26 August 2024

Trading conduct report 18-24 August 2024

Market monitoring weekly report

Trading conduct report 18-24 August 2024

1. Overview

1.1. Prices decreased this week, compared to last week, likely due to high wind generation and lower demand later in the week. Low temperatures led to high South Island demand at the start of the week, contributing to high Benmore prices and periods where South Island prices were higher than those in the North. TCC, Huntly 5 and three Rankines provided baseload generation this week. National controlled hydro storage increased slightly and is currently ~56% 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. Between 18-24 August:

(a) the average wholesale spot price across all nodes was $356/MWh

(b) 95% of prices fell between $106/MWh and $730/MWh.

2.3. Overall, the majority of spot prices were within $275-$413/MWh, with the weekly average price decreasing by around $125/MWh compared to the previous week. The average Benmore spot price was $29/MWh higher than at Ōtāhuhu.

2.4. Low hydro storage, limited gas supply and periods of low wind generation have contributed high prices over the last few weeks. Prices remained high this week but continued to decrease, likely as a result of increased wind generation as well as Methanex's sale of gas to thermal generators.

2.5. The high prices seen between Sunday and Thursday this week generally occurred during periods of relatively high demand due to low temperatures. The week's highest prices also often occurred when wind generation was low and/or there were large wind and/or demand forecasting inaccuracies.

(a) From Tuesday to Thursday morning, wind generation was low, generally below ~300MW. Additionally, it was overforecast by more than 100MW at times highlighted prices occurred on Sunday, Monday and Tuesday.

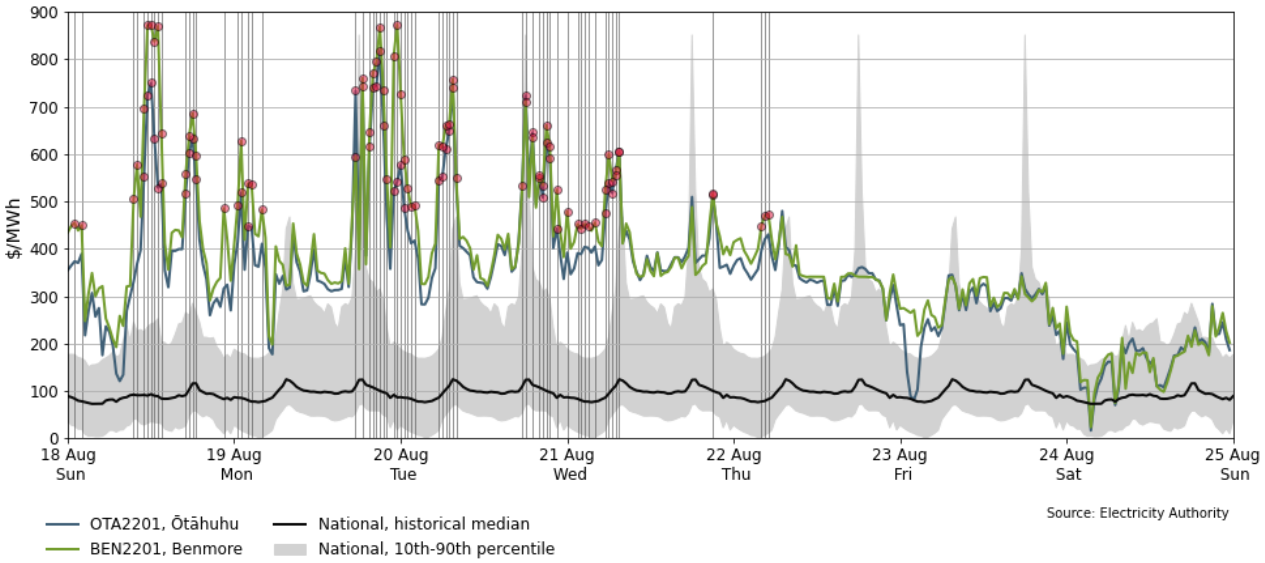
(b) Demand was often under-forecast by more than 100MW when highlighted prices occurred on Sunday and Monday.

2.6. Prices were often higher at Benmore than Ōtāhuhu on Sunday and Monday, due to low temperatures causing high demand in the South Island. The Benmore price reached a maximum of $873/MWh at 11:30pm on Monday, while the Ōtāhuhu price at the same time was $542/MWh.

2.7. Due to continued instances of high prices this week, the monitoring team have added all trading periods until August 23 for further analysis and additional information may be requested from generators.

2.8. 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.

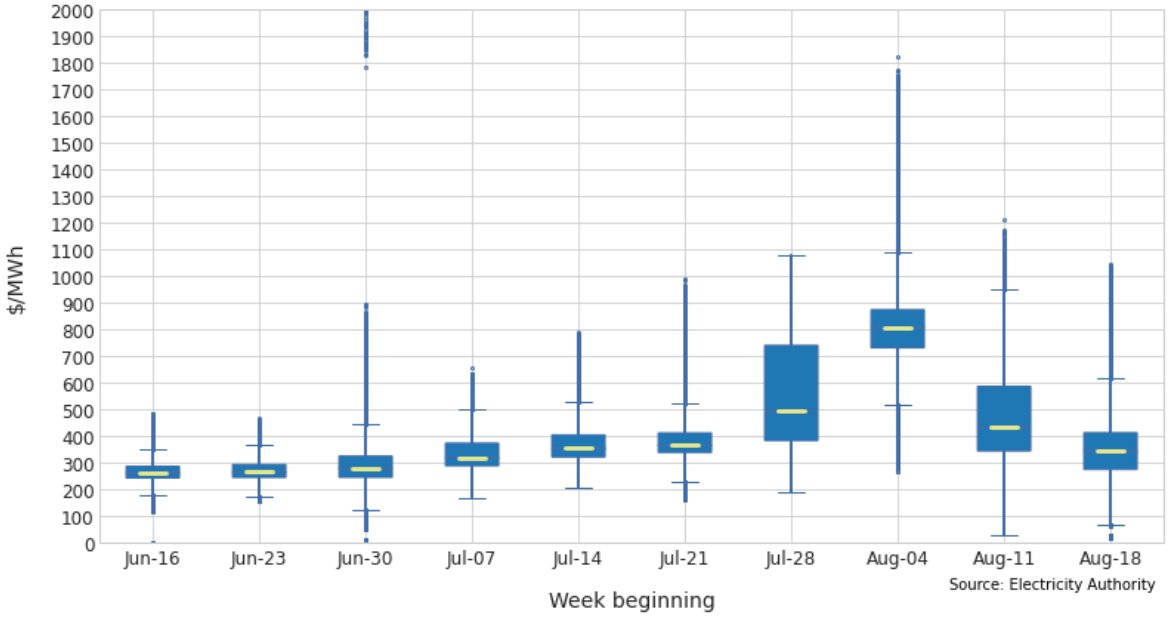
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 18-24 August



2.9. 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.

2.10. Compared to the previous week, the median price decreased by $89/MWh. The lower and upper quartiles also decreased, with the middle 50% of this week's prices below last week's median.

