1 July 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 23-29 June 2024

Market monitoring weekly report

Trading conduct report

1. Overview for week of 23-29 June

1.1. Spot prices were consistently above the historical median this week and mostly between \$200-\$300/MWh. High prices often occurred outside of peak demand periods, due to a combination of forecasting inaccuracies and hydro prices increasing as lake levels decline. TCC, Huntly 5 and two Rankines provided baseload generation this week. Hydro storage decreased to around 71% of the historical average.

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. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside their historic average 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.

2.3. Between 23-29 June:

(a) The average wholesale spot price across all nodes was \$276/MWh.

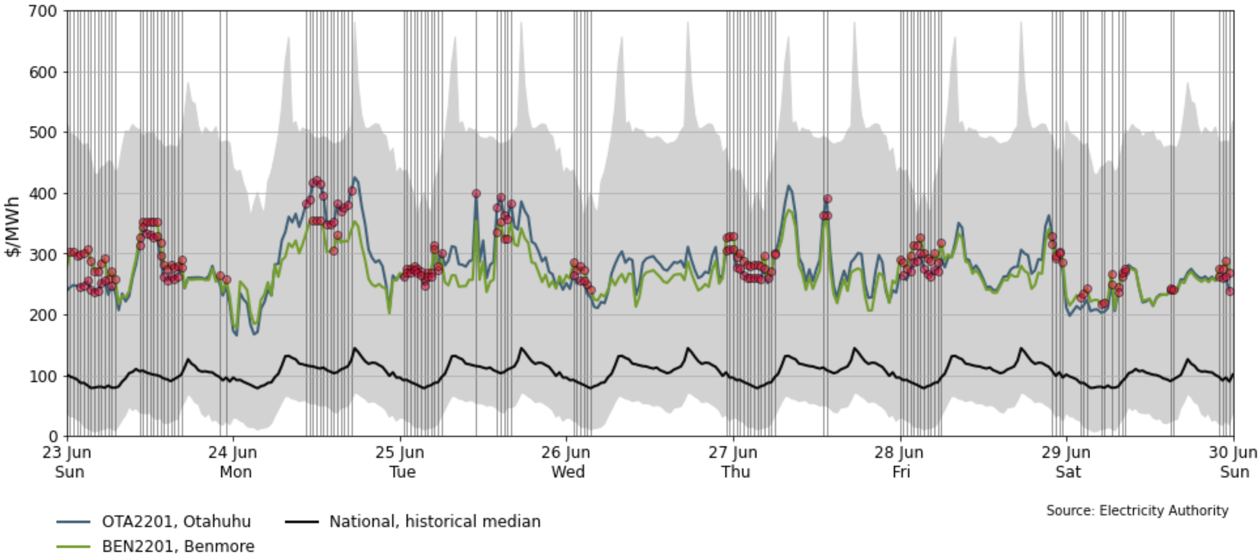
(b) 95 percent of prices fell between \$203/MWh and \$382/MWh.

2.4. Spot prices were between the historical median and 90th percentile this week. The Ōtāhuhu spot price reached a maximum of \$425/MWh on Monday at 5:30pm, when wind generation was low and demand was high.

2.5. This week, many of the highlighted prices occurred overnight, early in the morning or during the middle of the day, rather than during peak periods. The high prices at these times were generally due to demand and/or wind generation forecasting inaccuracies requiring high-priced hydro and thermal generation to be dispatched. The price spike on Thursday afternoon was likely the result of Huntly Rankine 1 tripping.

[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.

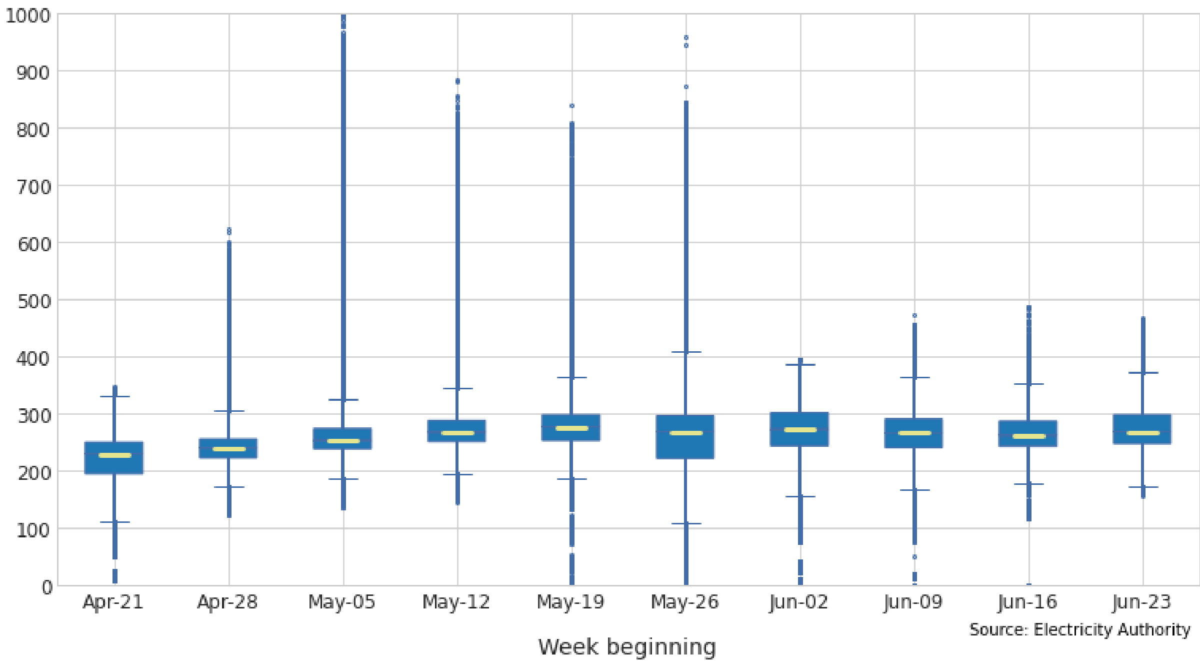
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 23-29 June



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. The distribution of prices this week was similar to the previous week, though the range of prices was smaller. The median price increased by $6/MWh to $268/MWh, and the middle 50% of prices were between $247/MWh and $297/MWh.

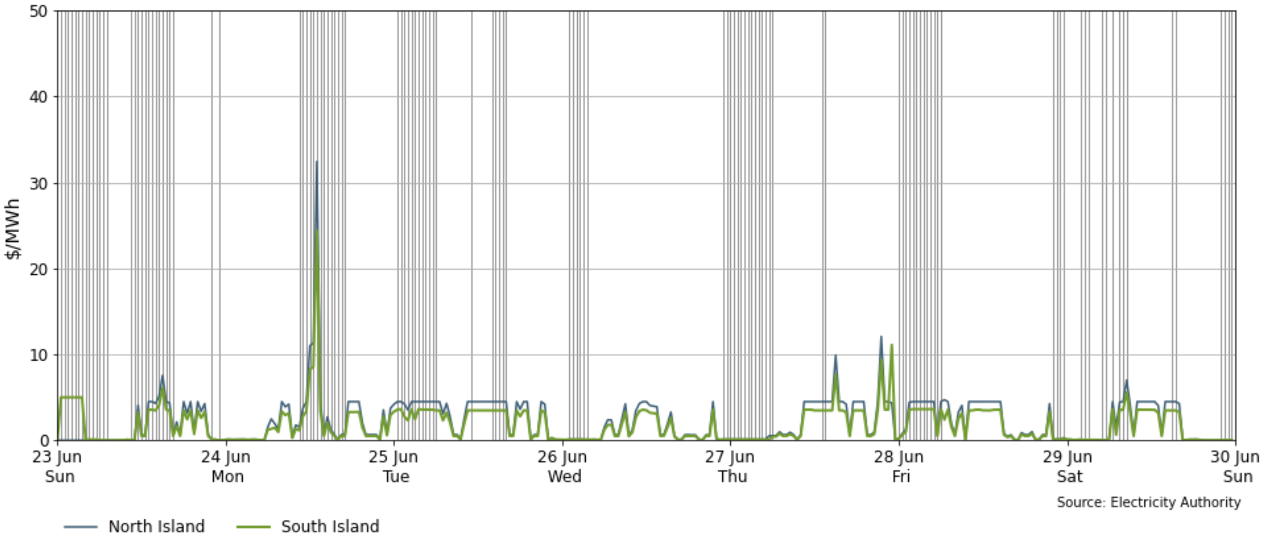
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

