17 June 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 9-15 June 2024

Market monitoring weekly report

Trading conduct report

1. Overview for week of 9-15 June

1.1. Spot prices were mainly above the historical median this week and mostly between $200-$300/MWh. There were some high prices, mainly due to low wind requiring increased hydro generation. Wind generation was very low on Wednesday, dropping below 1MW in the North Island. TCC, Huntly 5 and two Rankines provided baseload generation this week. Hydro storage decreased to around 76% 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 10^{th}-90^{th} 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 9-15 June:

(a) The average wholesale spot price across all nodes was $261/MWh.

(b) 95 percent of prices fell between $130/MWh and $345/MWh.

2.4. The majority of spot prices were between the historical median and 90^{th} percentile this week but dropped below $20/MWh early on Monday due to a combination of high wind and low overnight demand.

2.5. Prices spiked on Wednesday afternoon, with the Ōtāhuhu spot price reaching a maximum of $421/MWh at 4:30pm. North Island wind generation was very low at the time, requiring higher-priced hydro generation to be dispatched to meet demand. The same circumstances led to prices exceeding $300/MWh again that evening.

2.6. Prices were also over $300/MWh at both Benmore and Ōtāhuhu on Sunday afternoon and Thursday afternoon. The high prices on Sunday were due to under-forecast demand requiring increased thermal and hydro generation, while the high price on Thursday co-occurred with a Fast Instantaneous Reserve (FIR) spike price and over-forecast wind requiring increased hydro generation.

2.7. There were again periods this week where Benmore pries were higher than those at Ōtāhuhu. These prices are often associated with high North Island wind generation and high HVDC export southwards.

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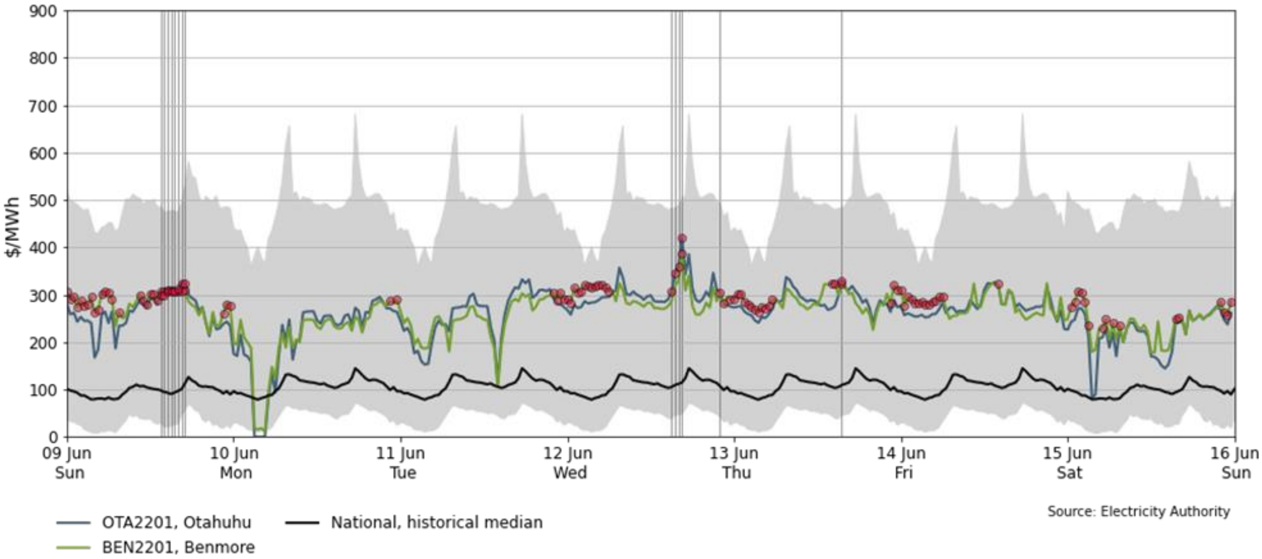
[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75^{th} percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75^{th} percentile (or third quartile value) and IQR is your inter-quartile range.

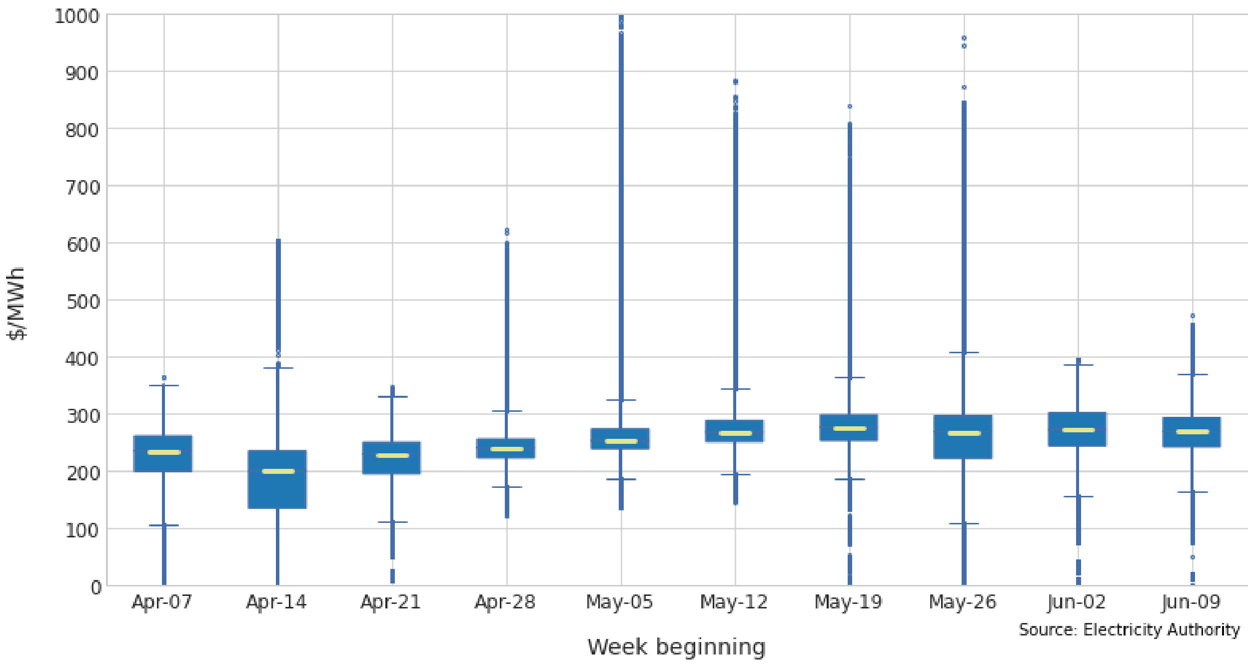
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 9-15 June



2.8. 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.

2.9. The distribution of prices this week was similar to the previous week, with the median price decreasing by $4/MWh to $268/MWh. The middle 50% of prices were between $242/MWh and $293/MWh.

