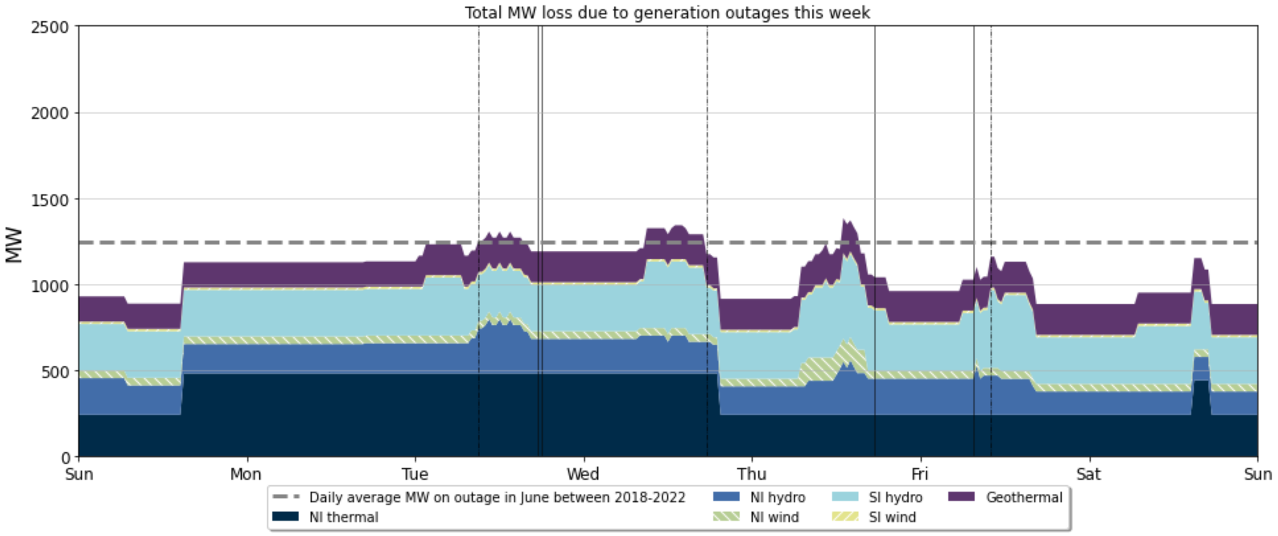
(c) Stratford station was on a short outage 10 June in the afternoon.

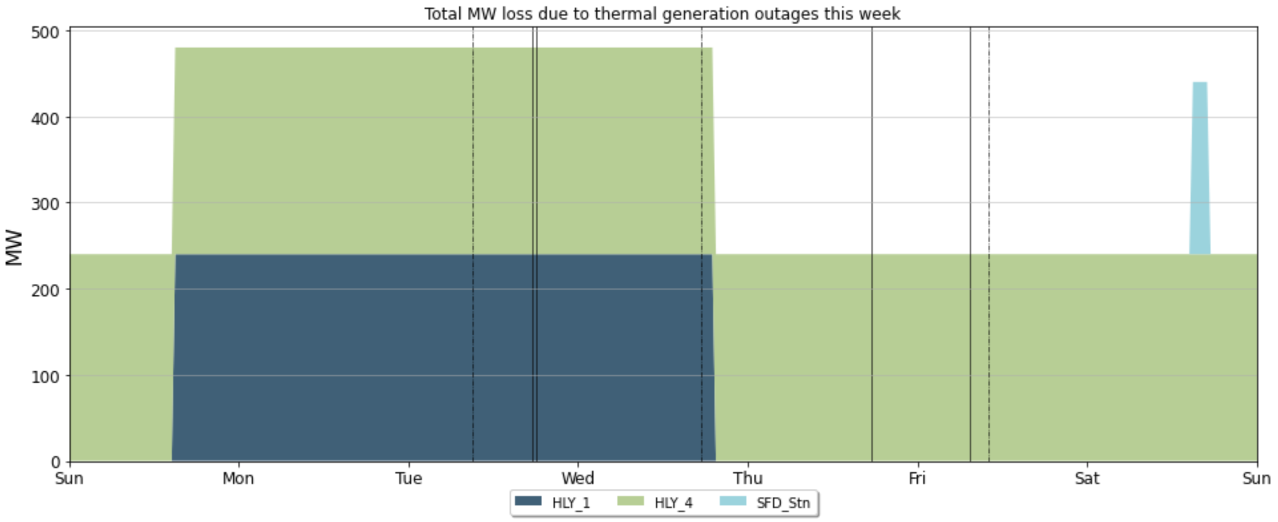
(d) Kawerau geothermal unit remains on outage until 14 June.