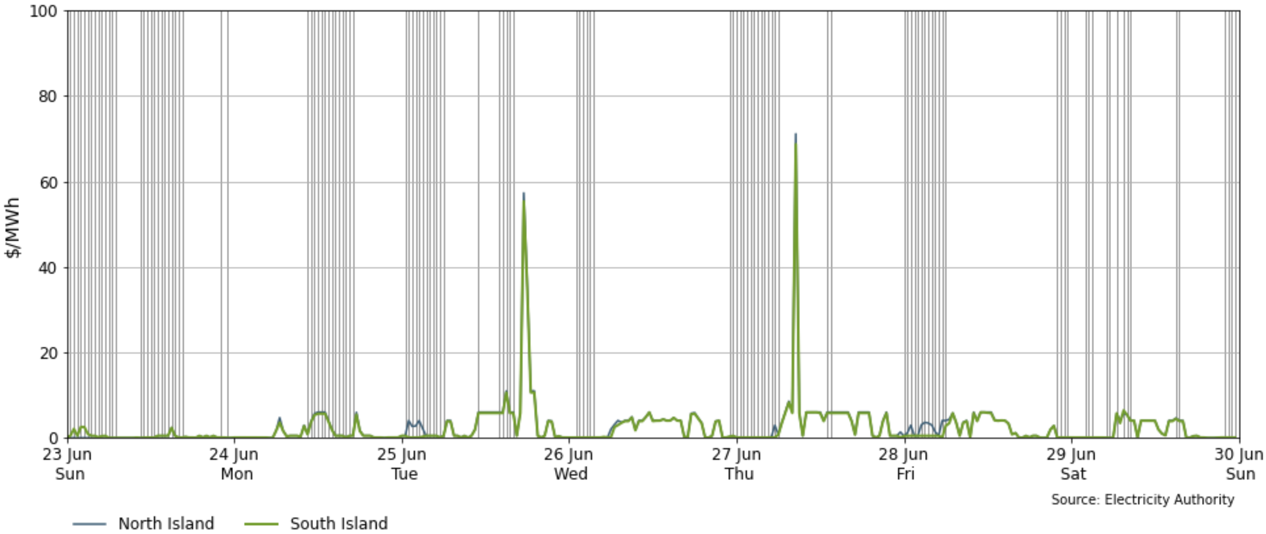
3.1. FIR prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week, but spiked at 1:00pm on Monday, exceeding $20/MWh in the South Island and $30/MWh in the North Island.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 23-29 June



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh this week but spiked over $50/MWh in both islands during the evening peak demand period on Monday, and the morning peak demand period on Thursday. This was likely due to generators directing more of their capacity towards energy than reserves, driving up reserve prices.

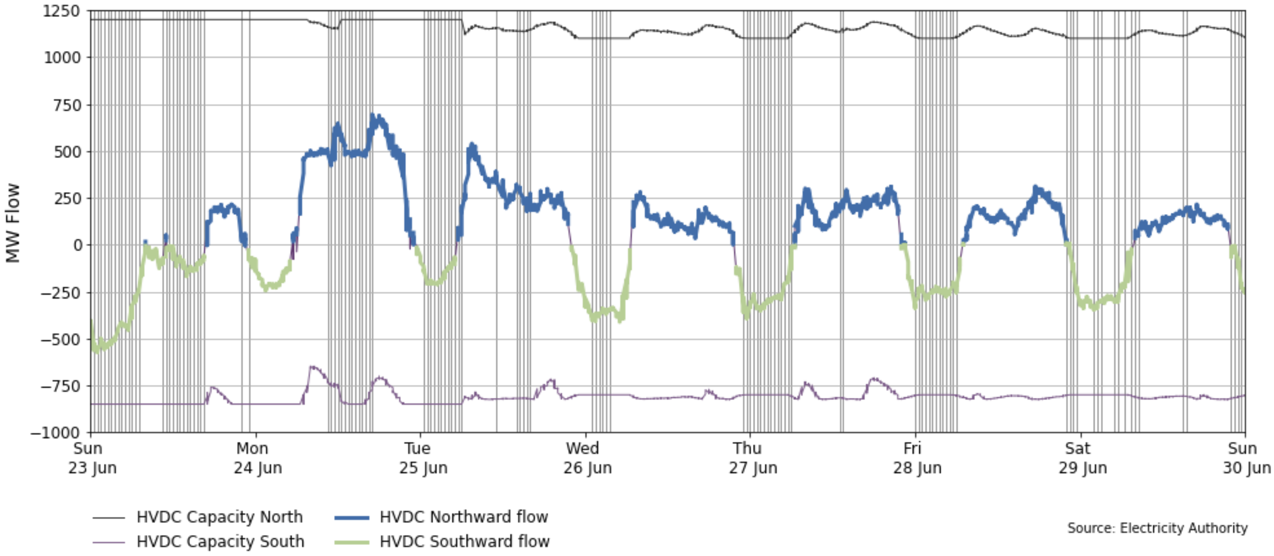
Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 23-29 June



4. HVDC

4.1. Figure 5 shows HVDC flow between 23-29 June. Most high spot prices this week occurred while the HVDC flow was southward, late at night or early in the morning.

Figure 5: HVDC flow and capacity between 23-29 June



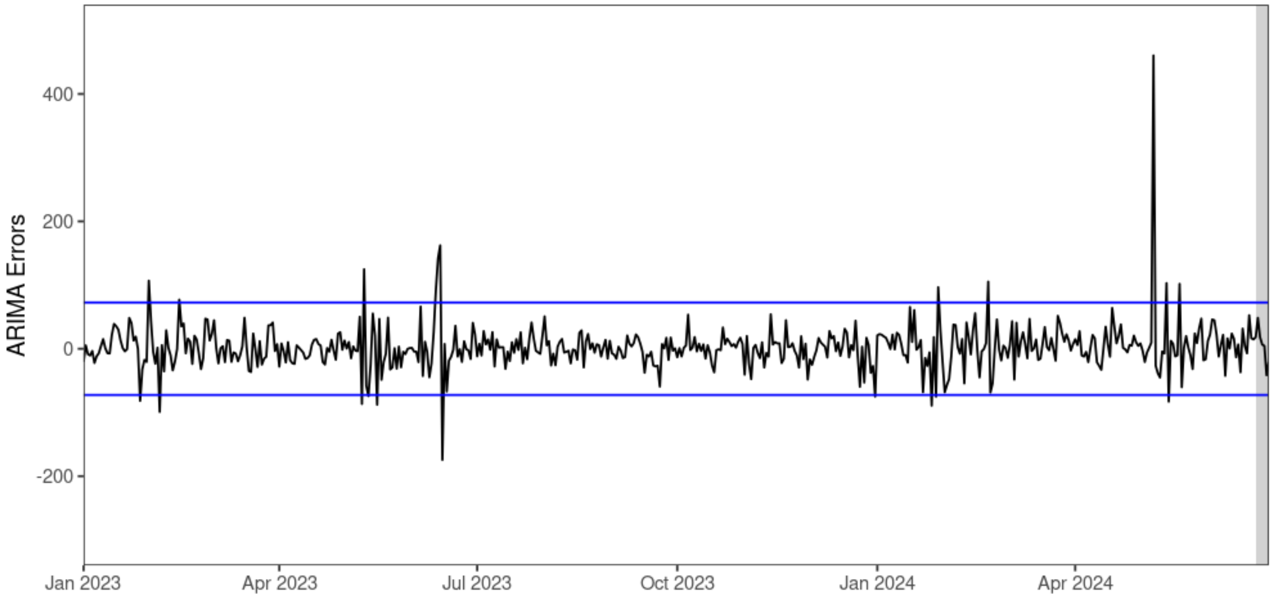
5. Regression residuals

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.

