22 April 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 14-20 April

1.1. Spot prices declined slightly this week, with most prices between $127-$233/MWh. Price separation occurred on Saturday due to a planned HVDC Pole 3 outage. During the HVDC outage, North Island prices were mainly above $400/MWh. Hydro storage increased this week and is now at ~102% of its historical average. The proportion of thermal generation decreased this week due to the increase in the proportion of hydro and wind generation.

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. Between 14-20 April:

(a) The average wholesale spot price across all nodes was $177/MWh.

(b) 95% of prices fell between $0.01/MWh and $310/MWh.

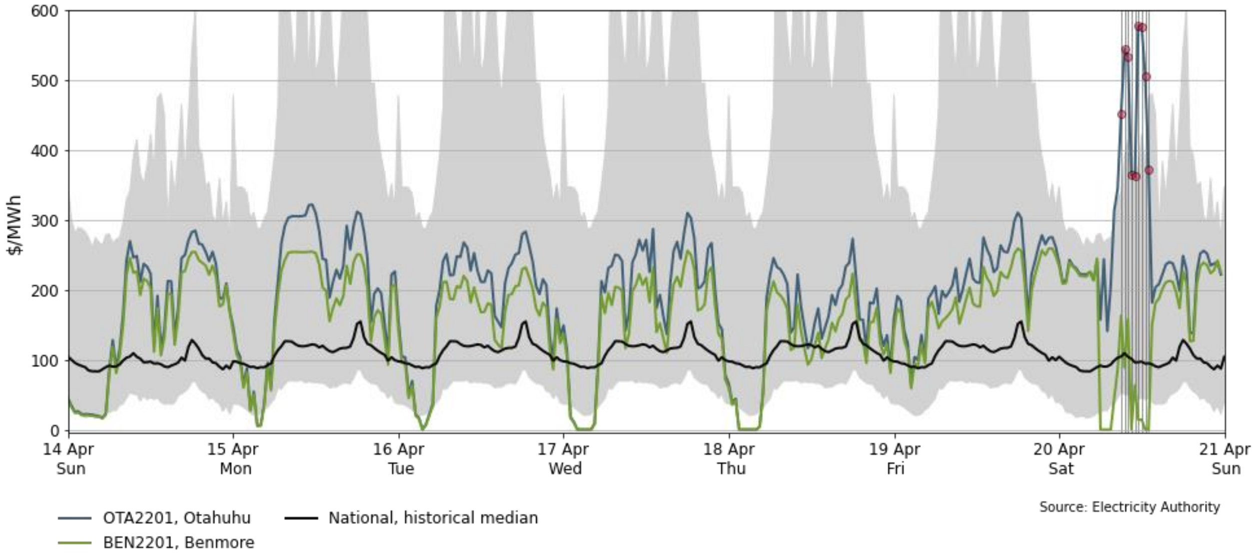
2.3. This week, the majority of the spot prices were above the national historical median. However, prices decreased compared to the previous week with the average price decreasing around $52/MWh. High wind generation along with sufficient hydro storage kept midweek overnight prices low.

2.4. The HVDC Pole 3 outage on Saturday caused prices to separate between islands, with Ōtāhuhu prices mainly above $400/MWh and around $200-$500/MWh higher than Benmore at this time. The highest price occurred during the 11.30am-12.00pm trading periods with Ōtāhuhu prices reaching ~$578/MWh. Low wind generation on Saturday saw an increase in thermal and hydro generation with some high-priced hydro contributing to the spike in North Island prices.

2.5. 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.

[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.

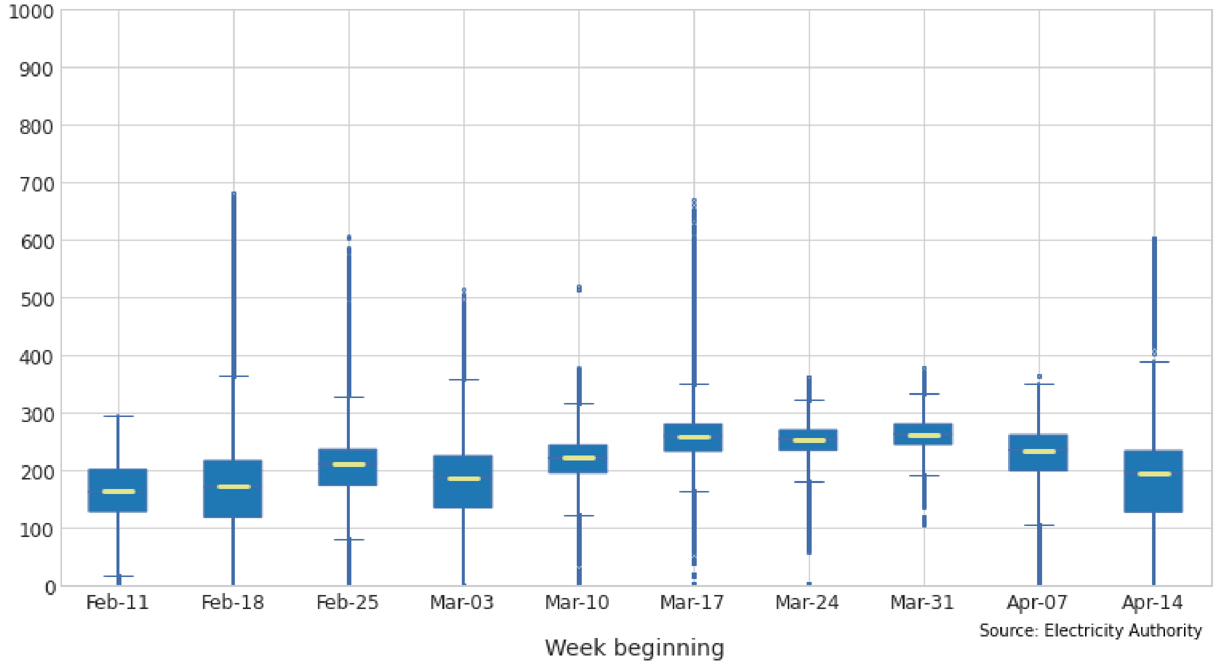
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 14-20 April



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% 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. The distribution of prices increased compared to the previous few weeks due to very low overnight prices and the high prices during the pole outage. This week's median price was $195/MWh, compared to $239/MWh in the previous week, a $44/MWh decrease. The middle 50% of the prices were between $127-$233/MWh.

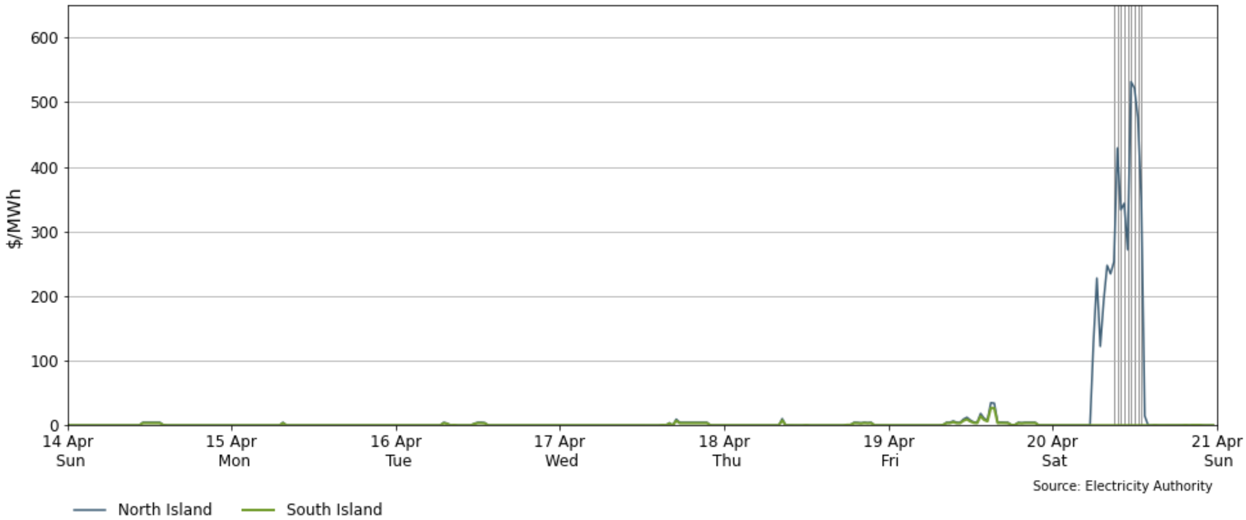
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