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

(f) West Wind is on outage until 24 November.

Figure 9: Total MW loss due to generation outages.



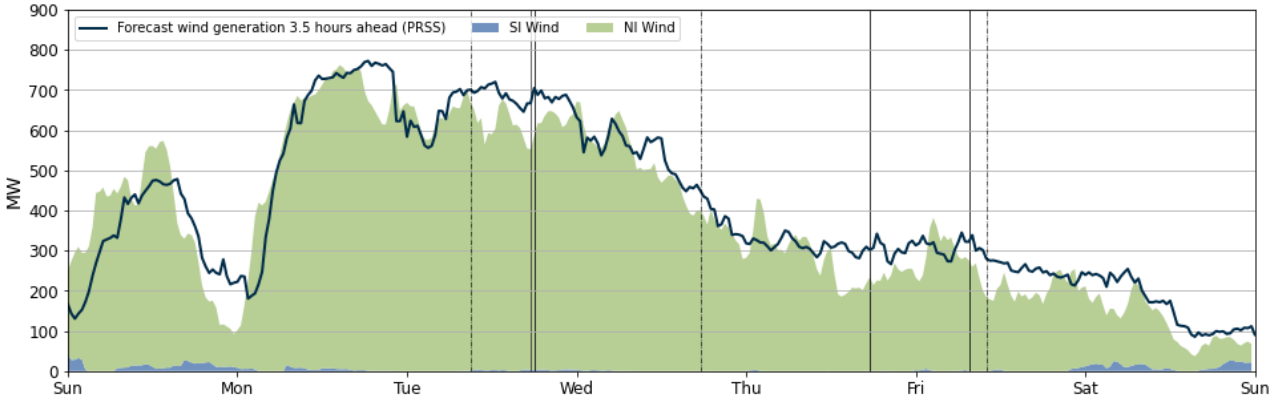


7. Generation

7.1. Figure 10 shows wind generation, from 4 – 10 June, ranged from ~37 MW to ~762 MW across the week. Wind generation was high from Sunday to Wednesday with generation above 400 MW except a drop off on Sunday evening. From Thursday onwards generation dropped to between 200 – 300 MW.

7.2. Several of the price spikes this week coincided with wind generation that was more than 50MW lower than forecast. This would have contributed to high prices when the market was already tight as it would have required additional generation to be dispatched to make up for the shortfall in wind generation.

Figure 10: Wind Generation and forecast.