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

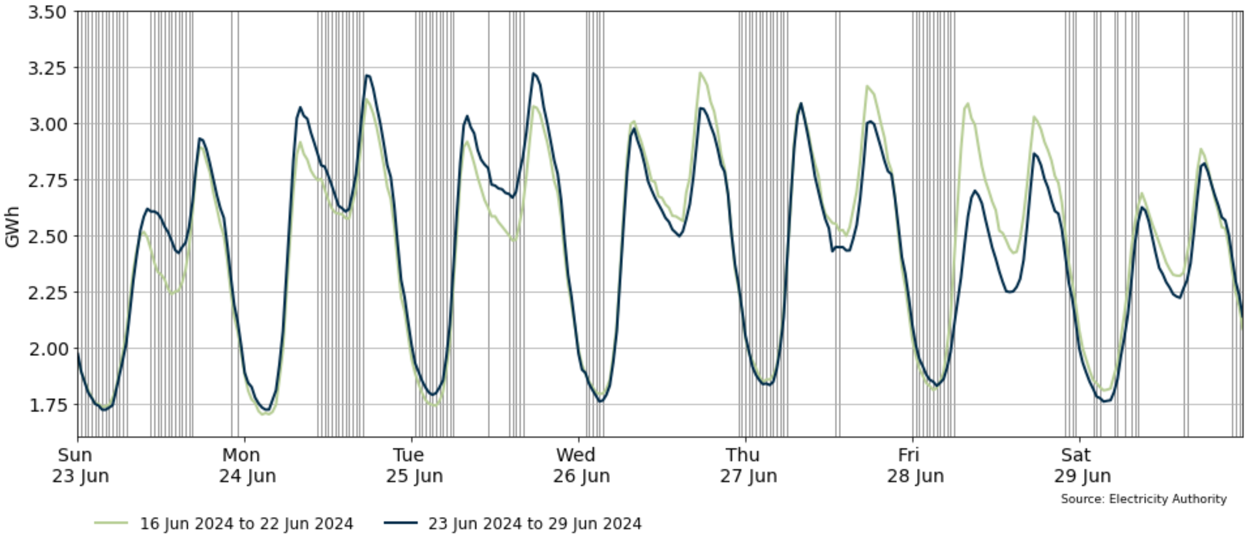
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 to 29 June 2024



6. Demand

6.1. Figure 7 shows national demand between 23-29 June, compared to the previous week. Demand was generally higher than the previous week until Wednesday, then lower than the previous week from Wednesday onwards. The maximum demand this week was 3.22GWh at 5:30pm on Tuesday.

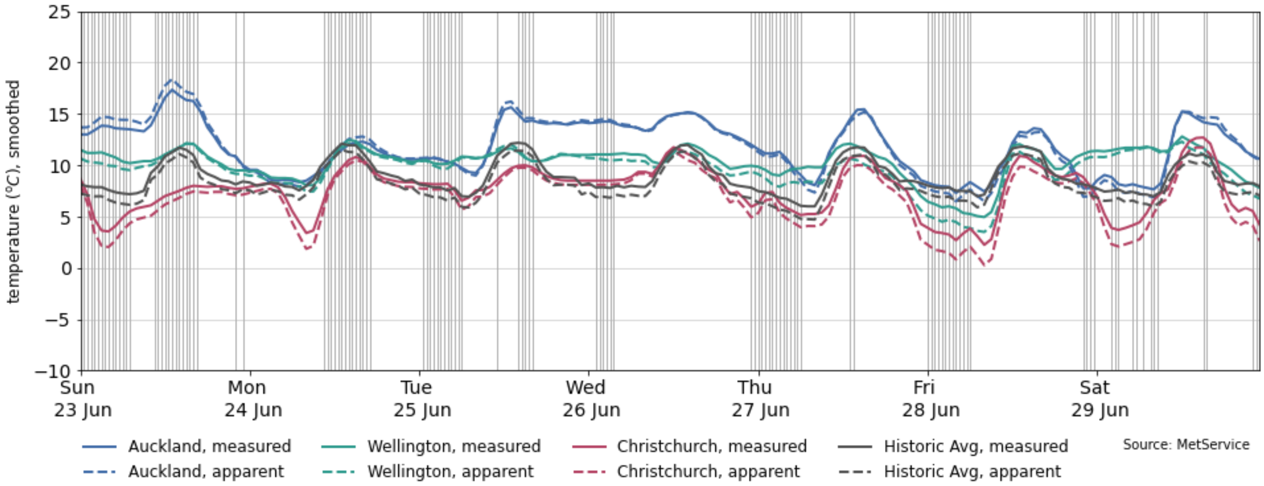
Figure 7: National demand between 23-29 June compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 23-29 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 mostly above average in Auckland, ranging from 10ºC to 18ºC. In Wellington, temperatures were close to average, ranging from 4ºC to 12ºC. Christchurch temperatures were generally close to or below average, ranging from 0ºC to 12ºC.

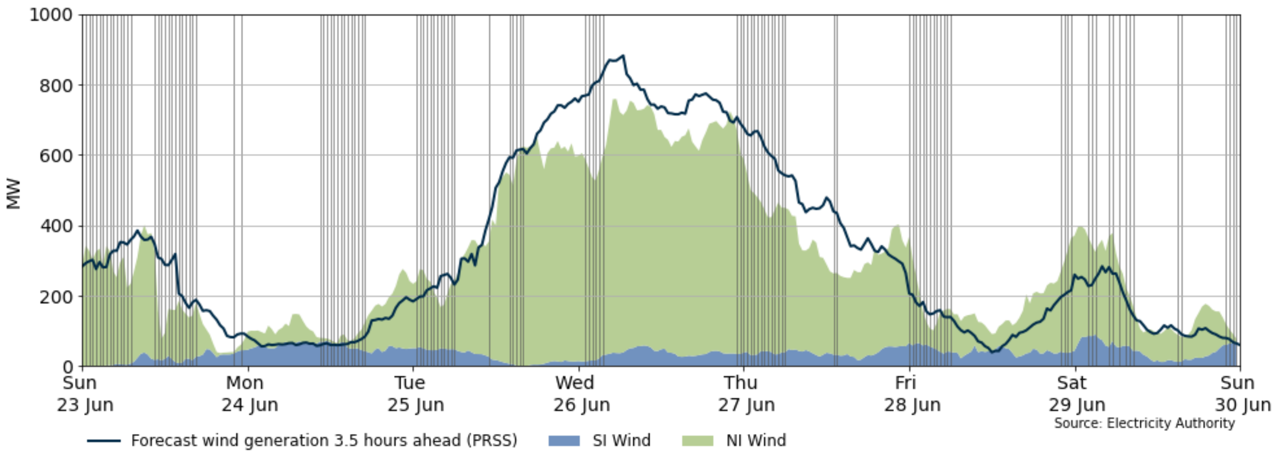
Figure 8: Temperatures across main centres between 23-29 June