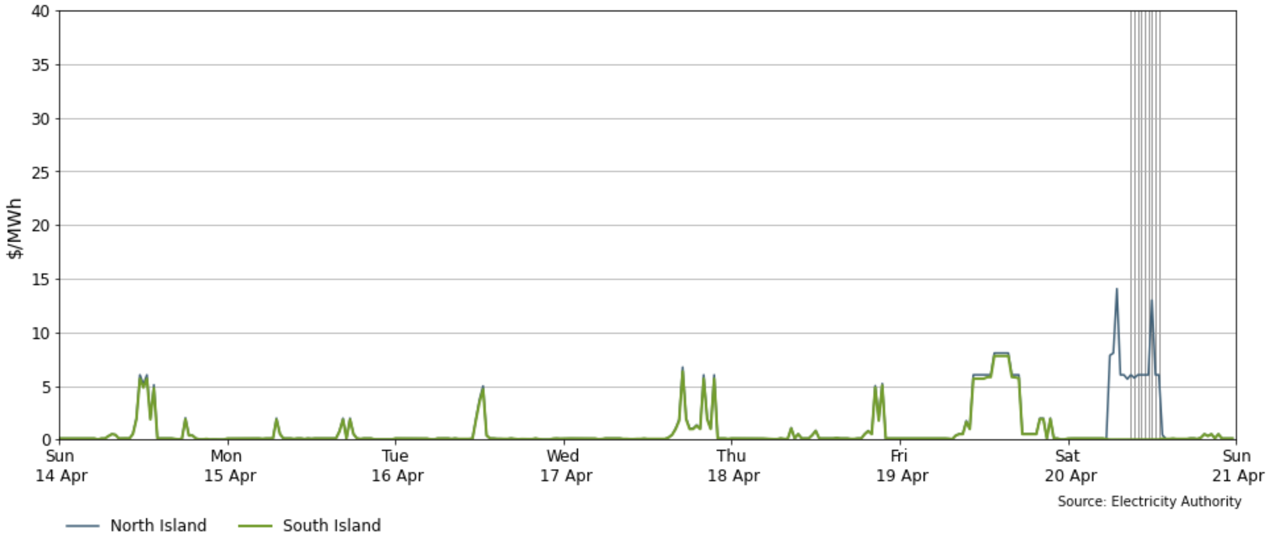
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh. On Saturday, the North Island FIR prices spiked due to the reduced HVDC transfer capacity because of its Pole 3 planned outage. The planned outage on the HVDC required more expensive North Island reserves to be dispatched to cover the risk set by the remaining HVDC pole.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 14-20 April



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. The SIR prices on both islands were mostly below $10/MWh this week. There were also some small increases to North Island SIR on Saturday during the planned HVDC Pole 3 outage, but SIR prices remained below $15/MWh.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 14-20 April



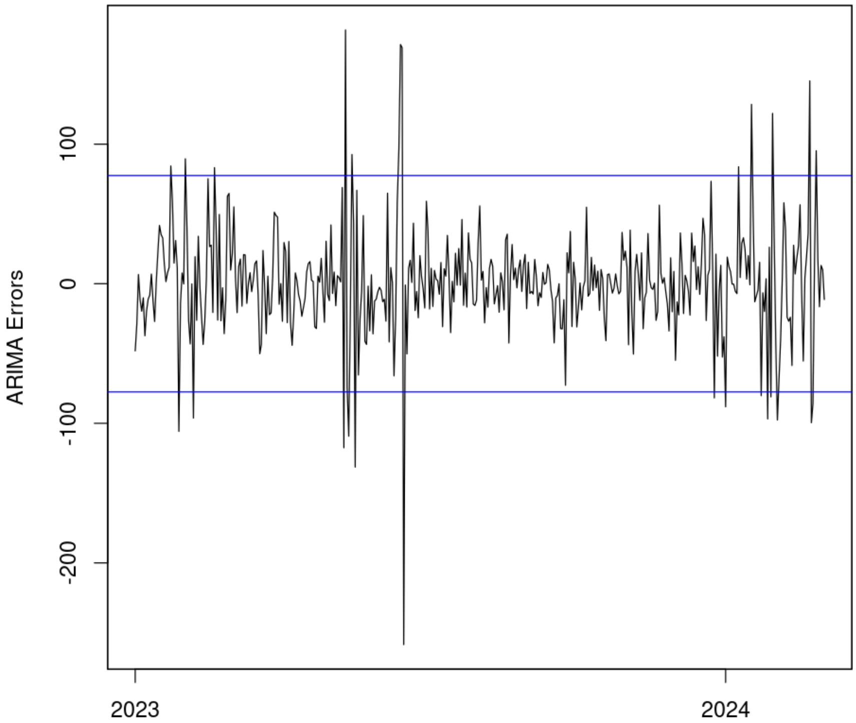
4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model spot prices. 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.

4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the 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.

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

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 20 April 2024

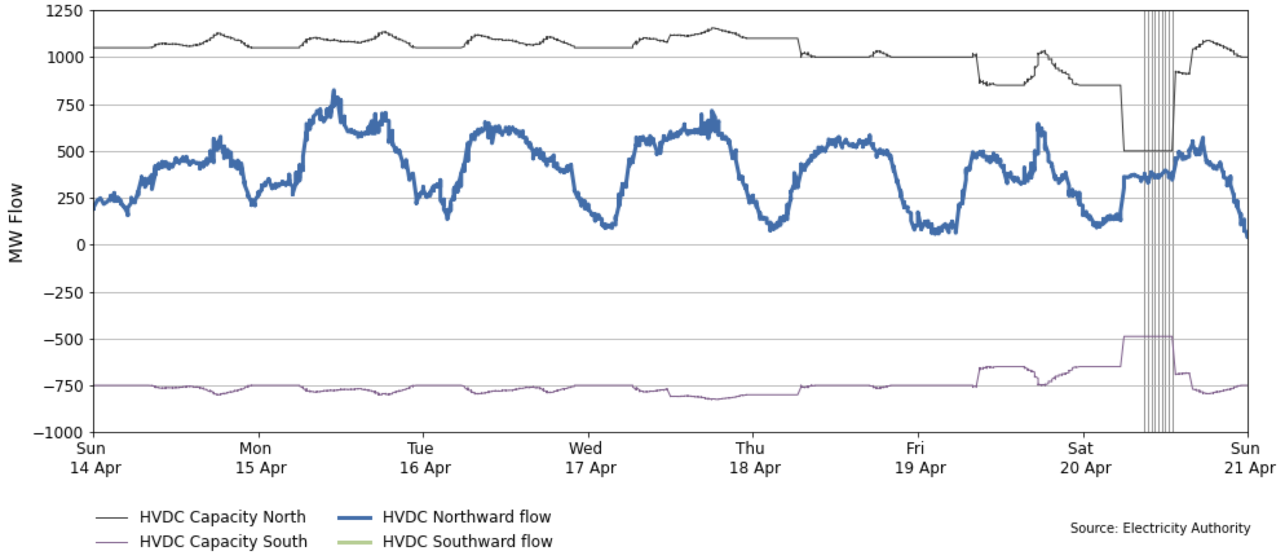


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 14-20 April. This week, the HVDC was flowing north every day, due to the increase in hydro generation. HVDC flows were limited during part of the day on Saturday because of a planned HVDC Pole 3 outage. The outage decreased the northward flow capacity to around 500MW over Pole 2.

