15 June 2026

Trading conduct report 7-13 June 2026

Market monitoring weekly report

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1. Overview

1.1. This week the average spot price increased from $32/MWh to $39/MWh. Despite higher demand and lower wind generation, prices have remained low due to high levels of hydro storage. National controlled storage has decreased slightly to 85% nominally full and is 120% of the historical average for this time of year.

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. Between 7-13 June:

(a) The average spot price for the week was $39/MWh, an increase of around $7/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $99/MWh.

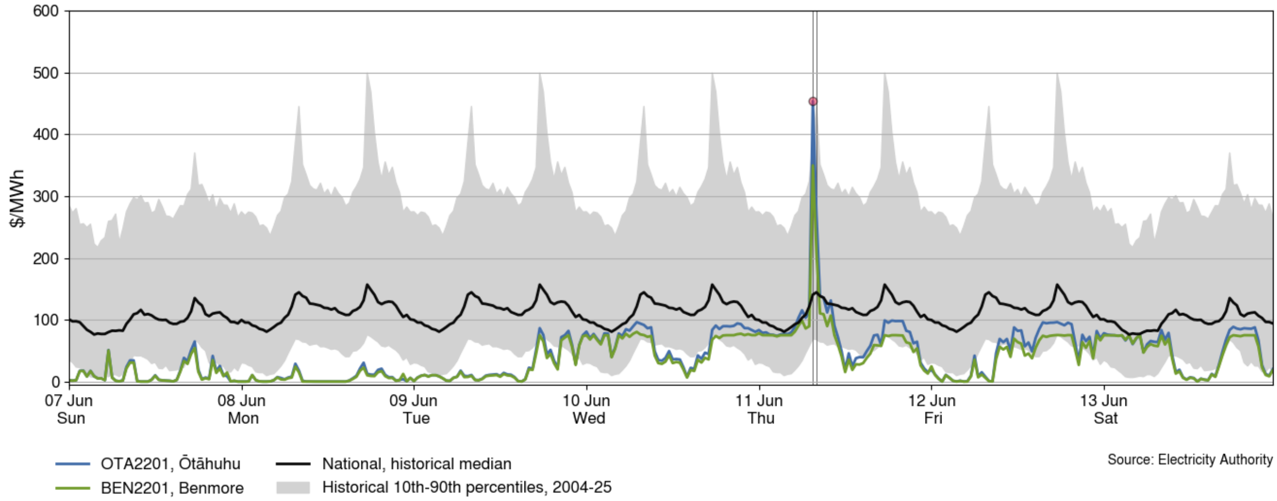
2.3. Prices were low between Sunday and Tuesday afternoon when wind generation was high and demand was lower.

2.4. Despite higher demand and lower wind generation, high levels of hydro storage have meant prices mostly remained low, aside from a price spike on Thursday morning.

2.5. The highest prices for the week occurred on Thursday at 7.30am at 8.00am. At this time, the spot price reached $350/MWh at Benmore, and $454/MWh at Ōtāhuhu. Demand reached its weekly high of 6.62GW, and was between 37 and 61MW above forecast. Wind generation was also low, at below 100MW, and was between 19 and 22MW below forecast. In addition, Maraetai unit 8 tripped, meaning 36MW of hydro generation became unavailable. Sustained instantaneous reserve (SIR) prices also spiked.

2.6. 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.

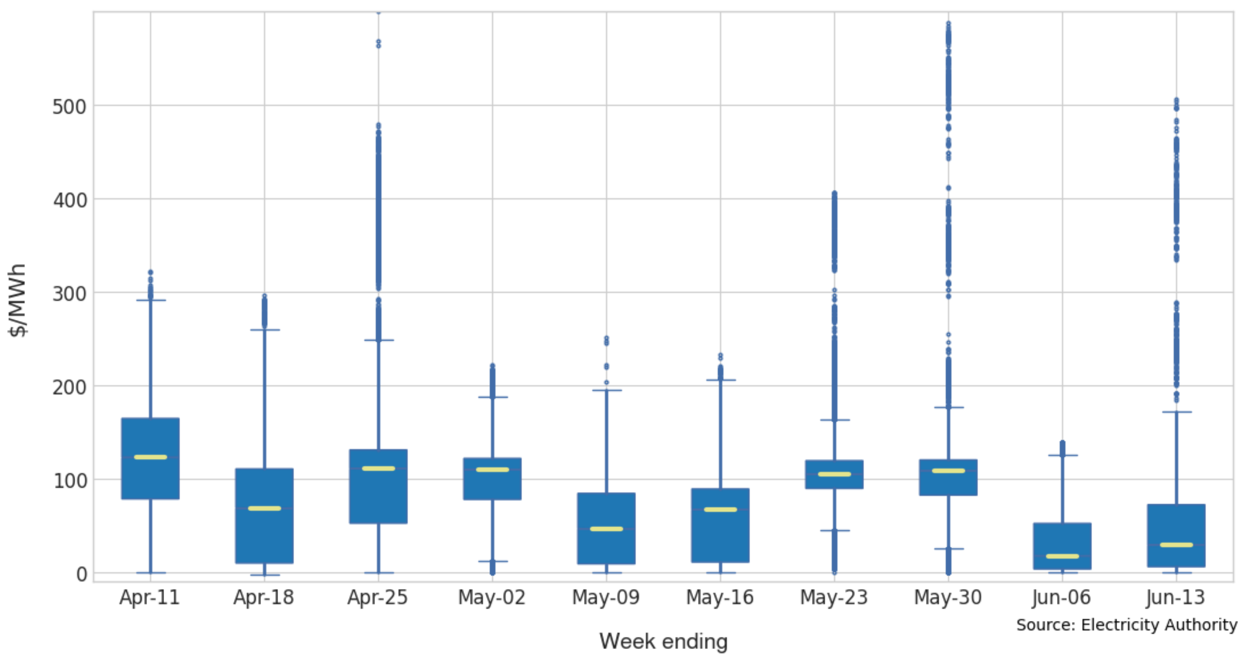
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 7-13 June



2.7. 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.

