23 September 2024

Trading conduct report 15-21 September 2024

Market monitoring weekly report

Trading conduct report 15-21 September 2024

1. Overview

1.1. Prices increased this week, compared to last week, but were still frequently below the historical median outside of peak demand periods. Significant wind forecasting inaccuracies, combined with high demand and limited availability of thermal generation due to outages, occurred when the Ōtāhuhu spot price reached $4,173/MWh on Tuesday morning. HVDC outages took place from Monday to Wednesday, leading to price separation between islands and high North Island SIR prices. Thermal generation remained low, with only Huntly 5 and one Rankine providing baseload generation for most of the week. National controlled hydro storage increased slightly this week and is currently ~104% of mean.

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 15-21 September:

(a) the average wholesale spot price across all nodes was $132/MWh.

(b) 95% of prices fell between $0.02/MWh and $310/MWh.

2.3. Overall, the majority of spot prices were within $26-$194/MWh, with the weekly average price increasing by around $60/MWh compared to the previous week.

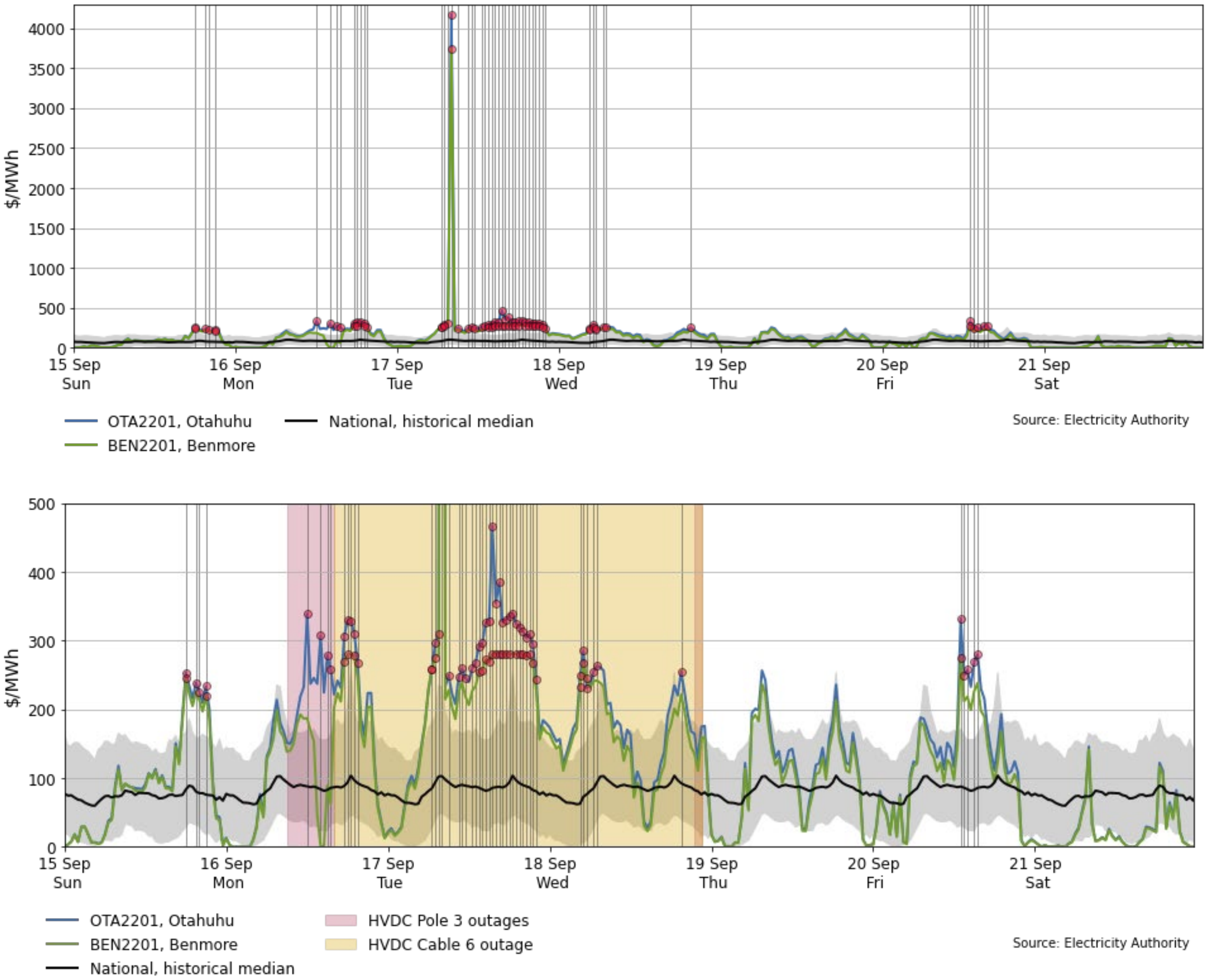
2.4. Prices were generally low overnight this week, often dropping below $1/MWh. However, they were often above the median during the day and above $200/MWh during peak demand periods. Several instances of inaccurate wind and demand forecasting, requiring higher-priced hydro and thermal generation to be dispatched, likely contributed to many of these high prices. Wind and demand forecasting discrepancies exceeded 100MW respectively on multiple occasions where prices have been highlighted.

2.5. The Ōtāhuhu spot price reached a maximum of $4,173/MWh at 8.00am on Tuesday, when demand was under forecast by 227MW and wind generation was over forecast by 55MW. Online baseload thermal generation units were running close to their maximum capacity and several thermal peaking units were on outage, leading to high priced generation being dispatched during the trading period. The market monitoring team is looking further into the dispatches during this trading period.

2.6. HVDC outages took place between Monday and Wednesday, limiting the flow of energy between islands and causing prices to separate. On Monday, this contributed to the Ōtāhuhu price being more than $300/MWh higher than the Benmore price at the same time. Prices separated again on Tuesday afternoon. This was due to both the HVDC outage and decreased thermal generation in the North Island after Huntly 5 (E3P) tripped[1], in combination with forecasting inaccuracies and high demand due to low temperatures, requiring higher-priced hydro generation to be dispatched.

2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-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, 15-21 September



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 $69/MWh. The interquartile range also increased, though the middle 50% of this week's prices remained below the lower quartile of most of the previous nine weeks.

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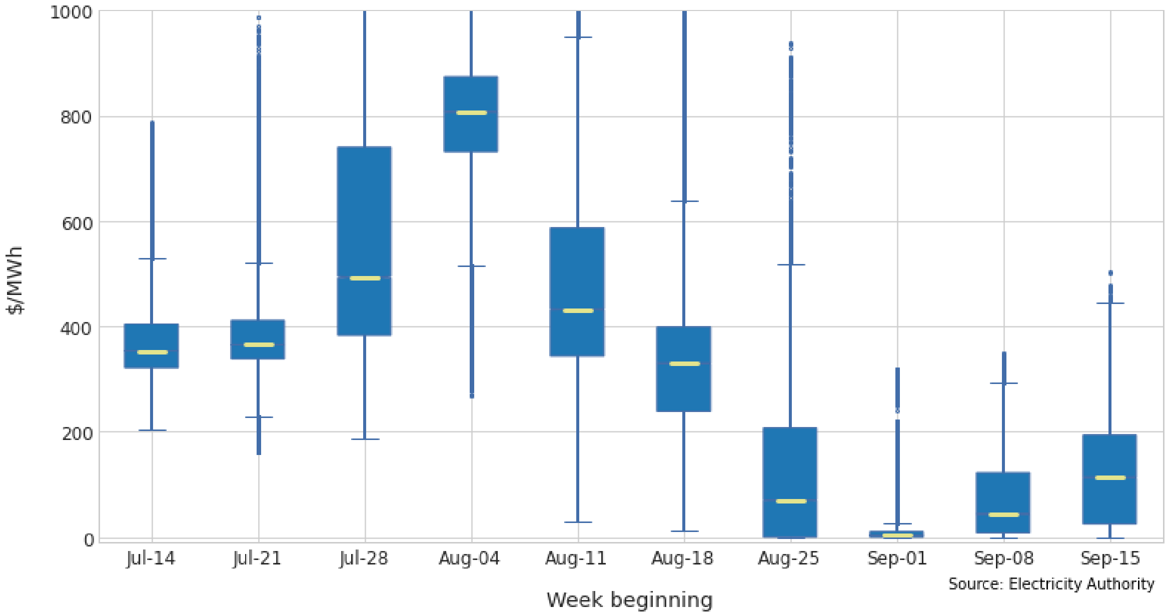
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks