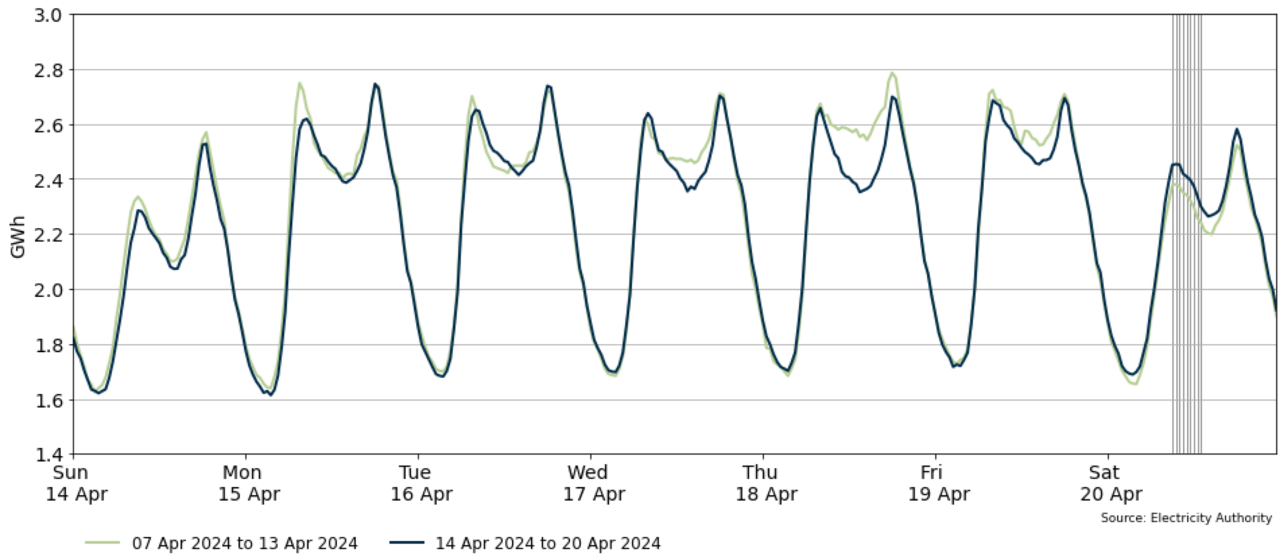
Figure 6: HVDC flow and capacity between 14-20 April



6. Demand

6.1. Figure 7 shows national demand between 14-20 April, compared to the previous week. Demand this week was slightly lower from Sunday to Friday compared to the previous week. On Saturday, demand increased compared to the previous week, likely related to lower temperatures on that day.

Figure 7: National demand between 14-20 April compared to the previous week

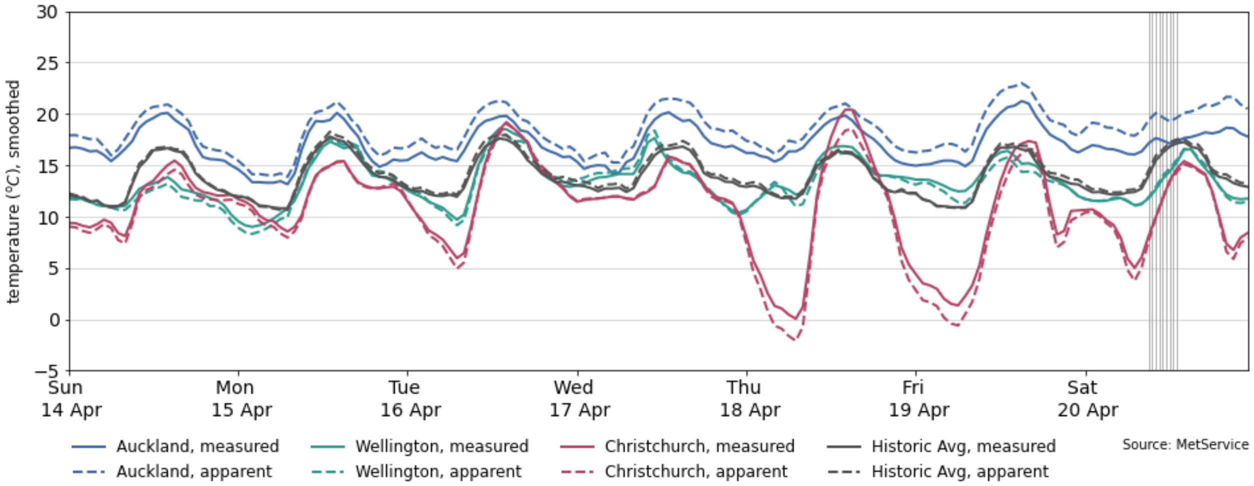


6.2. Figure 8 shows the hourly temperature at main population centres from 14-20 April. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures across the country were mostly close to the historical average this week between Sunday and Thursday. From Thursday onwards the temperature variation in Christchurch became more pronounced.

6.4. Apparent temperatures in Auckland varied between 14ºC and 18ºC. In Wellington, the apparent temperatures fluctuated between 8ºC and 23ºC. Apparent temperatures in Christchurch were between -2ºC and 19ºC this week.

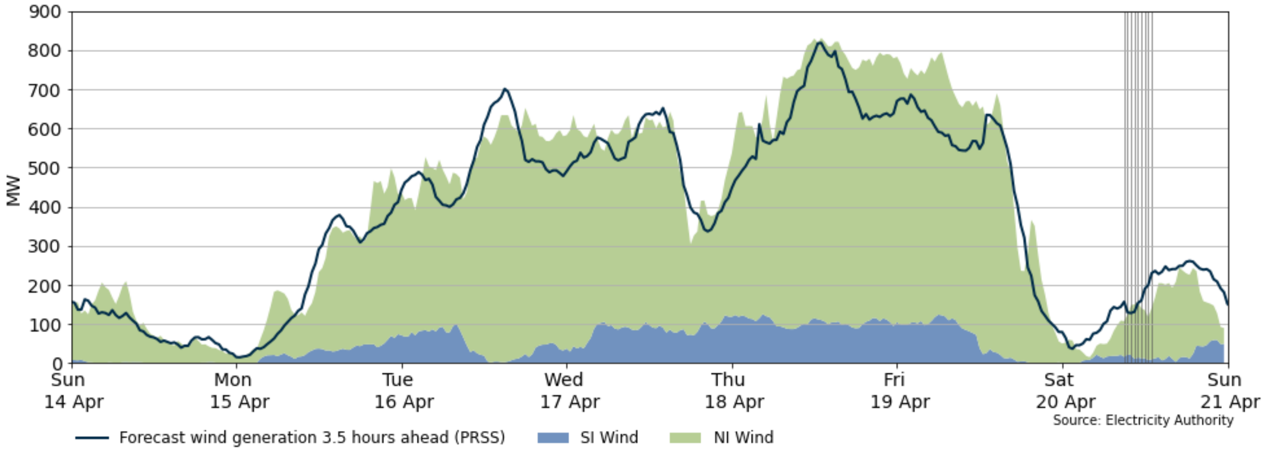
Figure 8: Temperatures across main centres between 14-20 April