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

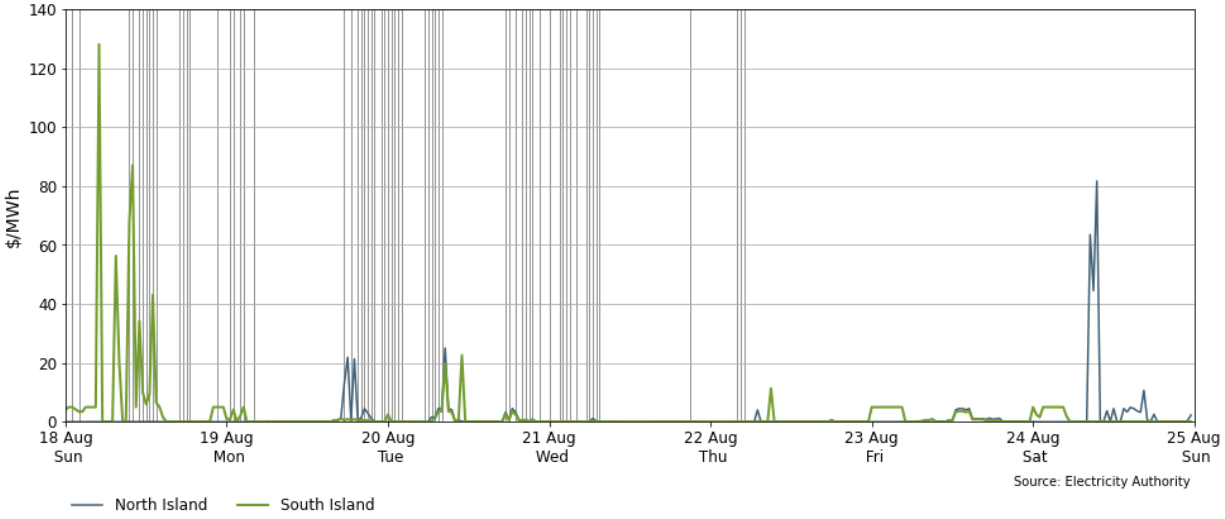


3. Reserve prices

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 were high in the South Island on Sunday, reaching $128/MWh at 5:00am while remaining at $0/MWh in the North Island. High wind generation in the North Island, combined with low hydro generation in the South Island, saw high southward HVDC flow. The increased southward flow resulted in the HVDC becoming the binding risk and causing the separation in prices.

3.2. Prices also spiked in the North Island on Saturday, reaching $82/MWh at 9:30am while remaining at $0.10/MWh in the South Island. The monitoring team is looking further into these reserve prices.

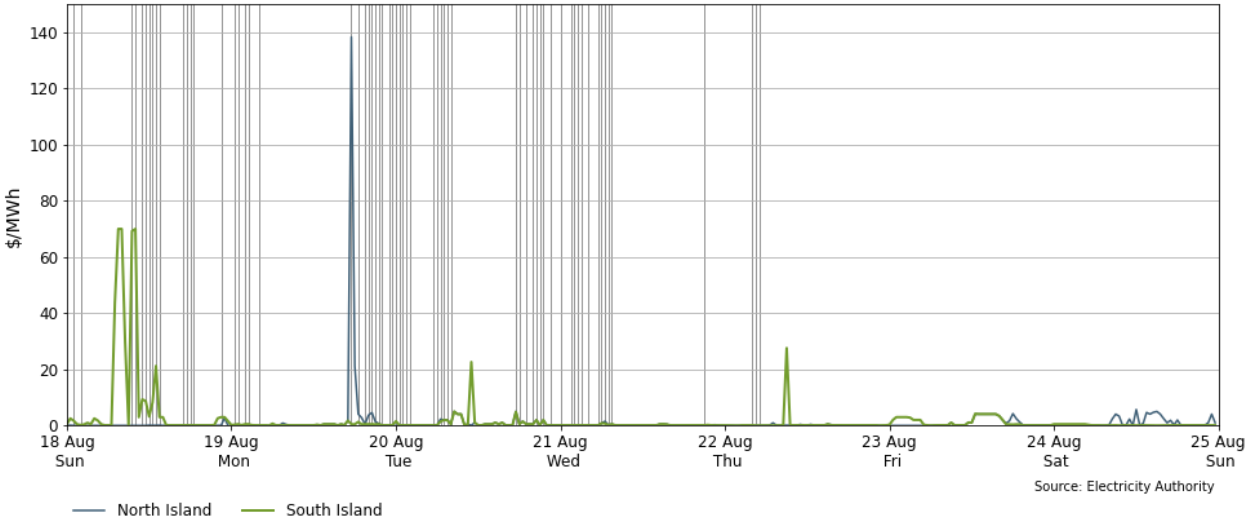
Figure 3: Fast instantaneous reserve price by trading period and island, 18-24 August



3.3. 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 at 5:30pm in the

North Island on Monday, reaching $138/MWh while remaining at $0.50/MWh in the South Island. This occurred as the SIR required to cover the risk setter increased, and energy dispatch from Huntly 2 ramped up, which decreased the amount of North Island SIR available.

Figure 4: Sustained instantaneous reserve by trading period and island, 18-24 August



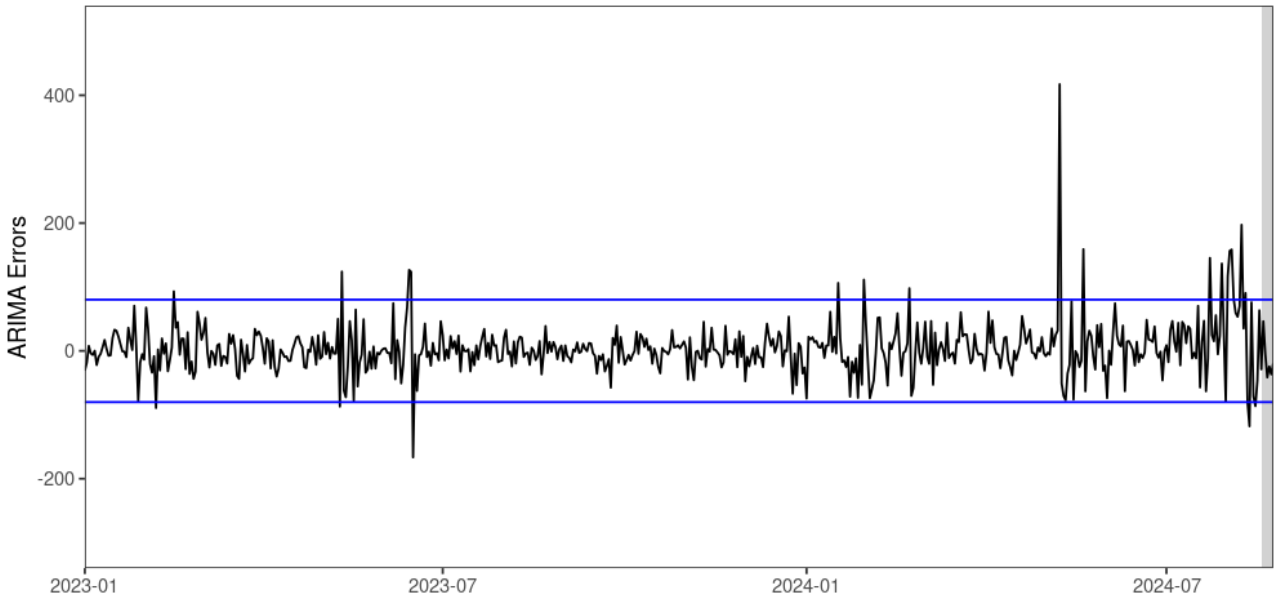
4. Regression residuals

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, there were no residuals above two standard deviations of the data, indicating that prices were similar to what the model expected.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 24 August 2024