7. Generation

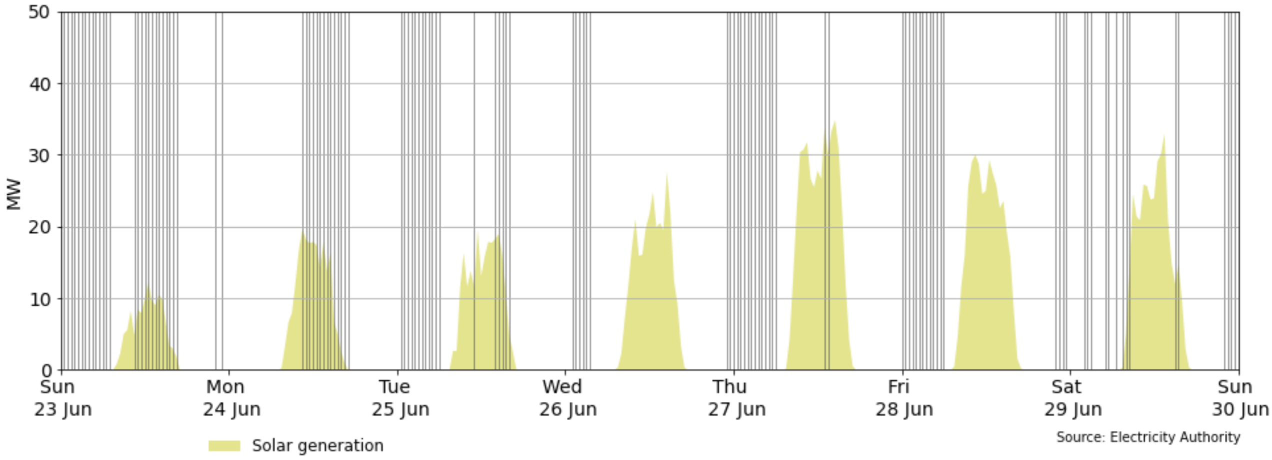
7.1. Figure 9 shows wind generation, from 23-29 June. Average wind generation was 309MW this week, ranging from 37MW-759MW. Wind generation was low and/or below forecast when many of the highlighted prices occurred. During the period of high prices early on Wednesday morning, wind generation was up to 279MW below forecast.

Figure 9: Wind generation and forecast between 23-29 June



7.2. Figure 10 shows solar generation from 23-29 June. Solar generation was low at the beginning of this week due to overcast conditions but reached at least 30MW each day from Thursday onwards. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource during winter.

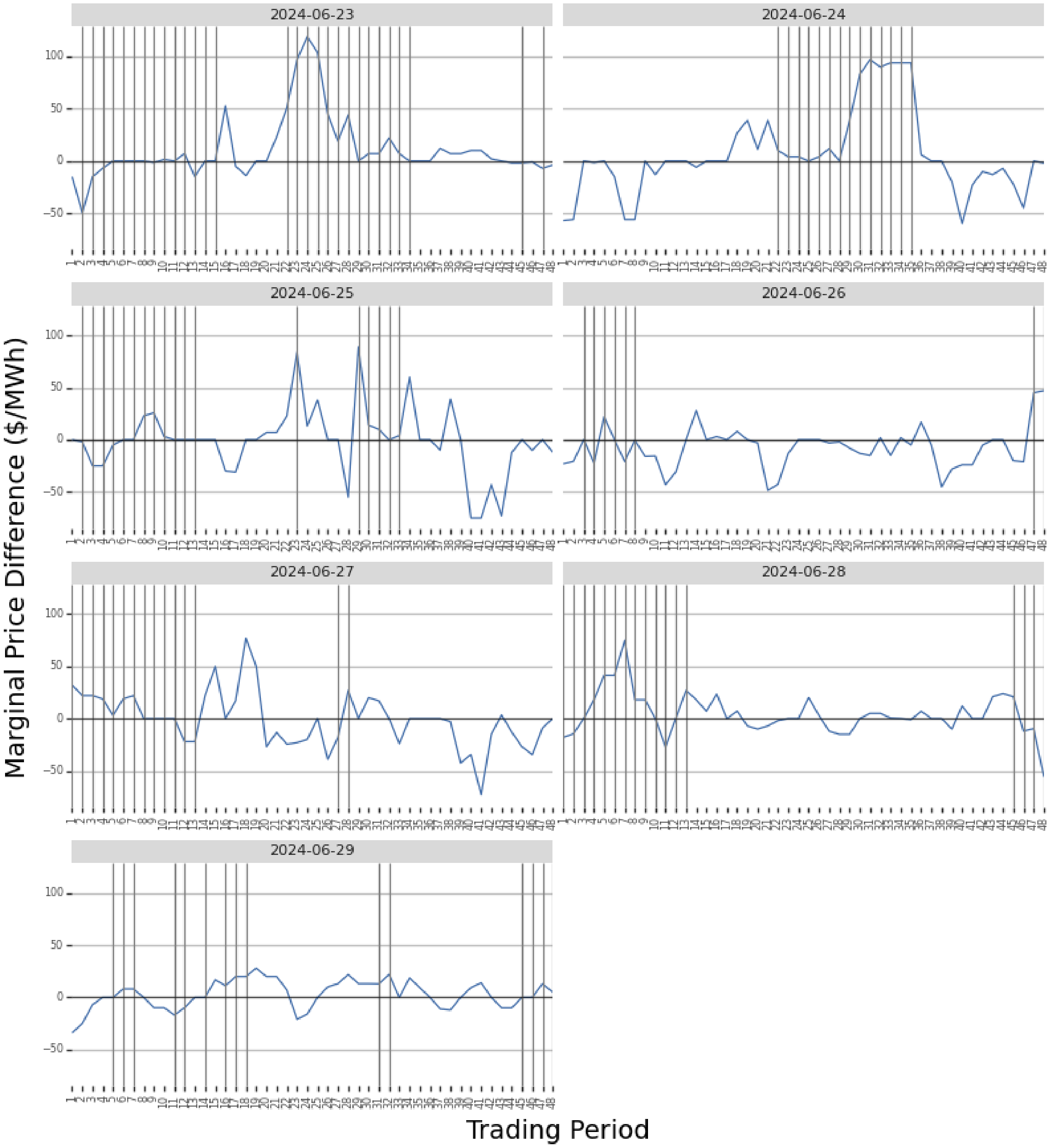
Figure 10: Solar generation between 23-29 June



7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS) projections. The figure highlights when forecasting inaccuracies are causing large differences in final prices. When the difference is positive this means that the 1-hour ahead 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 wind and demand forecasts 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.

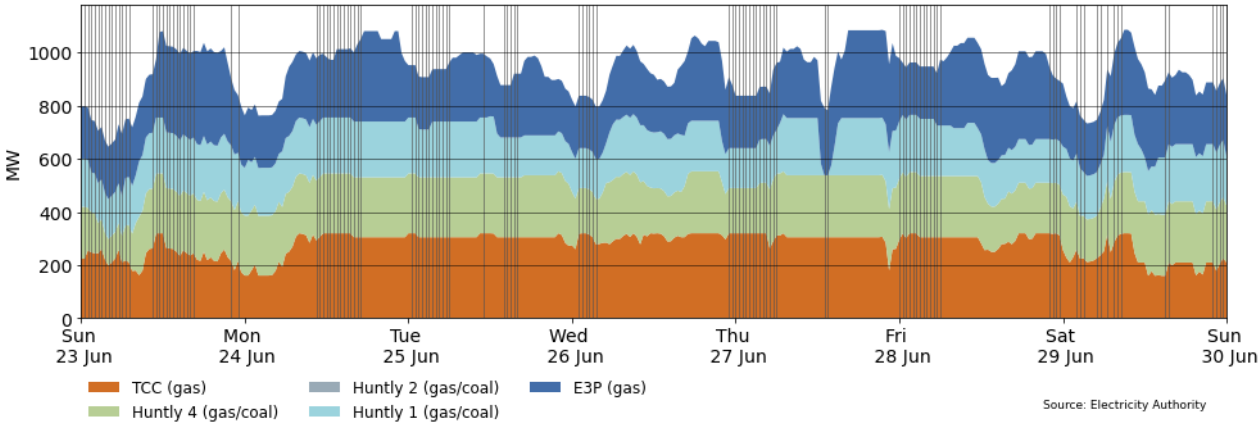
7.4. The most notable positive (marginal prices higher than simulation) difference this week was $119/MWh at 11:30am on Sunday; demand was higher than forecast and wind generation was lower than forecast at this time. Prices were also consistently higher than the simulation on Monday afternoon, when demand was higher than expected. Other positive differences were generally less than $50/MWh.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 23-29 June