7. Generation

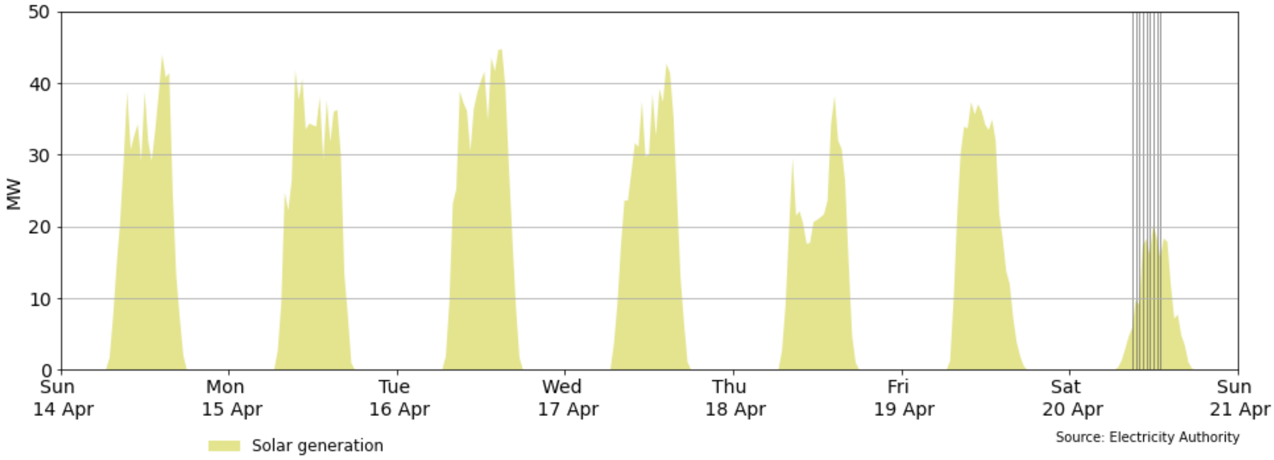
7.1. Figure 9 shows wind generation and forecast from 14-20 April. This week wind generation varied between 16MW and 831MW, with an average of 403MW. Wind generation was low at the start of the week, generally below 200MW. Generation increased on Monday and mostly remained between ~400-800MW until Friday. During the HVDC Pole 3 outage generation was below 160MW and over forecast for several trading periods.

Figure 9: Wind generation and forecast between 14-20 April



7.2. Figure 10 shows solar generation from 14-20 April. Solar generation was higher between Sunday and Wednesday, decreasing from Wednesday onwards and reaching a minimum on Saturday due to overcast conditions.

Figure 10: Solar generation between 14-20 April



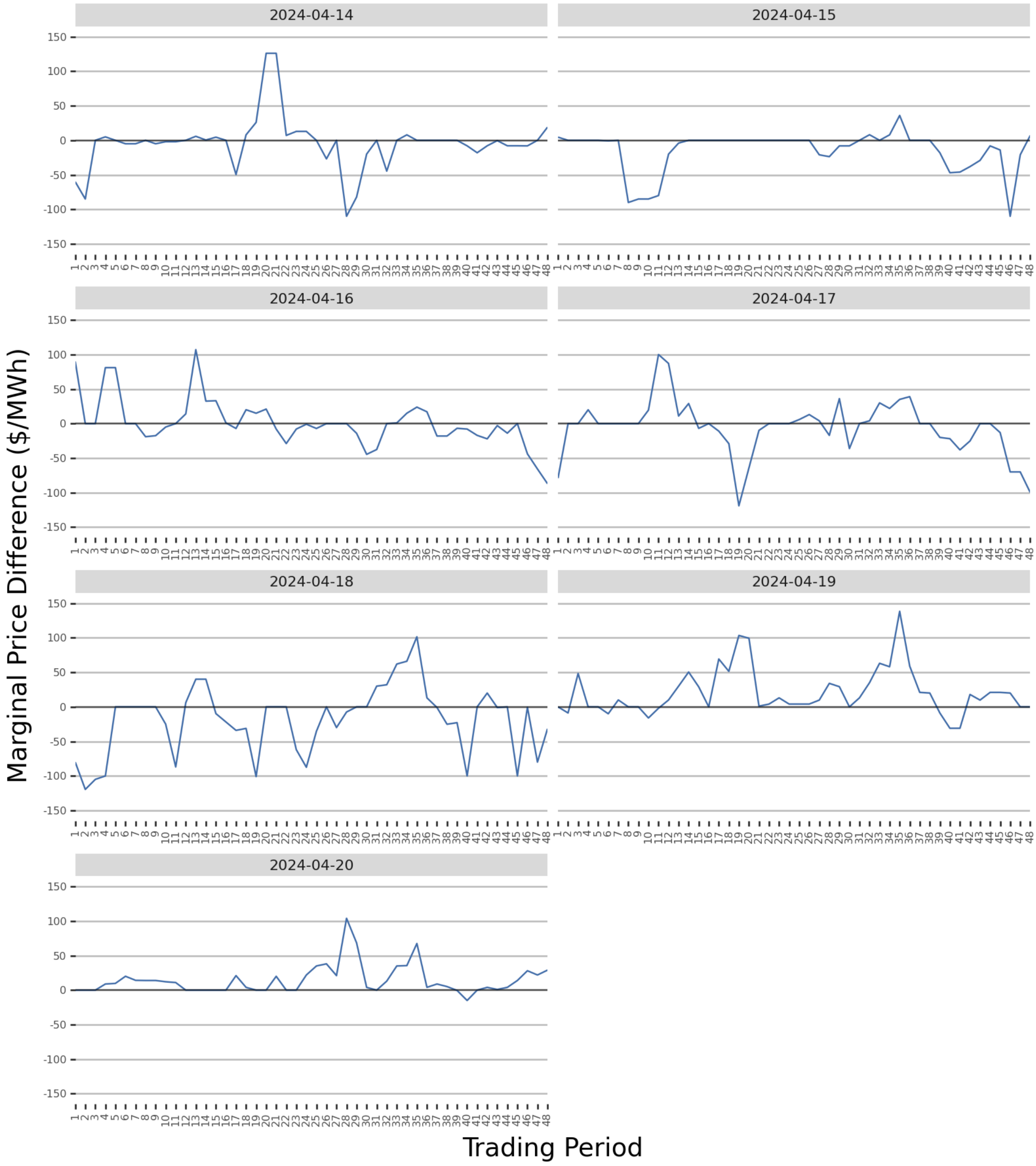
7.3. Figure 11 shows the difference between the real-time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1-hour ahead (PRSS) demand and wind forecasts at the national level. This plot highlights when forecasting inaccuracies are causing large differences between pre-dispatch and final prices. When the difference is positive this means that the 1-hour out forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD price will rarely be the same, but trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.4. This week the differences between the national marginal RTD and PRSS prices were mostly between +/-$100MWh but crossed that mark during at least one trading period every day.

7.5. The largest price difference occurred on Friday when the national marginal RTD price was almost $150/MWh higher than the PRSS forecast during trading period 35 at 5:00pm. Friday saw a few other under-forecast prices between trading periods 17 and 20, during the morning demand peak. On that occasion, wind was around 50MW lower than forecast while demand was ~100MW higher than forecast. Over-forecast prices occurred more frequently on Thursday, with only one crossing the $100/MWh inaccuracy mark, at 00:30am, during trading period 2.

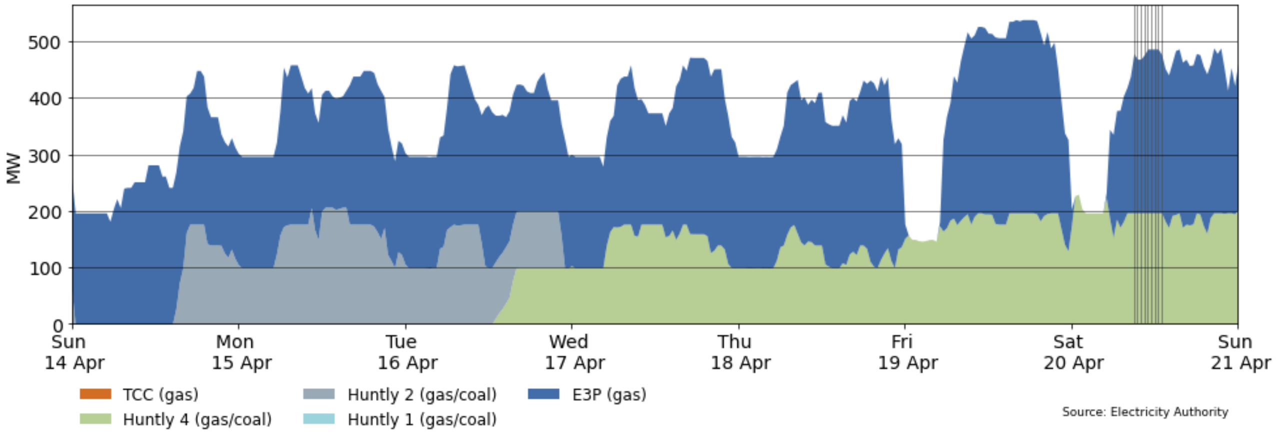
7.6. Regarding accuracy, compared to the previous week, PRSS prices were slightly less accurate this week, as price differences above $100/MWh were more frequent this week.

