8 July 2024

Trading conduct report 30 June-6 July 2024

Market monitoring weekly report

Trading conduct report

1. Overview

1.1. Spot prices were high towards the end of this week, often exceeding $300/MWh. Low wind and high demand on Friday morning resulted in reserve scarcity, with both spot and SIR prices reaching over $1,000/MWh. TCC, Huntly 5 and two Rankines provided baseload generation this week. Hydro storage decreased to around 72% of 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, it also singles 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. Figures 1 and 2 show the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than $300/MWh are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 30 June-6 July:

(a) the average wholesale spot price across all nodes was $296/MWh.

(b) 95% of prices fell between $146/MWh and $495/MWh.

2.4. Overall, the majority of spot prices were within $245/MWh and $323/MWh, with the weekly average price increasing by $20/MWh compared to the previous week.

2.5. Prices were below the historical 90th percentile at that start of the week but were often over $300/MWh from Wednesday onwards. This was due to low wind generation and high demand, in addition to some demand forecasting inaccuracies, and times of high-priced thermal and hydro generation dispatches. Additionally from mid-week onwards some hydro offers increased in price as hydro storage continues to decline.

2.6. Prices spiked on Friday morning, reaching a maximum at 8:00am of $2,326/MWh at Ōtāhuhu and $1,904/MWh at Benmore. Low wind generation, combined with demand being under forecast by ~100MW, the system ran with reserve scarcity and Huntly 5 and 6 were dispatched at high prices to meet demand.

2.7. The high price on Friday morning and the high prices on Saturday afternoon will be further analysed by the market monitoring team.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 30 June-6 July

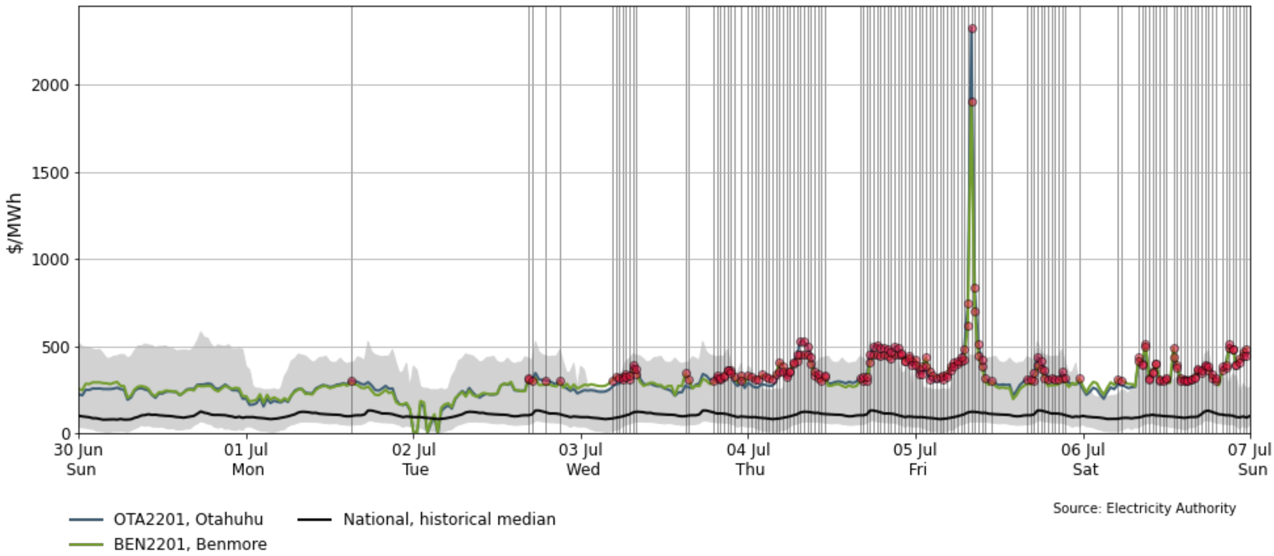
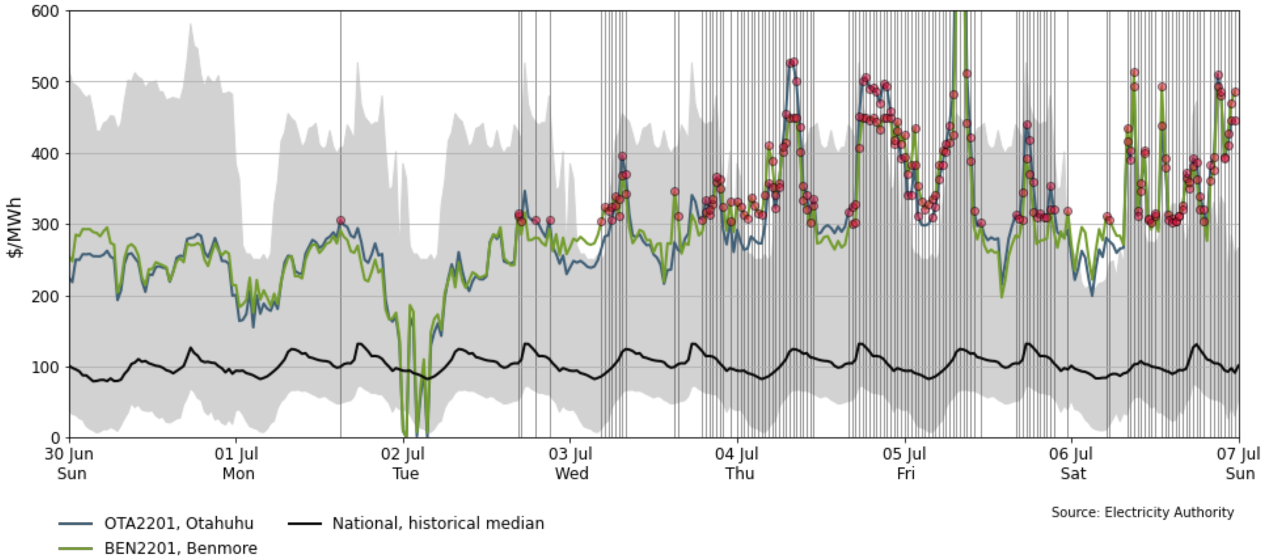


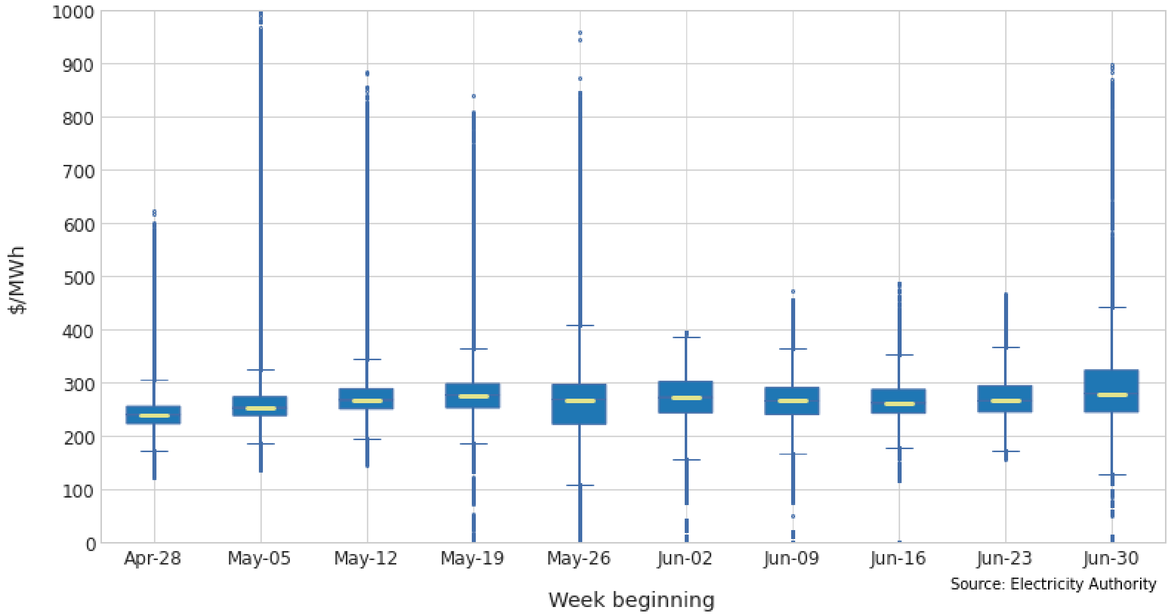
Figure 2: Wholesale spot prices ≤$600/MWh at Benmore and Ōtāhuhu, 30 June-6 July



2.8. Figure 3 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 blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.9. Compared to the previous week, the median price increased by $13/MWh. The range of prices also increased, as did the number of outliers, indicating that prices were more volatile.