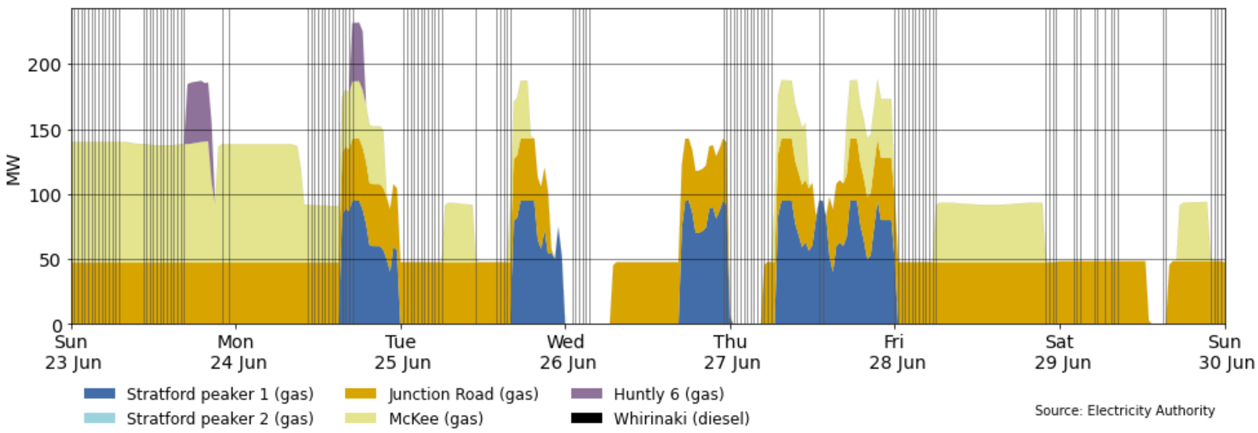
7.5. Figure 12 shows the generation of thermal baseload between 23-29 June. TCC, Huntly 5 (E3P) and Huntly 4 ran continuously this week. Huntly 1 also ran near continuously, but tripped on Thursday afternoon and began running again shortly afterwards.

Figure 12: Thermal baseload generation between 23-29 June



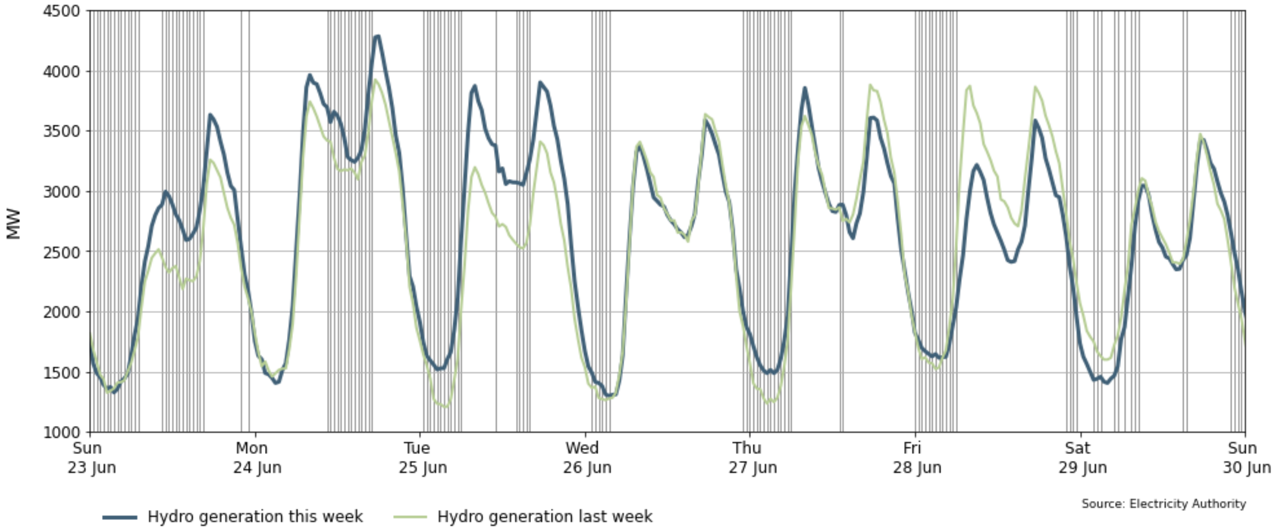
7.6. Figure 13 shows the generation of thermal peaker plants between 23-29 June. Junction Road ran almost continuously as baseload support, turning off early on Wednesday and Thursday and briefly on Saturday afternoon. McKee also ran continuously until Tuesday, then ran during peak and/or shoulder periods every day except Wednesday. Huntly 6 ran during the Sunday and Monday evening peaks. Stratford 1 ran from afternoon to midnight on Monday, Tuesday and Wednesday, as well as from morning peak on Thursday.

Figure 13: Thermal peaker generation between 23-29 June



7.7. Figure 14 shows hydro generation between 23-29 June. Overall, hydro generation was higher than the previous week, but was lower during the Thursday evening peak and Friday due to low demand.

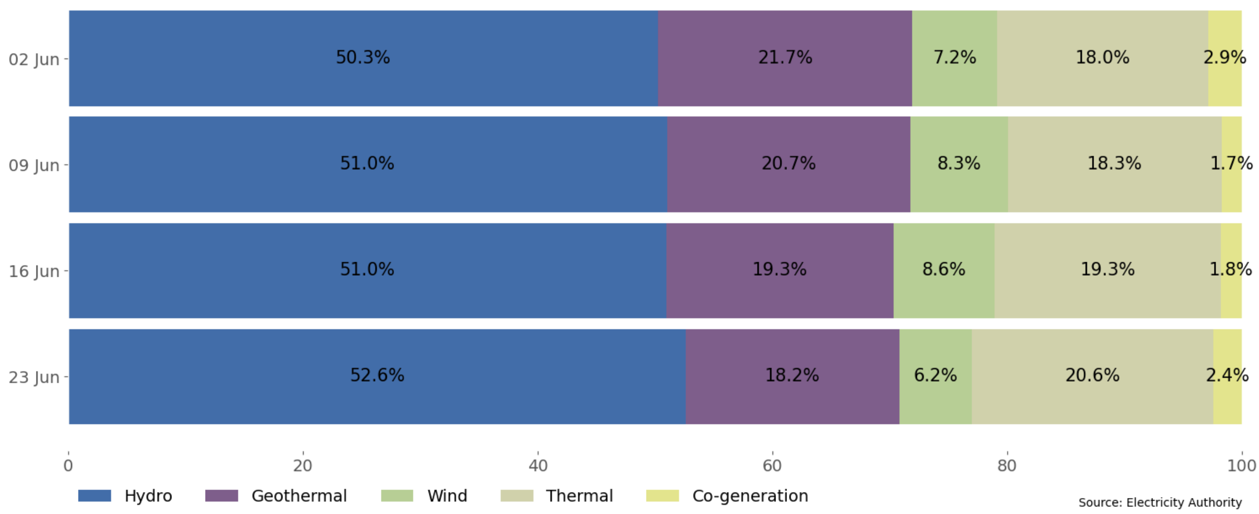
Figure 14: Hydro generation between 23-29 June



7.8. As a percentage of total generation, between 23-29 June, total weekly hydro generation was 52.6%, geothermal 18.2%, thermal 20.6%, wind 6.2%, and co-generation 2.4%.