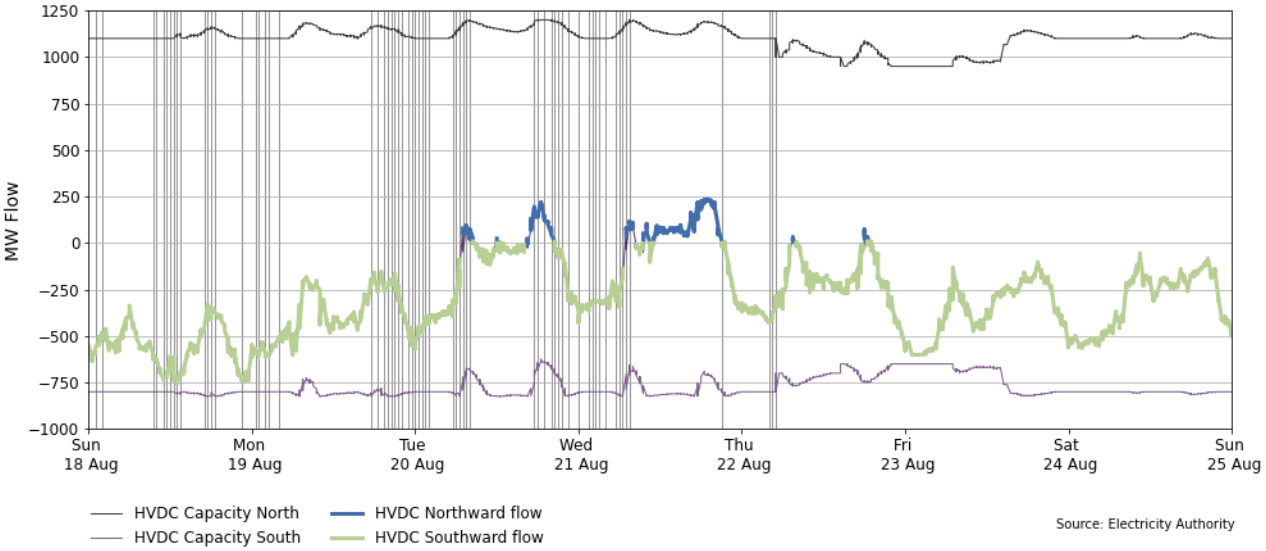


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 18-24 August. Due to low hydro generation in the South Island, HVDC flow was mostly southward this week. The flow was northward when prices were high on Tuesday morning and evening, and on Wednesday morning.

Figure 6: HVDC flow and capacity, 18-24 August

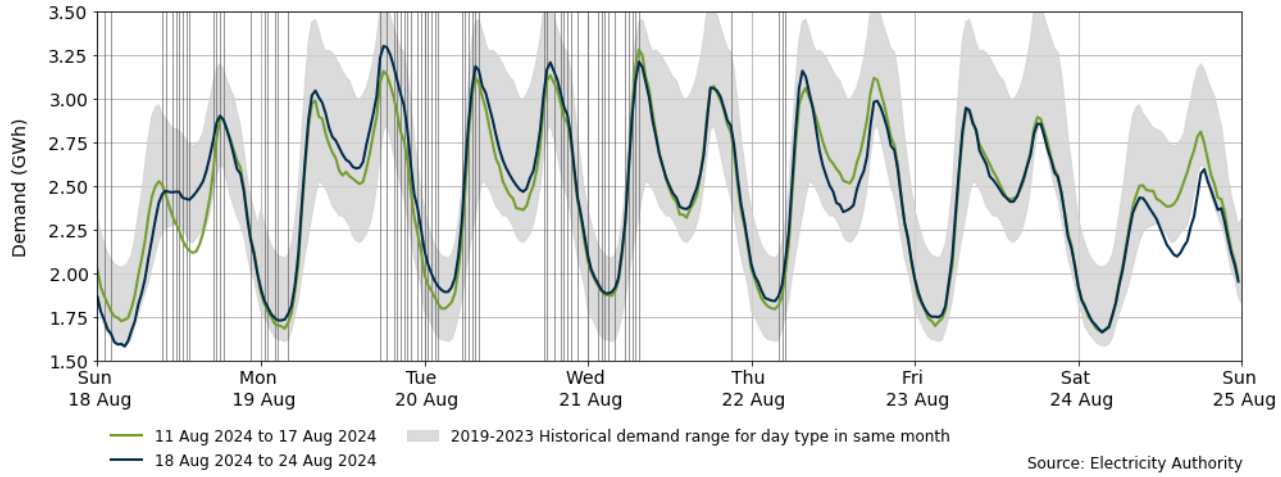


6. Demand

6.1. Figure 7 shows national demand between 18-24 August, compared to the historic range and the demand of the previous week. Demand was within or below the historical range for this time of year. Demand was generally higher than the previous week from Sunday evening to Thursday morning, while temperatures were low. Most of this week's highlighted

prices occurred during this time. The maximum demand this week was 3.3GWh at 6:00pm on Monday.

Figure 7: National demand, 18-24 August compared to historic range and previous week

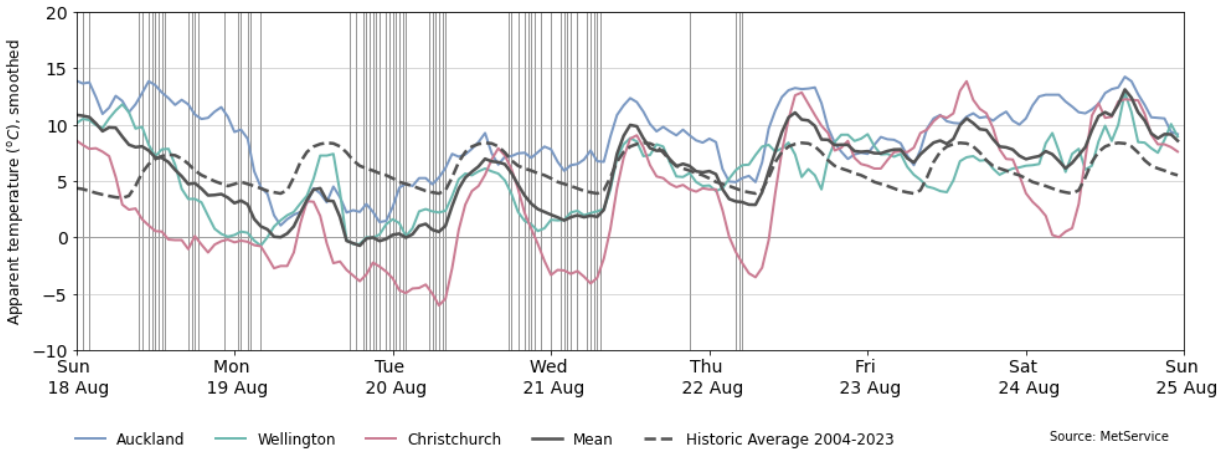


6.2. Temperatures ranged from 1°C to 15°C in Auckland, -1°C to 13°C in Wellington, and -6°C to 15°C in Christchurch. Temperatures were mostly below average between Sunday afternoon and Thursday morning, but increased and were above average for the rest of the week. Temperatures were below freezing in Christchurch when many of this week's highlighted prices occurred.

6.3. Figure 8 shows the hourly apparent temperature at main population centres from 18-24 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 temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Temperatures ranged from 1°C to 15°C in Auckland, -1°C to 13°C in Wellington, and -6°C to 15°C in Christchurch. Temperatures were mostly below average between Sunday afternoon and Thursday morning, but increased and were above average for the rest of the week. Temperatures were below freezing in Christchurch when many of this week's highlighted prices occurred.