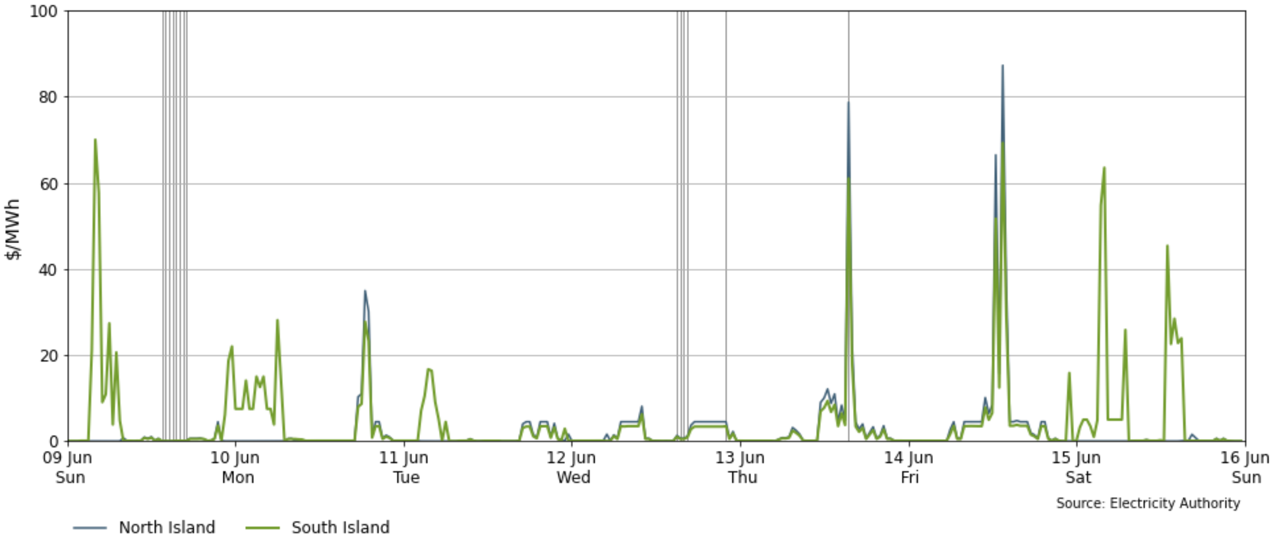
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

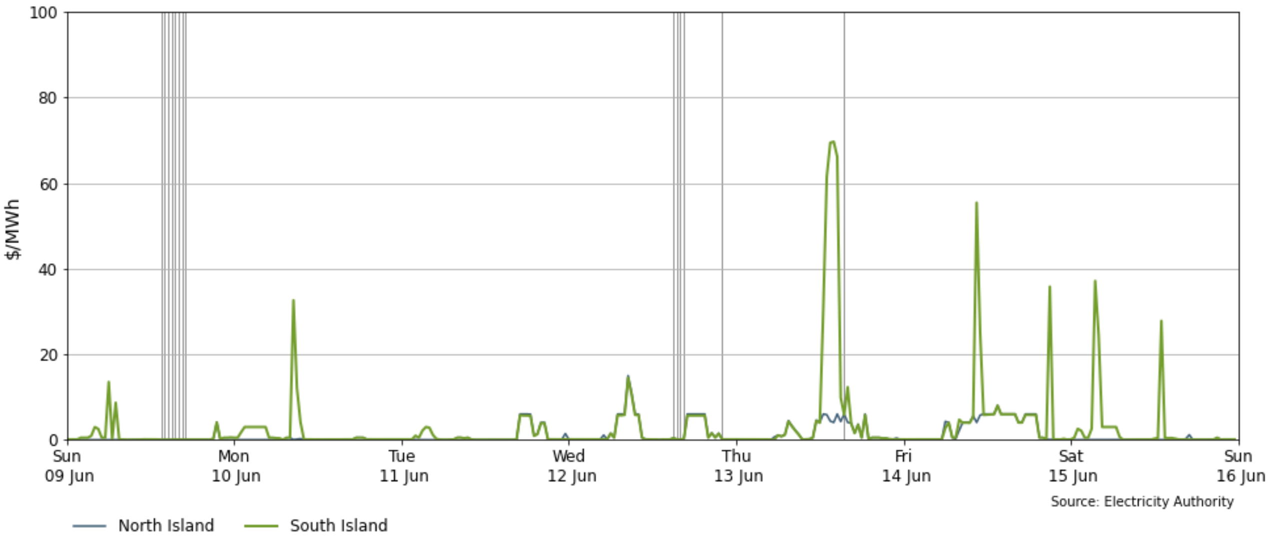
3.1. FIR prices for the North and South Islands are shown below in Figure 3. Higher South Island FIR prices on Sunday, Monday and Saturday were related to the HVDC exporting energy south. The high FIR prices in both islands on Thursday and Friday are being further analysed.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 9-15 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 $40/MWh on Thursday and Friday, these are being analysed further.

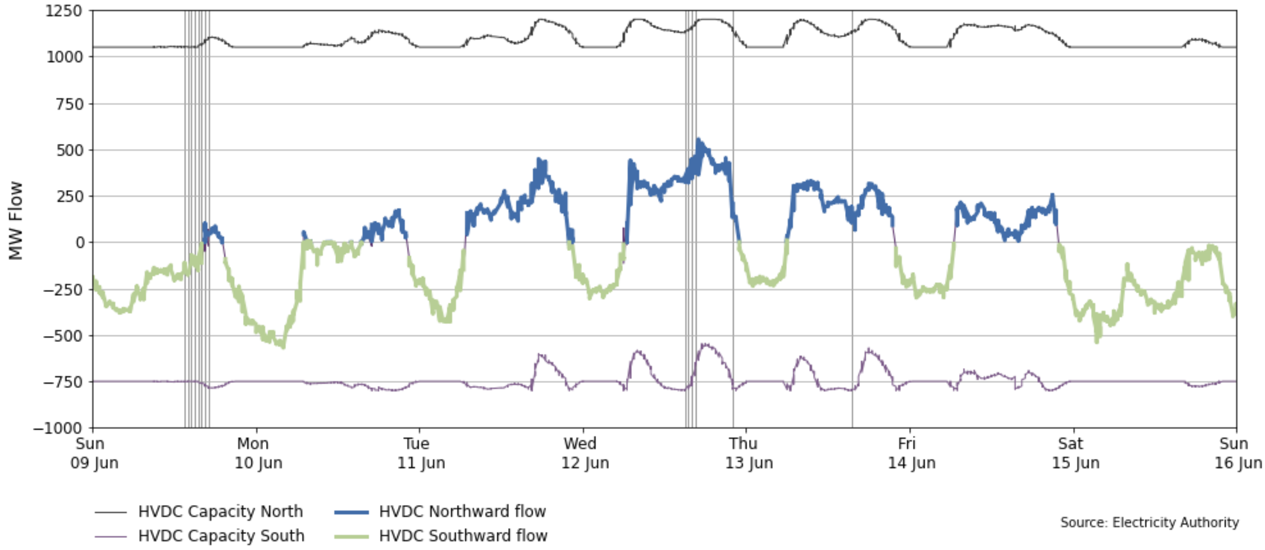
Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 9-15 June



4. HVDC

4.1. Figure 5 shows HVDC flow between 9-15 June. This week HVDC Northward flows occurred mostly during the day from Tuesday to Friday, when wind generation was high. Due to high wind generation and lower demand over the weekend, HVDC flow was mostly southward on Sunday and Monday and entirely southward on Saturday.