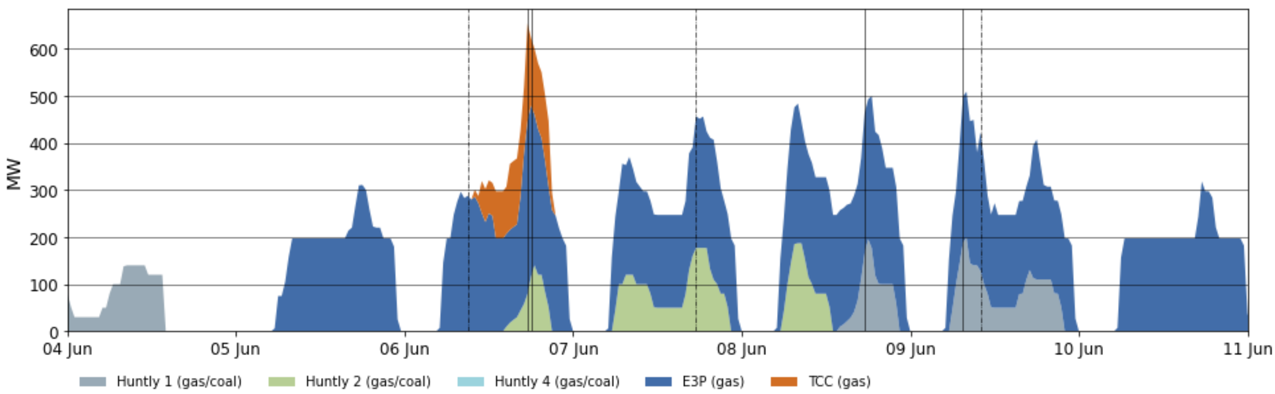


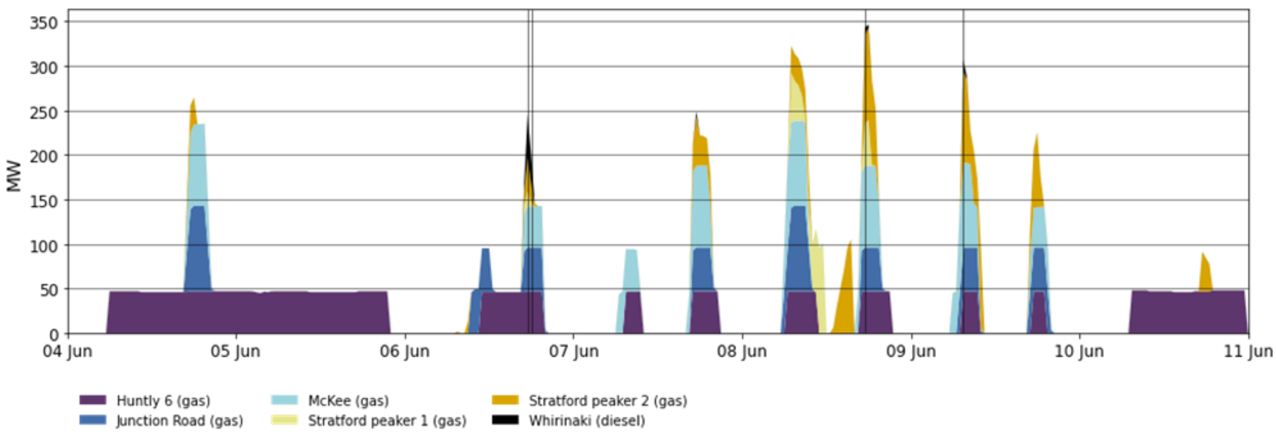
7.3. Figure 11 shows the generation of thermal baseload and thermal peaker plants between 4 – 10 June. E3P (Huntly 5) ran over the peak and shoulder periods from Monday to Saturday, again not running continuously likely due to the high hydro generation and sufficient wind during the week. Huntly 1 ran on Sunday morning and then again on Thursday afternoon and during the day Friday. Huntly 2 ran on Tuesday evening, Wednesday, and Thursday morning.

7.4. TCC ran from the morning peak through to the evening peak on Tuesday. This is the first time it has run since its brief appearance at the beginning of May. It may have generated due to the CAN notice issued the previous week indicating a potential NZGB shortfall on 7 June, or as a test after returning from outage (or a combination of both). Low prices due to high hydro generation are likely reasons for TCC not being turned on fully.

7.5. All thermal peakers came on at some stage last week. Huntly 6 ran every day, with it running continuously from Sunday morning through to Monday evening. High demand morning and evening peaks saw Junction Road, McKee and both Stratford units running on Thursday. Whirinaki also ran for a short time during Tuesday to Thursday evening peaks and Friday morning peak. Some of the peakers dispatched on Thursday evening and Friday morning were needed to provide reserve due to a drop in available interruptible load.