Figure 11: Difference between national marginal RTD price and gate closure PRSS prices, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 14-20 April



7.7. Figure 12 shows the generation of thermal baseload between 14-20 April. This week, Huntly 5 (E3P) ran continuously except for early morning hours on Friday and Saturday. To support the baseload, Huntly 2 ran continuously from Sunday afternoon to late Tuesday and Huntly 4 ran continuously from Tuesday afternoon onwards.

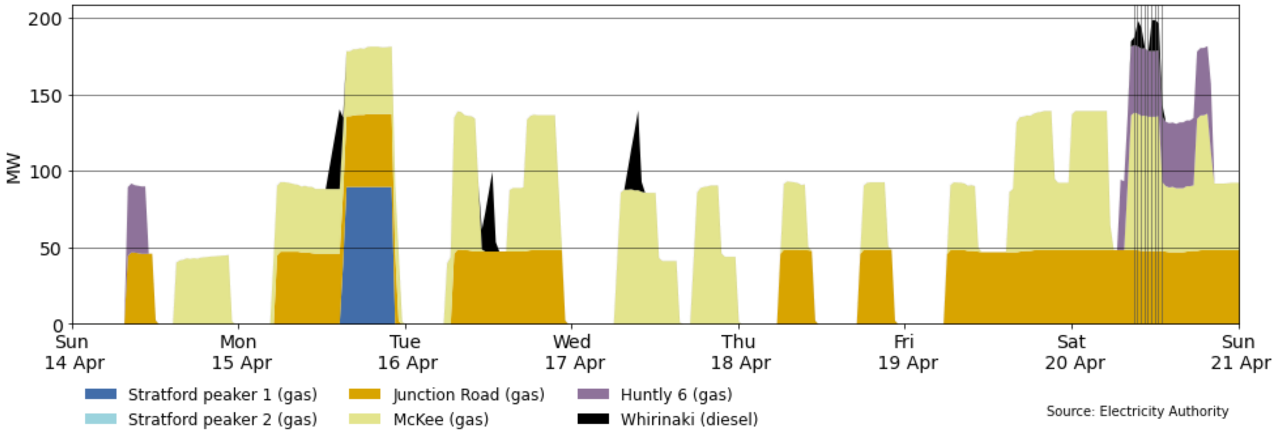
Figure 12: Thermal baseload generation between 14-20 April



7.8. Figure 13 shows the generation of thermal peaker plants between 14-20 April. Junction Road and McKee provided most of the peaker generation this week. Junction Road ran every day except for Wednesday and continuously from Friday onwards. McKee ran during peak and/or shoulder periods every day this week. Stratford 1 ran during the Monday evening peak period. Huntly 6 ran during Sunday morning peak, then again on Saturday over peak and shoulder periods.

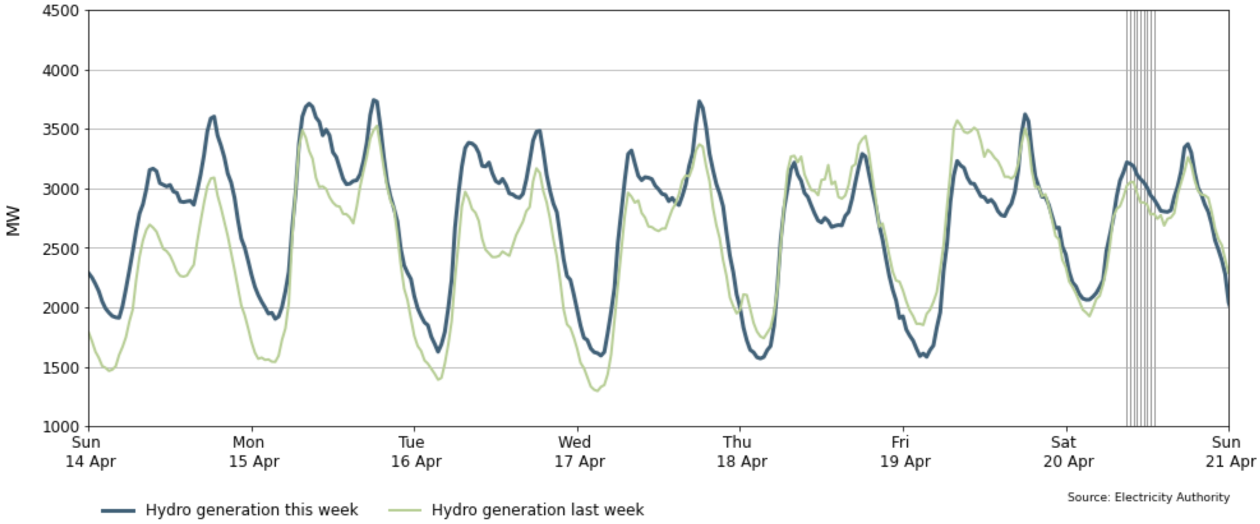
7.9. Different Whirinaki units ran for a few trading periods on Monday, Tuesday, and Wednesday, possibly due to testing. On Saturday, Whirinaki ran likely to provide reserves during the HVDC Pole 3 planned outage.

Figure 13: Thermal peaker generation between 14-20 April



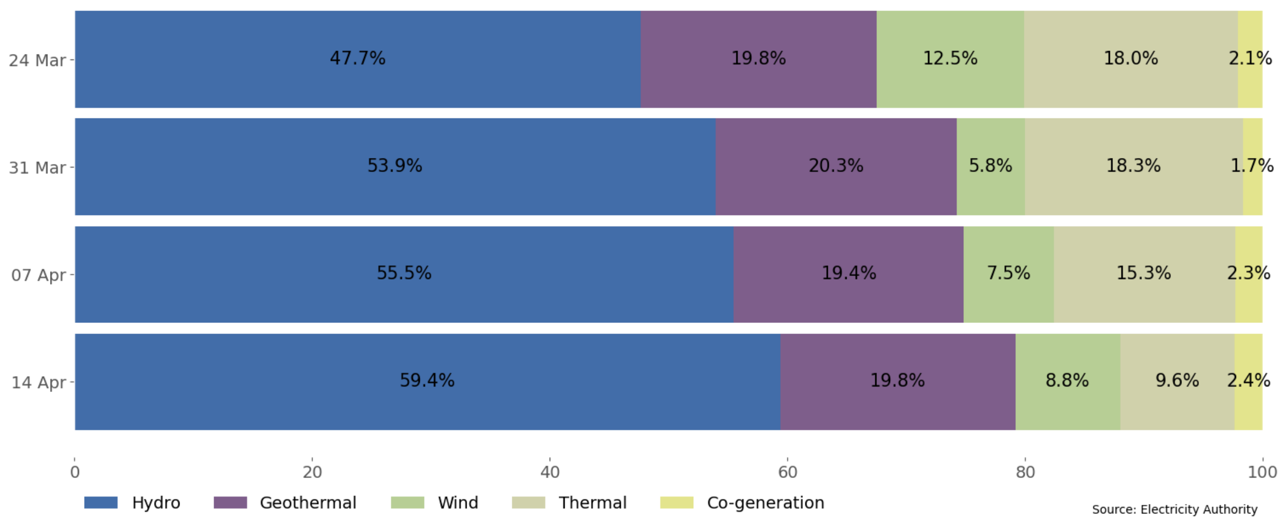
7.10. Figure 14 shows hydro generation between 14-20 April. This week, except for Thursday and Friday, hydro generation was higher than the previous week. The increase in hydro storage, now back at its historical average level, has seen an increase in hydro generation, particularly during periods of low wind generation.