Figure 5: HVDC flow and capacity between 9-15 June



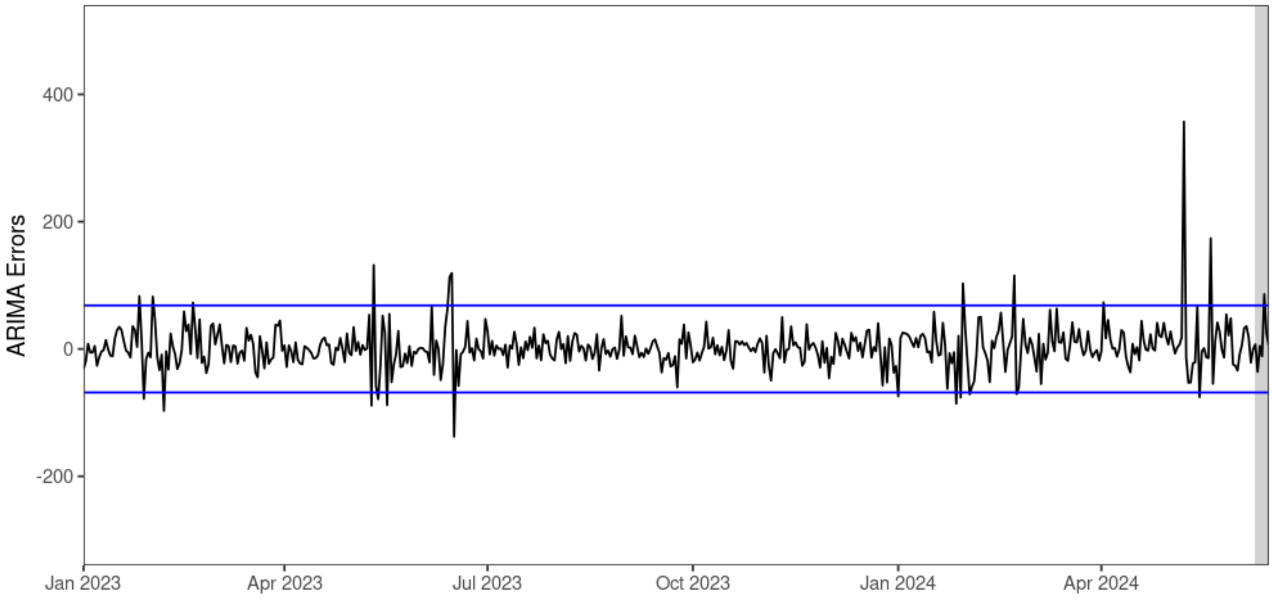
5. Regression residuals

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. The residual on Thursday was above two standard deviations of the data indicating that prices were higher than the model expected. This is likely due to high overnight prices on Thursday which pushed up the daily average price.

Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 to 15 June 2024

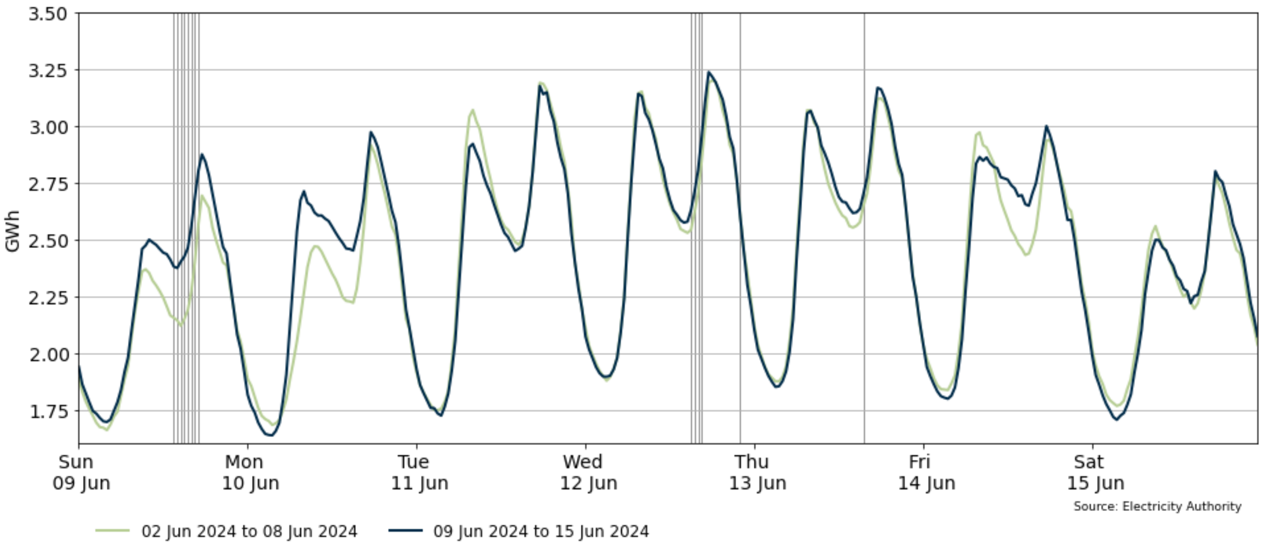


6. Demand

6.1. Figure 7 shows national demand between 9-15 June, compared to the previous week. Overall, demand was similar to the previous week, though it was higher on Sunday, Monday and Friday afternoon. The increase in demand on Monday is likely due to the King's Birthday public holiday the previous week.

6.2. The maximum demand this week was 3.24GWh at 5:30pm on Wednesday.

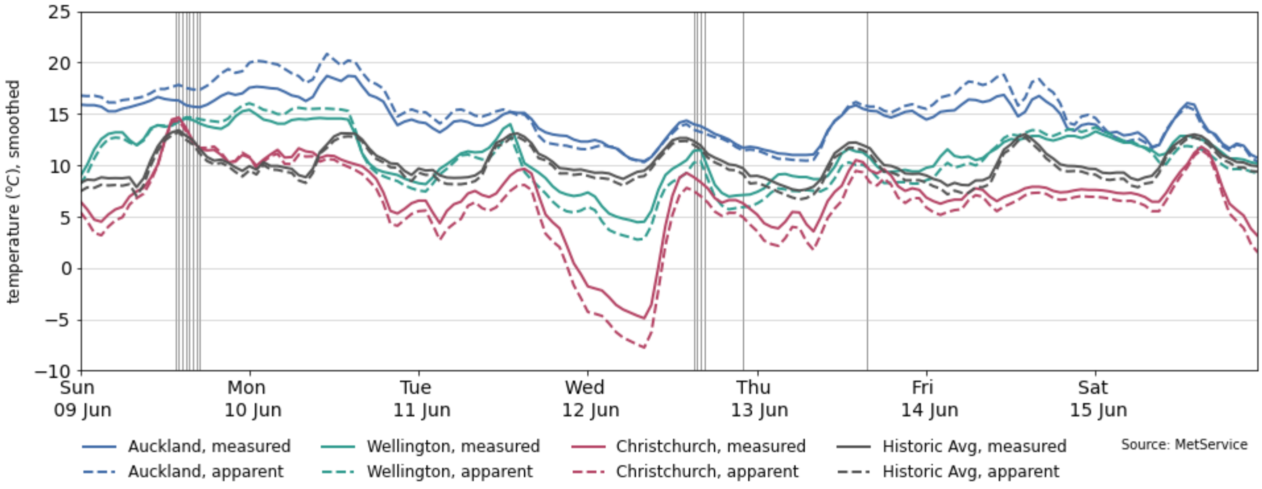
Figure 7: National demand between 9-15 June compared to the previous week



6.3. Figure 8 shows the hourly temperature at main population centres from 9-15 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.

6.4. Temperatures were above average in Auckland, ranging from 10ºC to 21ºC. In Wellington, temperatures ranged from 3ºC to 16ºC. Christchurch temperatures were mostly below average, ranging from -8ºC to 14ºC.

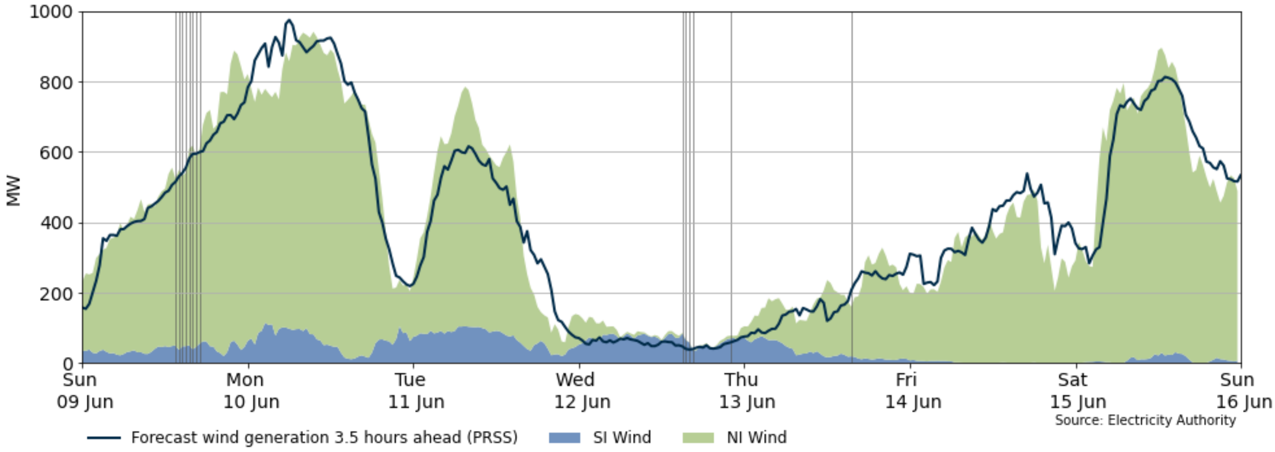
Figure 8: Temperatures across main centres between 9-15 June