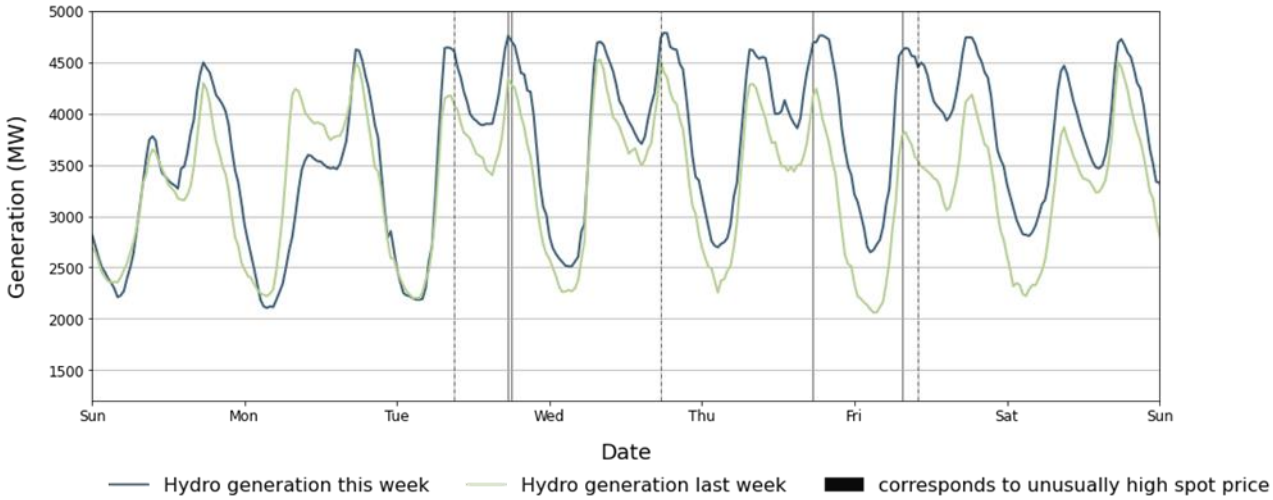
Figure 11: Thermal Generation.





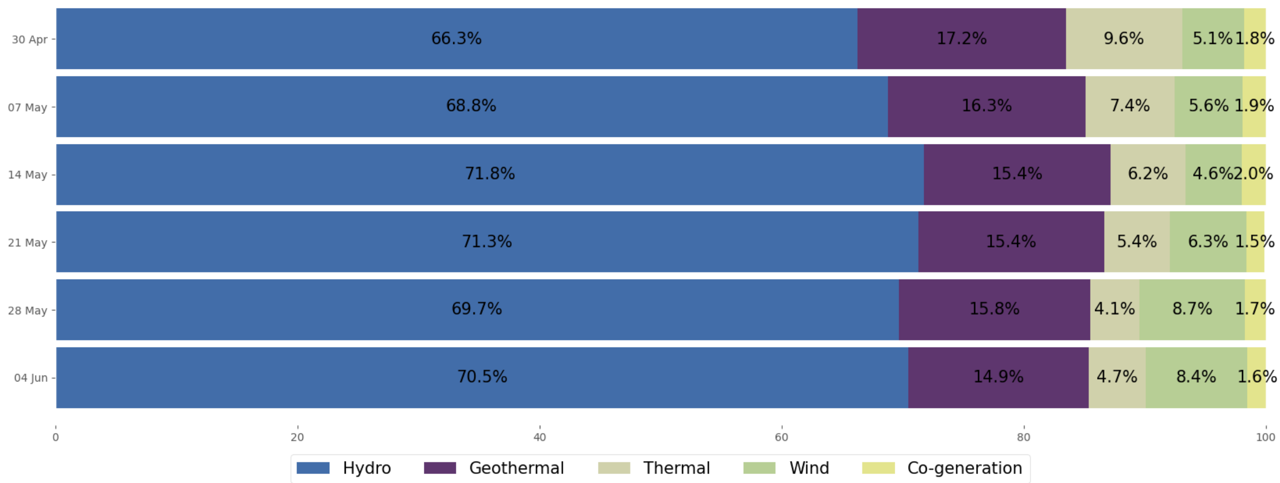
7.6. Figure 12 shows hydro generation between 4 – 10 June. Hydro generation increased compared to the previous week in line with the increased demand.

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



8.5. As a percentage of total generation, between 4 – 10 June, total weekly hydro generation was 70.5 percent, geothermal 14.9 percent, thermal 4.7 percent, wind 8.4 percent, and co-generation 1.6 percent. Thermal generation was higher than last week, but still lower than previous weeks due to both high hydro and high wind.

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



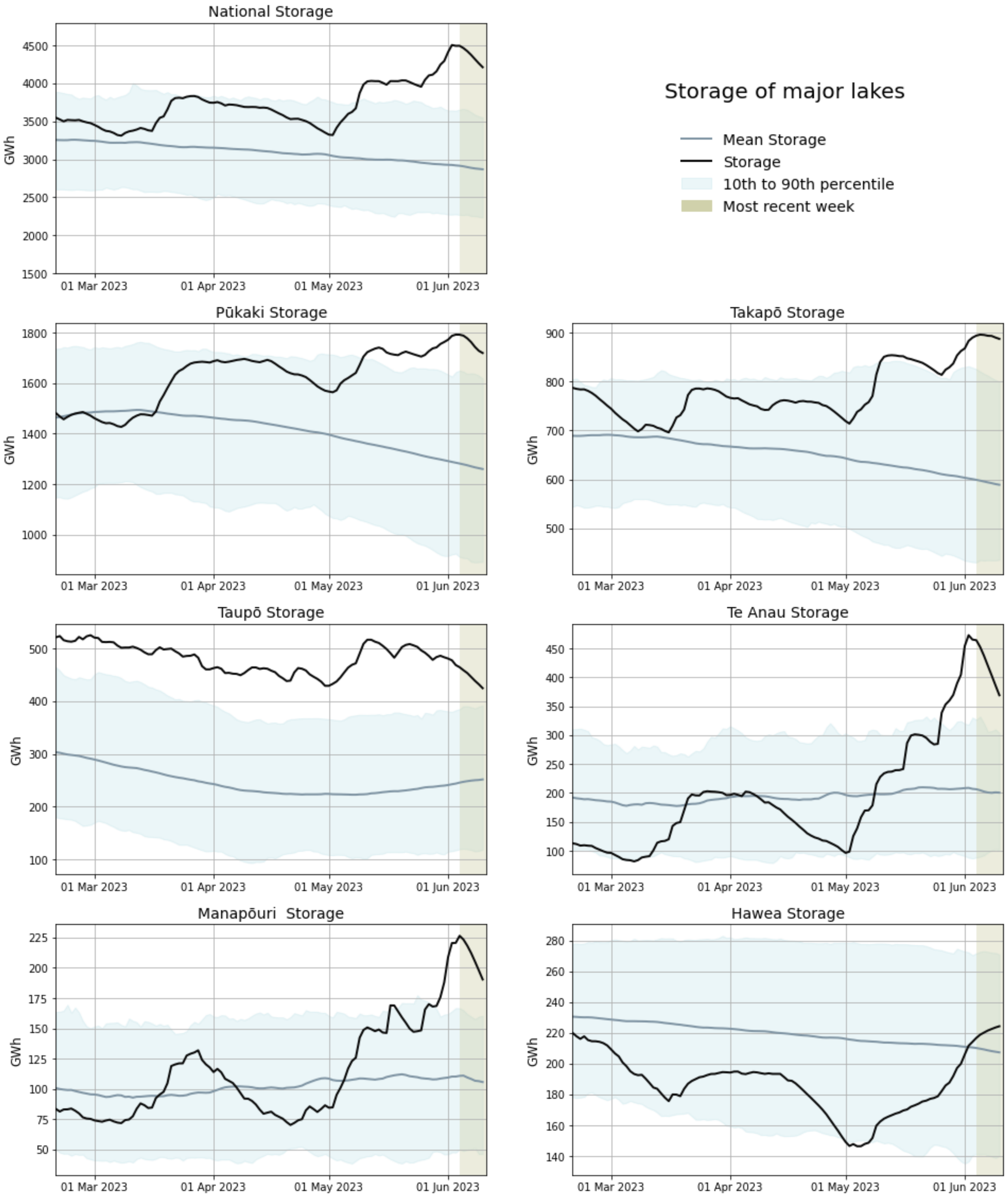
8. Storage/Fuel Supply

8.1. Figure 12 shows total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10^{th} to 90^{th} percentiles.

8.2. National hydro storage levels have decreased this week. However, controlled storage is still high at 98.6 percent of nominal full as of 10 June.

8.3. All lakes levels decreased this week, except Hawea which has had a steady increase, remaining above its historic mean. Taupō remains above its historic 90^{th} percentile at over 400GWh storage. Pūkaki and Takapō have been steadily decreasing but still remain above their 90^{th} percentiles. The steepest drop in lake levels was at Manapōuri and Te Anau, although these lakes also remain above their historic 90^{th} percentile. A combination of drier weather conditions, spilling and high hydro generation are the reasons for this week's drop in storage levels.

Figure 12: Hydro Storage.