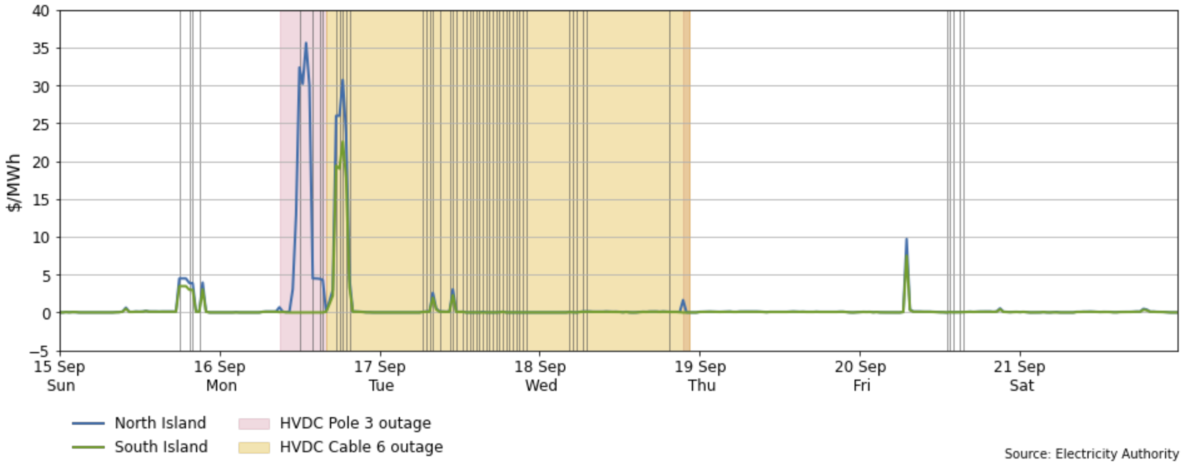


3. Reserve prices

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, reaching a maximum of $36/MWh in the North Island at 1:00pm on Monday while remaining at $0/MWh in the South Island. During the pole 3 outage, the reserve sharing capacity between the islands was reduced from 220MW to between 133 and 208 MW. The pole being out also reduces the 'risk offset' provided by the second pole when the HVDC is the risk setter in either island. Several times during the pole 3 outage, the HVDC was the risk setter in the North Island, the reduction in reserves available through reserve sharing, and the increase in the risk size due to there being no reserve offset provided by the second pole, caused the risk set by the HVDC to be higher than usual. This led to more expensive reserves in the North Island being needed during this time. The lack of reserve sharing would also have increased the reserves required when Huntly 5 was setting the risk.

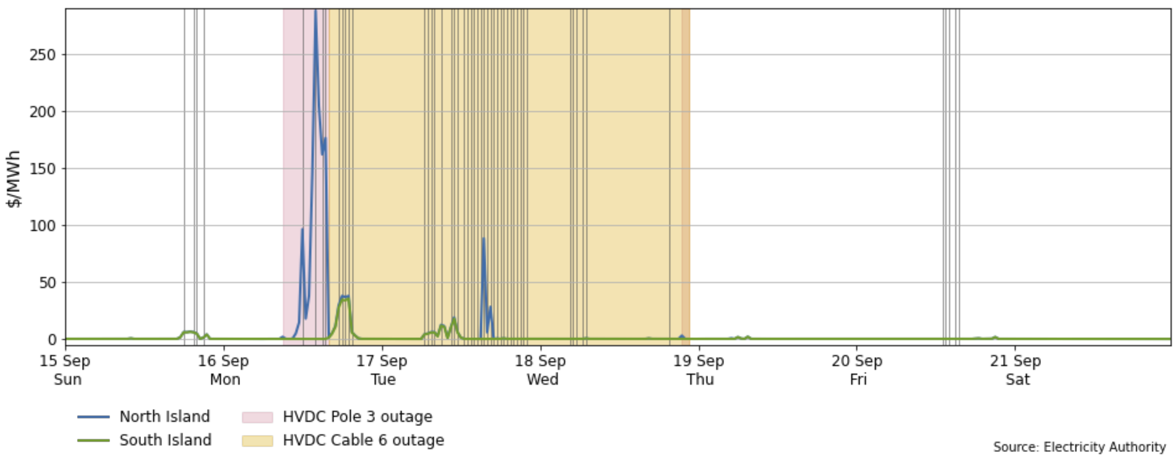
3.2. High reserve prices in both islands during Monday evening was due to the high demand for electricity, which resulted in more expensive reserves being needed to cover the risk setter.

Figure 3: Fast instantaneous reserve price by trading period and island, 15-21 September



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 reached a maximum of $288/MWh in the North Island at 2:00pm on Monday while remaining at $0/MWh in the South Island, this was due to the HVDC Pole 3 outage as explained above.

Figure 4: Sustained instantaneous reserve by trading period and island, 15-21 September



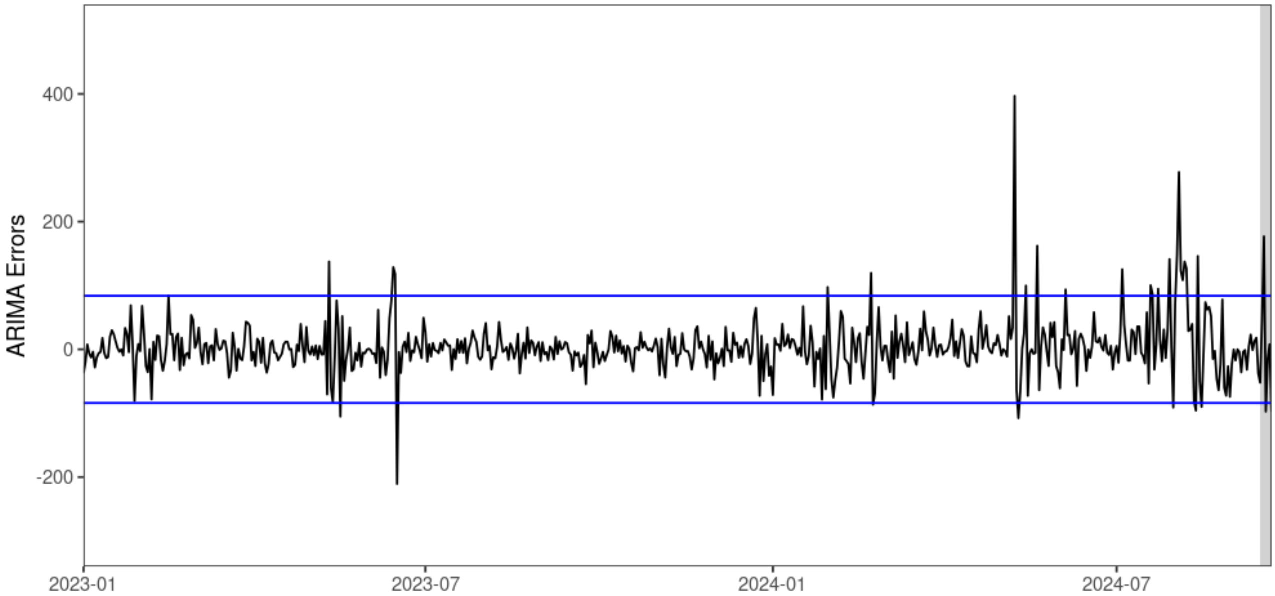
4. Regression residuals

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 residual on Tuesday was above two standard deviations of the data, indicating that prices on this day were higher than the model expected. This was likely due to the one very large spot price on Tuesday morning, which would be increasing the daily average Tuesday price. This very high price was influenced by factors not included in the ARMA model, including inaccurate demand and wind forecasts.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 21 September 2024