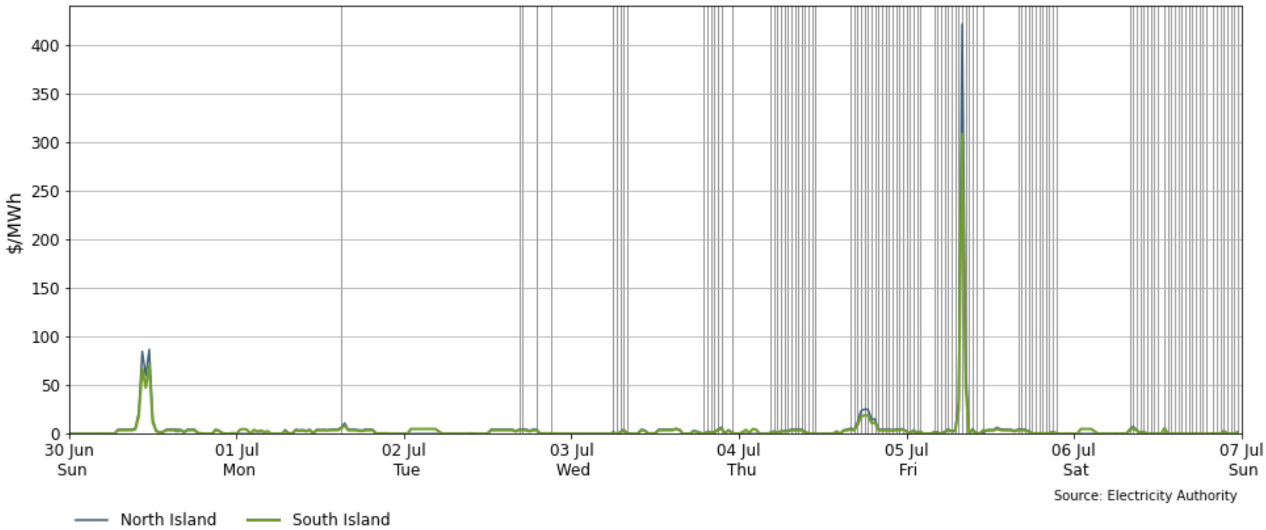
Figure 3: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

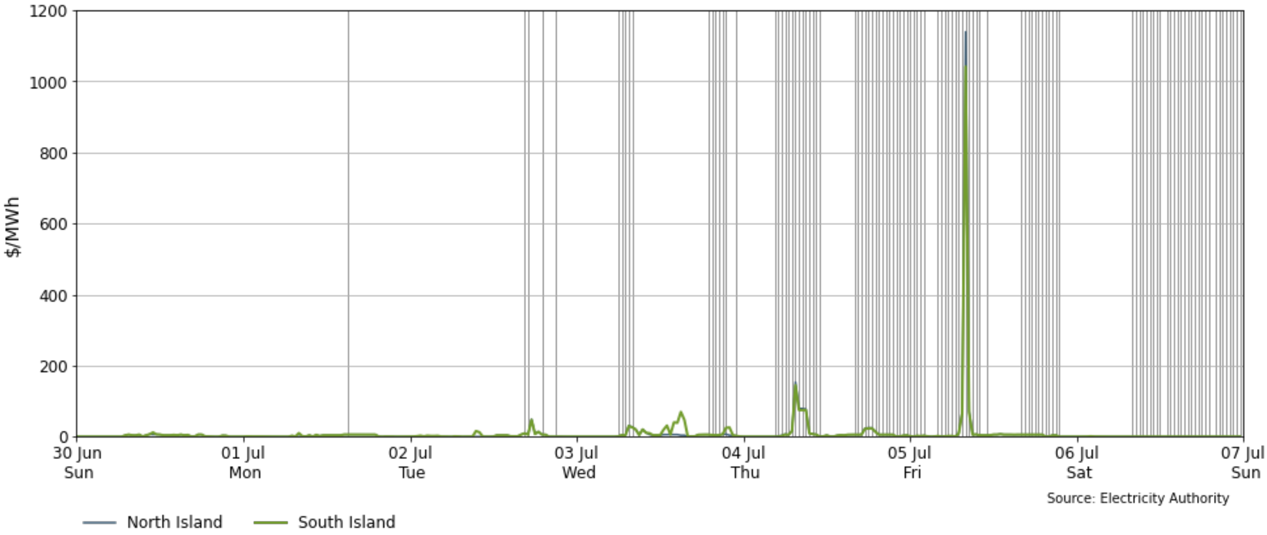
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 4. FIR prices were generally below $5/MWh, but spiked on Sunday and Friday. Between 10:30-11:30am on Sunday, prices in both islands were between $67/MWh-$87/MWh. At 8:00am on Friday, the FIR price reached $421/MWh in the North Island and $308/MWh in the South Island.

Figure 4: Fast instantaneous reserve price by trading period and island, 30 June-6 July 2024



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 5. SIR prices were generally below $1/MWh, but spiked on Thursday and Friday. Between 7:30-9:00am on Thursday, prices in both islands were between $75/MWh-$154/MWh. At 8:00am on Friday, the SIR price reached $1,140/MWh in the North Island and $1,042/MWh in the South Island. Demand was around 100MW higher than forecast at this time, and the system ran in SIR reserve scarcity for part of the trading period.

Figure 5: Sustained instantaneous reserve by trading period and island, 30 June-6 July 2024



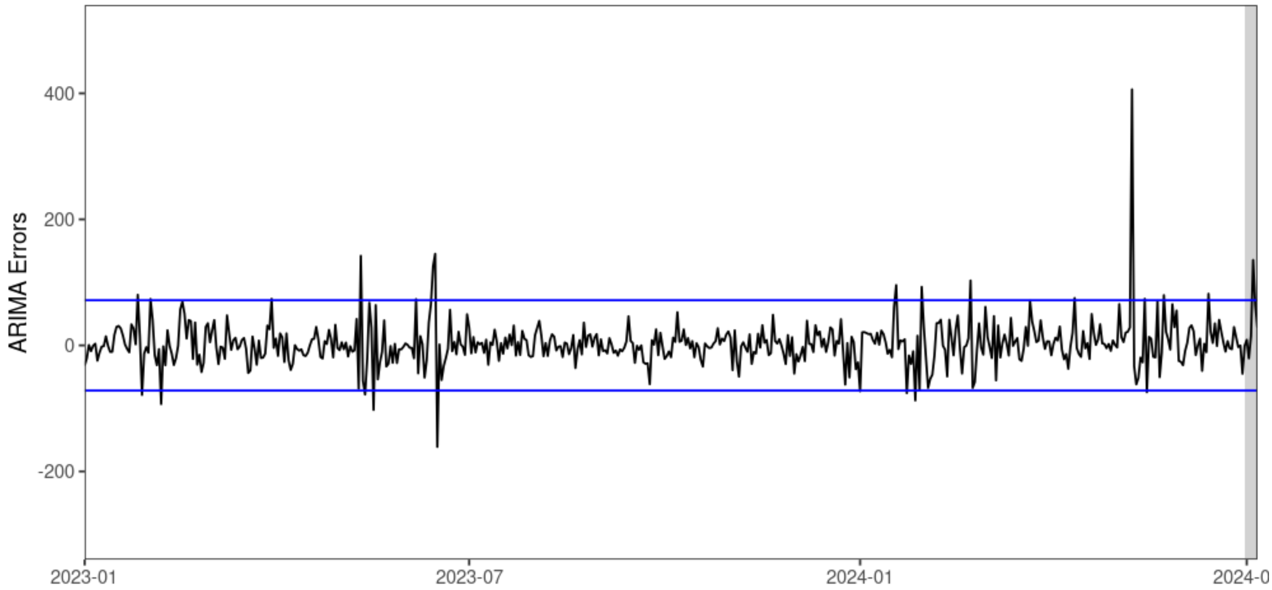
4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot 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.