7. Generation

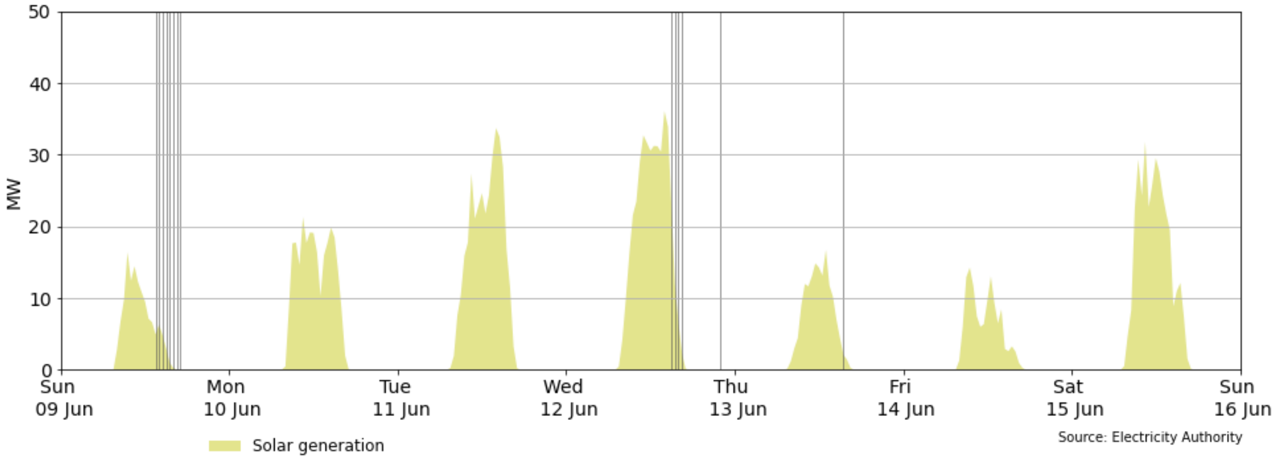
7.1. Figure 9 shows wind generation, from 9-15 June. Average wind generation was 413MW this week, ranging from 39MW-941MW. Wind generation was high on Monday and Saturday but very low on Wednesday, especially in the North Island, where it dropped below 1MW during the period of high prices that afternoon. When prices reached over $300/MWh on Thursday, wind generation was low and ~50MW below forecast.

Figure 9: Wind generation and forecast between 9-15 June



7.2. Figure 10 shows solar generation from 9-15 June. Maximum daily solar generation was between 14MW and 36MW this week. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource, as we approach the winter solstice.

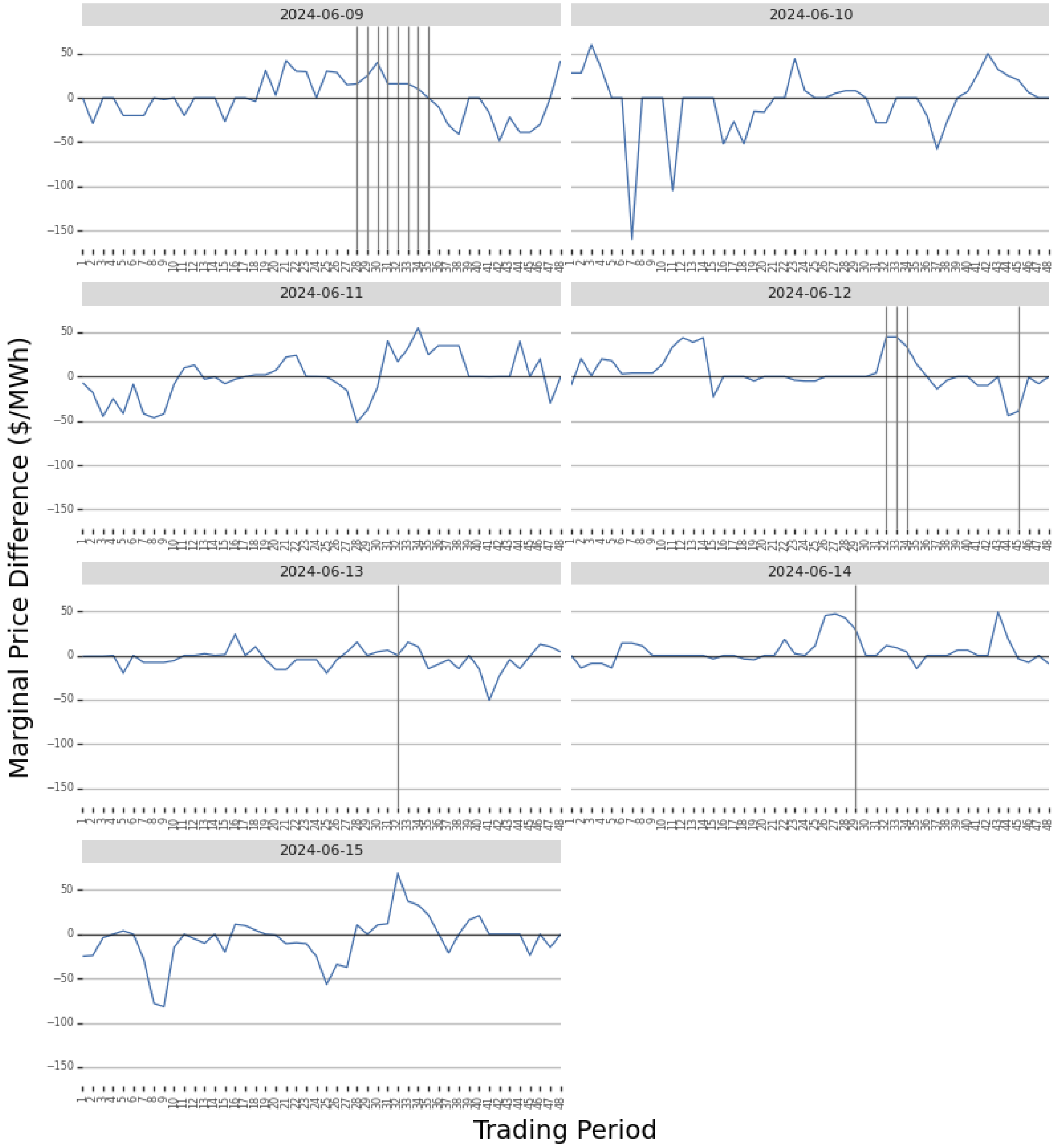
Figure 10: Solar generation between 9-15 June



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.