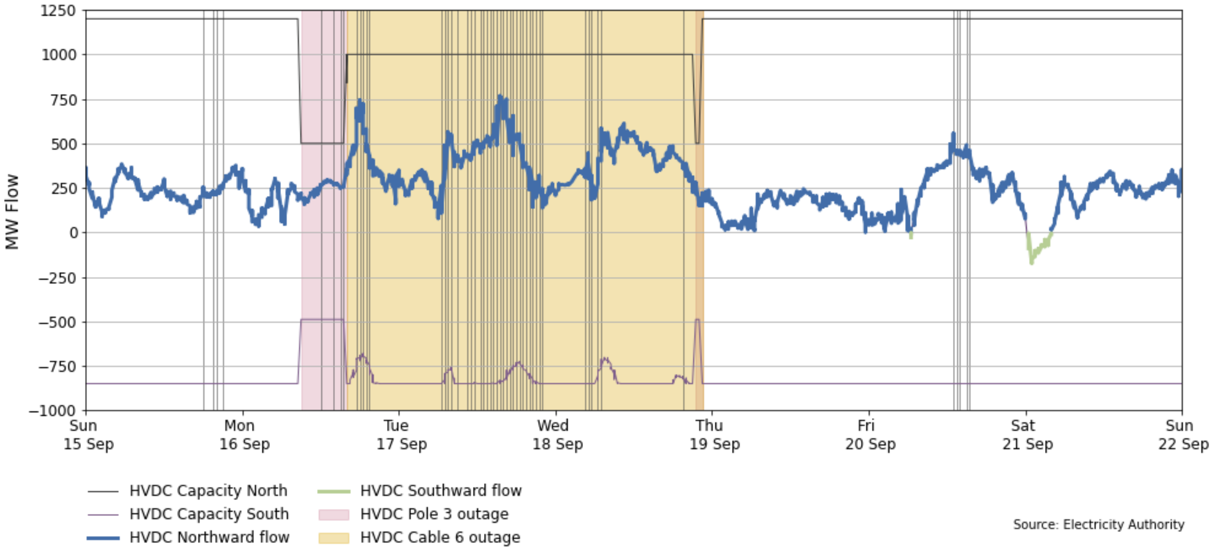
Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 15-21 September. Due to increased hydro storage and generation, and lower South Island demand due to the Tiwai demand response, HVDC flow was almost entirely Northward this week.

5.2. The HVDC Pole 3 was on outage from 9:00am to 4:00pm on Monday and 9:30pm to 10:30pm on Wednesday. HVDC Cable 6 was on outage from 4:00pm on Monday to 10:30pm on Wednesday. The outages limited capacity and flow between islands, leading to price separation between islands and high reserve prices.

Figure 6: HVDC flow and capacity, 15-21 September

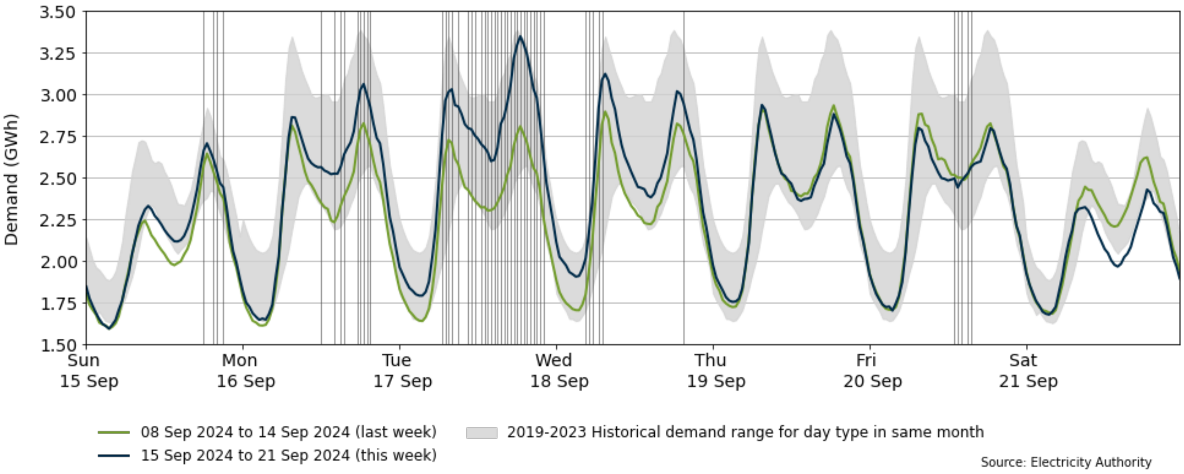


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 15-21 September, compared to the historic range and the demand of the previous week. Demand remained low this week, within or below the historical range for this time of year, partly due to the reduction in demand from Tiwai. It was highest between Monday evening and Wednesday morning, when temperatures were low across the country. The weekly maximum demand of 3.35GWh occurred at 6:30pm on Tuesday.

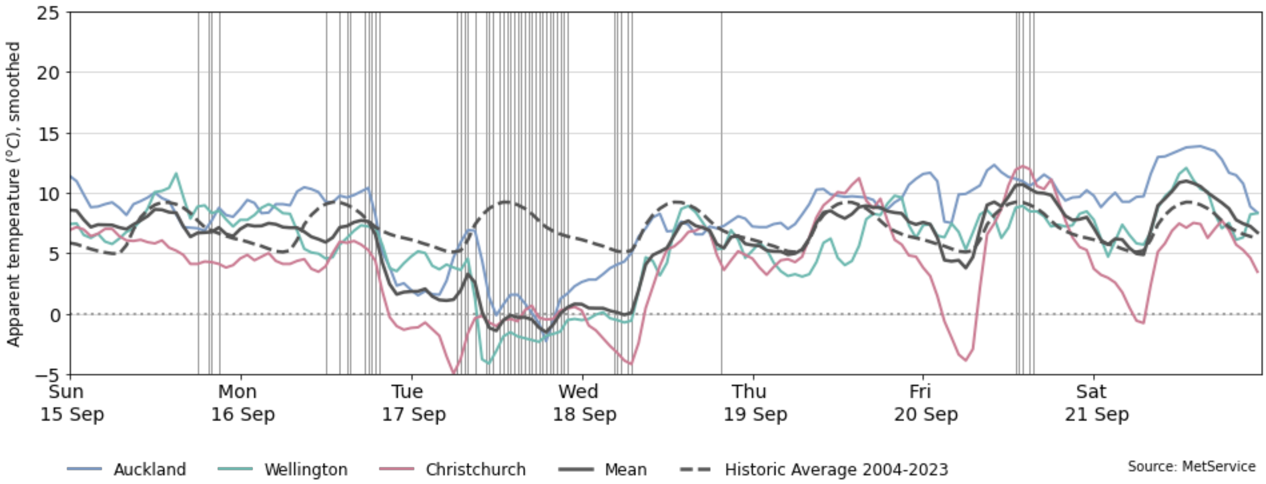
Figure 7: National demand, 15-21 September compared to historic range and previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 15-21 September 2024. The apparent temperature 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.