4.2. 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 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 in the regression analysis.

4.3. The residual on Thursday was above two standard deviations of the data indicating that prices were higher than the model expected. This could be due to the greater frequency of prices over $300/MWh that began occurring on Thursday.

Figure 6: Residual plot of estimated daily average spit prices, 1 January 2023 – 6 July 2024

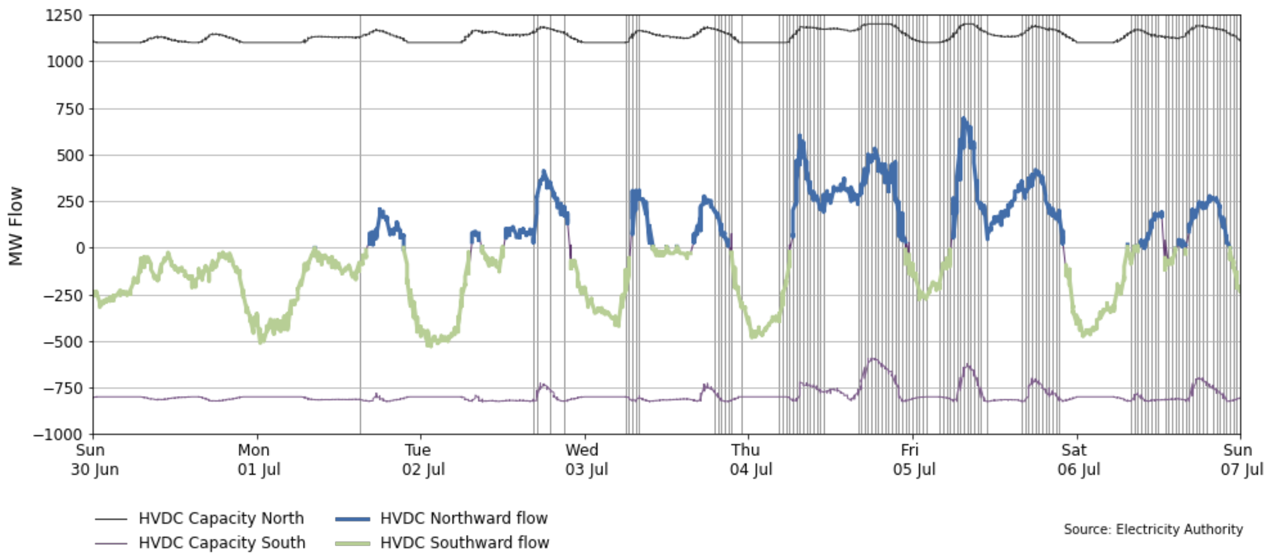


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 7 shows the HVDC flow between 30 June-6 July 2024. HVDC flows were mostly southward when wind generation was high at the start of the week. Flow was then northward at the times most of the high prices occurred.

Figure 7: HVDC flow and capacity, 30 June-6 July 2024

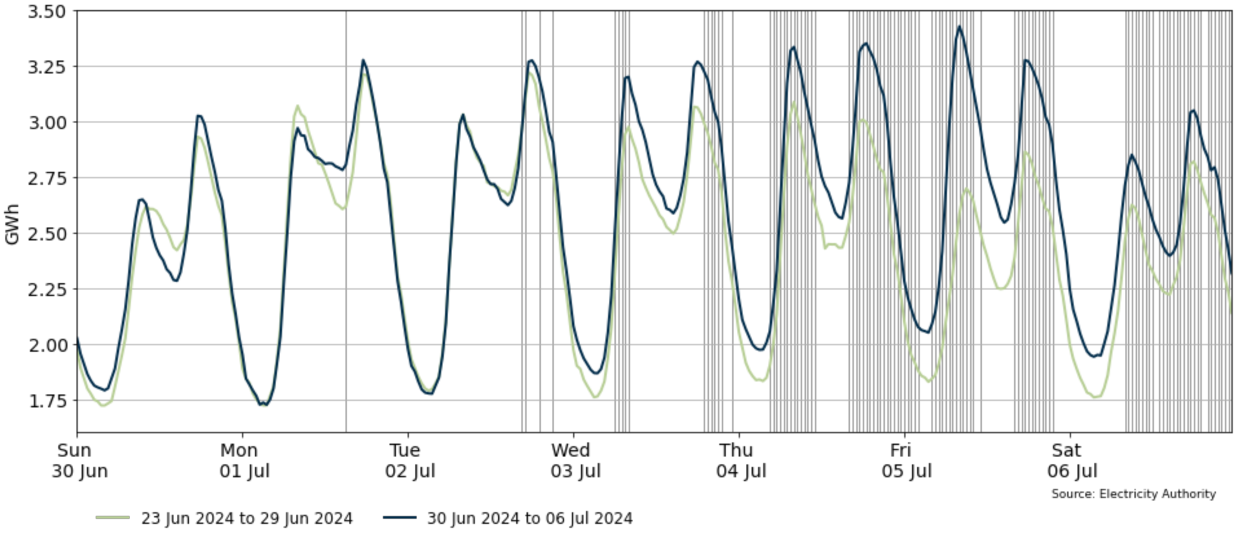


Source: Electricity Authority

6. Demand

6.1. Figure 8 shows national demand between 30 June-6 July 2024, compared to the previous week. Demand was generally higher than the previous week, particularly from Wednesday onwards, likely due to low temperatures. The maximum peak demand this week was 3.43GWh at 8:00am on Friday – the highest peak demand of the year so far.

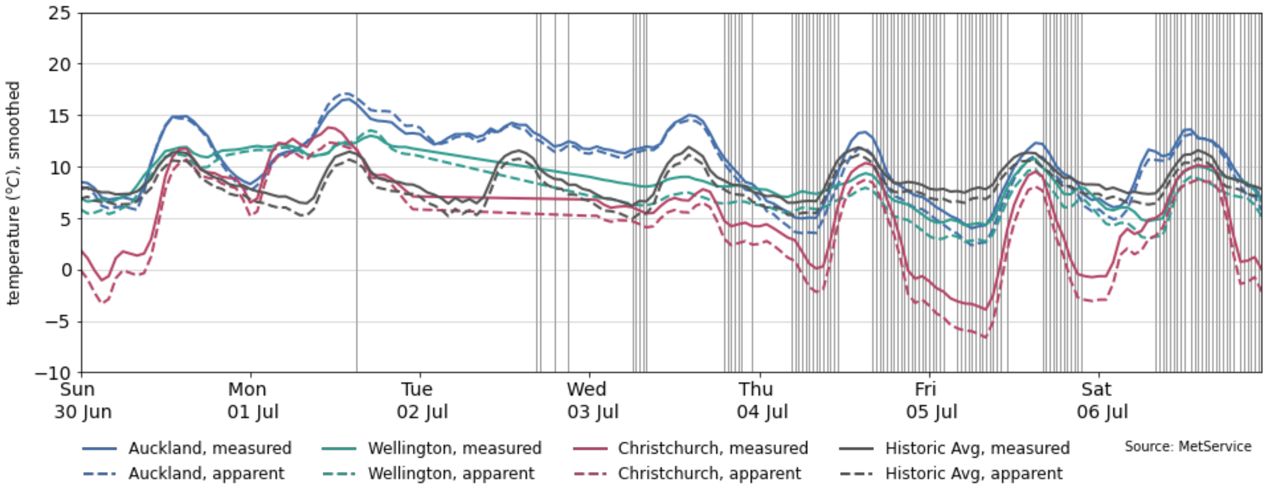
Figure 8: National demand, 30 June-6 July 2024 compared to the previous week



6.2. Figure 9 shows the hourly temperature at main population centres from 30 June-6 July 2024. 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. Temperature data between Monday evening and Wednesday night was not available for Wellington and Christchurch.