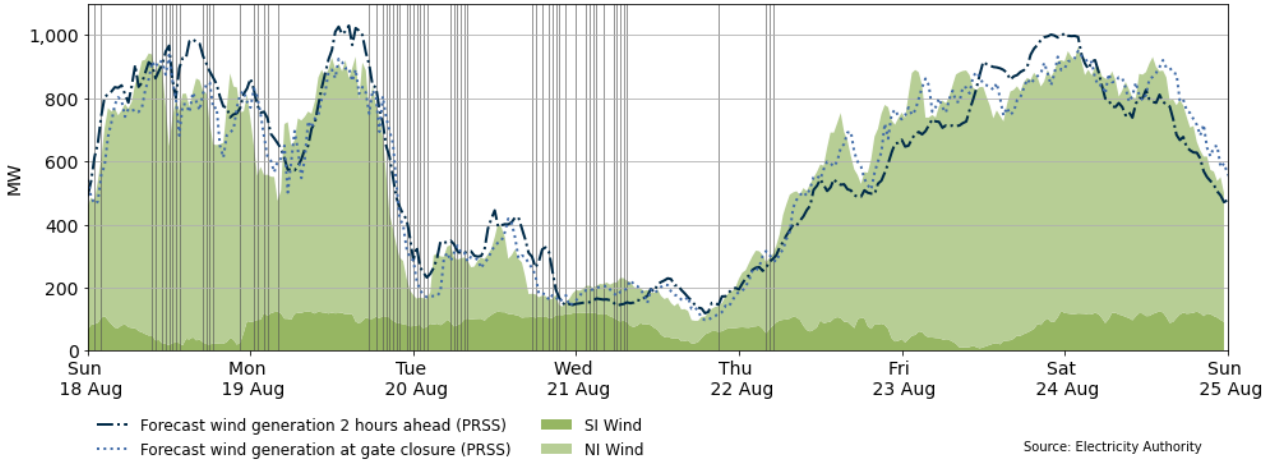
Figure 8: Temperatures across main centres, 18-24 August



7. Generation

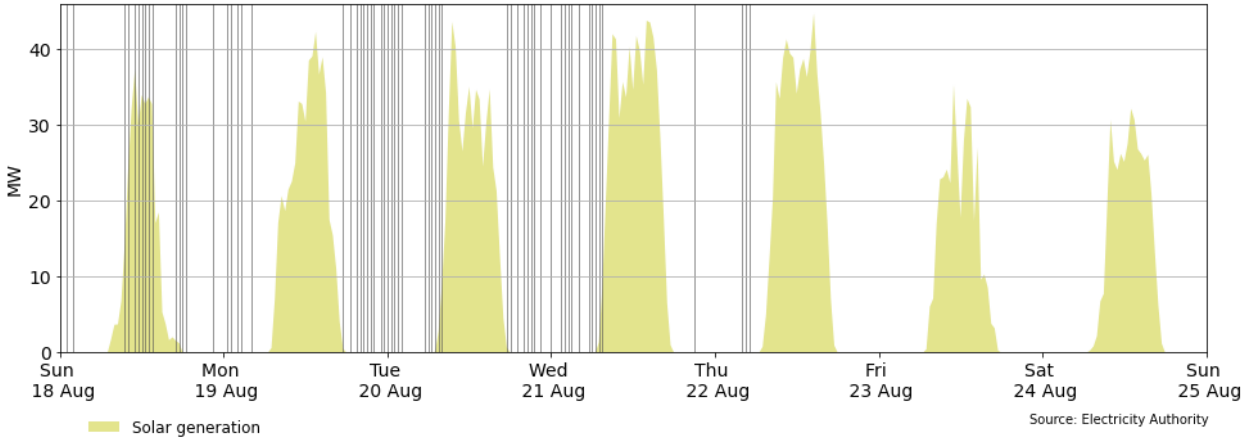
7.1. Figure 9 shows wind generation and forecast from 18-24 August. This week wind generation varied between 95MW and 963MW, with an average of 576MW. It was low on Tuesday and Wednesday, with the average generation on these days just 174MW-249MW. High wind generation throughout the rest of the week likely contributed to the decrease in prices this week. Many of this week's highest prices occurred when wind generation was low and/or below forecast.

Figure 9: Wind generation and forecast, 18-24 August



7.2. Figure 10 shows solar generation from 18-24 August. Maximum daily solar generation was over 30MW each day 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, 18-24 August



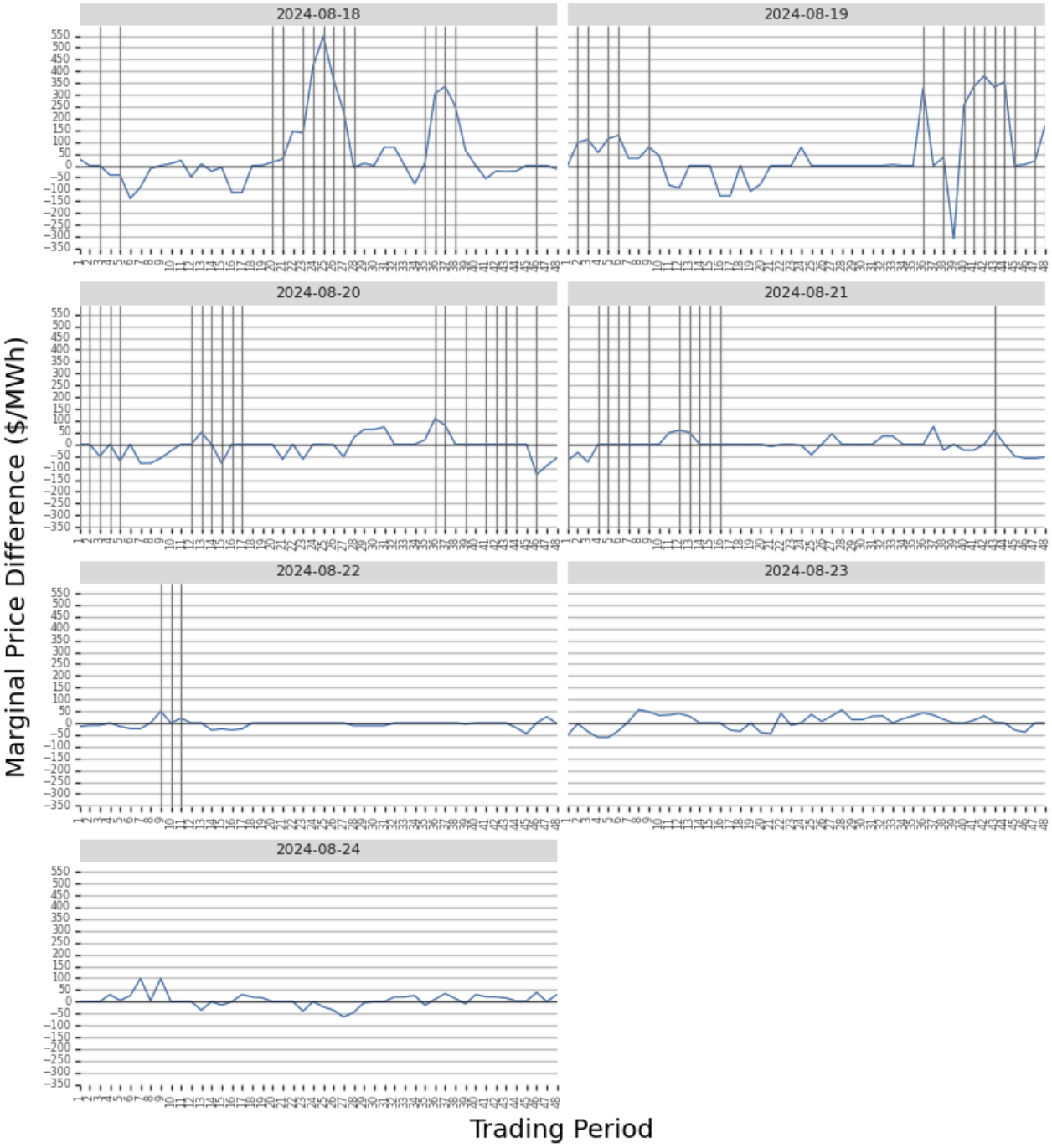
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

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

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.