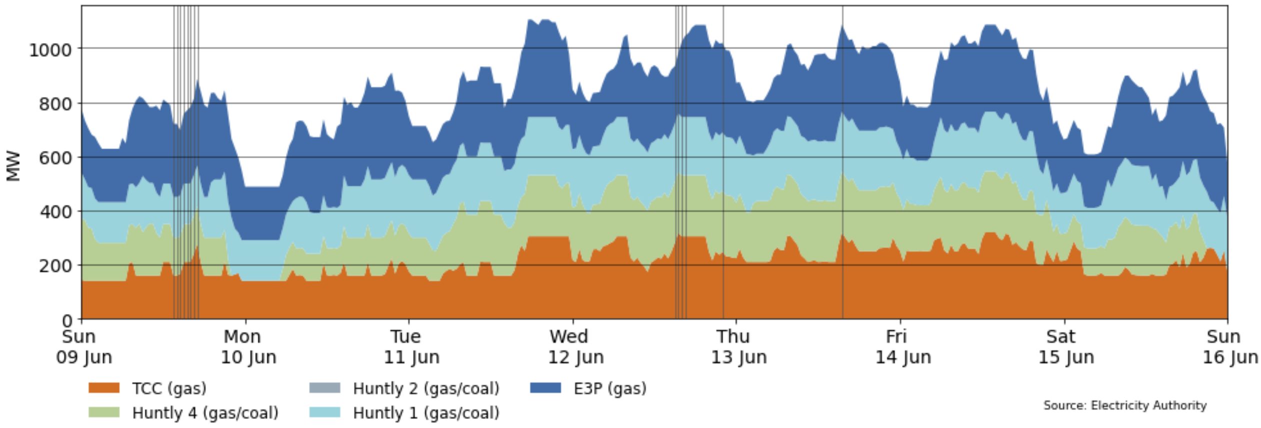
7.4. The most notable positive (marginal prices higher than simulation) difference this week was $69/MWh on Saturday. Other positive differences were generally less than $50/MWh.

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 9-15 June



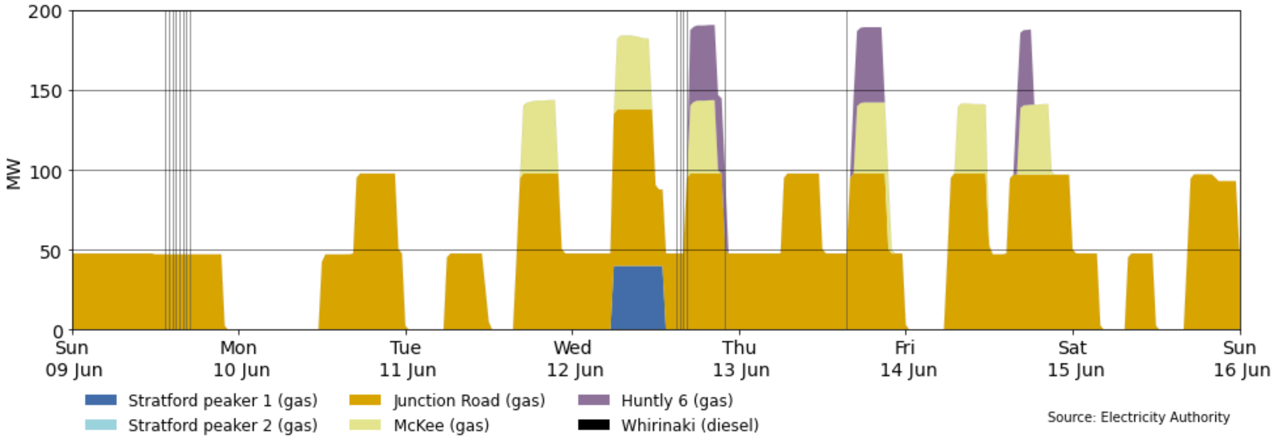
7.5. Figure 12 shows the generation of thermal baseload between 9-15 June. TCC, Huntly 5 (E3P) and Huntly 1 ran continuously this week. Huntly 4 also ran for most of the week, turning off overnight on Sunday and Saturday.

Figure 12: Thermal baseload generation between 9-15 June



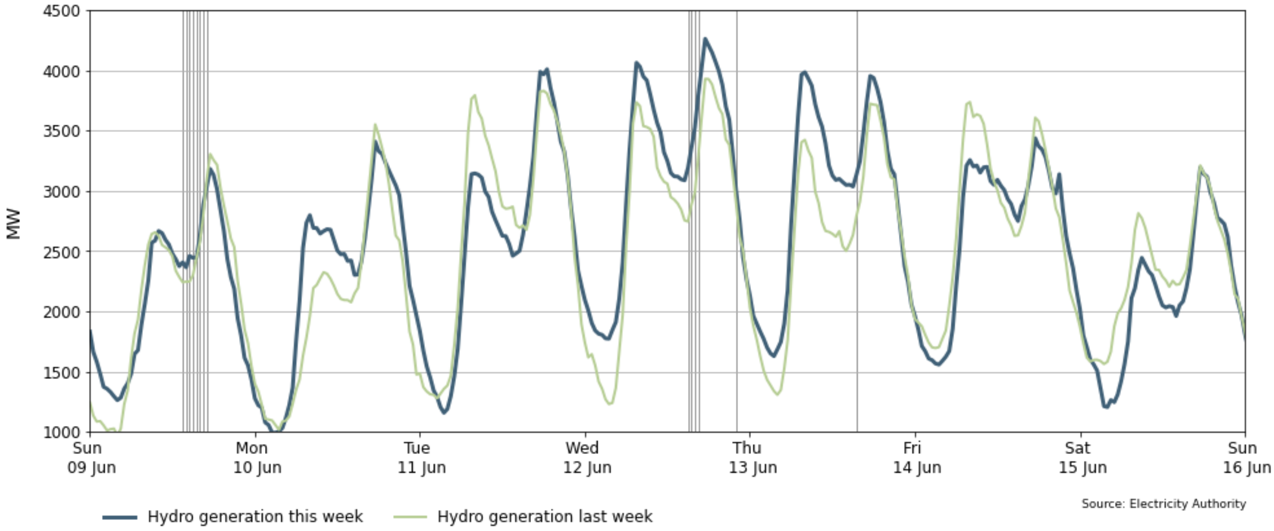
7.6. Figure 13 shows the generation of thermal peaker plants between 9-15 June. Junction Road ran during peak and shoulder periods each day, joined by McKee and/or Huntly 6 between Tuesday and Saturday. While wind generation was low on Wednesday and Thursday, Junction Road ran continuously, with Stratford 1 also running on Wednesday afternoon.

Figure 13: Thermal peaker generation between 9-15 June



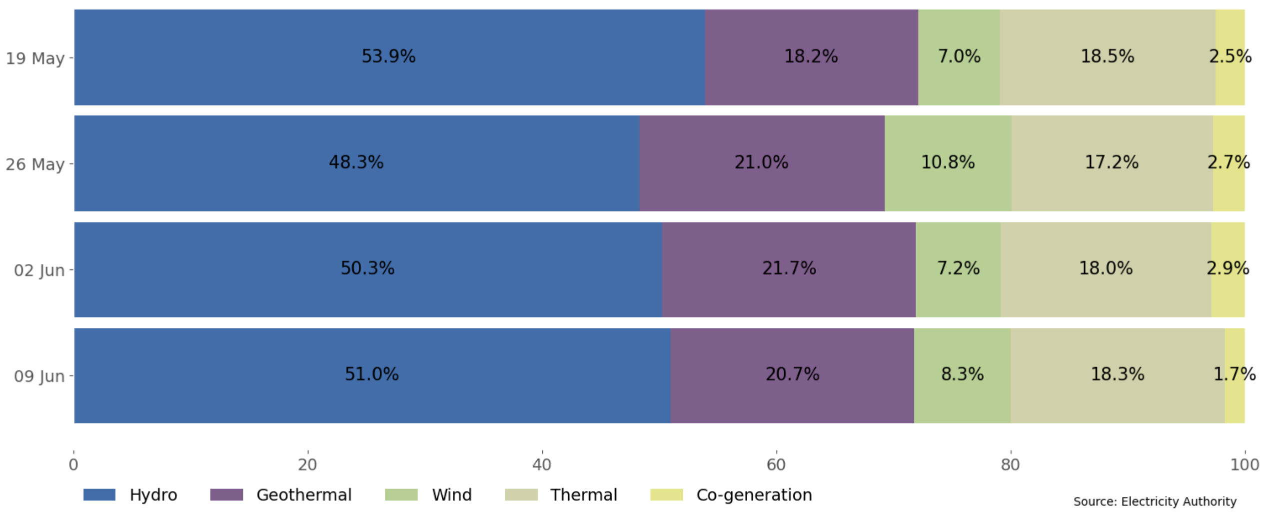
7.7. Figure 14 shows hydro generation between 9-15 June. Hydro generation was higher than the previous week while wind generation was low on Wednesday and Thursday. It was also higher on Monday, likely due to low demand the previous week due to King's Birthday. However, it was lower on Friday and Saturday, and the overall proportion of hydro generation was similar to the previous week.