6.3. Temperatures were mostly above average in Auckland at the start of the week, then below or close to average from Wednesday evening, ranging from 2°C to 17°C. Wellington temperatures were close to average, between 3°C to 14°C. Temperatures in Christchurch ranged from -7°C to 12°C and were particularly low on Friday. Low temperatures across the major cities on Friday morning likely pushed up demand for heating.

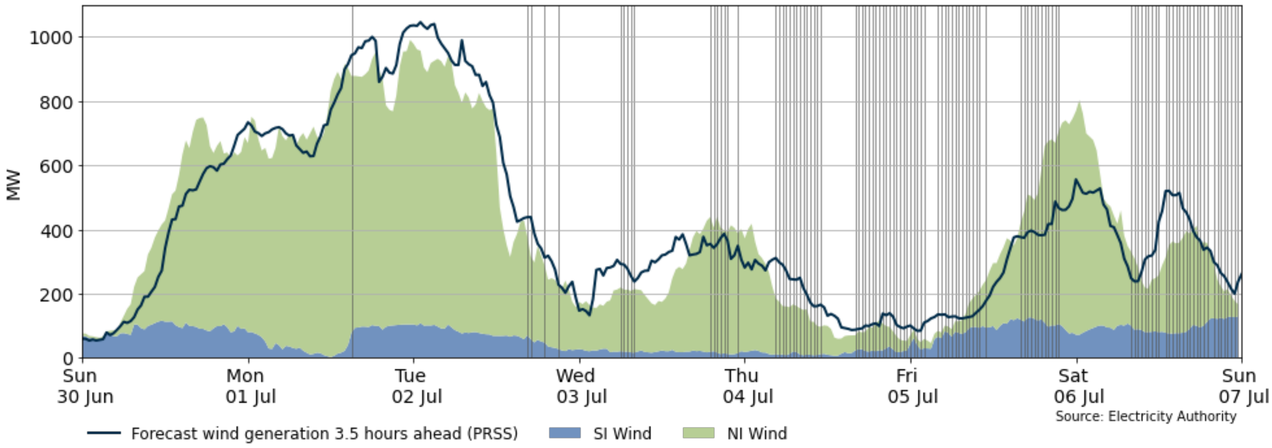
Figure 9: Temperatures across main centres, 30 June-6 July 2024



7. Generation

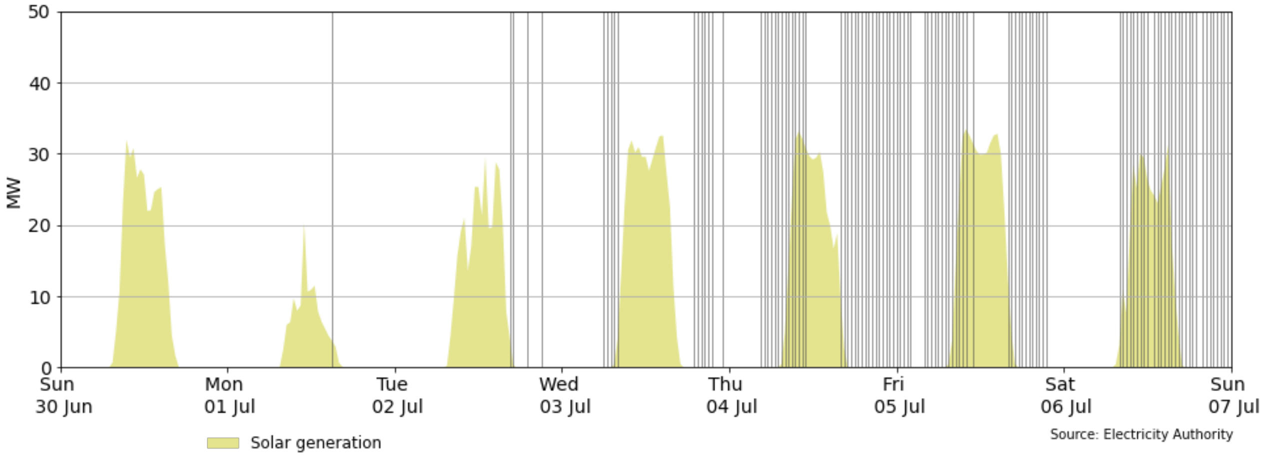
7.1. Figure 10 shows wind generation and forecast from 30 June-6 July 2024. This week wind generation varied between 46MW and 990MW, with an average of 415MW. Wind generation was high from Sunday until Tuesday, but was low and often below forecast when many of the high prices occurred later in the week. At the time prices spiked on Friday morning, North Island wind generation was just 56MW.

Figure 10: Wind generation and forecast, 30 June-6 July 2024



7.2. Figure 11 shows solar generation from 30 June-6 July 2024. Solar generation reached at least 30MW each day except Monday and Tuesday this week. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource during winter.

Figure 11: Solar generation, 30 June-6 July 2024

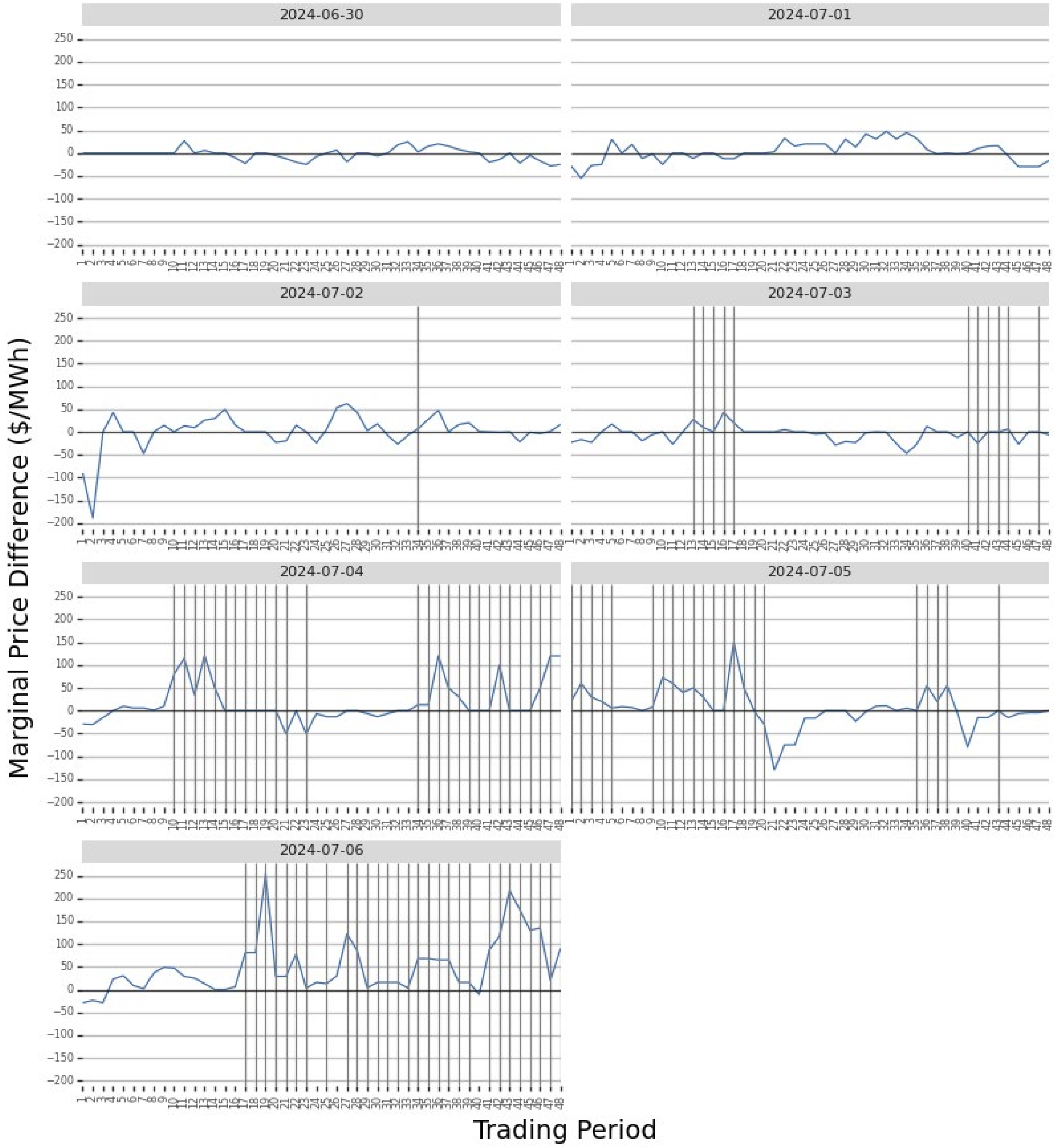


7.3. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to 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. 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.

[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

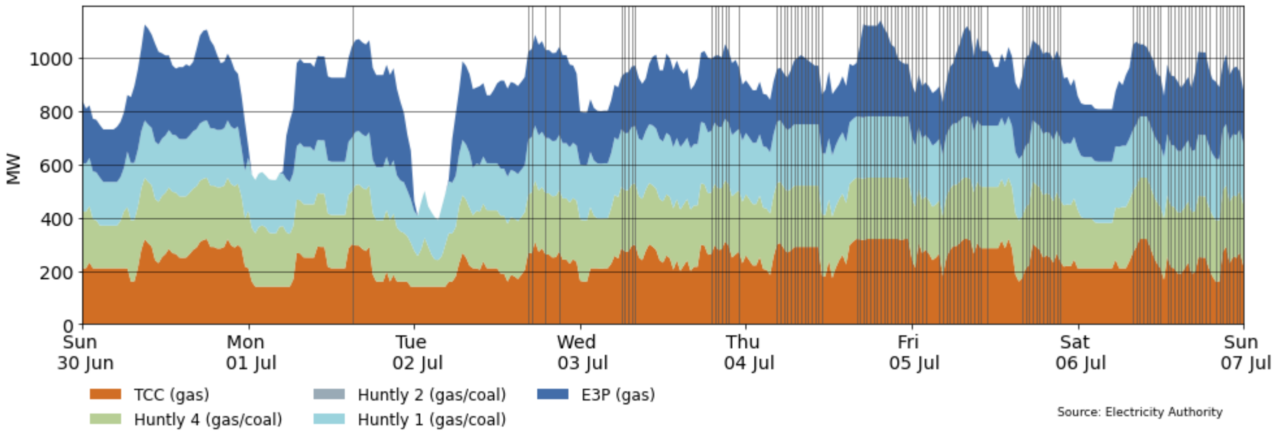
7.4. The most notable positive (marginal prices higher than simulation) difference this week was $255/MWh at 9:00am on Saturday; demand was higher than forecast and wind generation was lower than forecast at this time. Prices were also frequently higher than the simulation on Thursday and Friday, when demand was higher than expected.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 30 June-6 July 2024



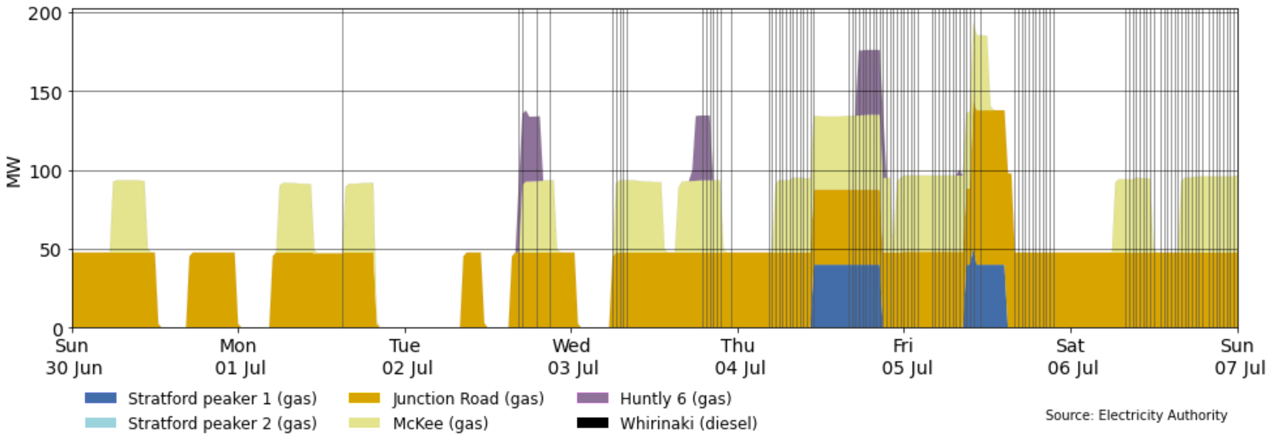
7.5. Figure 13 shows the generation of thermal baseload between 30 June-6 July 2024. TCC, Huntly 4, Huntly 1 and Huntly 5 (E3P) provided baseload generation this week. All units ran continuously except Huntly 5, which turned off early on Monday and Tuesday while wind generation was high.

Figure 13: Thermal baseload generation, 30 June-6 July 2024



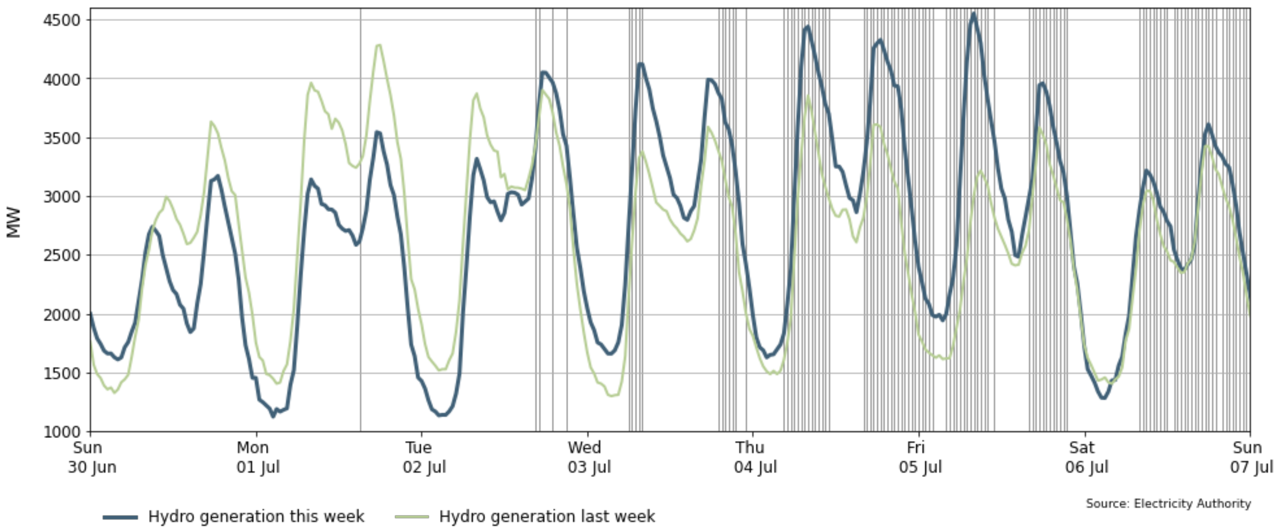
7.6. Figure 14 shows the generation of thermal peaker plants between 30 June-6 July 2024. Junction Road ran every day, during peak and shoulder periods from Sunday to Tuesday, then continuously from Wednesday onwards when wind generation was lower. McKee also ran each day during peak and/or shoulder periods. Stratford 1 ran on Thursday and Friday. Huntly 6 ran on Tuesday, Wednesday and Thursday. It was also briefly dispatched for one 5-minute trading period at the time of the price spike on Friday.

Figure 14: Thermal peaker generation, 30 June-6 July 2024



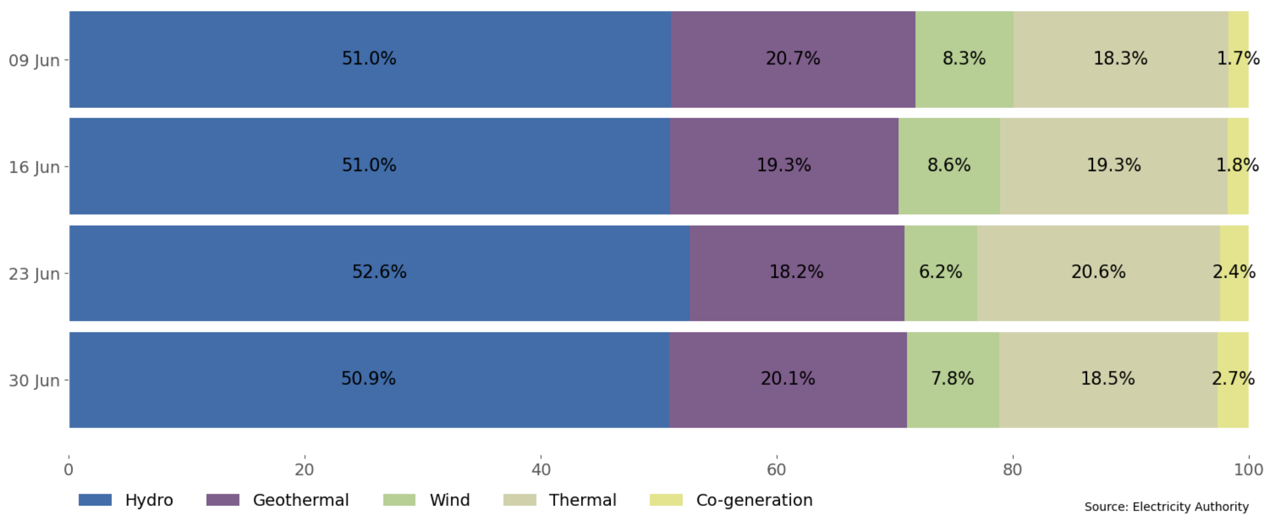
7.7. Figure 15 shows hydro generation between 30 June-6 July 2024. Hydro generation was lower than the previous week until Tuesday evening, while wind generation was high, and higher than the previous week from this point onwards.

Figure 15: Hydro generation, 30 June-6 July 2024



7.8. As a percentage of total generation, between 30 June-6 July 2024, total weekly hydro generation was 50.9%, geothermal 20.1%, wind 7.8%, thermal 18.5%, and co-generation 2.7%, as shown in Figure 16. The proportions of wind and geothermal generation increased this week, compensating for the decrease in hydro and thermal generation.

Figure 16: Total generation by type as a percentage each week, 9 June-6 July



8. Outages

8.1. Figure 17 shows generation capacity on outage. Total capacity on outage between 30 June-6 July 2024 ranged between ~1,000MW and ~1,300MW. Figure 18 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 11 July, earlier than its original scheduled return on 19 July.

(b) Stratford 2, which was originally scheduled to return from outage on 5 August, is now on outage until 2 September.

(c) Junction Road was on partial outage until 8 July.

(d) Huntly 6 was on outage on 3 July.

(e) McKee was on outage on 6 July.

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

Figure 17: Total MW loss from generation outages, 30 June-6 July 2024

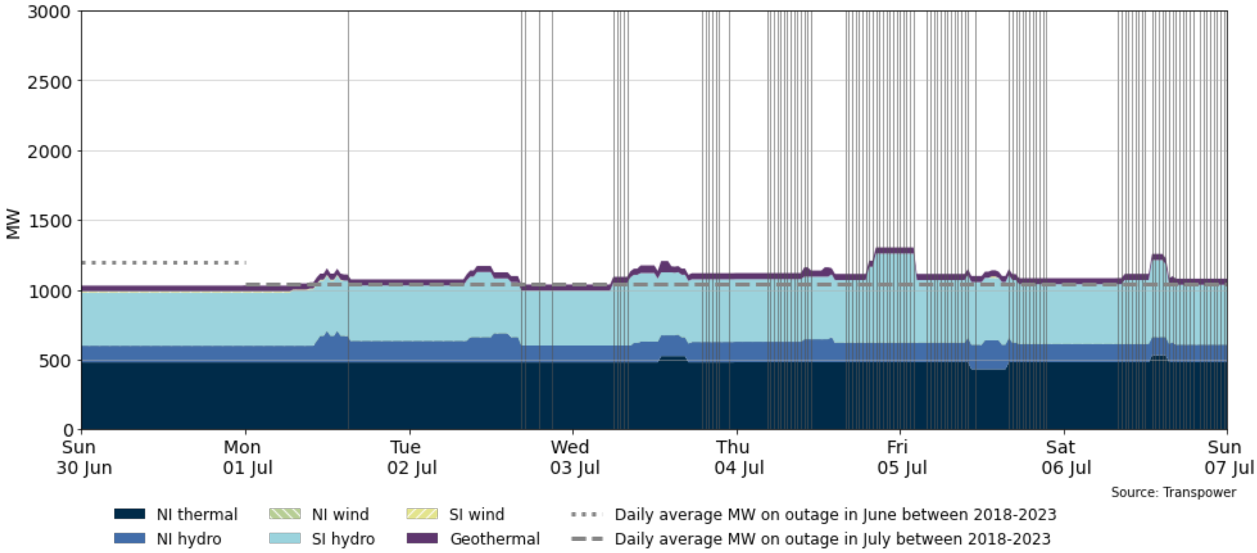
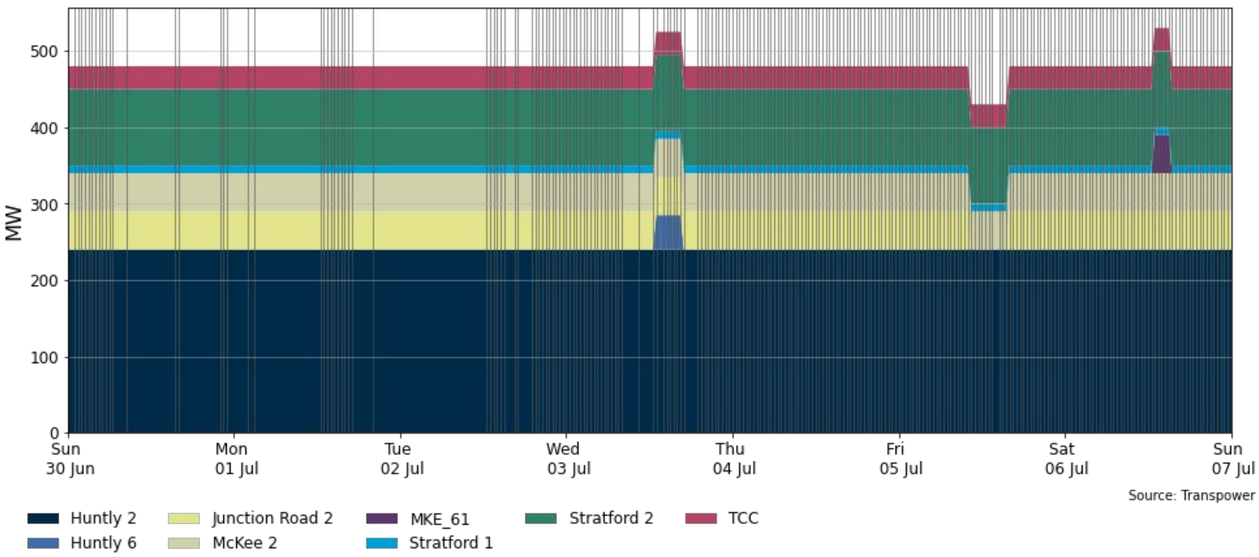


Figure 18: Total MW loss from thermal outages, 30 June-6 July 2024

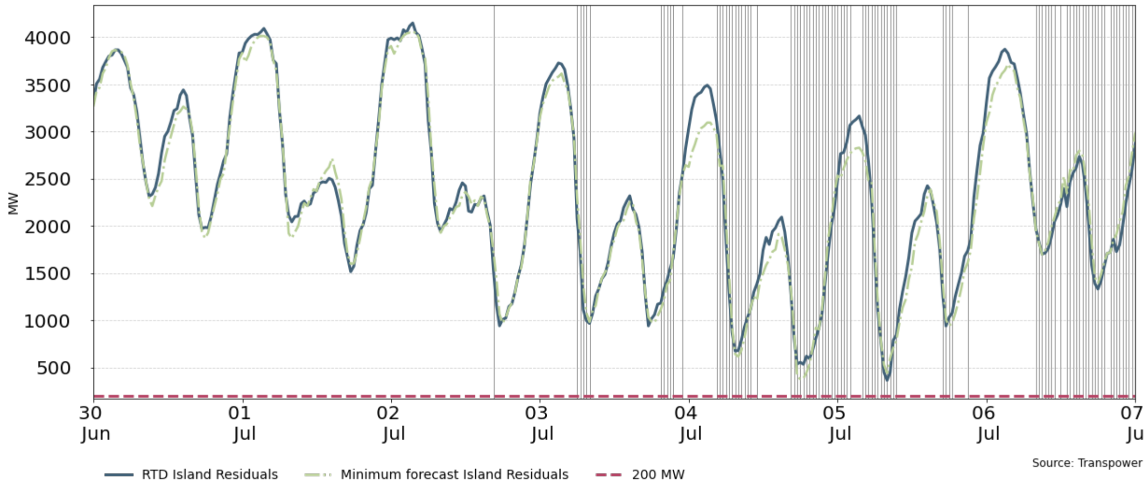


9. Generation balance residuals

9.1. Figure 19 shows the national generation balance residuals between 30 June-6 July 2024. 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 360MW at 8:00am on Friday.

Figure 19: National generation balance residuals, 30 June-6 July 2024



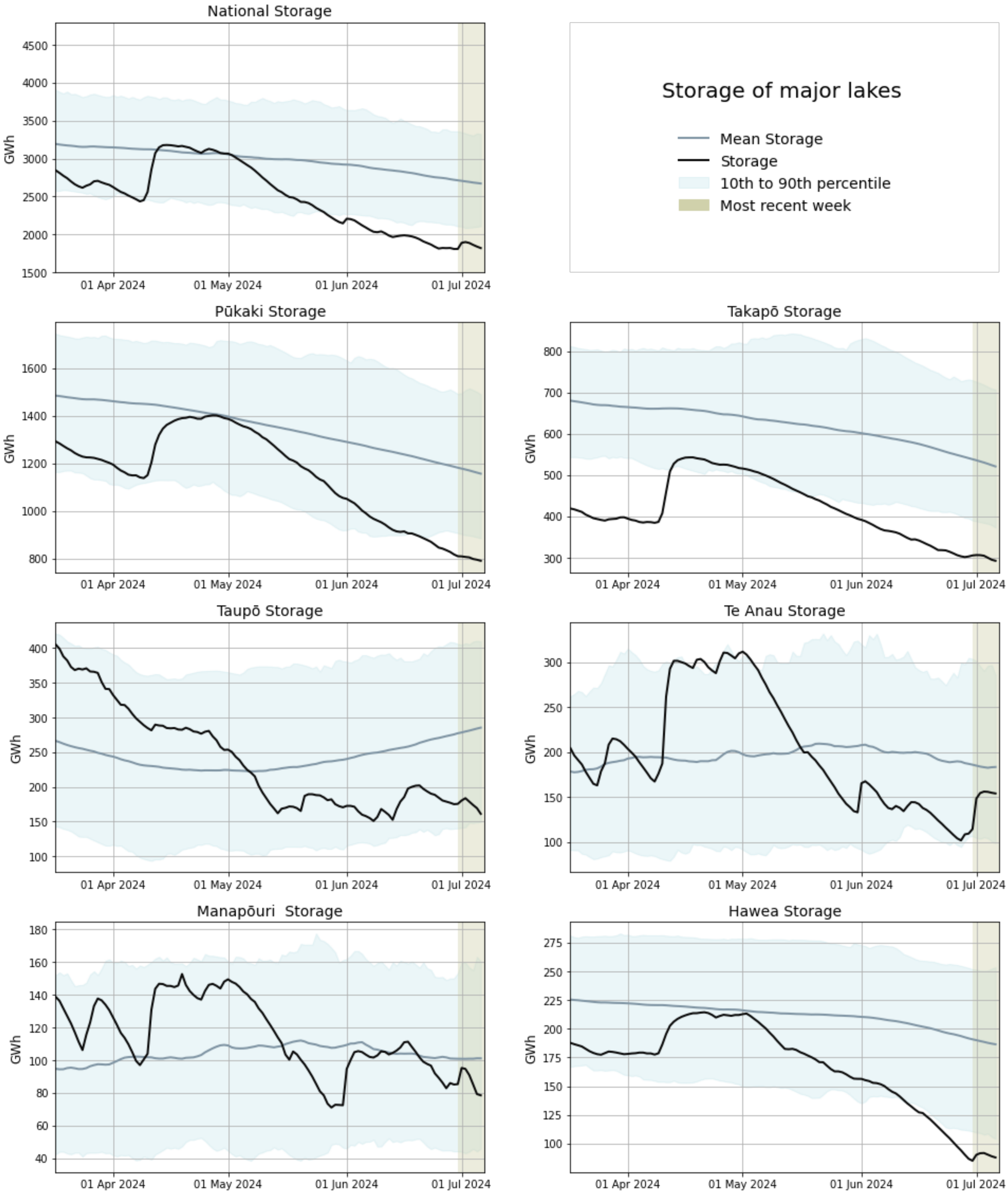
10. Storage/fuel supply

10.1. Figure 20 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 decreased this week and was ~72% nominally full and ~48% of the historical average for this time of the year as of 6 July.

10.3. Storage increased at Te Anau, which is now well above its 10th percentile but still below mean. Storage also increased at slightly at Hawea, though it remains below its 10th percentile. Storage decreased at all other lakes, with Pūkaki and Takapō below their 10th percentiles and Taupō and Manapōuri below their means.

Figure 20: Hydro storage



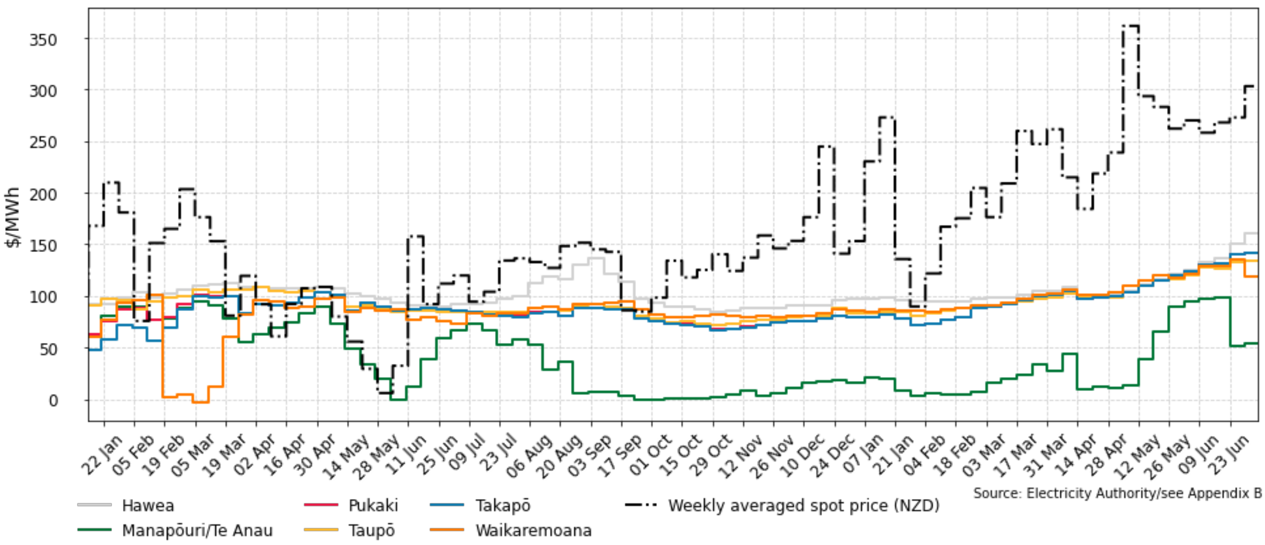
Source: Electricity Authority

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 21 shows the national water values between 1 July 2023 and 6 July 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. Water values increased by $0.70/MWh to $9.70/MWh at all lakes except Waikaremoana, which decreased by $15.50/MWh.