7.9. The proportion of wind generation decreased this week, as did geothermal generation due to the Tauhara geothermal plant outage. Thermal and hydro generation increased to compensate for this.

Figure 15: Total generation by type as a percentage each week between 2-29 June



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 23-29 June ranged from ~1,000-1,400MW, generally below or close to the long-term average for June. Figure 17 shows the thermal capacity outages.

Figure 16: Total MW loss due to generation outages between 23-29 June

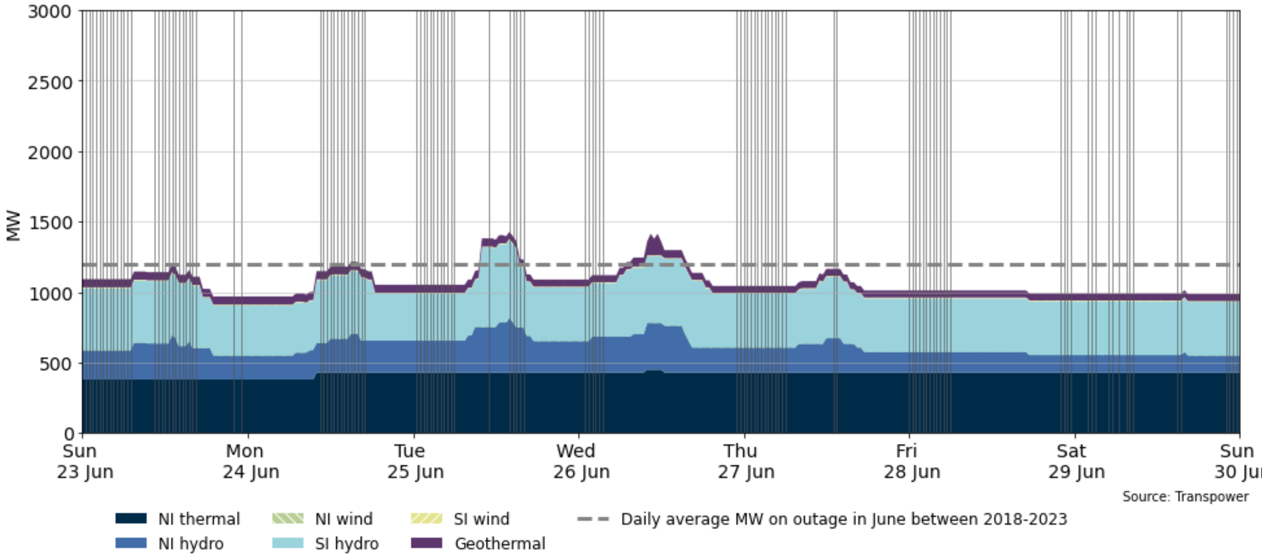
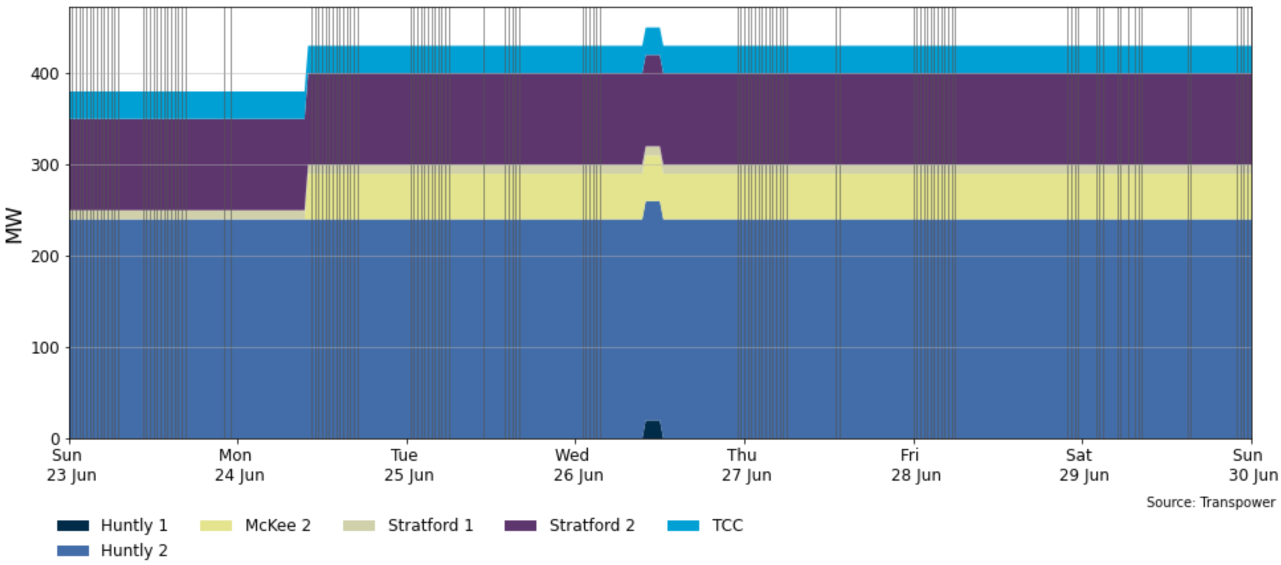


Figure 17: MW loss from thermal outages between 23-29 June



8.2. Notable outages include:

(a) Huntly 2 is on outage until 19 July.

(b) Stratford 2 is on outage until 5 August.

(c) McKee has one unit on outage from 24 June to 29 July.

(d) Tauhara geothermal plant was on outage from 24-29 June.

(e) Junction Road has one unit on outage from 2 June to 20 July.

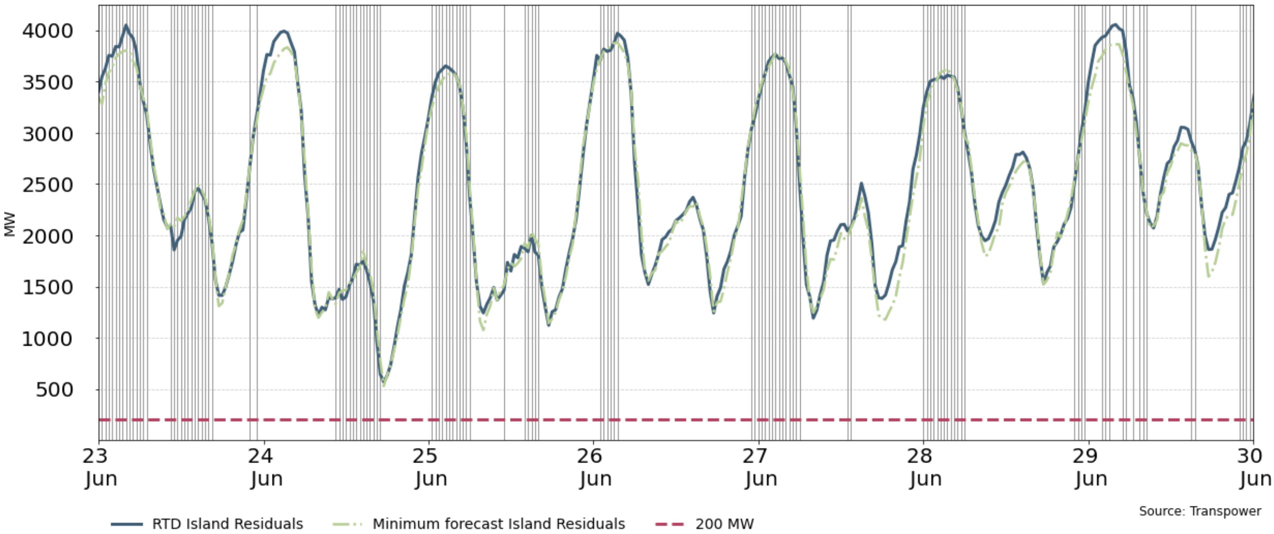
(f) Various North and South Island hydro units were on outage.