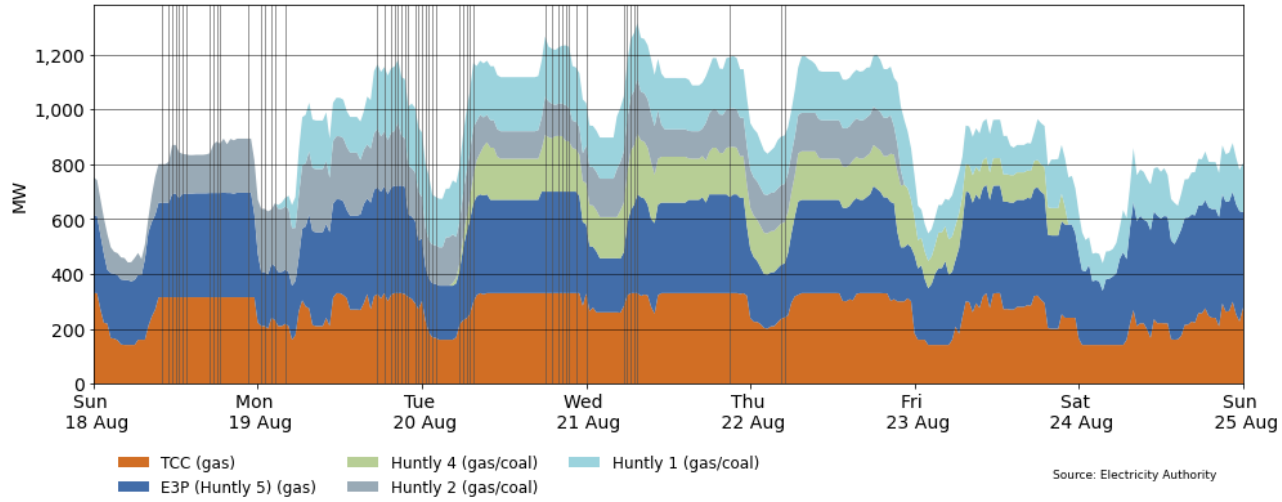
7.4. The most notable positive (marginal prices higher than simulation) differences this week (between $365/MWh-$547/MWh) occurred on Sunday afternoon, when demand was up to 127MW higher than forecast and wind generation was as much as 290MW lower than forecast. Positive differences exceeding $250/MWh also occurred that evening and on Monday evening, when demand and/or wind forecasting inaccuracies exceeded 100MW. Throughout the rest of the week, prices were generally similar to those simulated.

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, 18-24 August



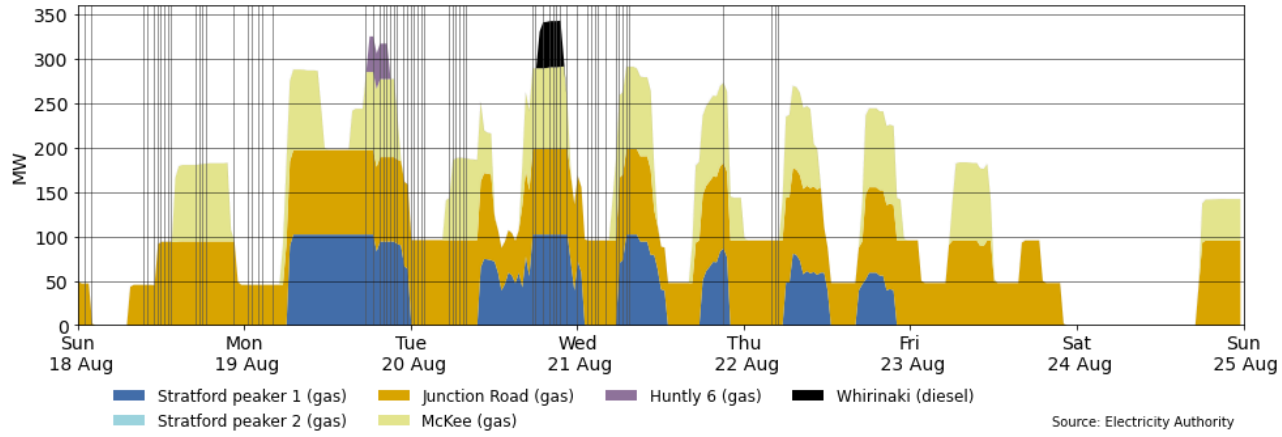
7.5. Figure 12 shows the generation of thermal baseload between 18-24 August. TCC and Huntly 5 (E3P) ran continuously for the entire week. Huntly 1 ran from Monday onwards, Huntly 2 ran until Friday and Huntly 4 ran from Tuesday, after returning from outage, to Saturday.

Figure 12: Thermal baseload generation, 18-24 August



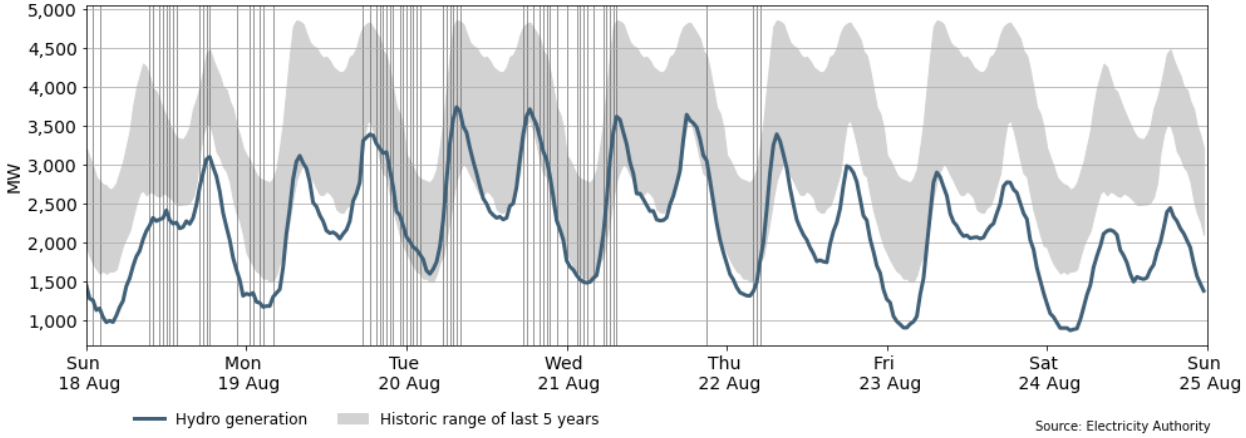
7.6. Figure 13 shows the generation of thermal peaker plants between 18-24 August. Junction Road ran continuously as baseload support from Sunday afternoon to Friday evening, as well as on Saturday evening. McKee also ran each day during peak and/or shoulder periods. Stratford 1 ran during peak and shoulder periods from Monday to Thursday. Huntly 6 ran during the evening peak on Monday and Whirinaki ran during the evening peak on Tuesday.