Figure 14: Hydro generation between 14-20 April



7.11. As a percentage of total generation, between 14-20 April, total weekly hydro generation was 59.4%, geothermal 19.8%, wind 8.8%, thermal 9.6%, and co-generation 2.4%, as shown in Figure 15. The proportion of thermal generation decreased to less than 10% this week due to increases in hydro and wind generation.

Figure 15: Total generation by type as a percentage each week between 24 March and 20 April



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 14-20 April ranged between ~1250MW and ~1900MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 29 April 2024

(b) Stratford 2 is on outage until 30 June 2024

(c) McKee was on partial outage until 15 April 2024

(d) Junction Road was on partial outage until 22 April 2024

(e) Stratford 1 was on outage on 16 April

(f) Huntly 4 was on partial outage between 14-15 April

(g) Several North and South Island hydro units were on outage this week.

Figure 16: Total MW loss due to generation outages between 14-20 April

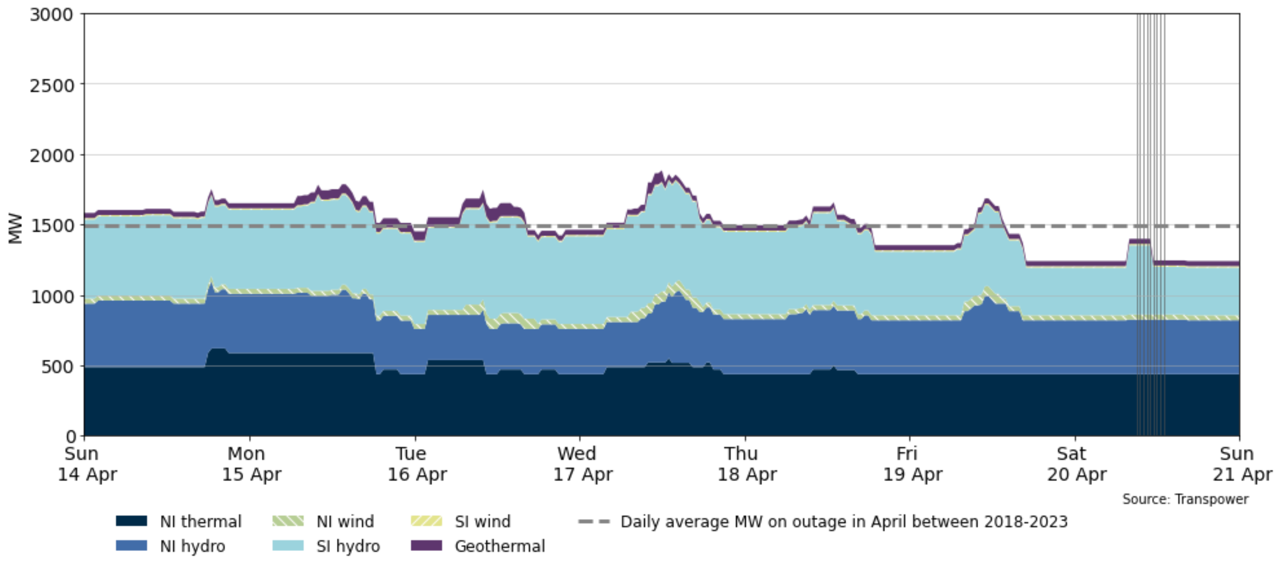
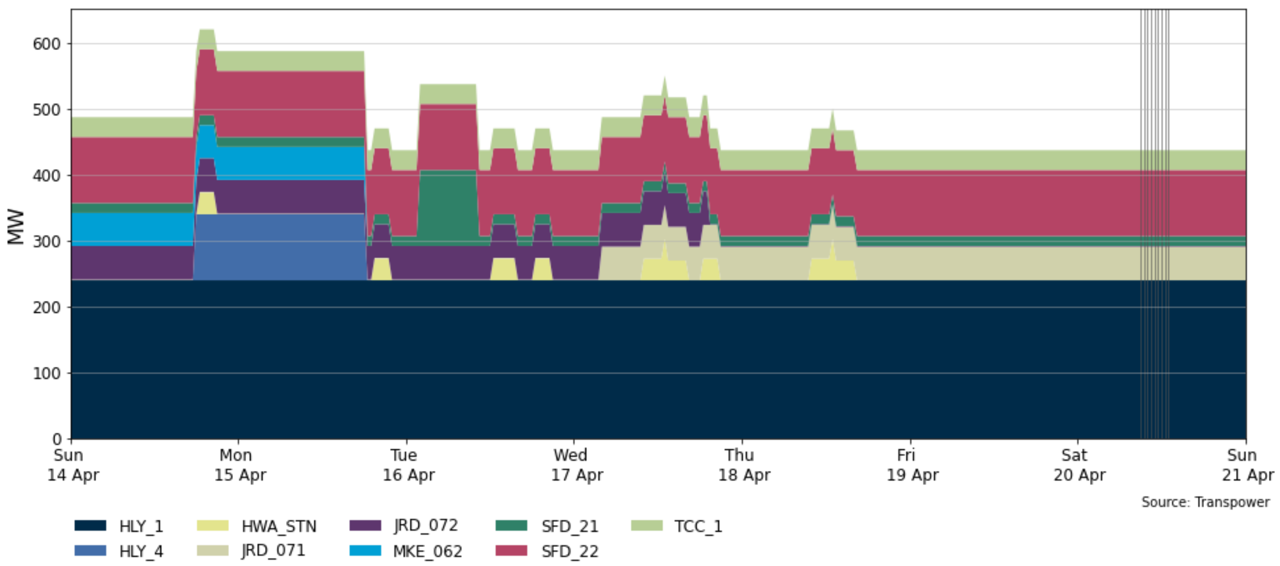


Figure 17: MW loss from thermal outages between 14-20 April

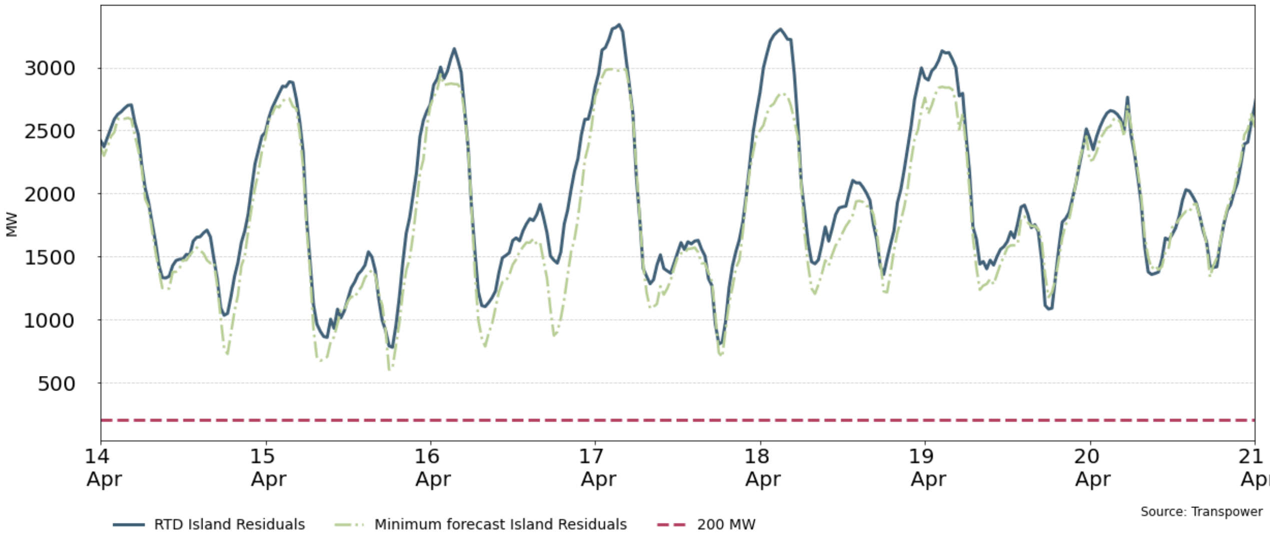


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 14-20 April. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals, and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Generation residuals were healthy this week, with the minimum national residual levels at around 780MW and the minimum North Island residual levels at around 532MW.