9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 23-29 June. 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. The minimum North Island residual was around 570MW on Monday evening.

Figure 18: National generation balance residuals 23-29 June



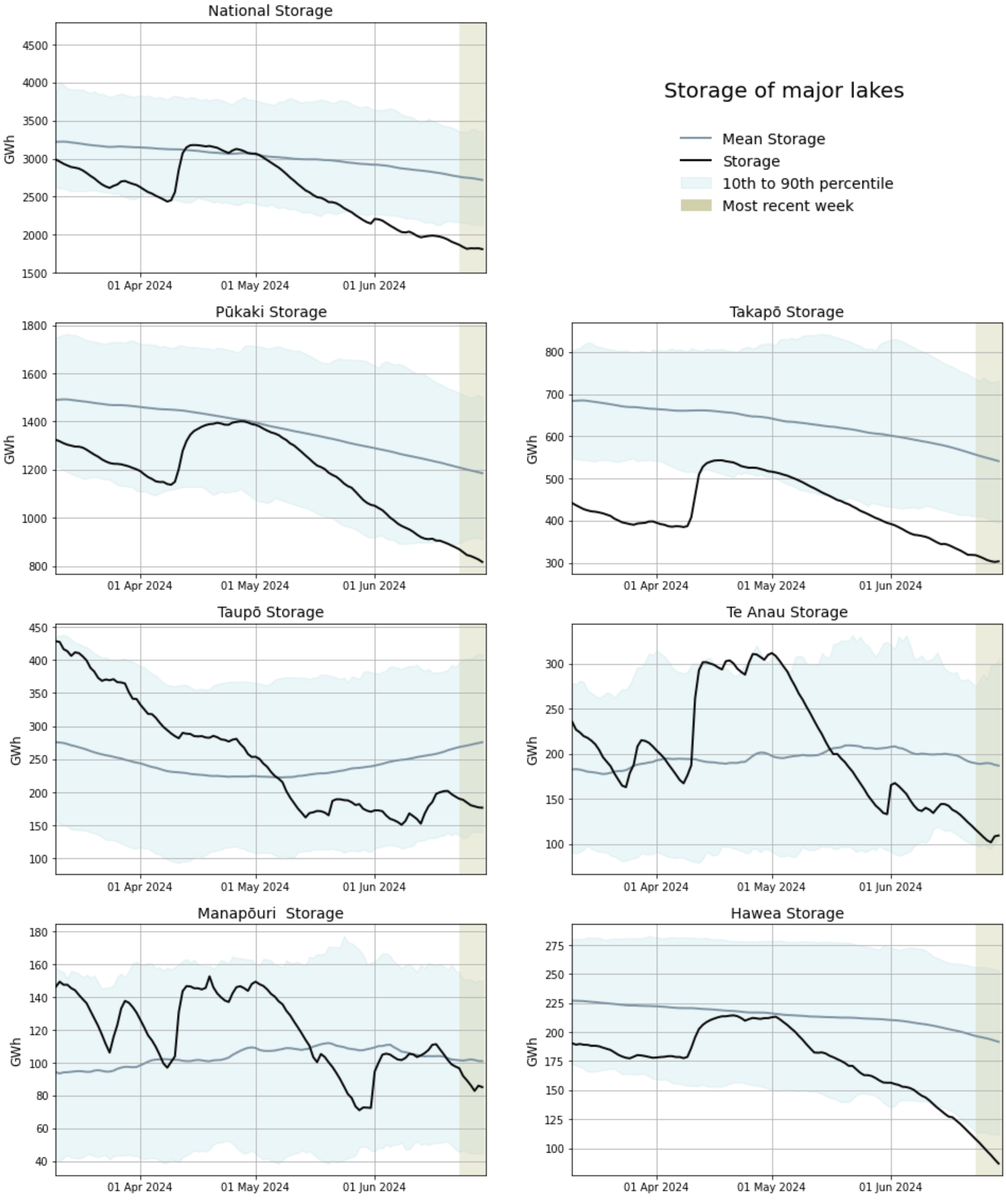
10. Storage/fuel supply

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 hydro storage levels decreased this week, to ~49% nominally full and ~71% of the historical average for this time of the year (as of 29 June).

10.3. Storage decreased at all major lakes this week, though Manapōuri and Te Anau both saw a brief increase in storage towards the end of the week. Levels at all lakes are below mean. Pūkaki, Takapō and Hawea are below their 10th percentiles.

Figure 19: Hydro storage



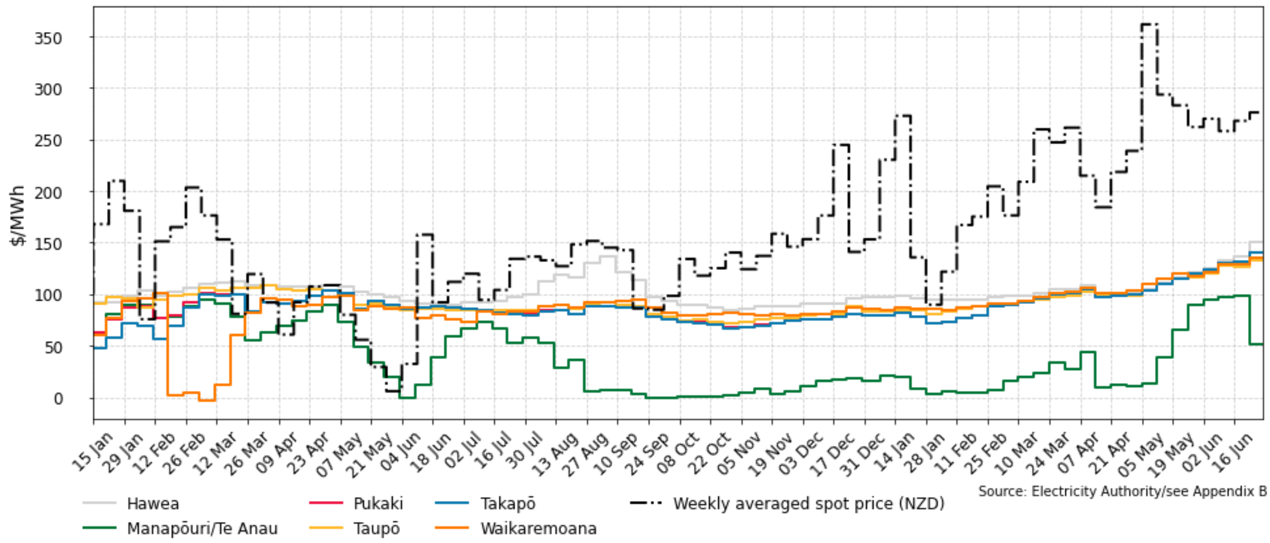
Source: Electricity Authority

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 29 June 2024 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.

11.2. Water values increased compared to the previous week for all major lakes except Manapōuri/Te Anau, which saw a decrease of ~$47.50/MWh. Changes at other lakes ranged from ~$6.00/MWh (Waikaremoana) to an increase of ~$14.50/MWh (Hawea).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 29 June 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 June 2024. The SRMCs for coal and diesel have seen small changes from the previous month, both decreasing slightly. The gas SRMCs decreased slightly this month, possibly due to a lower carbon price.

12.4. The latest SRMC of coal-fuelled Rankine generation is ~$159/MWh. The cost of running the Rankines on gas remains more expensive at ~$312/MWh.