Figure 13: Thermal peaker generation, 18-24 August



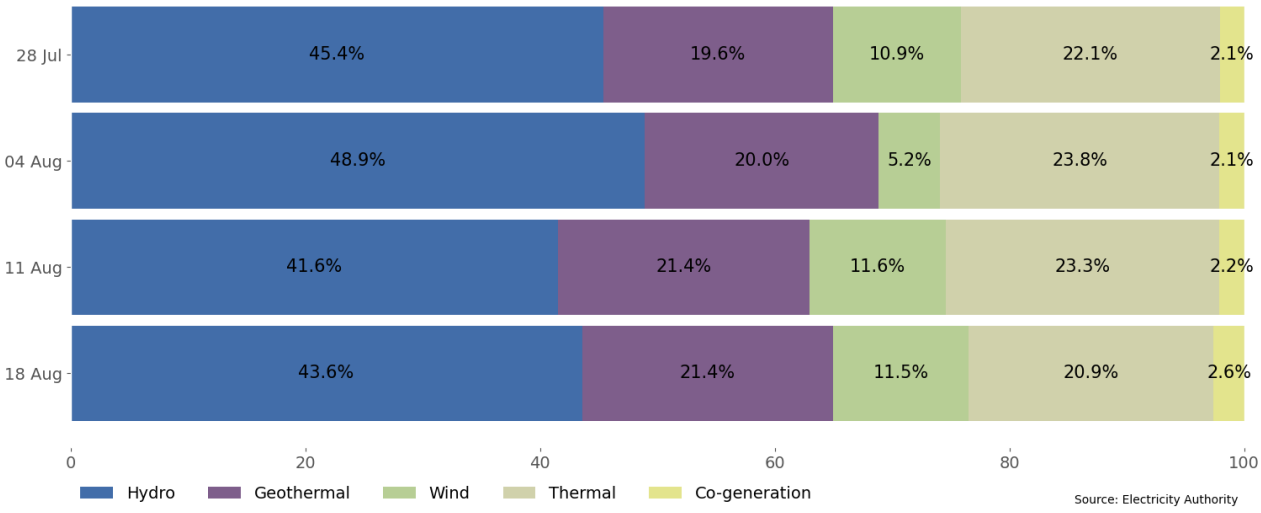
7.7. Figure 14 shows hydro generation between 18-24 August. Hydro generation increased this week compared to the previous week but remained low, mostly below the historical range of the last five years. This is due to low hydro storage, with a significant portion of hydro generation capacity priced highly to reduce likelihood that it will be dispatched and to conserve water. However, at times some of this capacity was needed. Hydro generation was highest on Tuesday and Wednesday this week due to high demand and lower wind generation, which likely contributed to the high prices on these days.

Figure 14: Hydro generation, 18-24 August



7.8. As a percentage of total generation, between 18-24 August, total weekly hydro generation was 43.6%, geothermal 21.4%, wind 11.5%, thermal 20.9%, and co-generation 2.6%, as shown in Figure 15. The proportion of hydro generation increased this week, while thermal generation decreased.

Figure 15: Total generation by type as a percentage each week, 28 July-24 August 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 18-24 August ranged between ~750MW and ~1,250MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 4 was on outage until 19 August.

(b) Stratford 2 is on outage until 27 September.

(c) TCC was on partial outage on Friday.

(d) Kawerau geothermal plant was on outage on 18 August.

Figure 16: Total MW loss from generation outages, 18-24 August

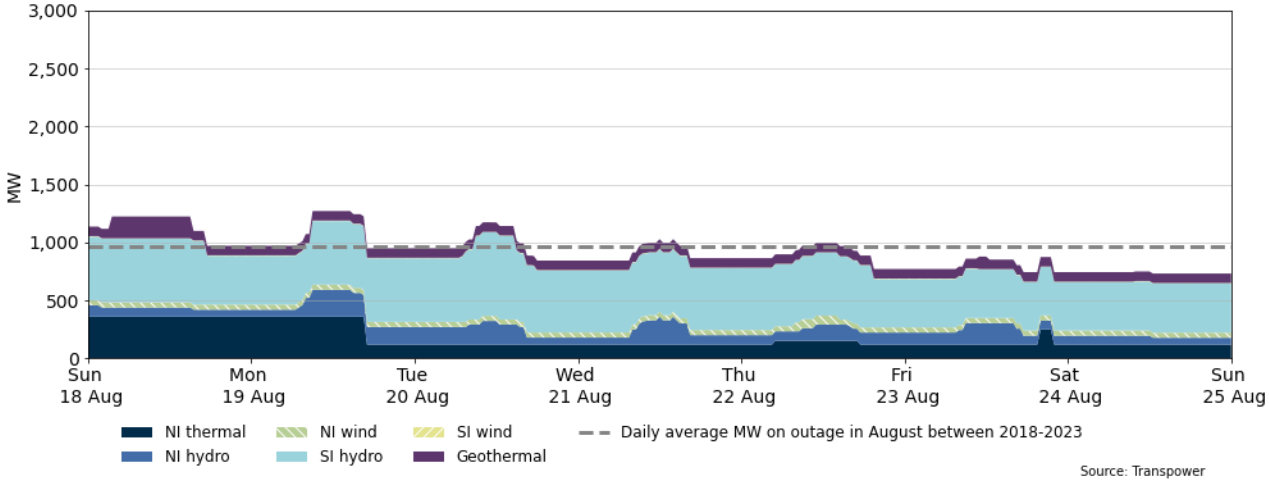
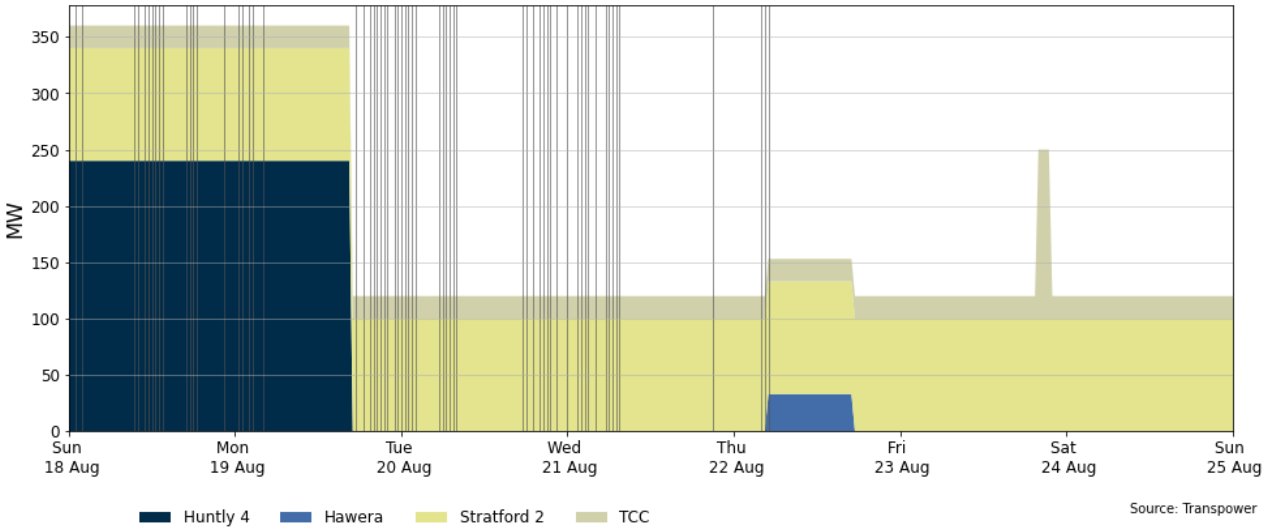