6.3. Temperatures ranged from -2°C to 14°C in Auckland, -5°C to 12°C in Wellington, and -6°C to 12°C in Christchurch. Temperatures were mostly close to average this week but were low between Monday evening and Wednesday morning. This led to increased demand on these days, likely contributing to higher prices.

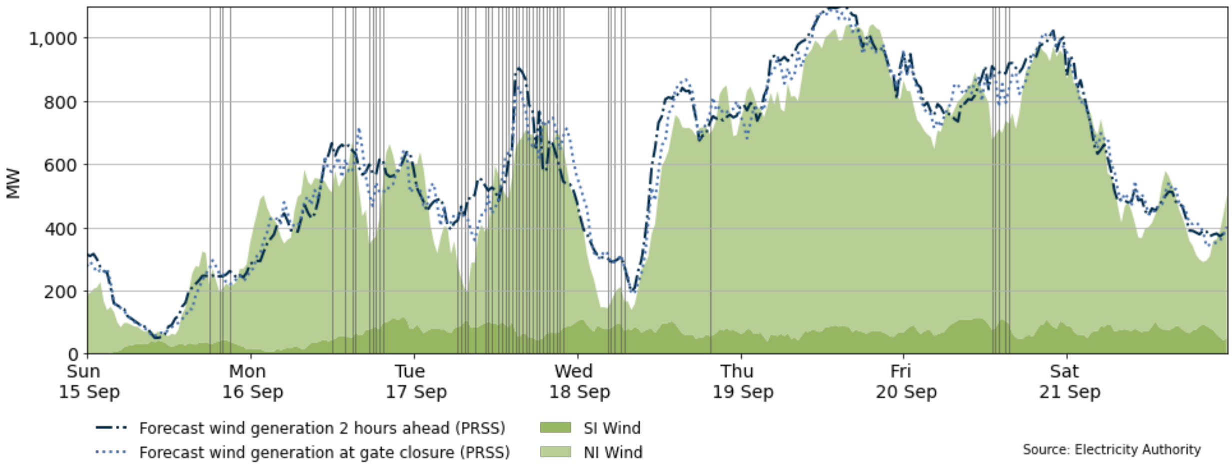
Figure 8: Temperatures across main centres, 15-21 September



7. Generation

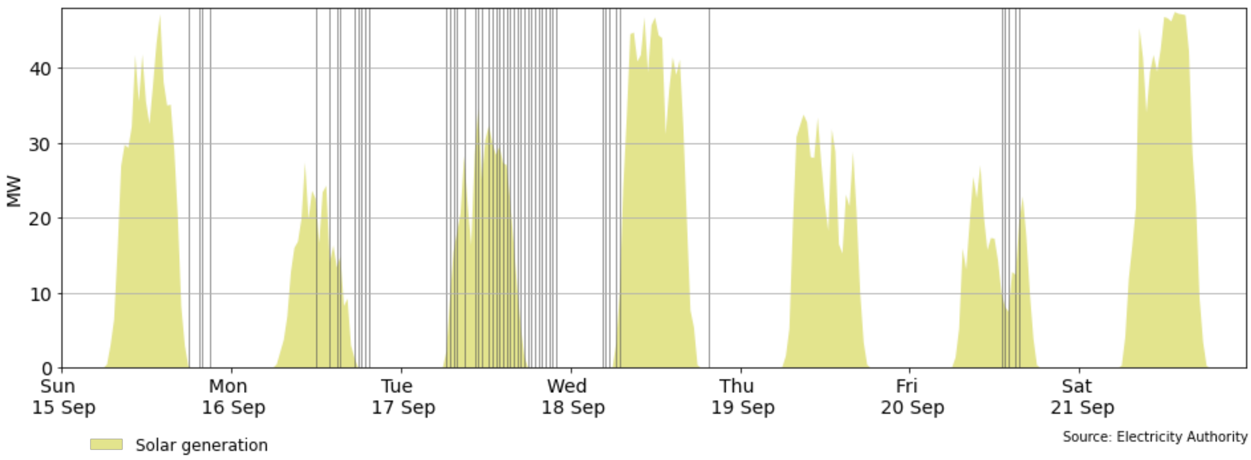
7.1. Figure 9 shows wind generation and forecast from 15-21 September. This week wind generation varied between 55MW and 1,042MW, with a daily average of 557MW. Wind generation was low and/or below forecast at the times many of this week's highlighted prices occurred, particularly on Tuesday when it was over forecast by as much as 228MW. The monitoring team is in contact with the wind farm owners whose farms are resulting in the largest errors.

Figure 9: Wind generation and forecast, 15-21 September



7.2. Figure 10 shows solar generation from 15-21 September. Maximum daily solar generation was over 30MW each day except Monday and Friday.

Figure 10: Solar generation, 15-21 September



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[2]) 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

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

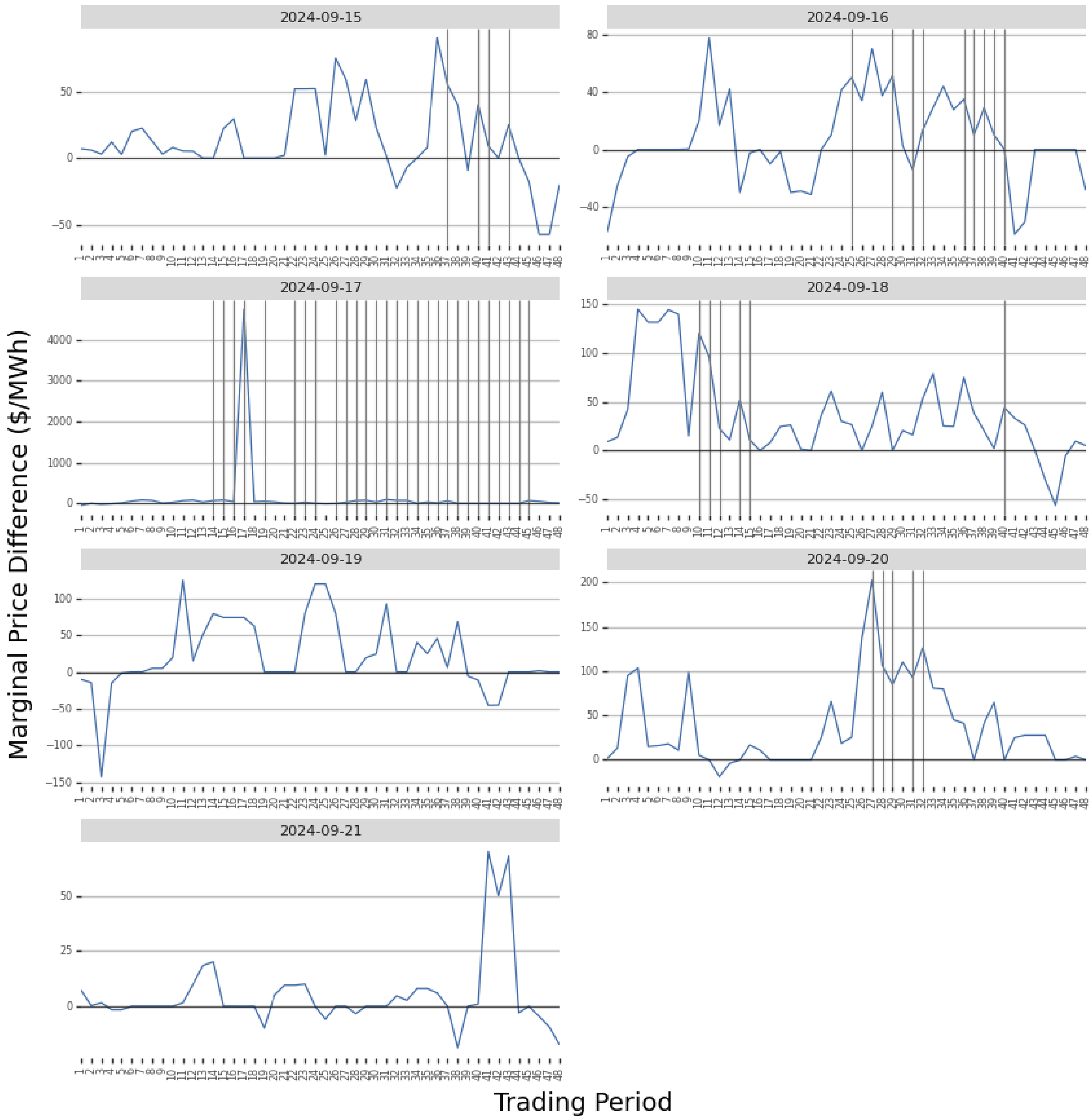
forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.4. Sunday was the only day where prices were largely similar to those simulated. On Monday, there were some positive differences in the prices around peak times.