Figure 18: National generation balance residuals 14-20 April



10. Storage/fuel supply

10.1. Figure 19 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.

10.2. National controlled storage increased this week and is now sitting at ~79% of nominally full and ~102% of the historical average for this time of the year (as of 20 April).

(a) Lake Taupō is still sitting between its 90th percentile and its historical average after a slight decrease in storage this week.

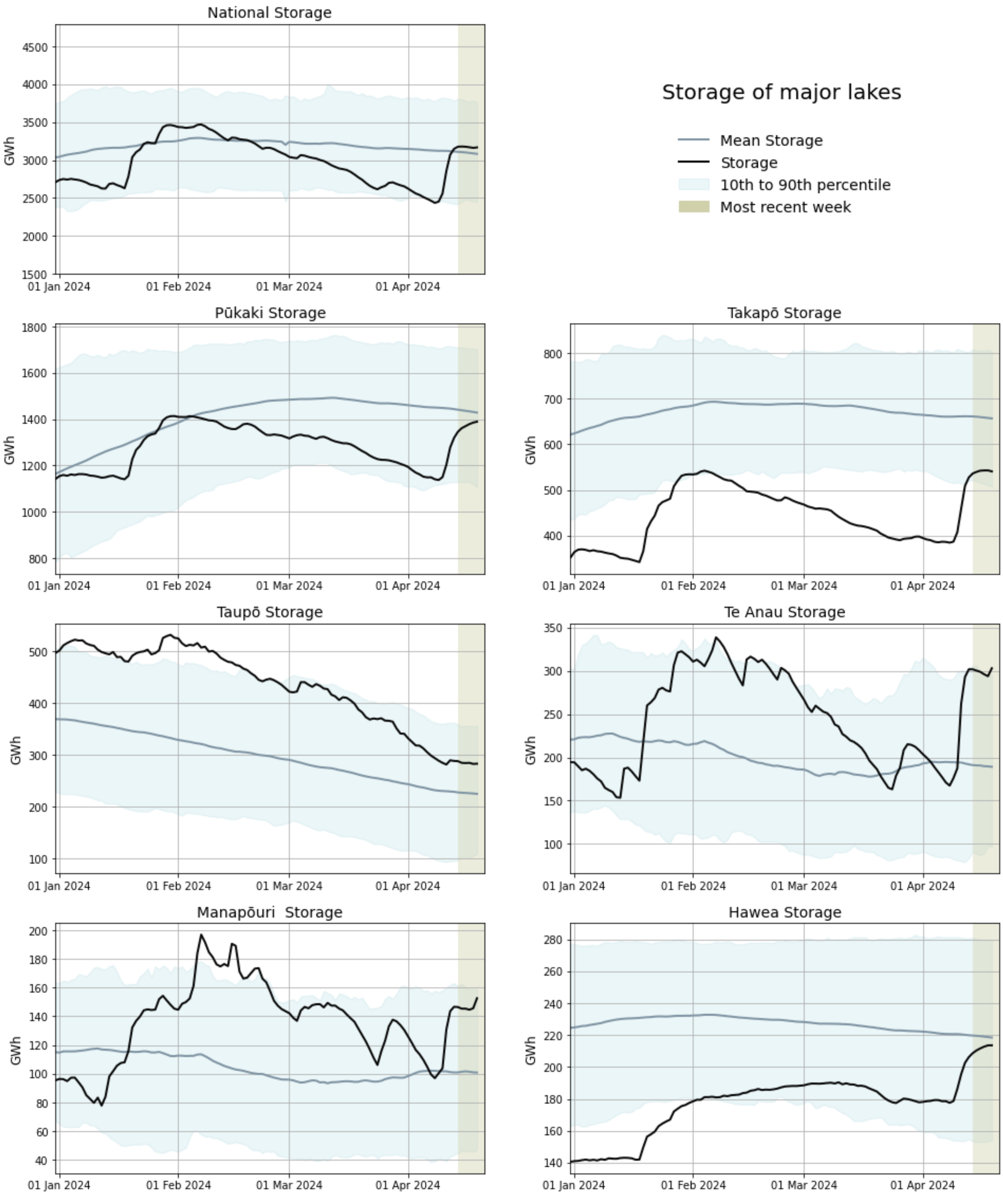
(b) Lake Pūkaki increased this week, now sitting slightly below its historical average.

(c) Lake Takapō storage increased this week, now above its 10th percentile.

(d) Lake Manapōuri and Te Anau also saw an increase in storage. The lakes are around their 90th percentile.

(e) Lake Hawea storage also increased and is sitting close to its historical average mark.

Figure 19: Hydro storage



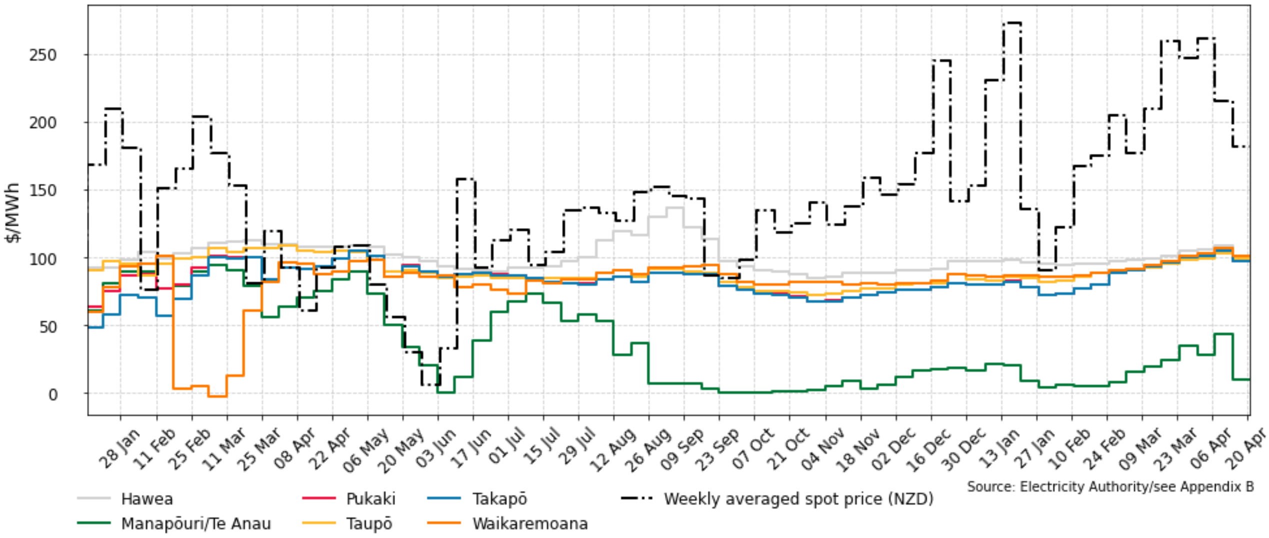
Source: Electricity Authority

11. JADE water values

11.1. 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 20 shows the national water values between 8 January 2023 and 20 April 2024 obtained from JADE calculated 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.