Figure 17: Total MW loss from thermal outages, 18-24 August

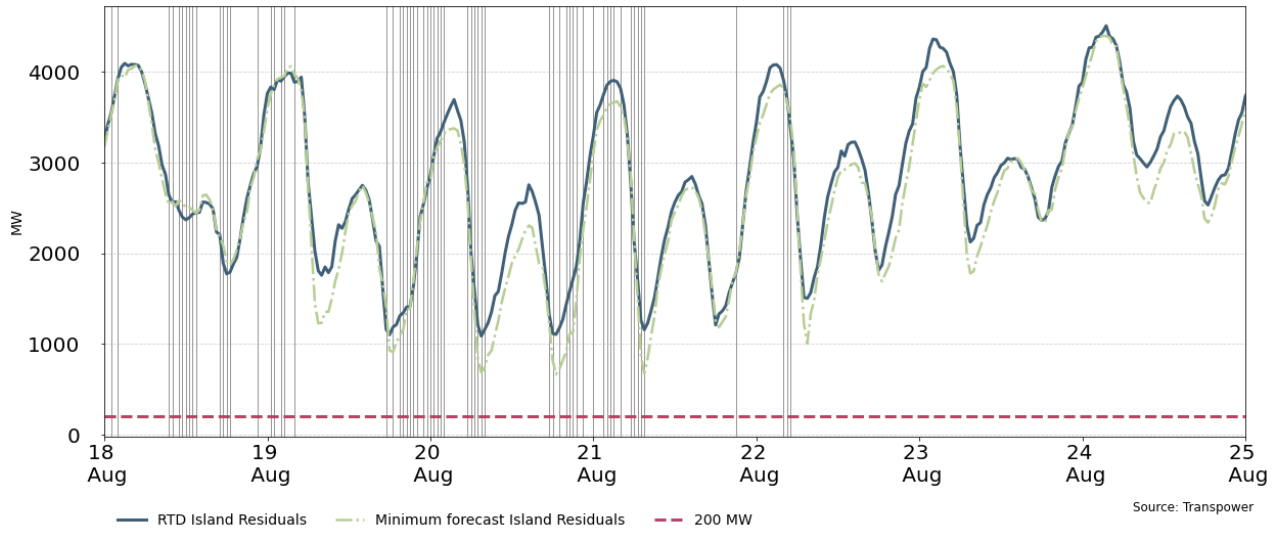


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 18-24 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 192MW at 6:30pm on Monday.

Figure 18: National generation balance residuals, 18-24 August



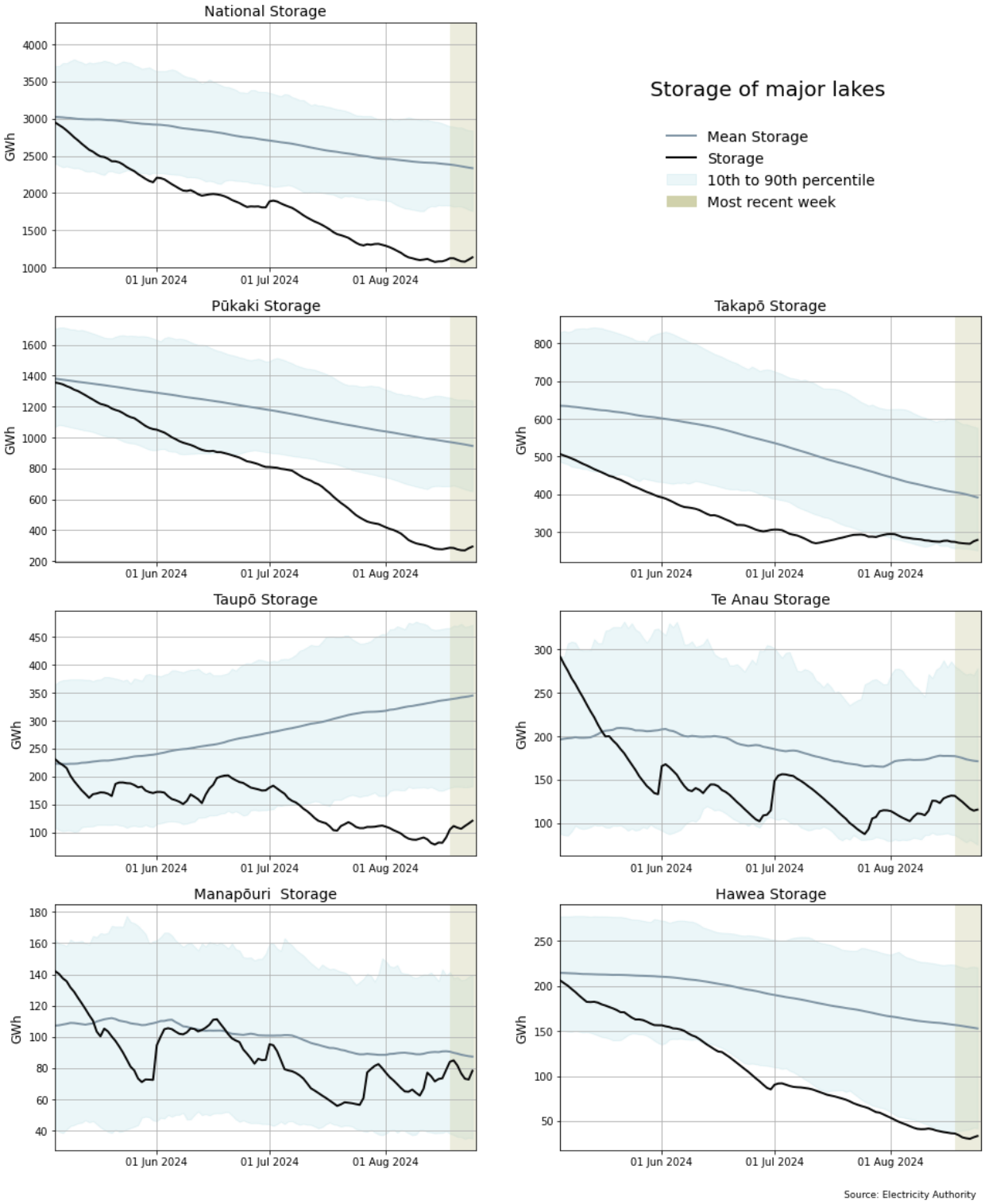
10. Storage/fuel supply

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 increased this week and is ~33% nominally full and ~56% of the historical average for this time of the year as of 24 August.

10.3. Storage increased at Pūkaki and Taupō, which are still below their 10th percentiles, and at Takapō, which is just above its 10th percentile. Storage decreased at Te Anau and Manapōuri, with both lakes still below mean but above their 10th percentiles. Storage also decreased at Hawea, which is below its 10th percentile.

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 August 2024. The SRMC for gas has increased from the previous month, while the coal SRMC has remained stable and the diesel SRMC has decreased.