Figure 14: Hydro generation between 9-15 June



7.8. As a percentage of total generation, between 9-15 June, total weekly hydro generation was 51%, geothermal 20.7%, thermal 18.3%, wind 8.3%, and co-generation 1.7%.

Figure 15: Total generation by type as a percentage each week between 19 May-15 June



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 9-15 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 9-15 June

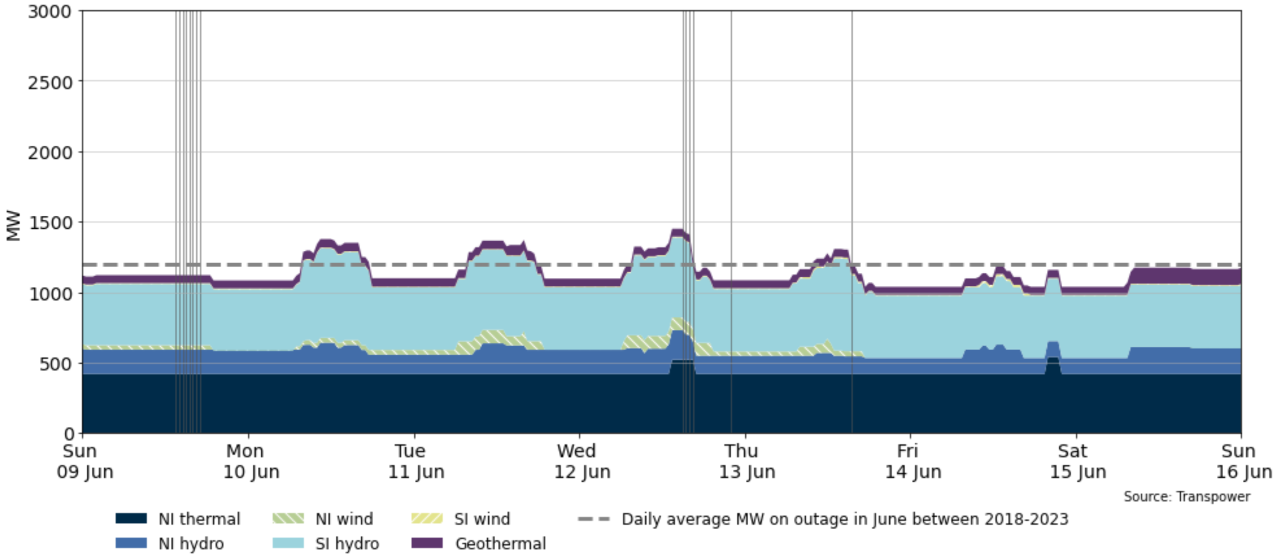
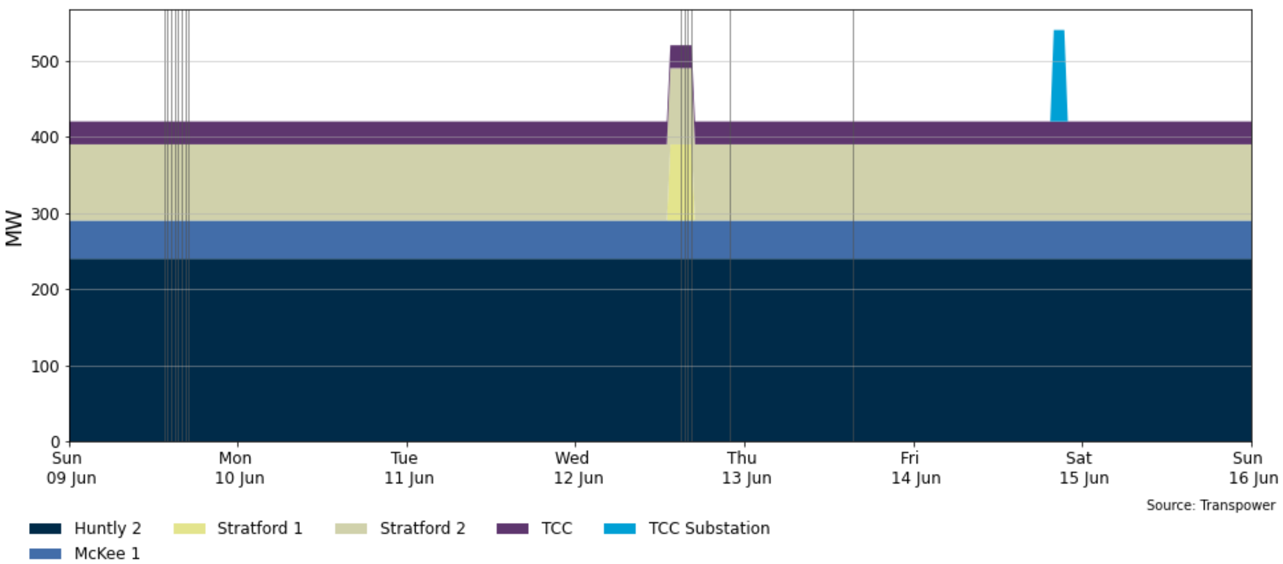


Figure 17: MW loss from thermal outages between 9-15 June



8.2. Notable outages include:

(a) Huntly 2 is on outage until 19 July 2024.

(b) TCC was on outage on 14 June.

(c) Stratford 1 was on outage on 12 June.

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

(e) McKee is on partial outage until 18 June.

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

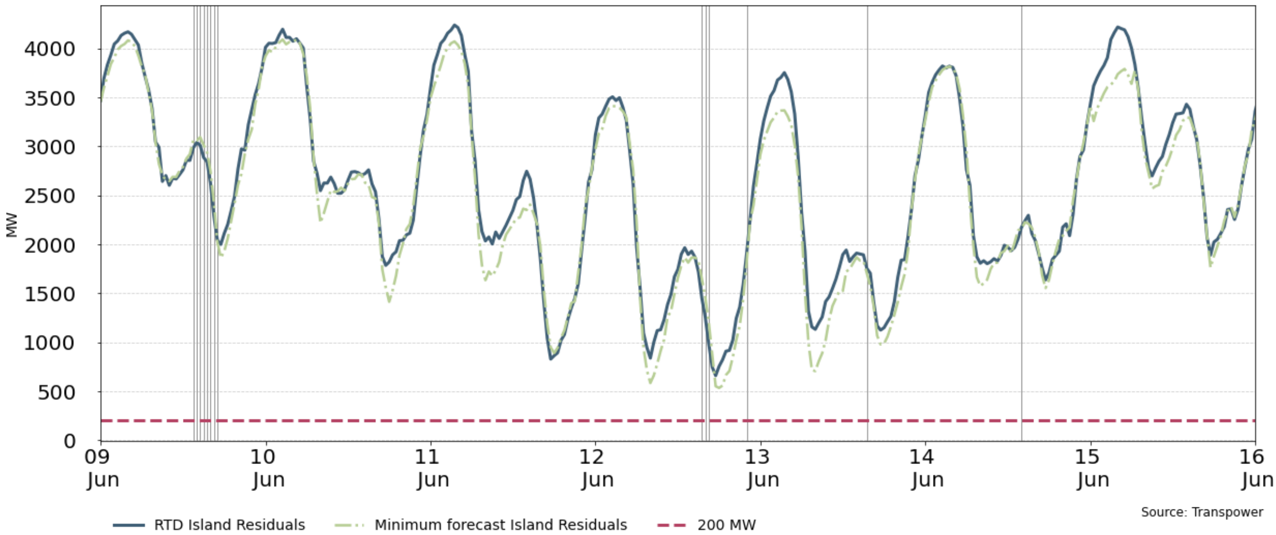
9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 9-15 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 470MW on Wednesday evening.