11.2. Compared to the previous week, all lakes saw a decrease in their water values. The decrease was in the order of $4-$8/MWh at all lakes except for Manapōuri/Te Anau, which saw a decrease in water values of around $34/MWh, after a $16/MWh increase in the previous week.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 20 April 2024



12. Prices versus estimated costs

12.1. 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).

12.2. 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.

12.3. Figure 21 shows an estimate of thermal SRMCs as a monthly average up to 1 April 2024. The SRMCs for coal and diesel have seen small changes from the previous month. The coal SRMC decreased, while the diesel SRMC has increased slightly. The gas SRMCs have increased this month, likely due to current gas availability and demand.

[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.

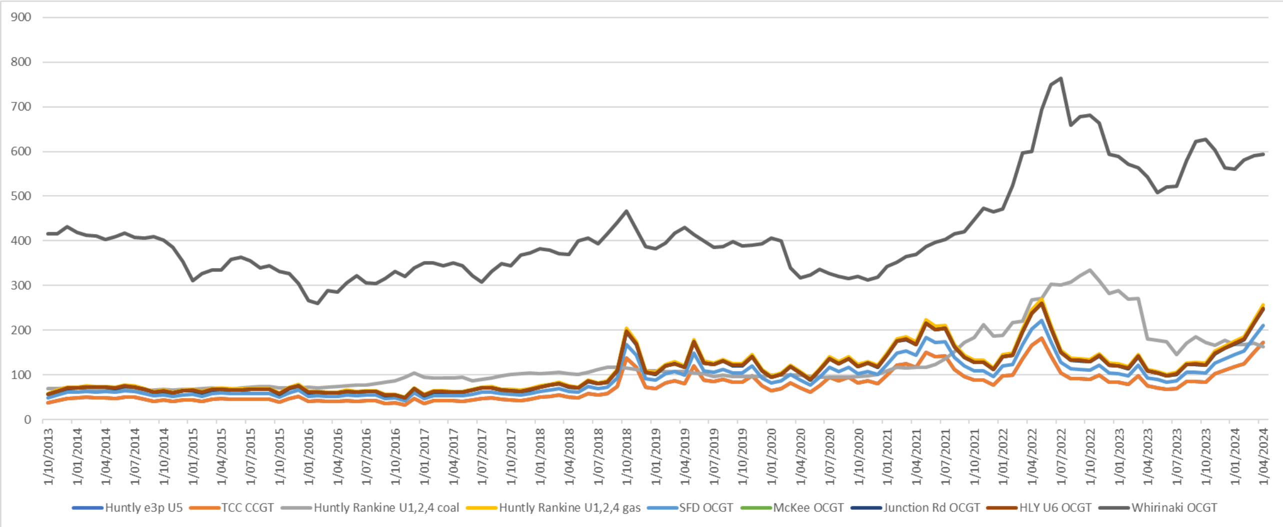
12.4. The latest SRMC of coal-fuelled Rankine generation is ~$164/MWh. The cost of running the Rankines on gas remains more expensive at ~$257/MWh.

12.5. The SRMC of gas-fuelled thermal plants is currently between ~$173/MWh and ~$257/MWh.

12.6. The SRMC of Whirinaki is ~$594/MWh.

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

Figure 21: Estimated monthly SRMC for thermal fuels



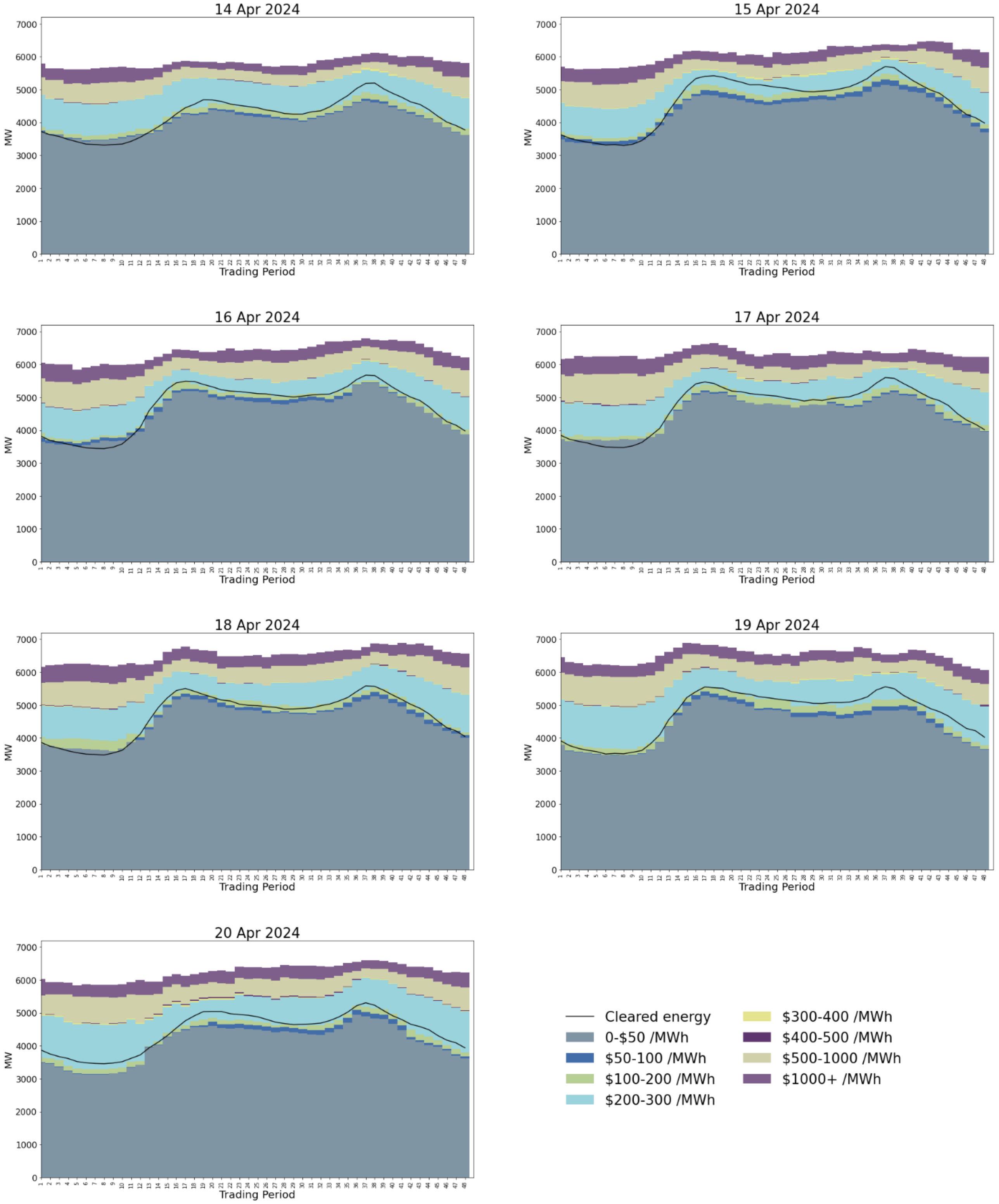
Source: Electricity Authority/see Appendix C

13. Offer behaviour

13.1. Figure 22 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

13.2. Offer stacks between $50-$200/MWh were reasonably thin meaning most offers this week cleared in the $200-$300/MWh region. Although there has been an overall increase in hydro storage, the offers are reflective of current gas prices, with some storage lakes remaining below average for this time of year, and the need to conserve water for winter.

Figure 22: Daily offer stacks[3]



Source: Electricity Authority

[3] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

14. Ongoing work in trading conduct

14.1. This week, prices generally appeared to be consistent with supply and demand conditions.

14.2. 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
21/01/2024-27/01/2024	Several	Further analysis	Mercury	Waikato hydro dams	Hydro offers
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Hydro offers