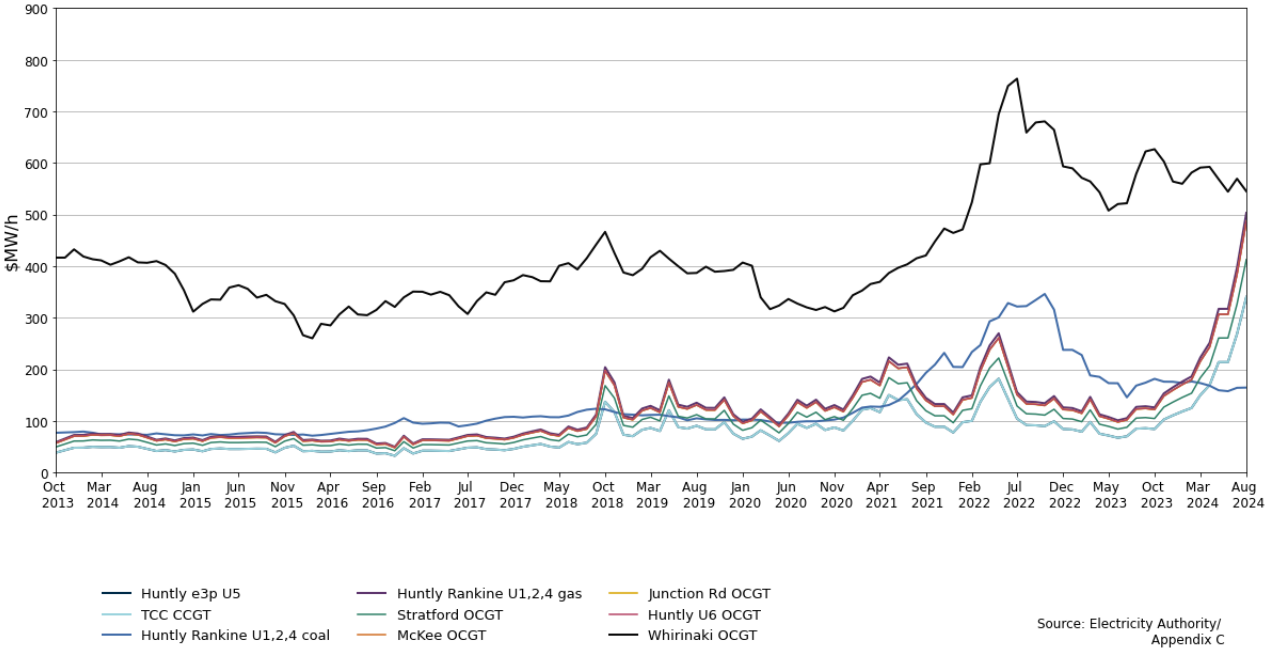
11.4. The latest SRMC of coal-fueled Rankine generation is ~$165/MWh. The cost of running the Rankines on gas remains more expensive at ~$503/MWh.

11.5. The SRMC of gas fuelled thermal plants continues to increase and is currently between ~$340/MWh and ~$503/MWh.

11.6. The SRMC of Whirinaki is ~$545/MWh.

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

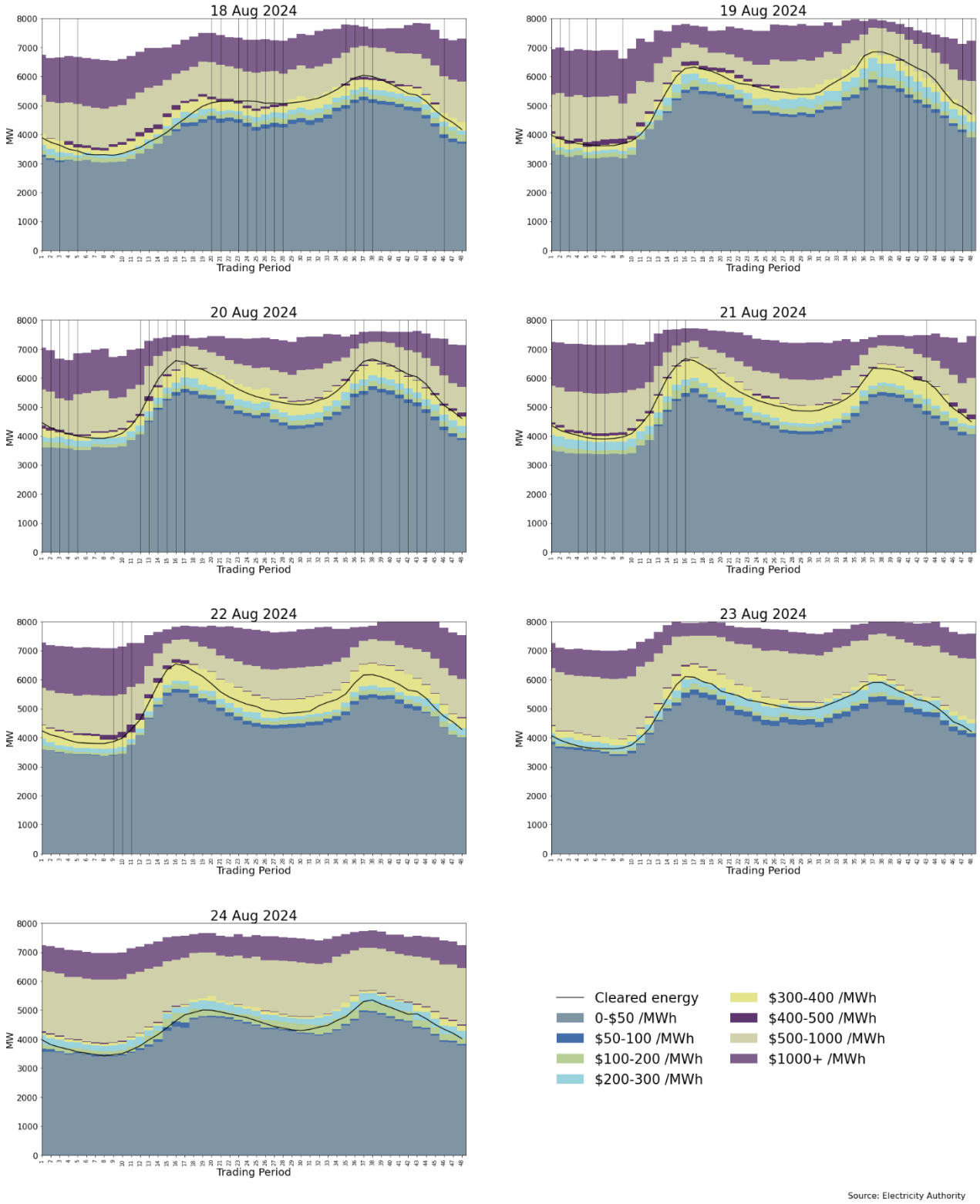


12. Offer behaviour

12.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Between Monday and Thursday, most offers cleared in the $300-$400/MWh band. Due to the thin $400-$500/MWh band, forecasting inaccuracies tended to push prices above $500/MWh. On Friday and Saturday, the amount of offers in the $300-$400/MWh band decreased while the $500-$1,000/MWh band increased, but most offers cleared below $400/MWh. Over the course of the week, the quantity of offers in the $200-$300/MWh band increased as thermal and hydro generators offers have changed to reflect the current market conditions.

Figure 21: Daily offer stacks



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. Prices generally appeared to be consistent with supply and demand conditions this week, but as prices remain high, we will be closely analysing offer behaviour to confirm this.

13.2. 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 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
1/07/2024-23/08/2024	Several	Further analysis	N/A	N/A	High energy prices
24/07/2024	18-20	Further analysis	Genesis	Huntly	Reserve offers