7.5. Sustained positive differences exceeding $100/MWh began occurring from Tuesday onwards, when demand was under forecast by more than 100MW and wind was often over forecast. This signals that prices may have been lower in the second half of the week if demand and wind forecasts had been more accurate.

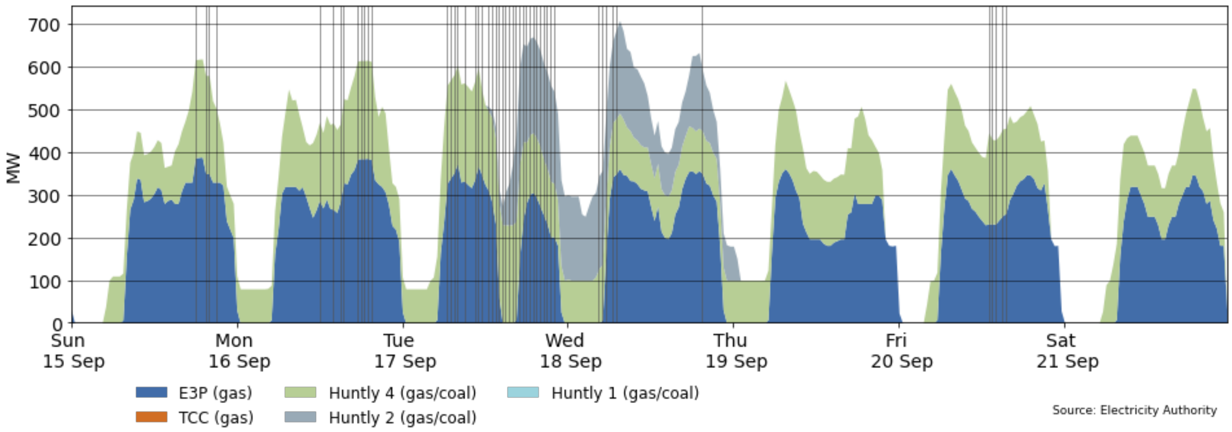
7.6. The most notable positive (marginal prices higher than simulation) difference this week was $4,748/MWh at 8:00am on Tuesday, when wind generation was 227MW lower than forecast and demand was 56MW higher than forecast. Positive differences greater than $100/MWh also occurred on Wednesday, Thursday and Friday.

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, 15-21 September



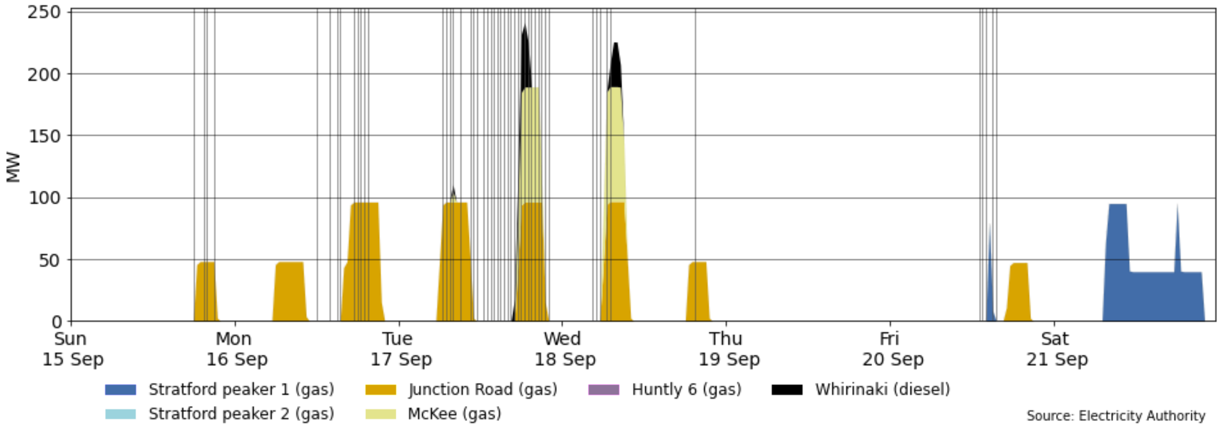
7.7. Figure 12 shows the generation of thermal baseload between 15-21 September. Huntly 2, Huntly 4 and Huntly 5 (E3P) provided baseload generation this week. E3P ran from morning to midnight every day from this week, but briefly stopped running on Tuesday afternoon after it tripped. Huntly 2 ran continuously from Tuesday afternoon after Huntly 5 tripped, until early on Thursday. Huntly 4 ran continuously from Sunday to Thursday, then during peak and shoulder periods on Friday and Saturday.

Figure 12: Thermal baseload generation, 15-21 September



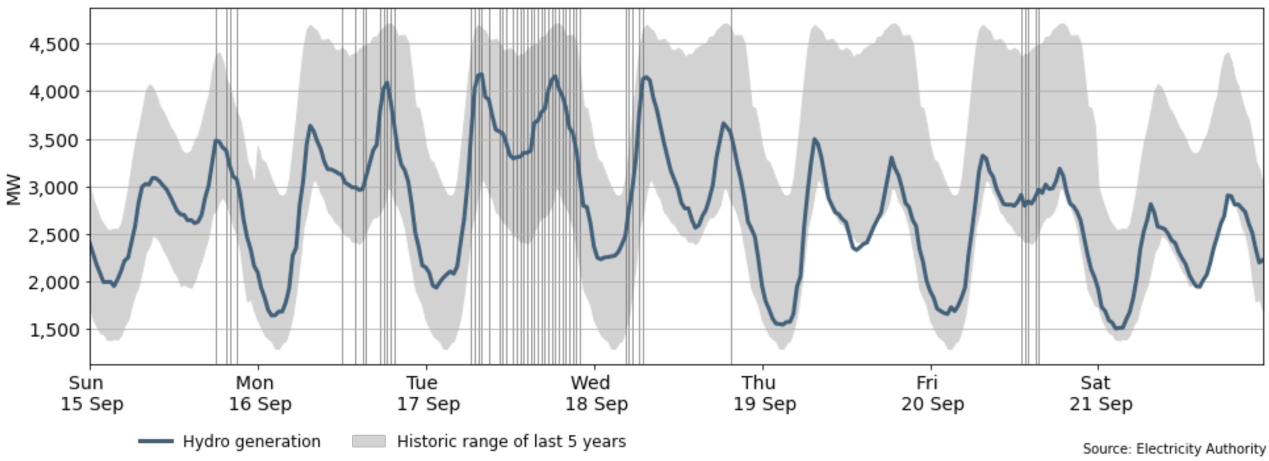
7.8. Figure 13 shows the generation of thermal peaker plants between 15-21 September. Junction Road ran during peak and/or shoulder periods on Sunday to Wednesday and on Friday. It was joined by McKee and Whirinaki on Tuesday and Wednesday, when prices were high. Stratford 1 ran on Friday afternoon, when prices were high and wind was over forecast, and during peak and shoulder periods on Saturday.

Figure 13: Thermal peaker generation, 15-21 September



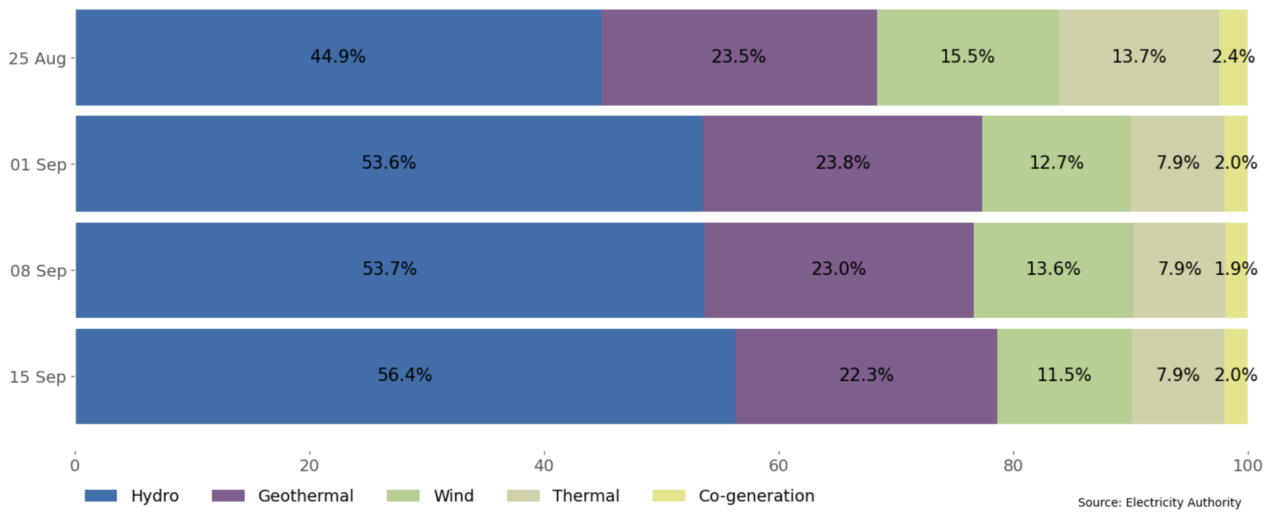
7.9. Figure 14 shows hydro generation between 15-21 September. Hydro generation remained low this week when compared to the historical range of the last five years. Hydro generation was highest between Monday evening and Wednesday morning, when low temperatures led to high demand.

Figure 14: Hydro generation, 15-21 September



7.10. As a percentage of total generation, between 15-21 September, total weekly hydro generation was 56.4%, geothermal 22.3%, wind 11.5%, thermal 7.9%, and co-generation 2.0%, as shown in Figure 15. The proportion of wind generation decreased slightly this week, leading to an increase in the proportion of hydro generation. The proportion of thermal generation remained low.

Figure 15: Total generation by type as a percentage each week, 25 August – 21 September 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 15-21 September ranged between ~940MW and ~1,500MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford 2 is on outage until 8 October.

(b) Stratford 1 was on outage until 20 September. This outage was extended, having originally been scheduled to end on 15 September.

(c) Whirinaki Unit 2 is on outage from 21-23 September.

(d) McKee had one unit on outage until 16 September.

(e) Huntly 6 is on outage until 27 September.

(f) A number of South Island hydro units were also on outage this week, including units from Manapōuri, Benmore and Ōhau.

Figure 16: Total MW loss from generation outages, 15-21 September

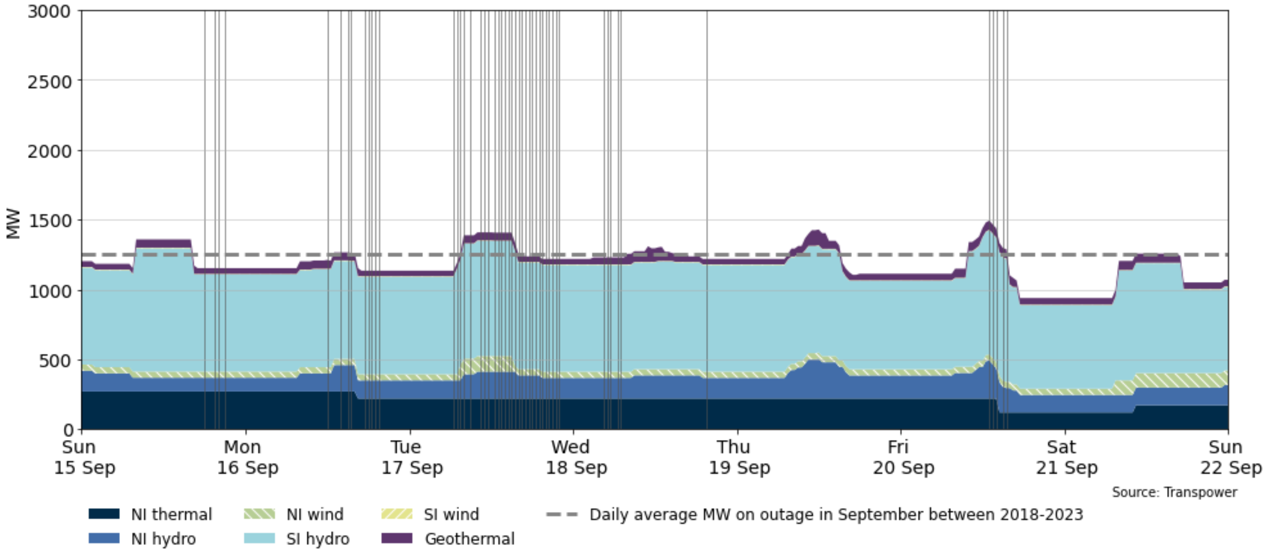
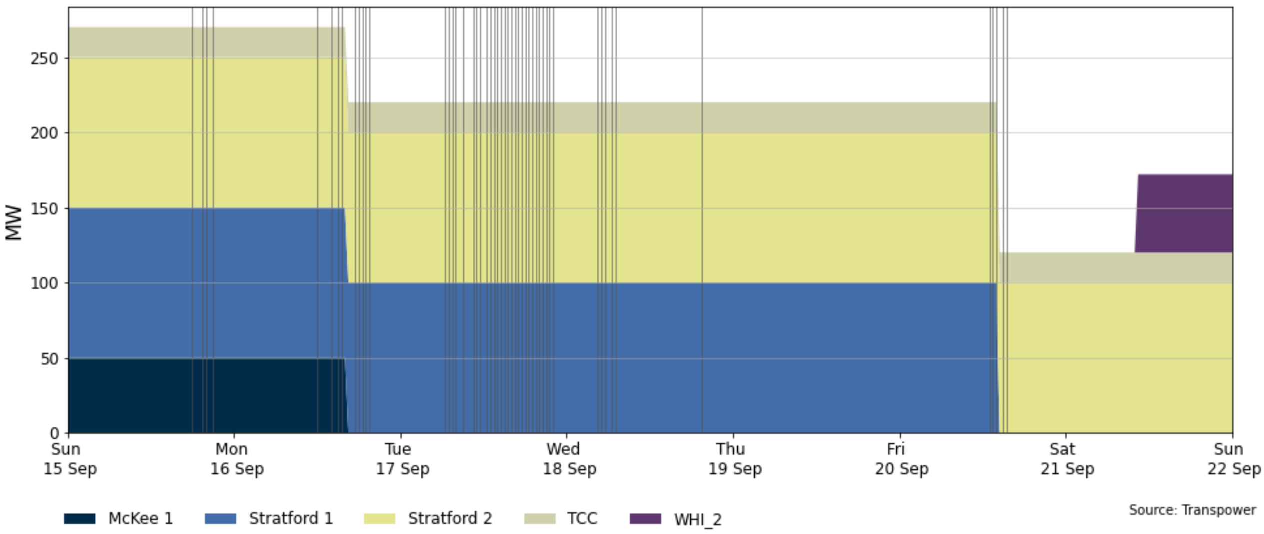


Figure 17: Total MW loss from thermal outages, 15-21 September



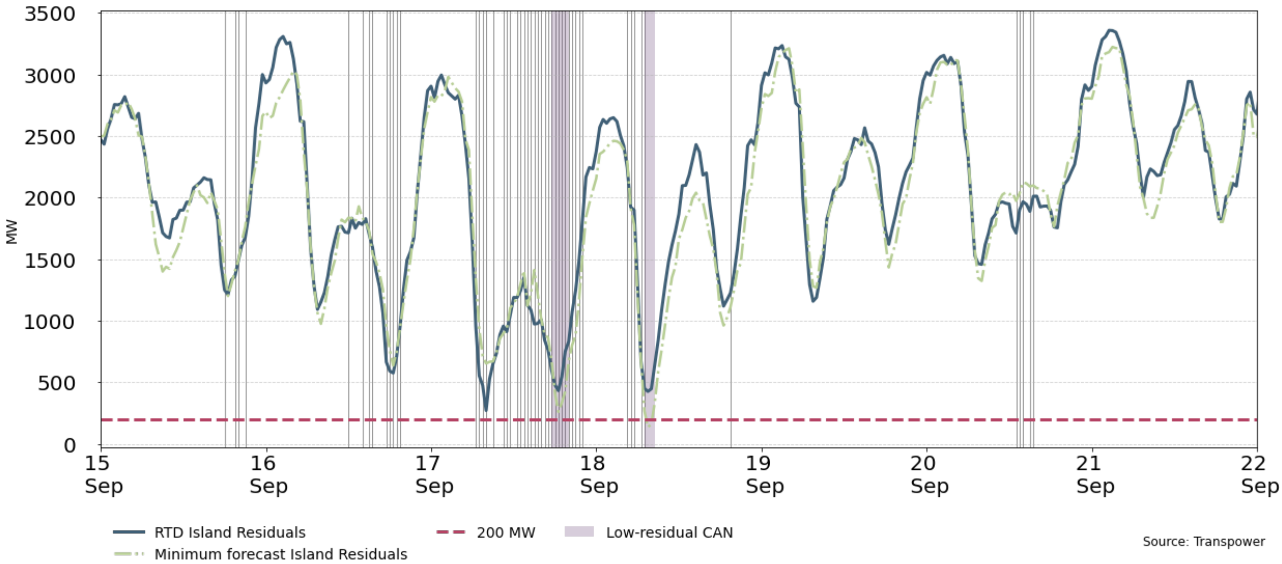
9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 15-21 September. 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. The minimum North Island residual this week was 141MW at 8.00am on Tuesday. CANs were issued for low residual situations between 5.30pm-8.00pm on Tuesday and 7.00am-

8.30am on Wednesday. Demand was high due to low temperatures during these times, as well as being under forecast by as much as 323MW. High-priced hydro and thermal generation had to be dispatched as a result, resulting in high prices.

Figure 18: National generation balance residuals, 15-21 September



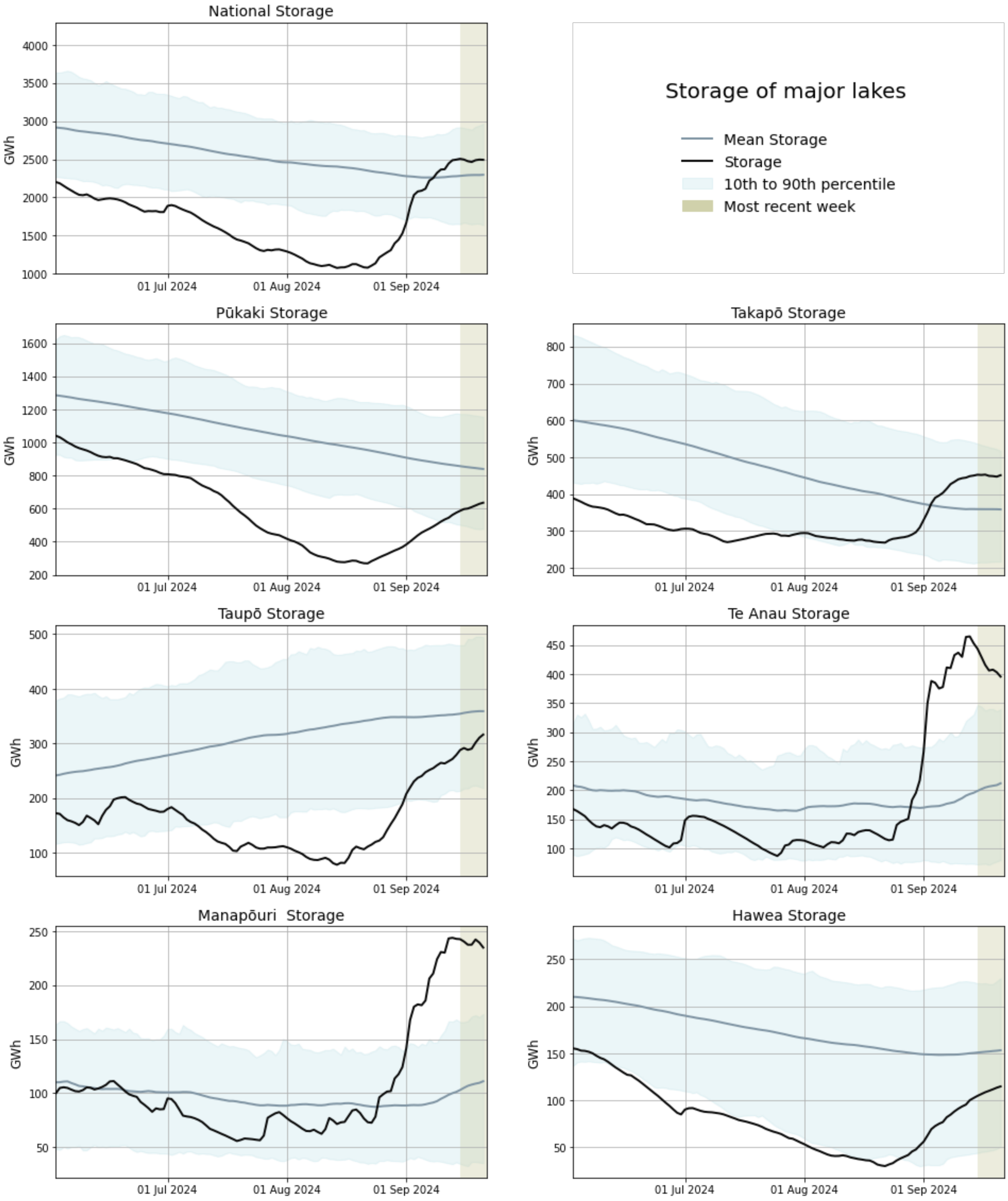
10. Storage/fuel supply

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 slightly this week. As of 21 September, storage was 61% nominally full and ~104% of the historical average for this time of the year.

10.3. Takapō storage was stable this week, remaining above its historic mean. Taupō, Pūkaki and Hawea are above their 10th percentiles and continue to increase toward their respective historic means. Levels at Te Anau and Manapōuri decreased but remain above their 90th percentiles and high operating ranges. Spilling is still occurring in the Upper and Lower Waiau catchment due to the recent high inflows in the area.

Figure 19: Hydro storage



Source: Electricity Authority

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 September 2024. The SRMC for gas has decreased significantly from the previous month, while the coal SRMC and diesel SRMC have increased slightly. The drop in gas SRMCs is a result of Methanex temporarily closing their Motunui plant to resell gas to thermal generators, as well as less thermal generation being dispatched due to increased hydro storage.

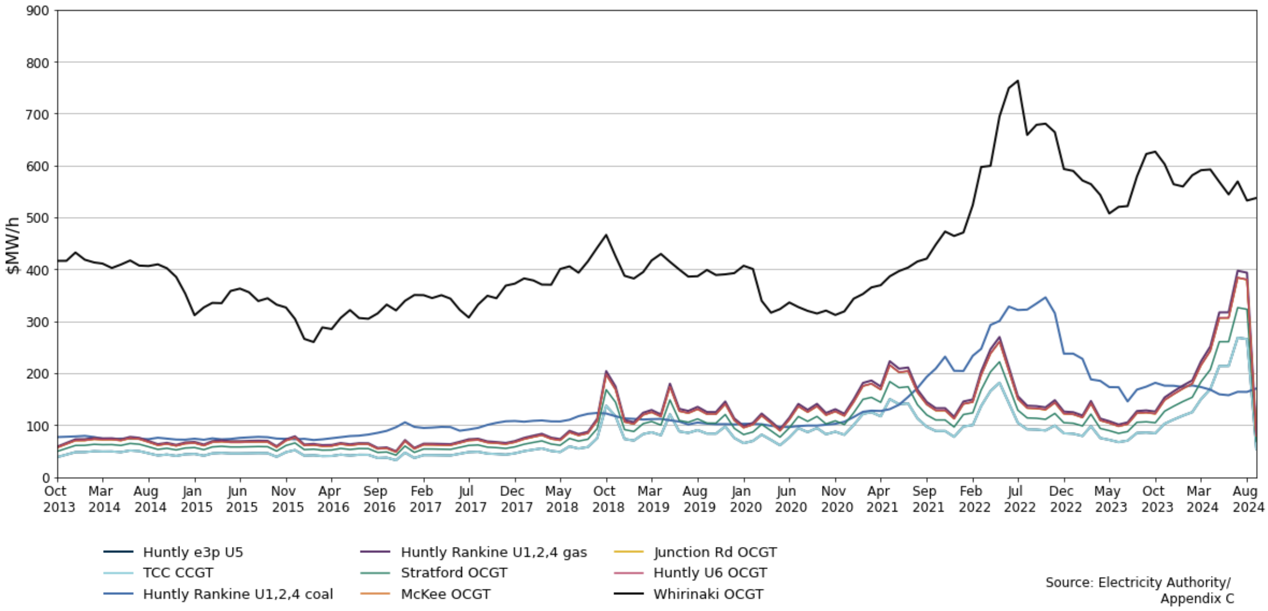
11.4. The latest SRMC of coal-fueled Rankine generation is ~$171/MWh. The cost of running the Rankines on gas is now less expensive at ~$82/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between ~$55/MWh and ~$82/MWh.

11.6. The SRMC of Whirinaki is ~$537/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

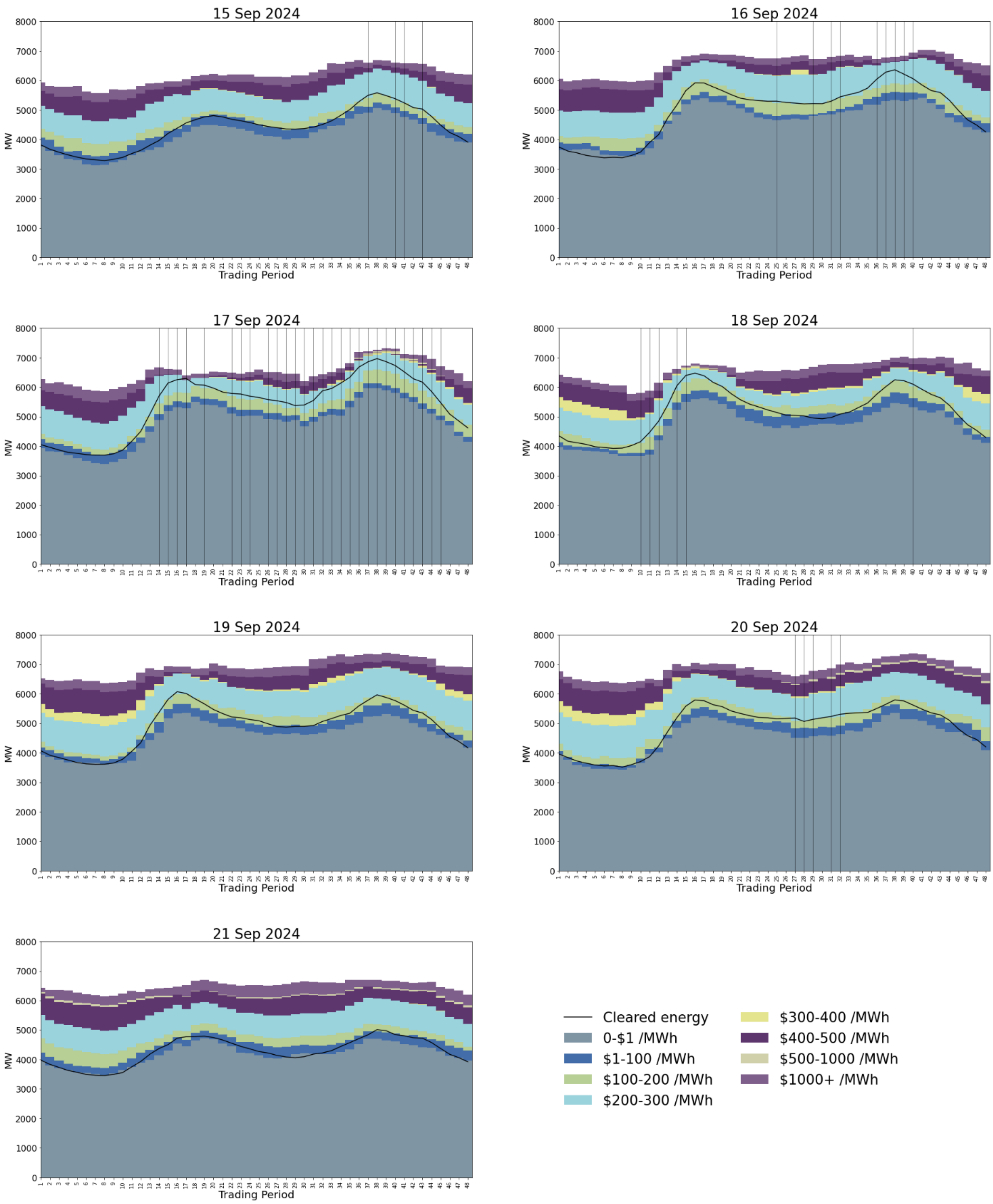


12. Offer behaviour

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. Most offers cleared in the $1-$300/MWh regions this week. There were very few offers in the $300-$400/MWh and $500-$1,000/MWh bands for most of the week. This meant increased demand and wind forecasting inaccuracies, which reduces the real time of energy in the $0-1/MWh band, saw energy clearing in some of those high priced regions.

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, however, some generators' offer behaviour is being analysed further to ensure compliance with the trading conduct rule.

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
1/07/2024-23/08/2024	Several	These trading periods are now part of a s16 review	N/A	N/A	High energy prices
26/08/2024-26/08/2024	Several	Further analysis	Manawa	Tararua wind farms	Wind forecasting
27/08/2024-02/09/2024	Several	Further analysis	Genesis	Rangipo and Waikaremoana	Hydro offers
17/09/2024	17	Further analysis	Nova	McKee	Thermal offers