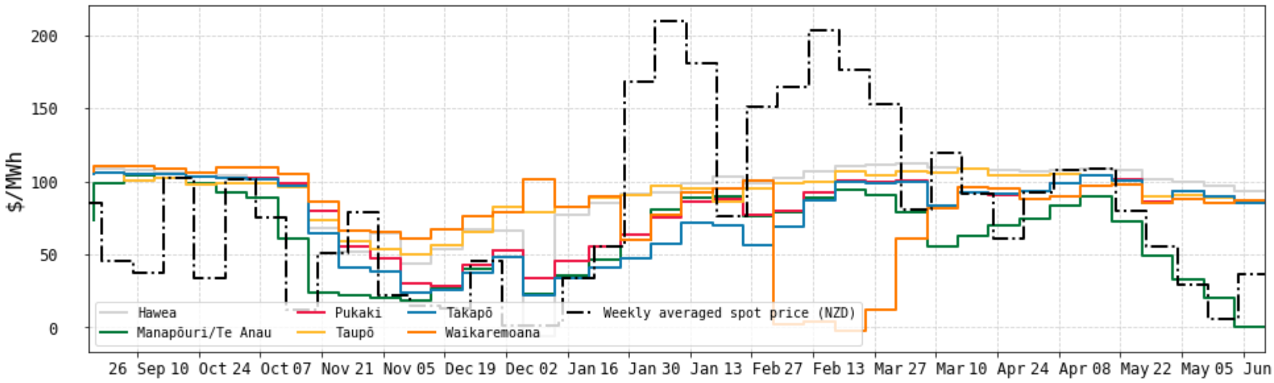
9.

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 13 shows the national water values between 15 September 2022 and 10 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 13: JADE water values across various reservoirs between 15 September 2022 and 10 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 14 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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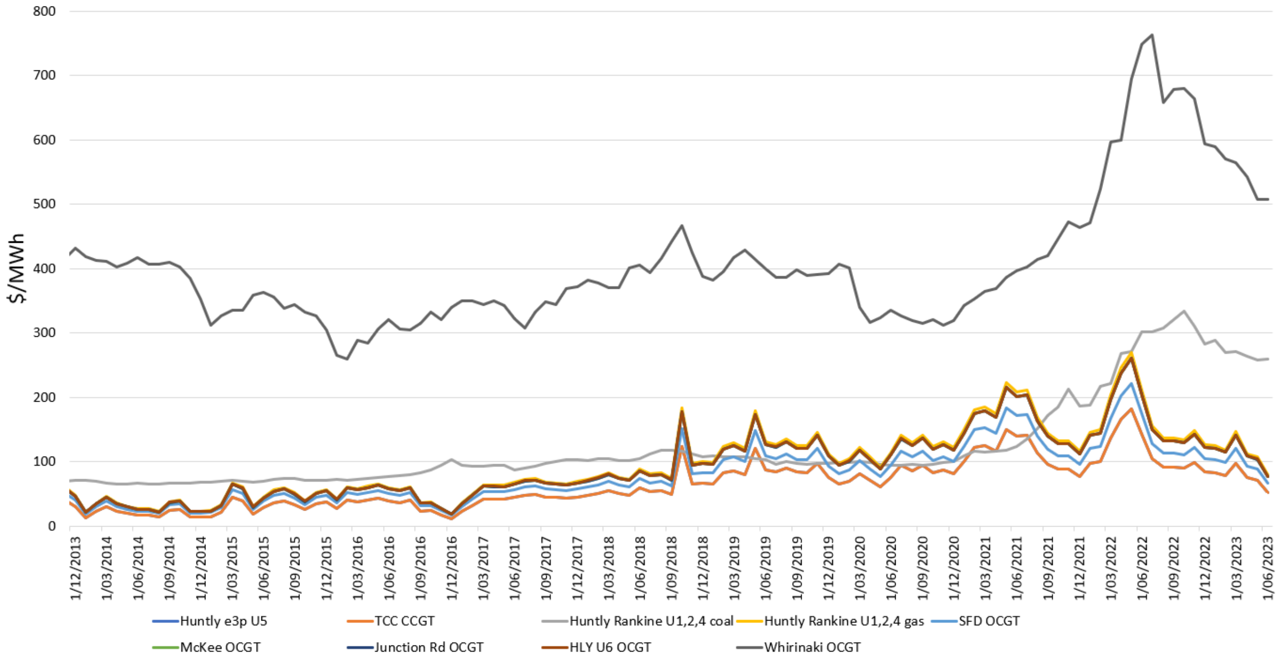
[1] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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 14: Estimated monthly SRMC for thermal fuels.