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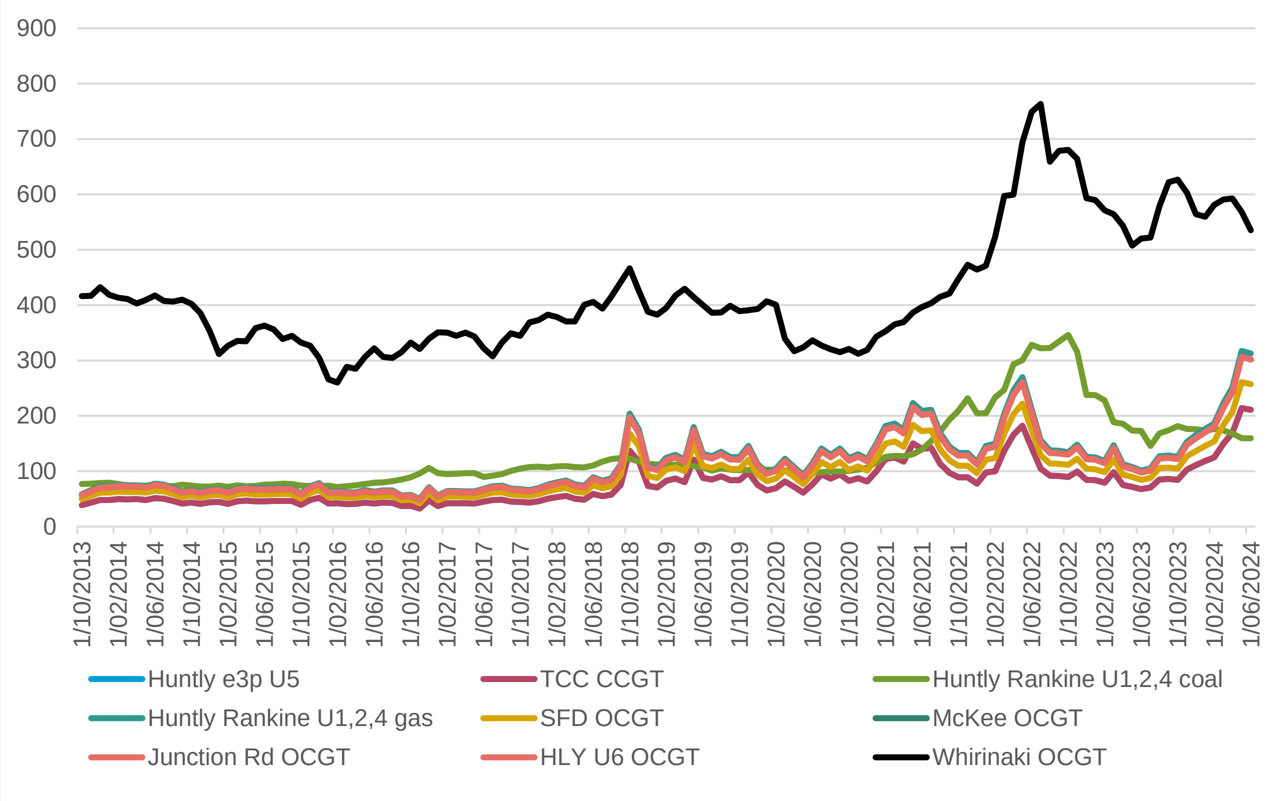
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas fuelled thermal plants is currently between ~$210/MWh and ~$312/MWh.

12.6. The SRMC of Whirinaki is ~$535/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

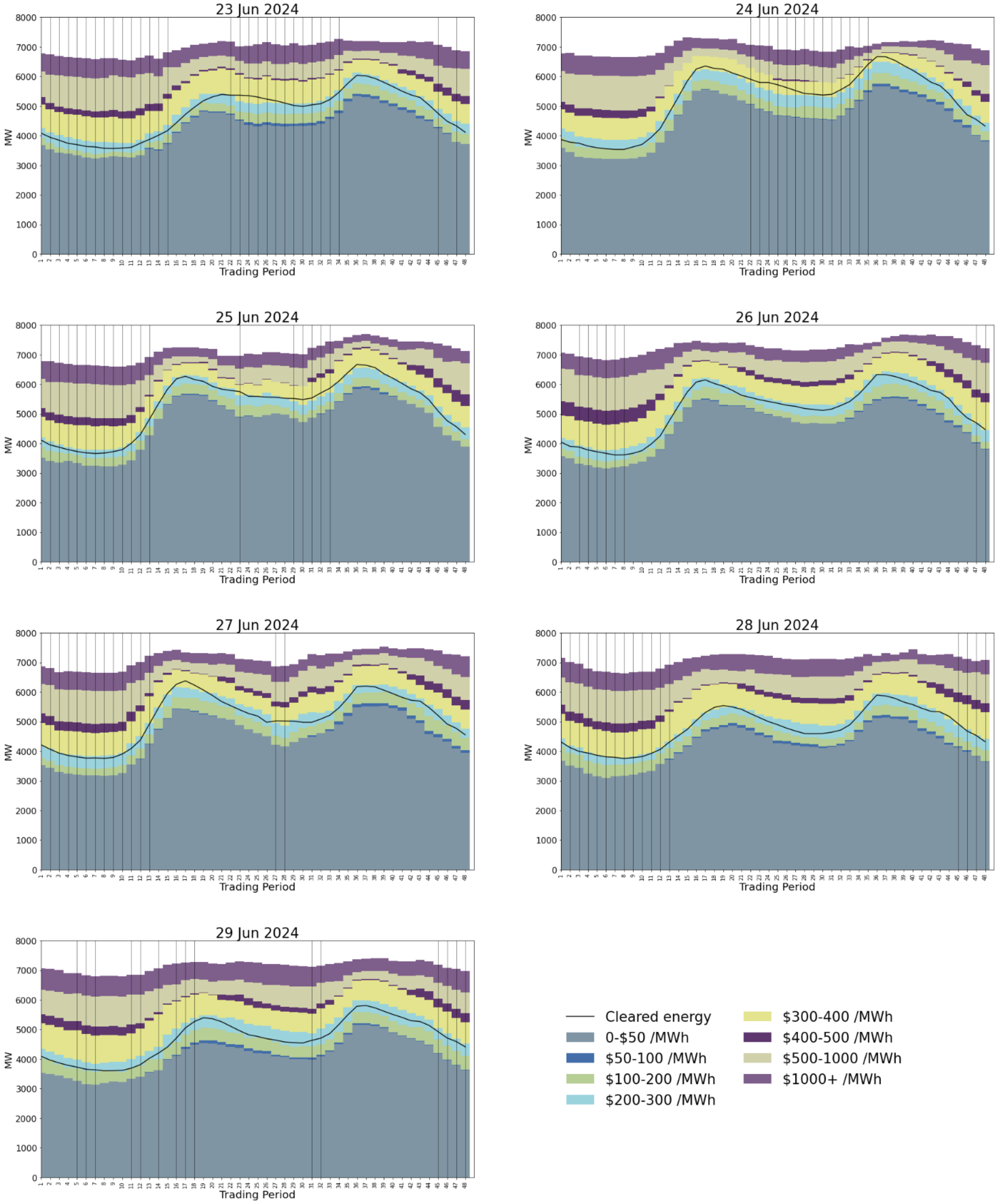


13. Offer behaviour

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. Hydro generation pricing has increased as lake levels have declined, and the number of offers in the $200-$400/MWh region has remained high as a result.

13.2. Most offers cleared in the $200-$300/MWh region, with some clearing in the $300-$400/MWh and $400-$500/MWh bands.

Figure 22: Daily offer stacks



Source: Electricity Authority

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	Trading period	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	Passed to Compliance	Contact	Multiple	High hydro offers
21/01/2024-27/01/2024	Several	Further analysis	Mercury	Waikato hydro dams	Energy offers
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Energy offers
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers