12 August 2024

Trading conduct report 4-10 August 2024

Market monitoring weekly report

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1. Overview

1.1. Prices increased again this week, as lake levels continued to drop and gas prices remained high. Low temperatures led to high demand on Tuesday and Wednesday morning, contributing to spot prices exceeding $1,300/MWh at both Benmore and Ōtāhuhu. TCC, Huntly 5 and three Rankines provided baseload generation this week. National controlled hydro storage decreased to around 54% 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. Suspected non-compliance situations may be passed onto the Authority's compliance team. In addition to general monitoring, this report 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. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 4-10 August:

(a) the average wholesale spot price across all nodes was $825/MWh

(b) 95% of prices fell between $591/MWh and $1,037/MWh.

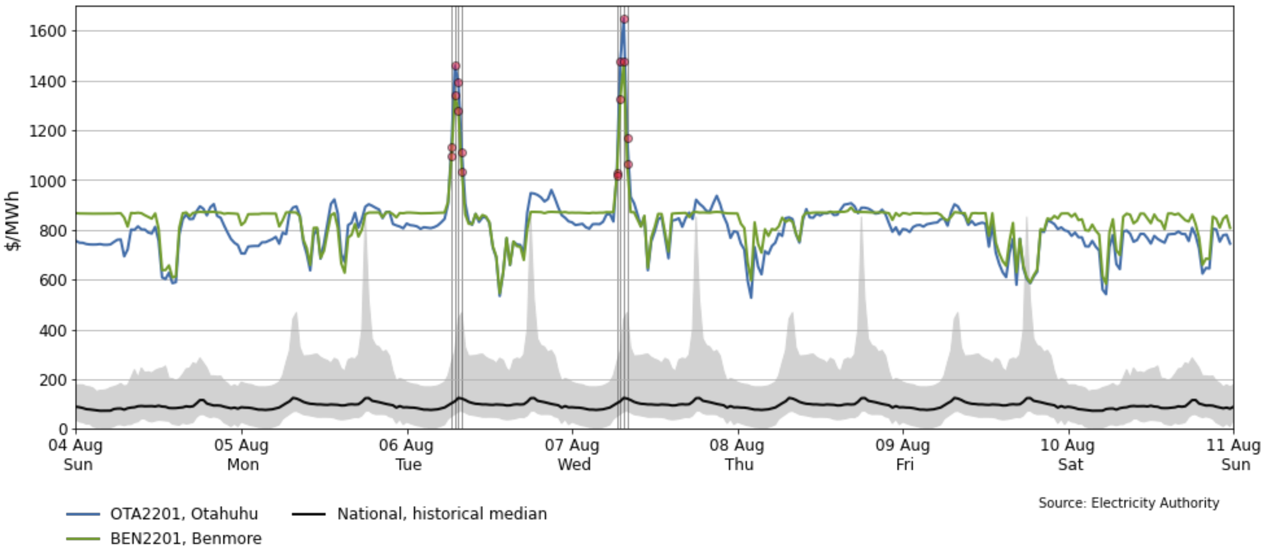
2.4. Overall, the majority of spot prices were within $757-$881/MWh, with the weekly average price increasing by around $304/MWh compared to the previous week. The average Benmore spot price was $29/MWh higher than at Ōtāhuhu.

2.5. Prices were consistently very high this week, with few below the 90th percentile. These consistent high prices are primarily the result of low hydro storage, periods of low wind generation, and thermal generation costs rising due to limited gas supply.

2.6. Prices were particularly high between 6:30am-8:00am on Tuesday and Wednesday, with the Ōtāhuhu price reaching a weekly maximum of $1,649/MWh at 7:30am on Wednesday. This may have been partly due to demand forecasting inaccuracies; demand was under forecast by more than 90MW during both periods of highlighted prices, requiring additional high-priced hydro and thermal generation to be dispatched.

2.7. Due to the consistent high prices this week, all trading periods are under further analysis and additional information requests have been sent to generators.

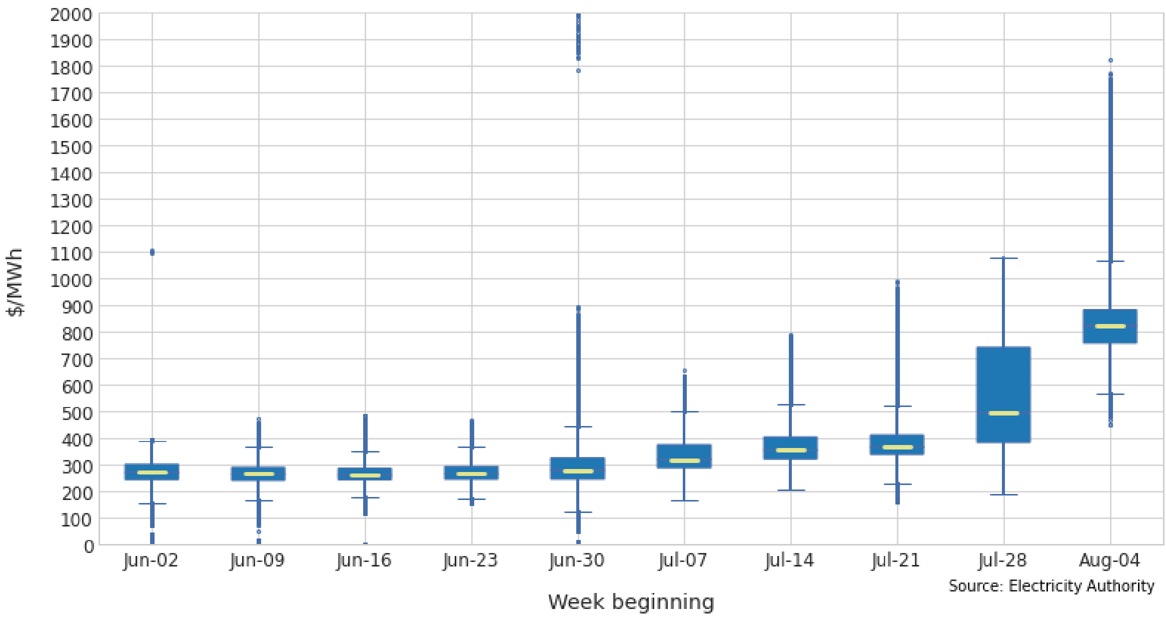
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 4-10 August



2.8. 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 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 $329/MWh. The lower and upper quartiles also increased, with the middle 50% of this week's prices entirely above the middle 50% of last week's prices. The interquartile range decreased significantly, but the number of outliers increased.

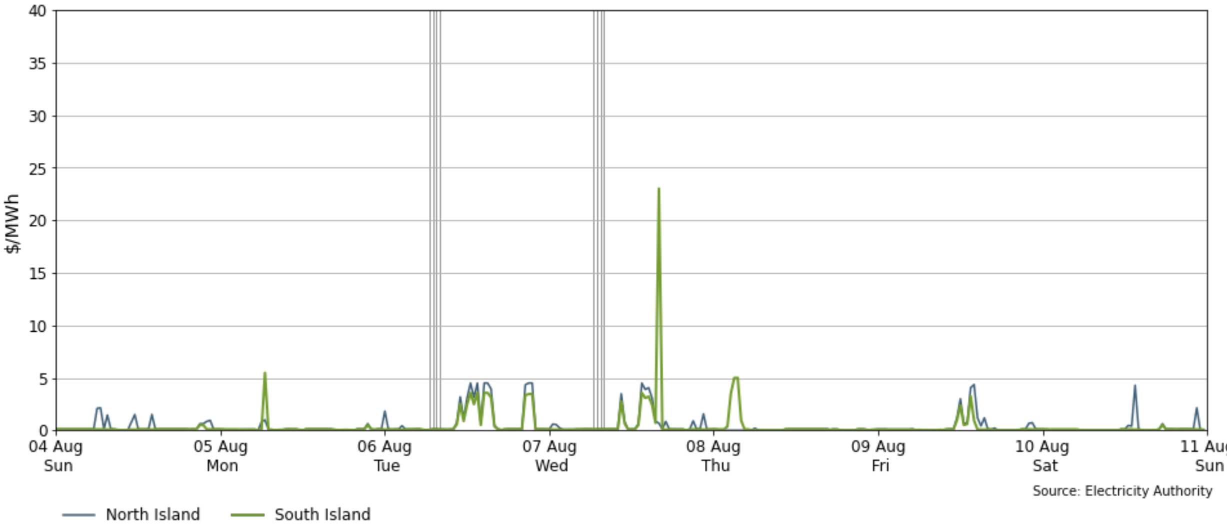
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

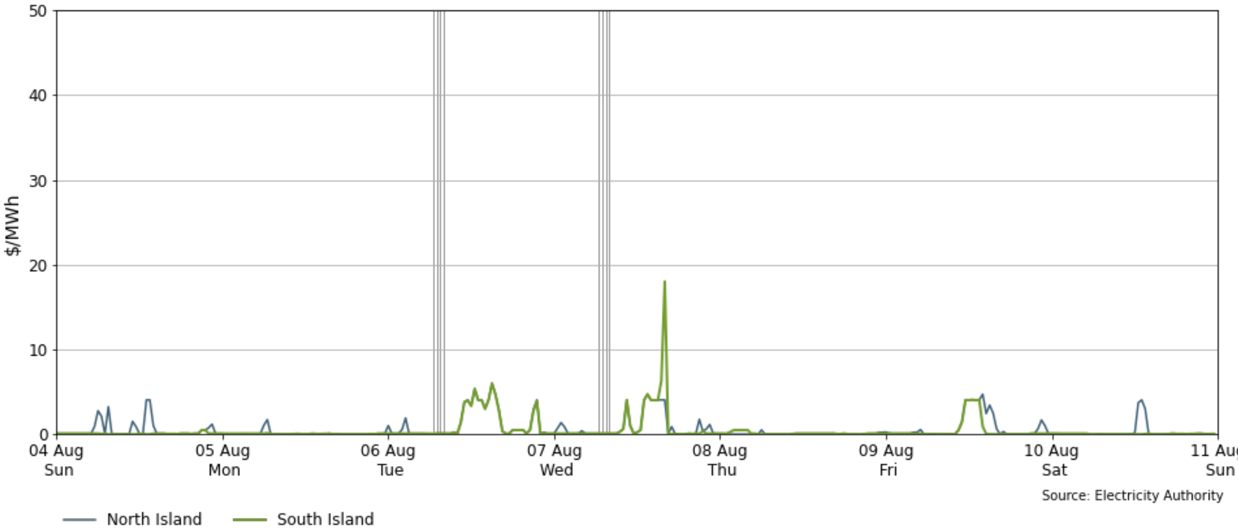
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week, but spiked on Wednesday afternoon, reaching $23/MWh at 4:00pm in the South Island while remaining below $1/MWh in the North Island.

Figure 3: Fast instantaneous reserve price by trading period and island, 4-10 August



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 also spiked at 4:00pm on Wednesday afternoon, reaching $18/MWh in the South Island while remaining at $4/MWh in the North Island.

Figure 4: Sustained instantaneous reserve by trading period and island, 4-10 August



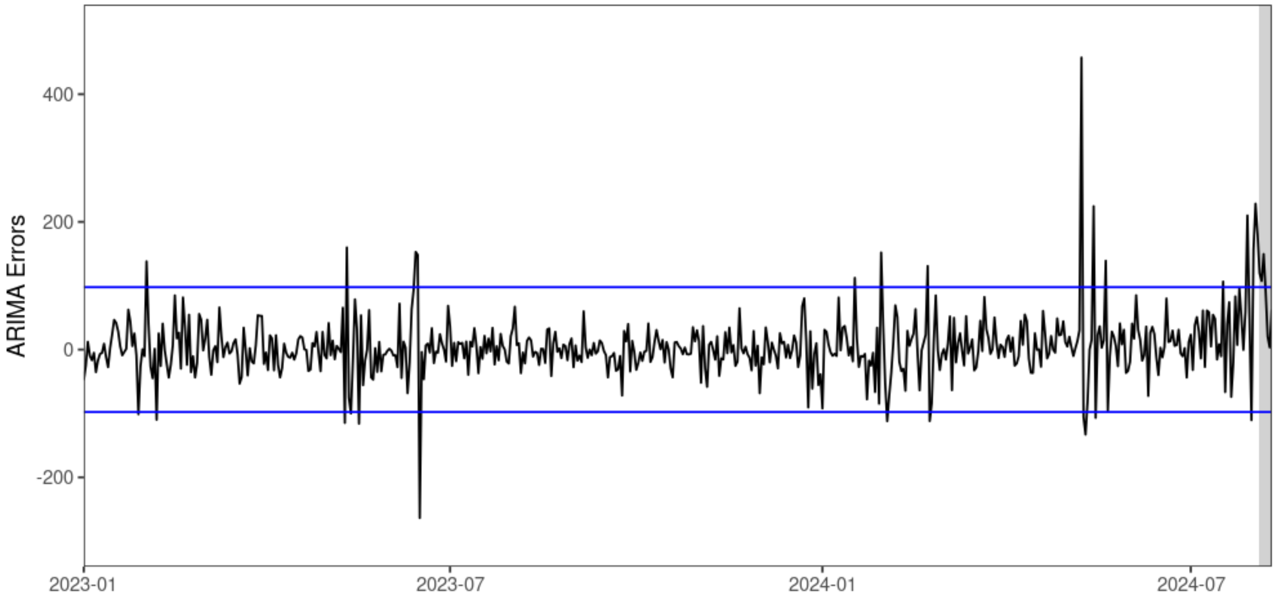
4. Regression residuals

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 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 in the regression analysis.

4.3. This week, the residuals on Sunday, Monday, and Tuesday were above two standard deviations of the data, indicating that prices on these days were higher than the model expected. This may be due to factors not included in the ARMA model, such as high prices caused by inaccurate demand forecasts. We are carefully considering offer behaviour this week to ensure high prices are fully in line with current conditions.

Figure 5: Residual plot of estimated daily average spit prices, 1 January 2023 – 10 August 2024

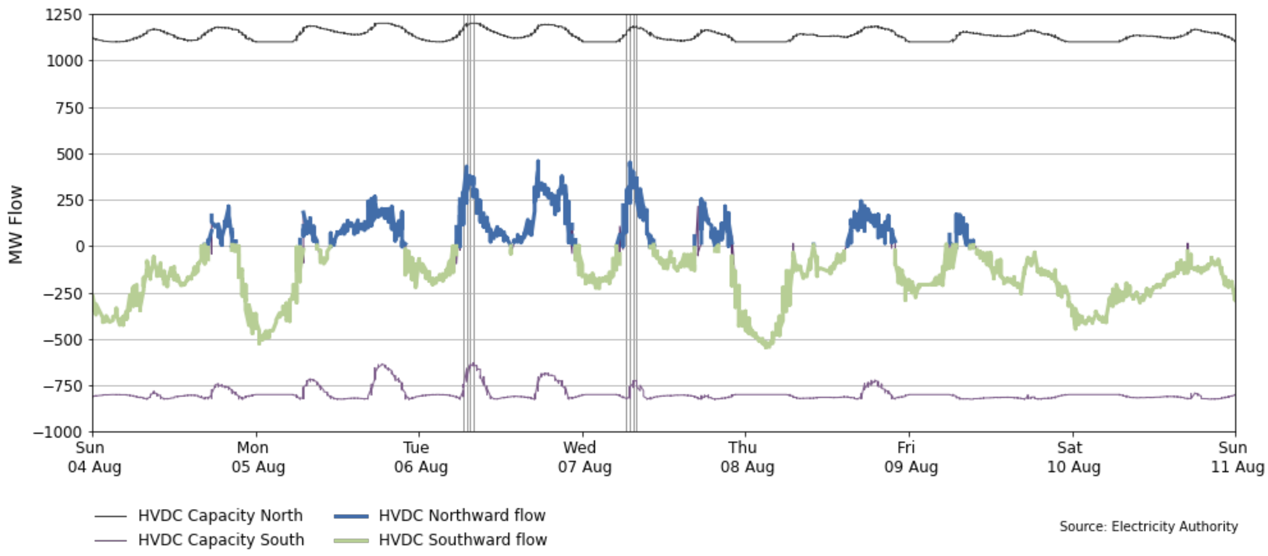


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 4-10 August. Due to high demand and low wind generation in the North Island, HVDC flow was northward at the time the highlighted prices occurred on Tuesday and Wednesday.

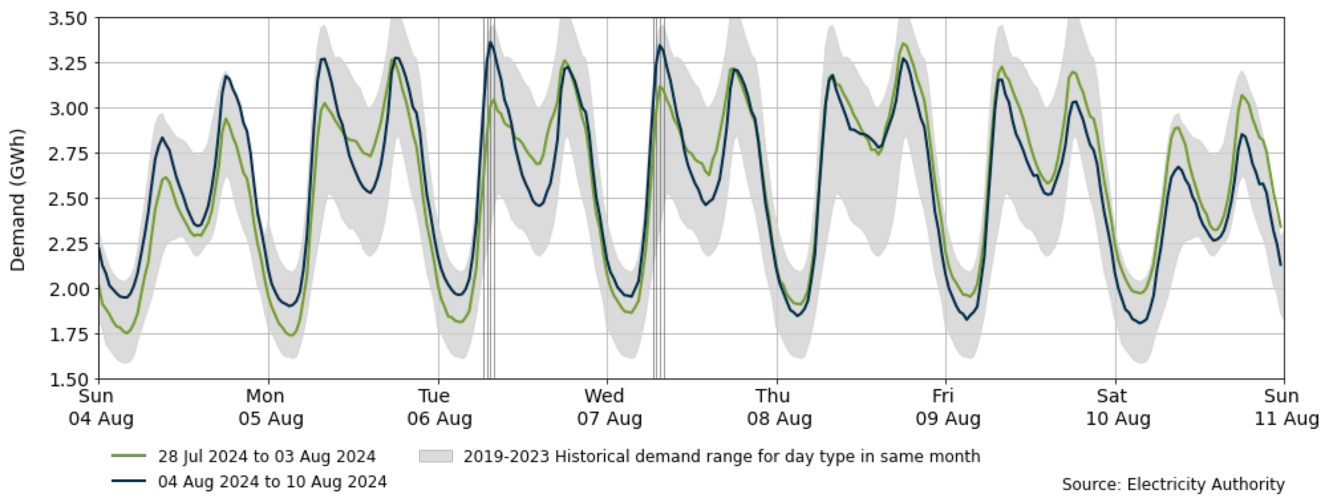
Figure 6: HVDC flow and capacity, 4-10 August



6. Demand

6.1. Figure 7 shows national demand between 4-10 August, compared to the historic range and the demand of the previous week. Demand was mostly within the historical range for this time of year, but was significantly higher than the previous week at the time the highlighted prices occurred. The maximum demand this week was 3.36GWh at 7:30am on Tuesday, with low temperatures likely driving up demand in the first half of the week.

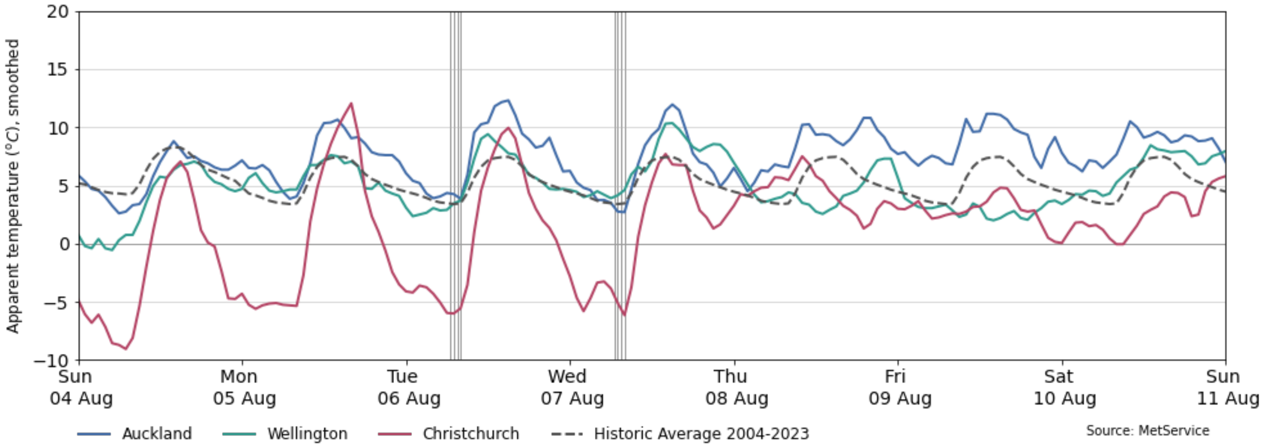
Figure 7: National demand, 4-10 August compared to historic range and previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 4-10 August 2024. The apparent temperate is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures ranged from 2°C to 12°C in Auckland, -1°C to 10°C in Wellington, and -9°C to 13°C in Christchurch. Temperatures were lowest at the start of the week, frequently below freezing in Christchurch, but increased and were closer to average from Thursday onwards.

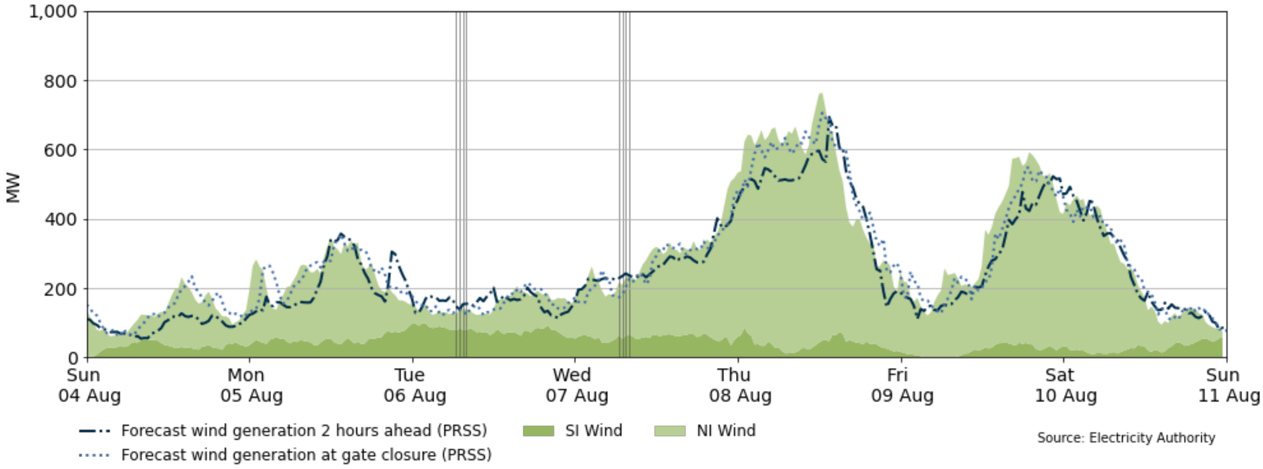
Figure 8: Temperatures across main centres, 4-10 August



7. Generation

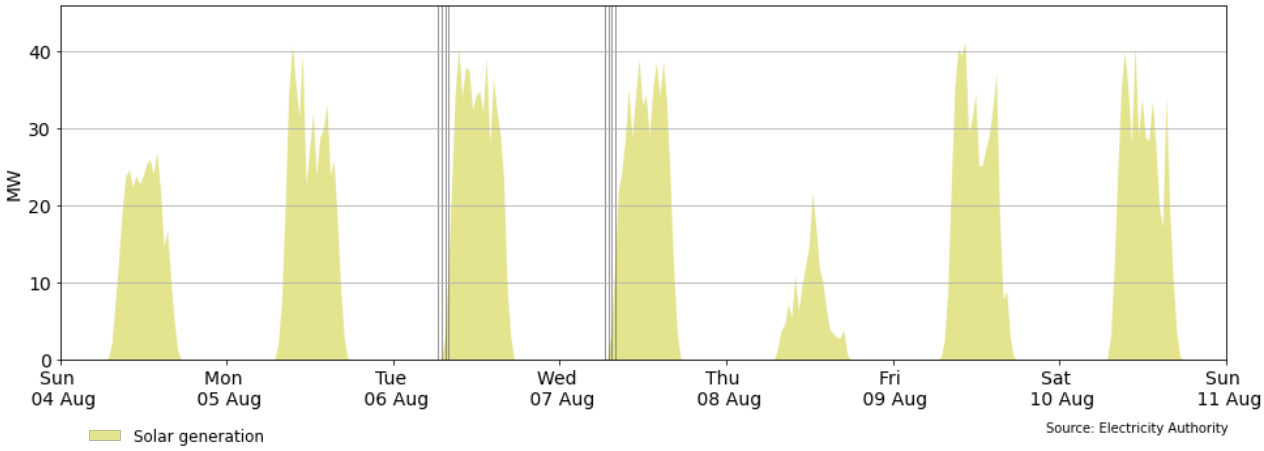
7.1. Figure 9 shows wind generation and forecast from 4-10 August. This week wind generation varied between 61MW and 763MW, with an average of 273MW. Low wind generation, requiring higher-priced thermal and hydro generation to be dispatched to meet demand, may have contributed to this week's high prices.

Figure 9: Wind generation and forecast, 4-10 August



7.2. Figure 10 shows solar generation from 4-10 August. Maximum daily solar generation was over 40MW each day except Wednesday and Thursday this week. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource during winter.

Figure 10: Solar generation, 4-10 August

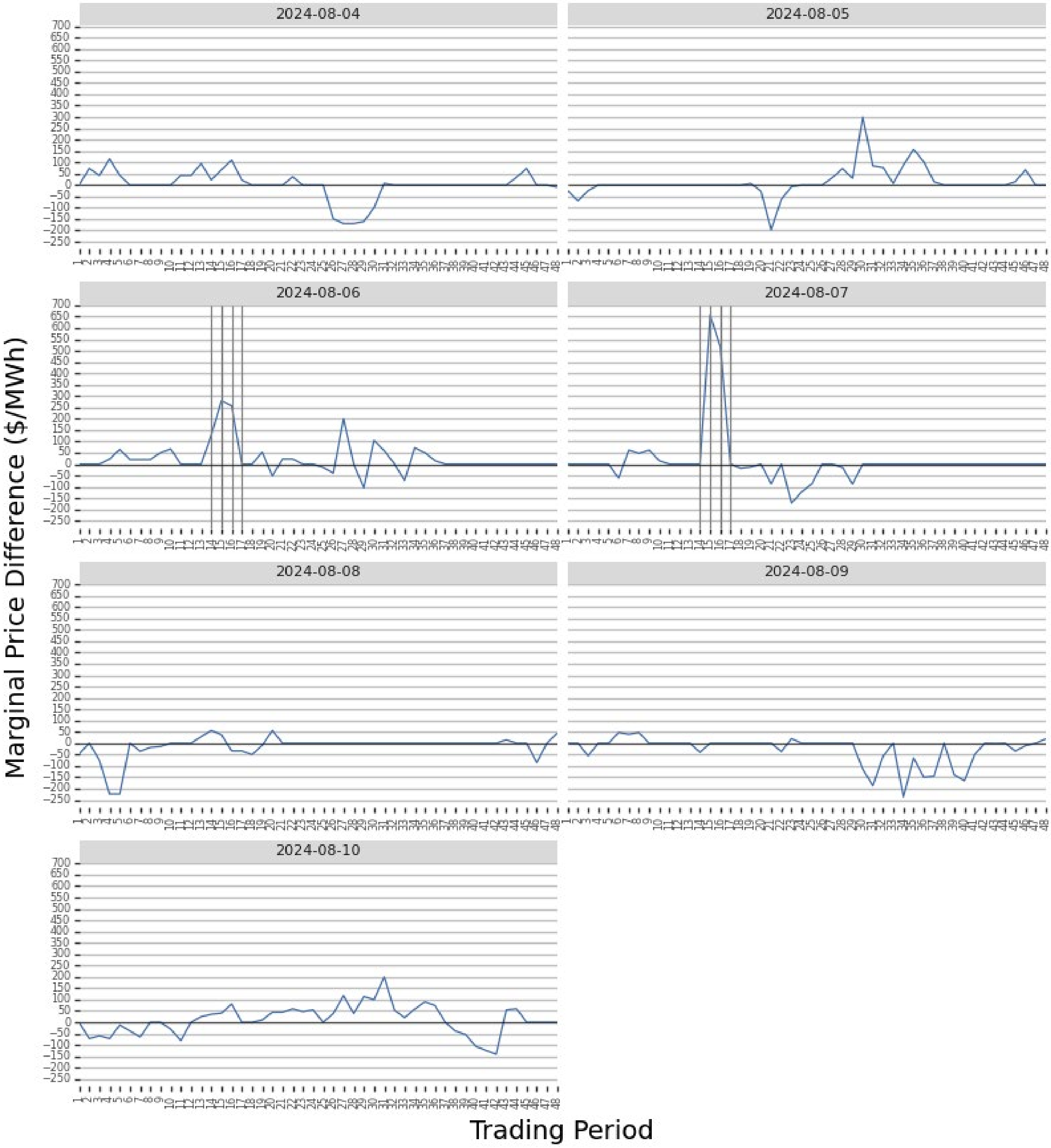


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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.

7.4. The most notable positive (marginal prices higher than simulation) difference this week was $657/MWh at 7:00am on Wednesday, when demand was 91MW higher than forecast. Positive differences exceeding $250/MWh also occurred on Monday and Tuesday; demand was also higher than forecast at these times. However, most often, prices were similar those simulated.

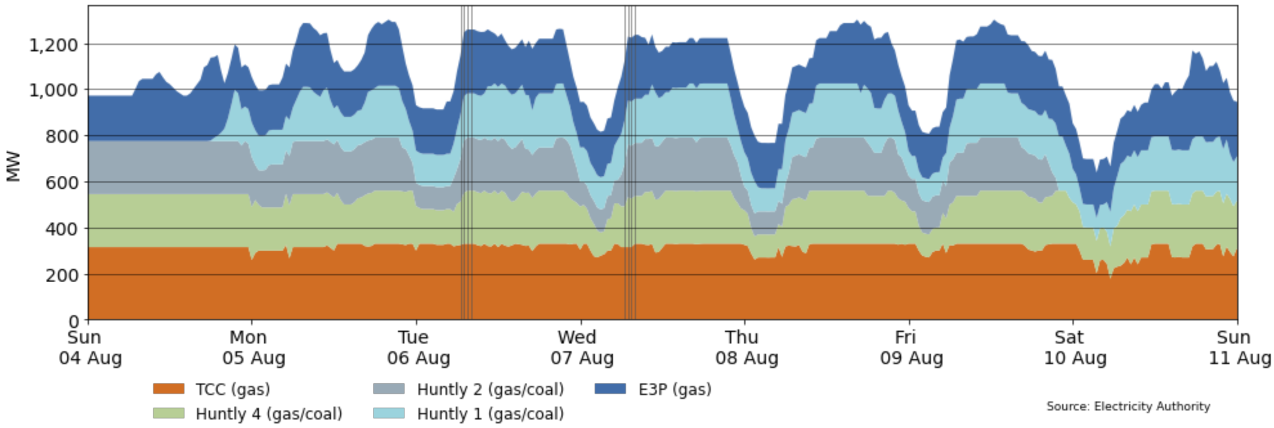
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 4-10 August



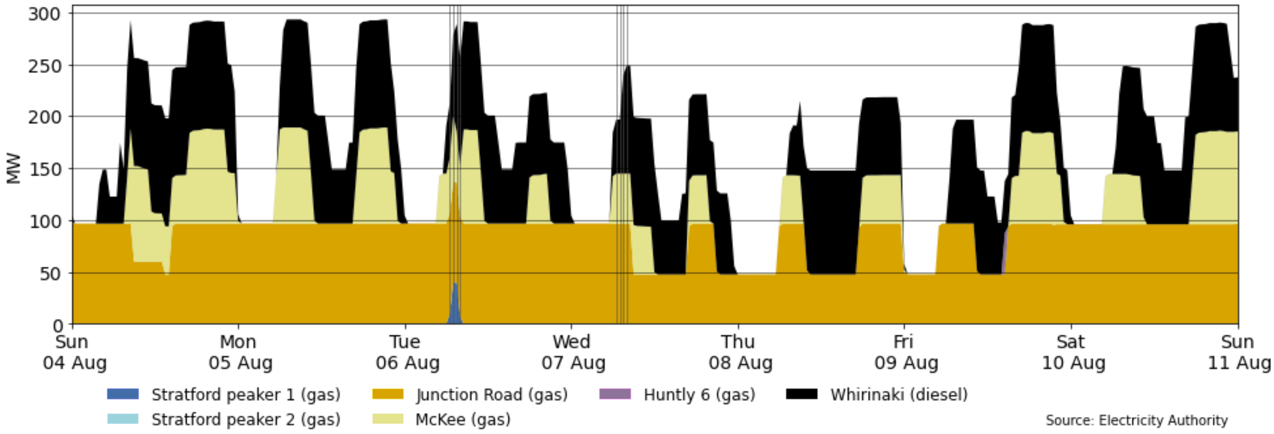
7.5. Figure 12 shows the generation of thermal baseload between 4-10 August. TCC, Huntly 4, Huntly 2, Huntly 1 and Huntly 5 (E3P) ran continuously to provide baseload generation this week. Huntly 1 began running on Sunday evening after returning from outage, and Huntly 2 went on outage on Friday evening. All other units ran the entire week.

Figure 12: Thermal baseload generation, 4-10 August



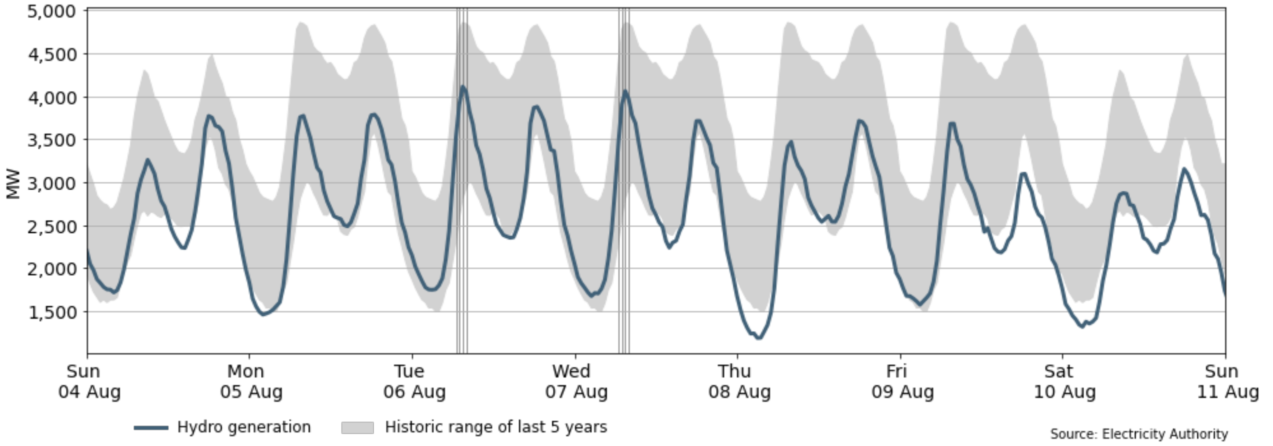
7.6. Figure 13 shows the generation of thermal peaker plants between 4-10 August. Junction Road ran continuously as baseload support, with McKee and Whirinaki also running each day during peak and/or shoulder periods. Stratford 1 also ran briefly on Tuesday morning.

Figure 13: Thermal peaker generation, 4-10 August



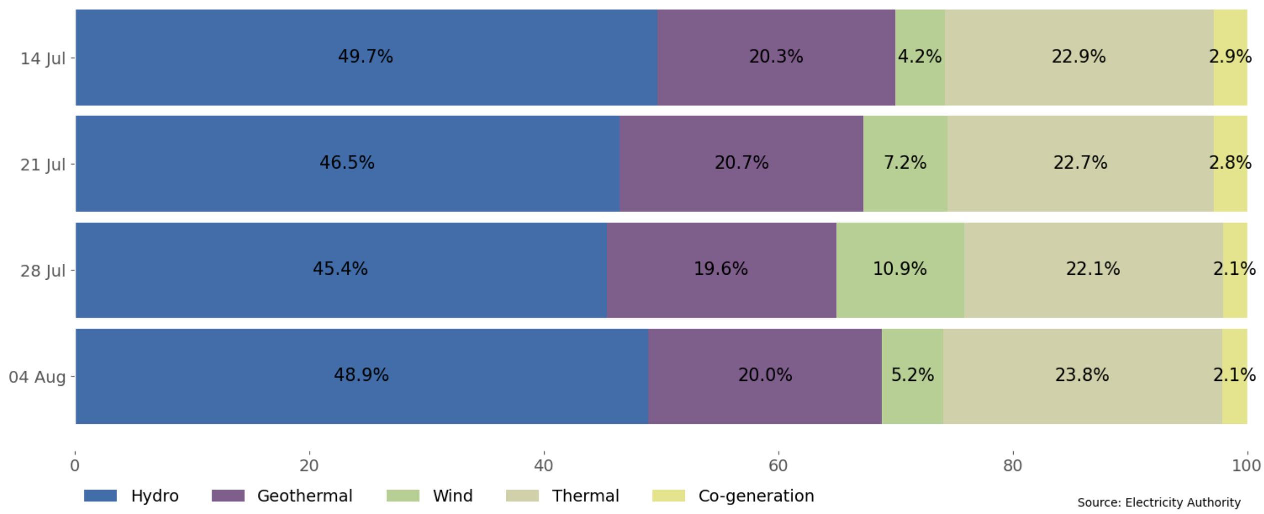
7.7. Figure 14 shows hydro generation between 4-10 August. Hydro generation remained low this week, often close to the minimum of or below the historical range. This is due to low hydro storage, with a significant portion of hydro generation capacity priced highly to reduce likelihood that it will be dispatched and to conserve water. However, at times this capacity was needed. Hydro generation was relatively high on Tuesday and Wednesday morning due to high demand, which may have contributed to the high prices at these times.

Figure 14: Hydro generation, 4-10 August



7.8. As a percentage of total generation, between 4-10 August, total weekly hydro generation was 48.9%, geothermal 20.0%, wind 5.2%, thermal 23.8%, and co-generation 2.1%, as shown in Figure 15. Wind generation decreased this week, requiring more hydro and thermal generation to be dispatched.

Figure 15: Total generation by type as a percentage each week, 14 July-10 August 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 4-10 August ranged between ~710MW and ~1,300MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 was on outage from 9-11 August.

(b) Huntly 1 was on outage until 4 August.

(c) Stratford 2 is now on outage until 27 September, having previously been scheduled to return on 23 September.

(d) Whirinaki Unit 1 was on outage until 4 August.

(e) Whirinaki Unit 2 was on outage on 7 August and 8 August.

(f) Huntly 6 was on outage on 7 August and 8 August.

Figure 16: Total MW loss from generation outages, 4-10 August

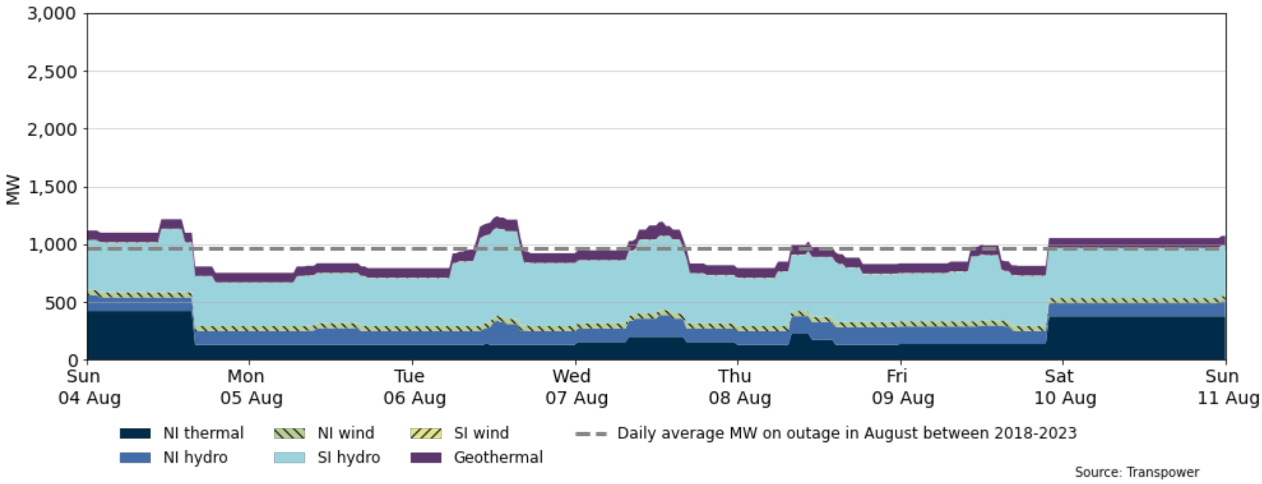
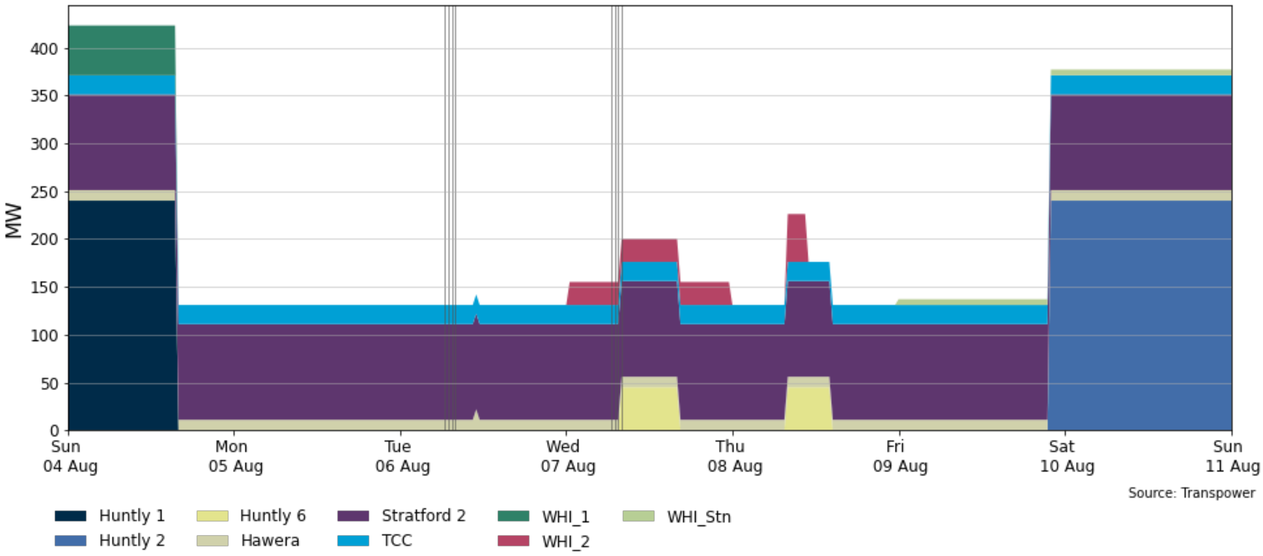


Figure 17: Total MW loss from thermal outages, 4-10 August

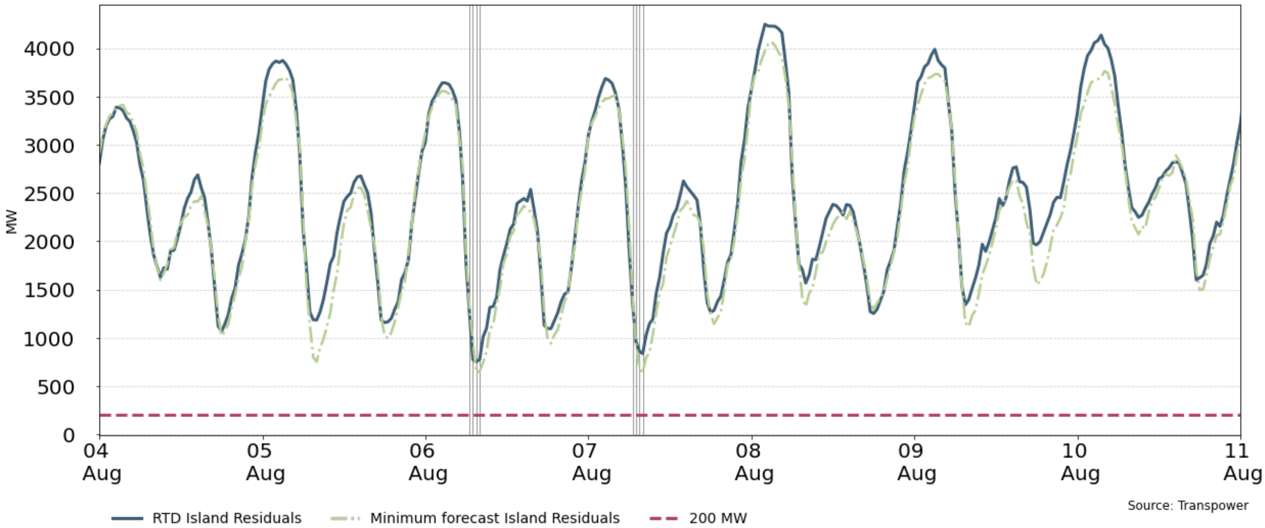


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 4-10 August. 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 balances were healthy this week. The minimum North Island residual was 420MW at 6:00pm on Sunday.

Figure 18: National generation balance residuals, 4-10 August



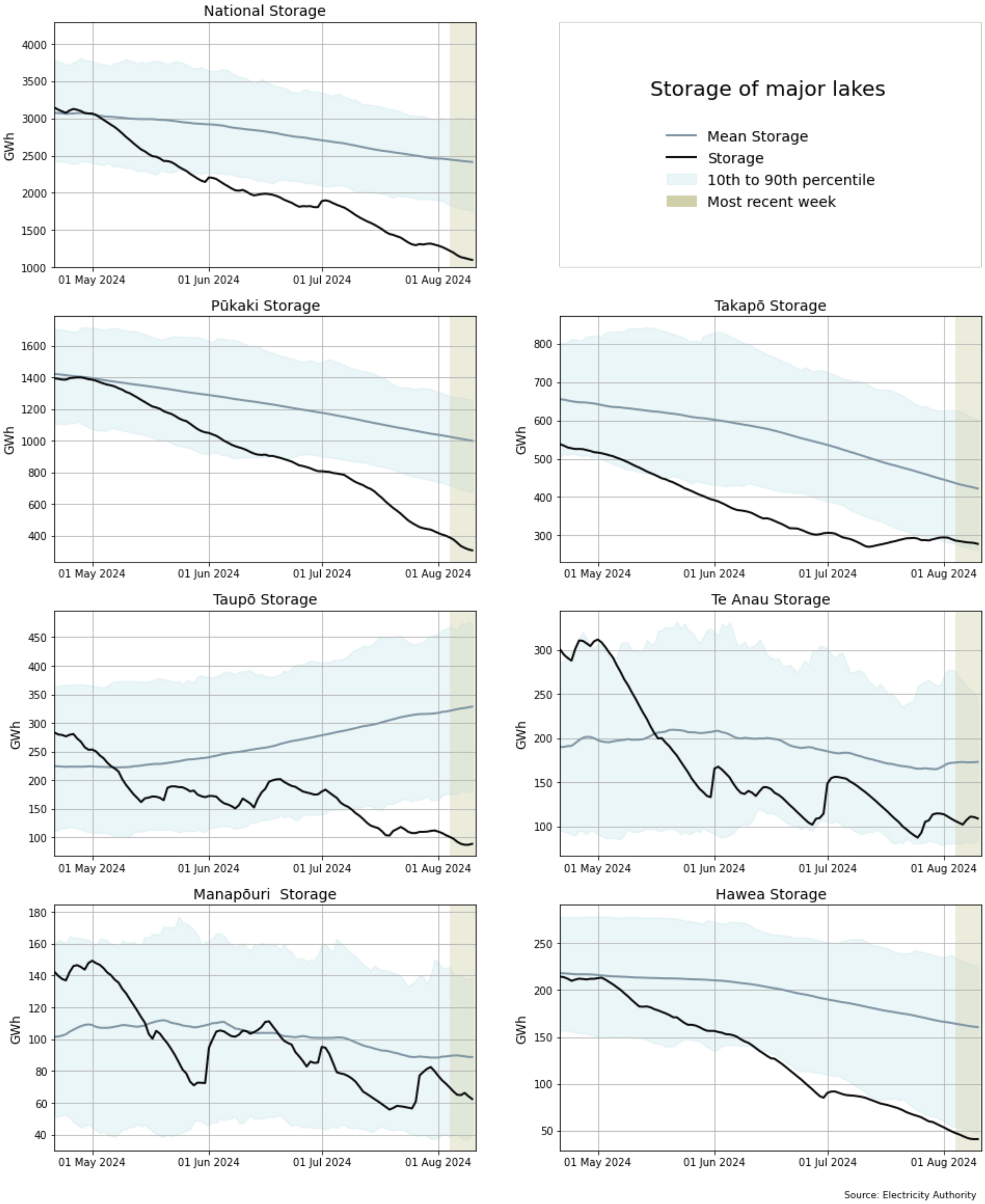
10. Storage/fuel supply

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 decreased this week, to ~33% nominally full and ~54% of the historical average for this time of the year as of 3 August.

10.3. This week, storage decreased at all major lakes except Te Anau, which increased slightly. All lakes are currently below their historical means, with Pūkaki, Taupō and Hawea below their 10th percentiles.

Figure 19: Hydro storage



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 20 shows an estimate of thermal SRMCs as a monthly average up to 1 July 2024. The SRMC for diesel and gas have both increased from the previous month, while the coal SRMC has remained stable.

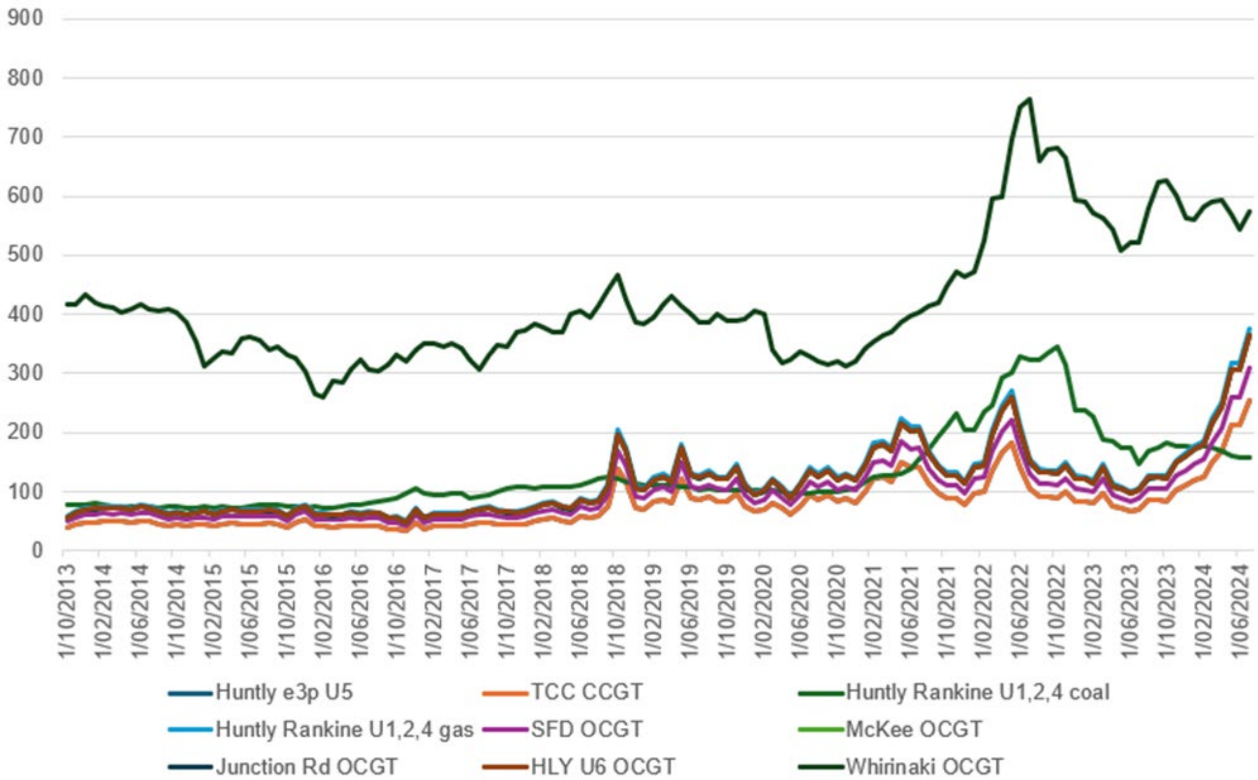
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$158/MWh. The cost of running the Rankines on gas remains more expensive at ~$377/MWh.

11.5. The SRMC of gas fuelled thermal plants continues to increase and is currently between ~$254/MWh and ~$377/MWh.

11.6. The SRMC of Whirinaki is ~$573/MWh. Whirinaki ran on Saturday this week, when prices were elevated for most of the day.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

Figure 20: Estimated monthly SRMC for thermal fuels



Source: Electricity Authority/see Appendix C

12. JADE water values

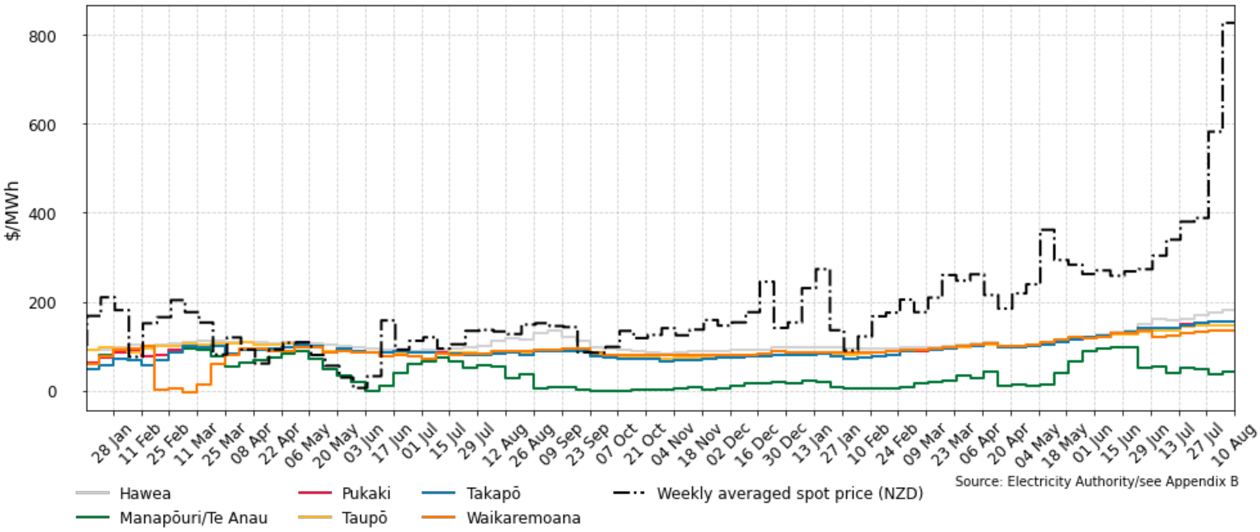
12.1. The JADE[2] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 21 shows the

[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.

national water values between 8 January 2023 and 3 August 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.

12.2. Water values did not change significantly this week, with differences ranging from a decrease of $0.90/MWh (Waikaremoana) to an increase of $6.50/MWh (Manapōuri/Te Anau). Overall, the model indicates a significant increase in water values over the last few months.

Figure 21: JADE water values across various reservoirs, 8 January 2023 and 3 August 2024

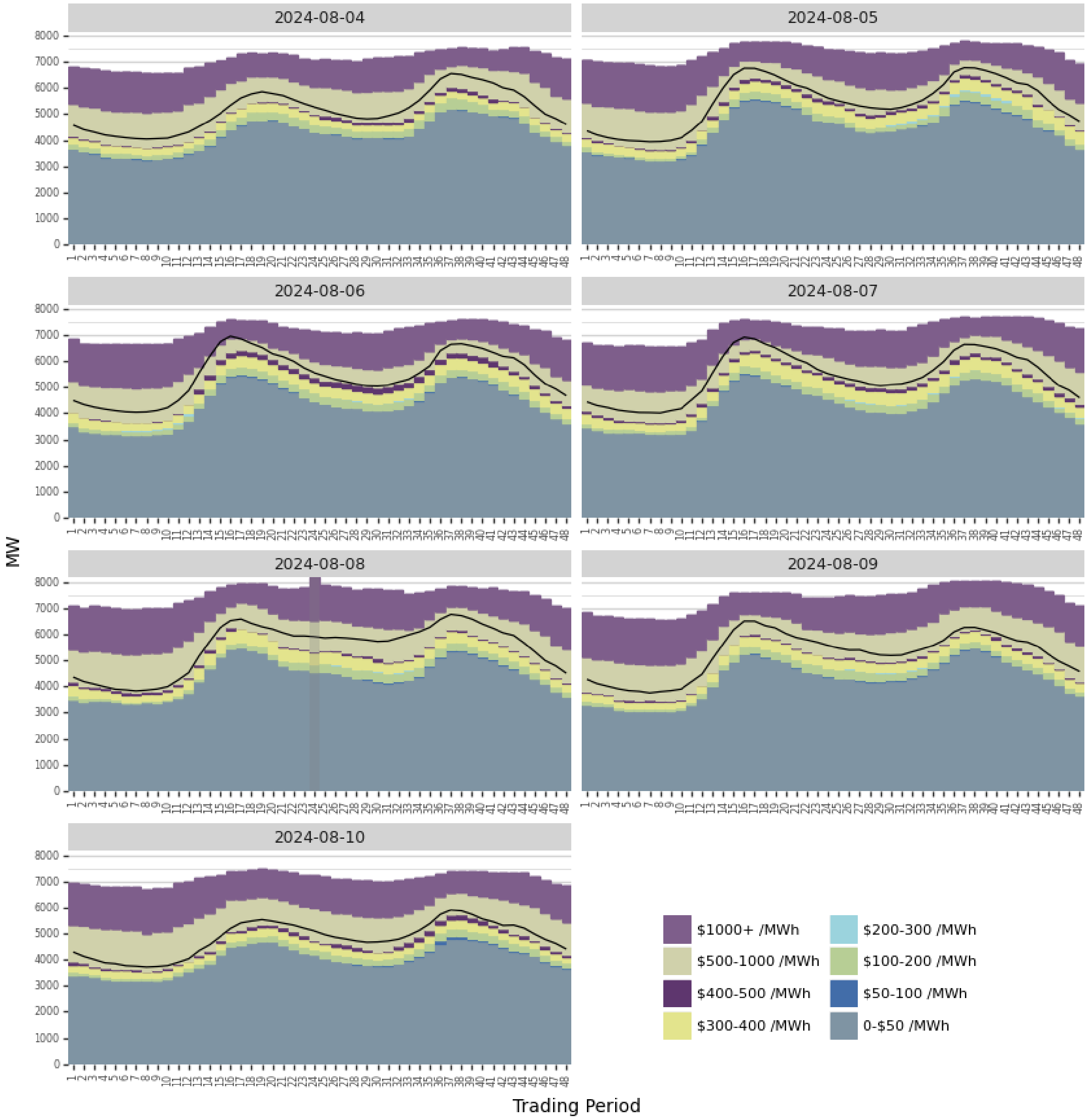


13. Offer behaviour

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. Most offers cleared in the $500-$1,000/MWh band this week. The number of offers over $1,000MWh has increased since last week, mostly due to hydro generation being offered at higher prices as lake levels continue to fall.

Figure 22: Daily offer stacks[3]



14. Ongoing work in trading conduct

14.1. Though fuel supply limitations will often cause prices to increase, the high wholesale prices seen this week are of major concern to the Authority. We will be closely analysing recent offer behaviour to ensure it is consistent with supply and demand conditions and have requested additional information from participants regarding their offers from 1 July 2024 onwards.

14.2. Further analysis is being done on the trading periods in Table 1 as indicated.

[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.

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 for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
1/07/2024-10/08/2024	Several	Further analysis	N/A	N/A	High energy prices