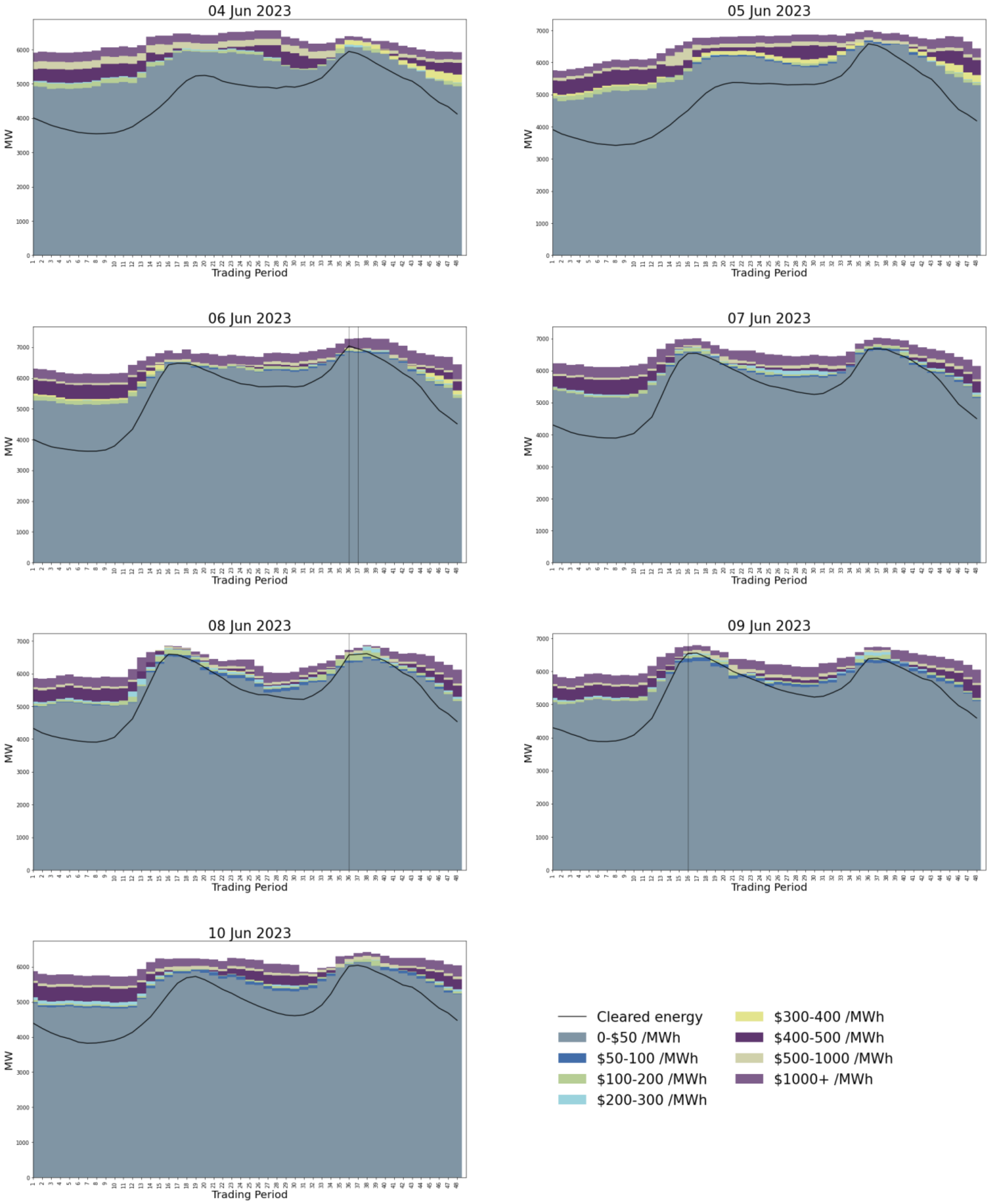


12. Offer Behaviour

12.1. Figure 15 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 continues to be a high quantity of generation offered between $0 and $50/MWh due to high hydro storage. As a result, most of the cleared energy fell in this band. As hydro storage fell there was a small increase in the quantity of generation offered between $50-100/MWh and $100-200/MWh towards the end of the week. However, the stack remains thin above the $50/MWh, contributing to volatile prices.

Figure 15: 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.
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.