Figure 18: National generation balance residuals 9-15 June



10. Storage/fuel supply

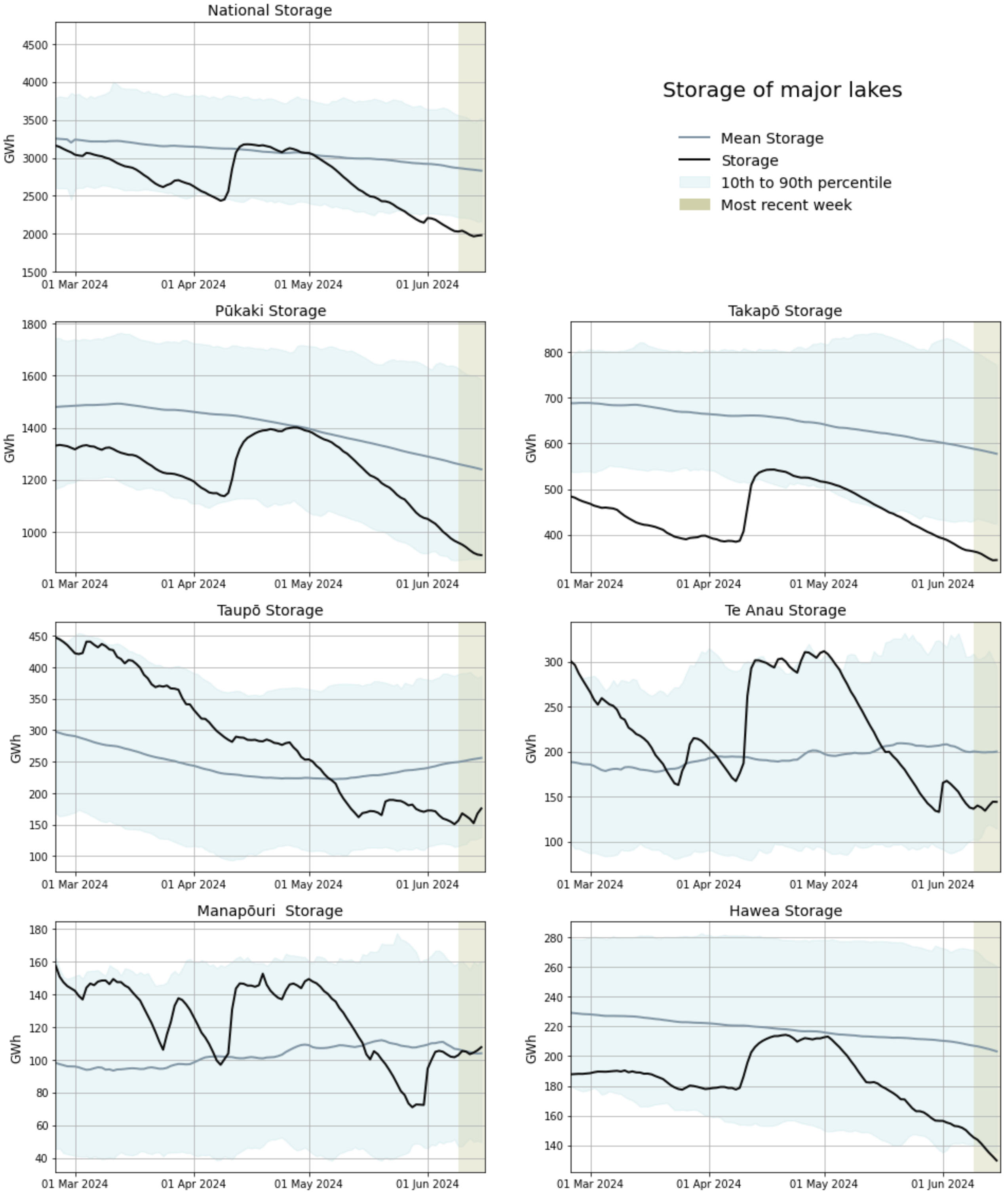
10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National hydro storage levels declined this week, to ~54% nominally full and ~76% of the historical average for this time of the year (as of 15 June).

10.3. Pūkaki storage is close to its 10th percentile regions and Takapō is now well below its 10th percentile with storage under 400GWh. Taupō storage remains below its mean and close to its 10th percentile region, although did see some inflows during the week. Hawea storage continues to decline with storage now just below its 10th percentile region.

10.4. Te Anau saw a small uptick in storage during the week but remains below its historic mean. Manapōuri also saw small increases, with storage currently close to its mean.

Figure 19: Hydro storage



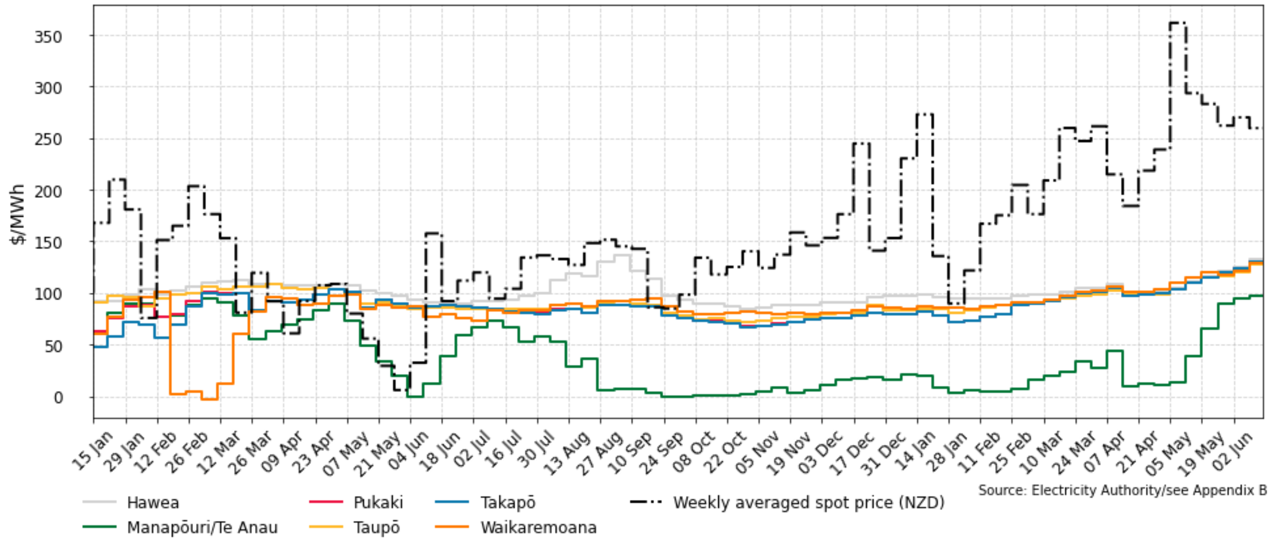
Source: Electricity Authority

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 15 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. Compared to the previous week, there was an increase in water values across all lakes between ~$2.20/MWh (Manapōuri/Te Anau) to ~$8.10/MWh (Waikaremoana).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 15 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.