Figure 21: JADE water values across various reservoirs, 8 January 2023 to 6 July 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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 June 2024. T 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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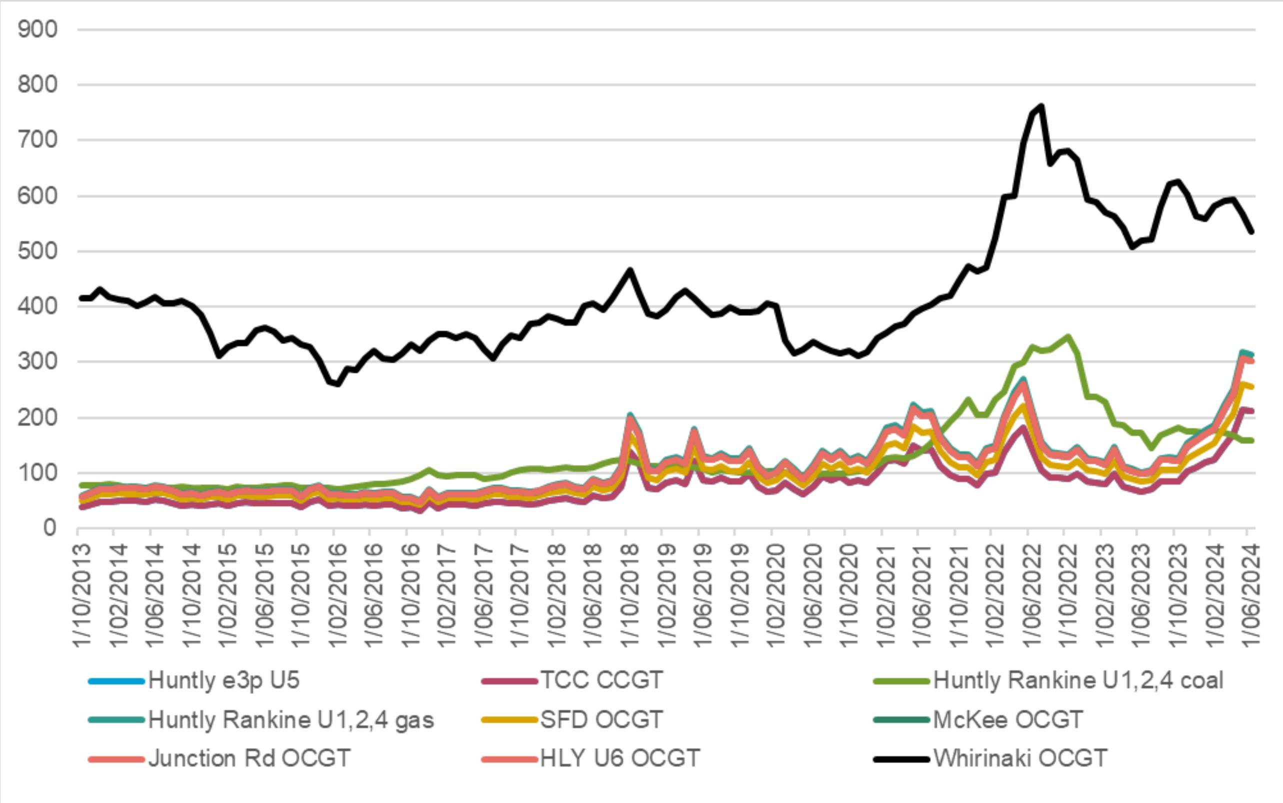
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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.

Figure 22: Estimated monthly SRMC for thermal fuels

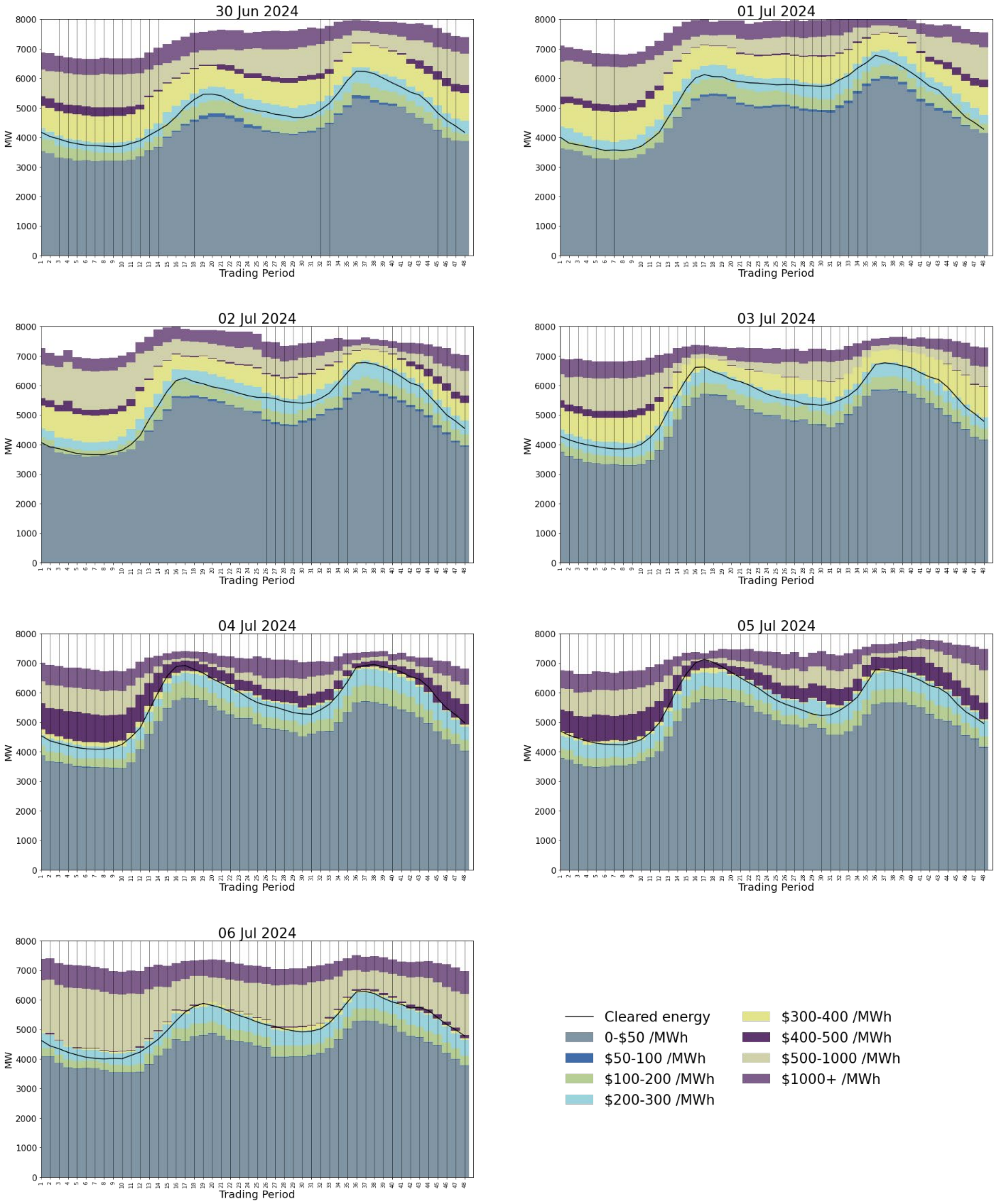


13. Offer behaviour

13.1. Figure 23 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. From Sunday to Wednesday, most offers cleared in the $200-300/MWh region, but prices were higher from Thursday onwards. There were an increased number of offers in the $400-$500/MWh range on Thursday and Friday, and very few in the $300-$400/MWh region. On Saturday, the number of offers in the $500-$1,000MWh band increased significantly, while the number in the $300-$500/MWh region decreased.

Figure 23: 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, however, the high price on Friday morning and the high prices on Saturday afternoon will be further analysed by the market monitoring team.

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
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
05/07/2024	17	Further analysis	N/A	N/A	SIR offers
06/07/2024	41-48	Further analysis	N/A	N/A	Energy offers