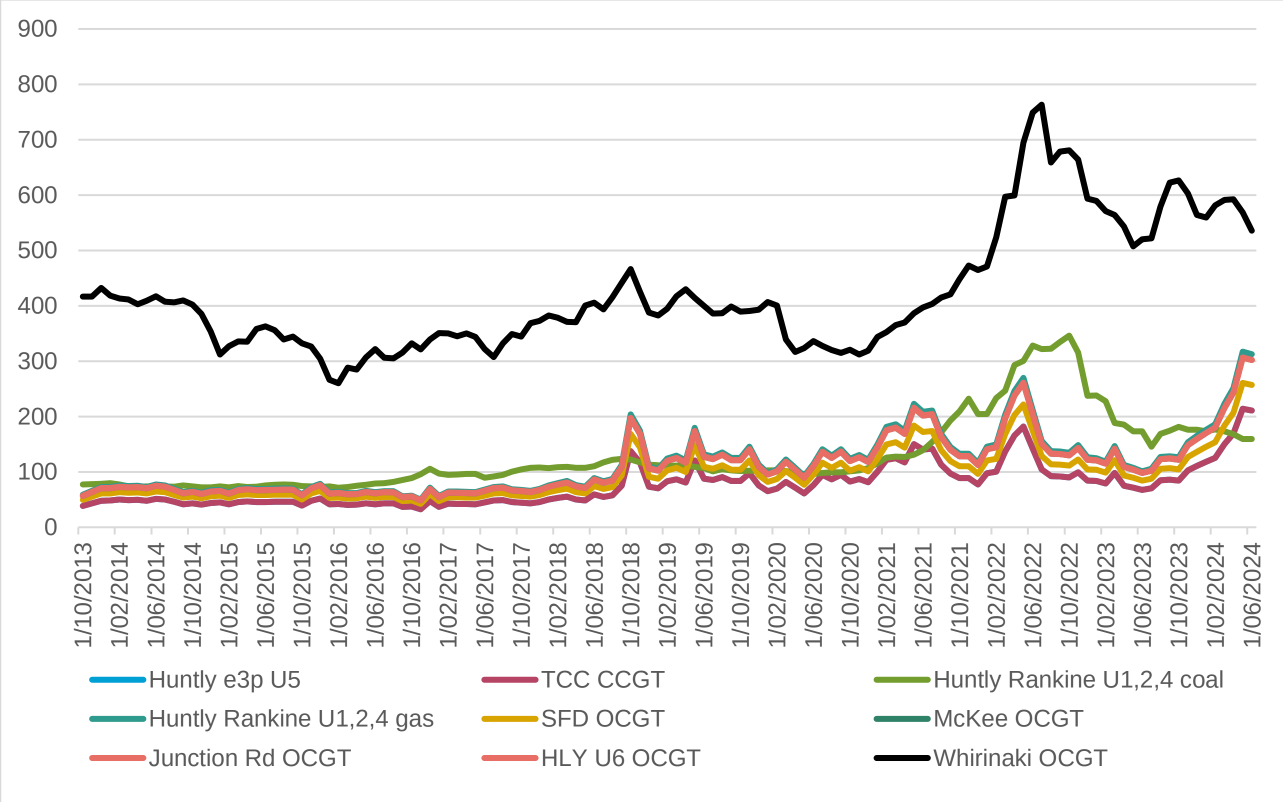
12.5. The SRMC of gas fuelled thermal plants is currently between ~$210/MWh and ~$312/MWh.

[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.

12.6. 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

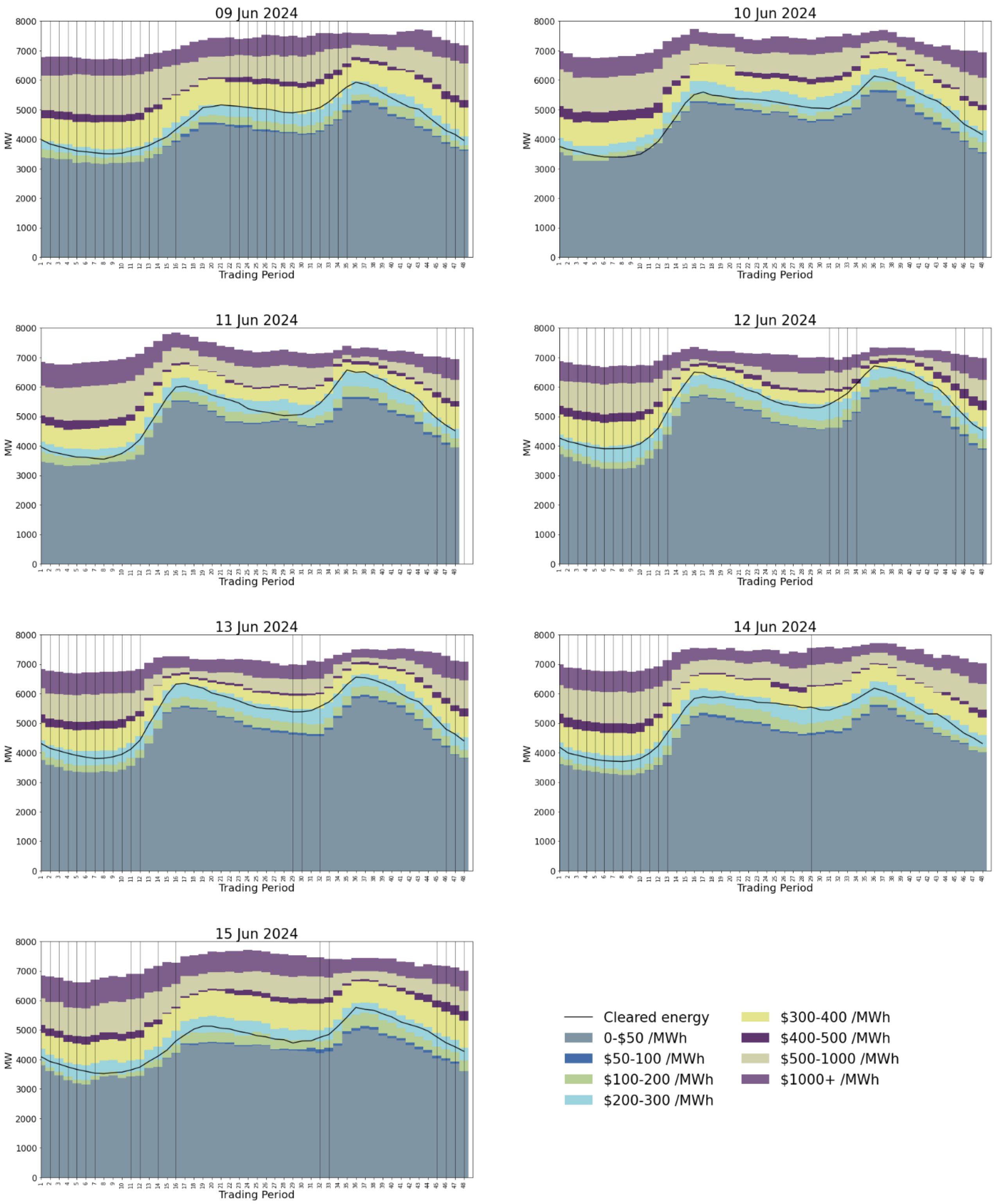


13. Offer behaviour

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. The $200-$300/MWh and $300-$400/MWh bands remain prominent as significant quantities of hydro generation are priced to reflect the declining lake levels.

13.2. Most offers cleared in the $200-$300/MWh region, with several in the $300-$400/MWh and $100-$200/MWh regions. Offers reached the $400-$500/MWh band during Wednesday's price spike.

Figure 22: Daily offer stacks



Source: Electricity Authority

14. Ongoing work in trading conduct

14.1. Further analysis will be done on the trading periods this week which saw high FIR and SIR prices.

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	Further analysis	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
13/06/2024-14/06/2024	Several	Further analysis	N/A	N/A	Reserve prices