2.8. The distribution of spot prices this week was wider than last week. The median price was $29/MWh and most prices (middle 50%) fell between $6/MWh and $72/MWh.

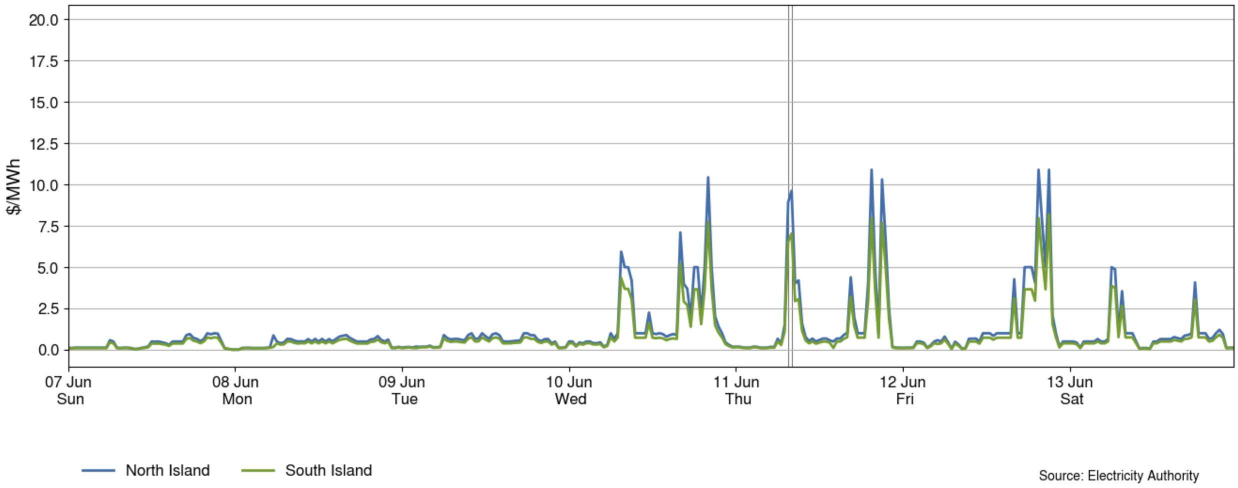
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



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 low this week, spiking to ~10$/MWh at times from Wednesday to Friday. Reserves prices were higher in the second half of the week when Huntly 5 turned on.

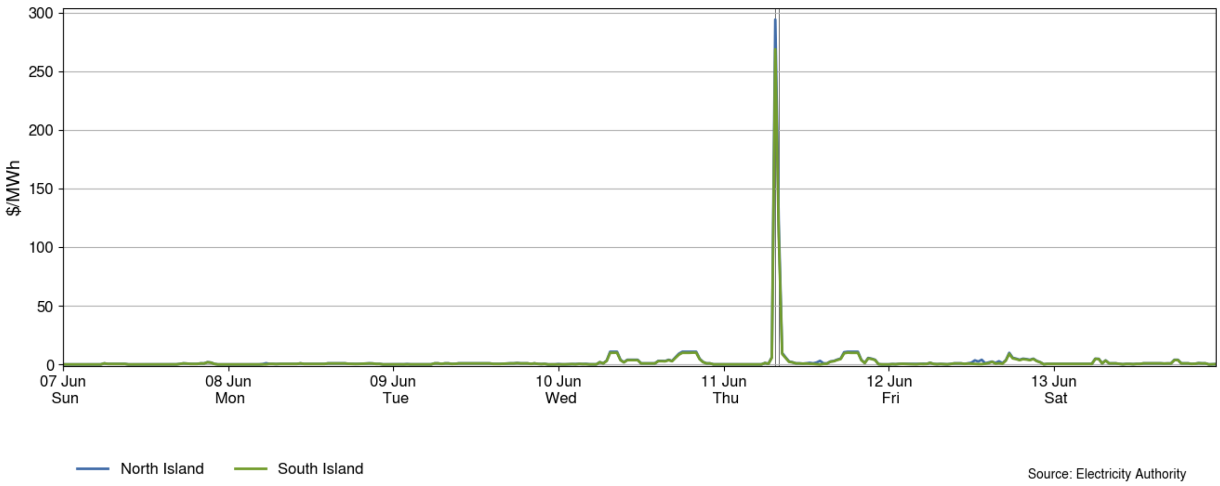
Figure 3: Fast instantaneous reserve price by trading period and island, 7-13 June



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly low this week, aside from a spike on Thursday morning at the same time as the spot price spike.

3.3. On Thursday at 7.30am and 8.00am, SIR prices spiked, reaching $294/MWh in the North Island and $269/MWh in the South Island. At this time, Huntly 5 was the risk setter, and its generation increased, meaning more reserve was needed to cover this risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 7-13 June



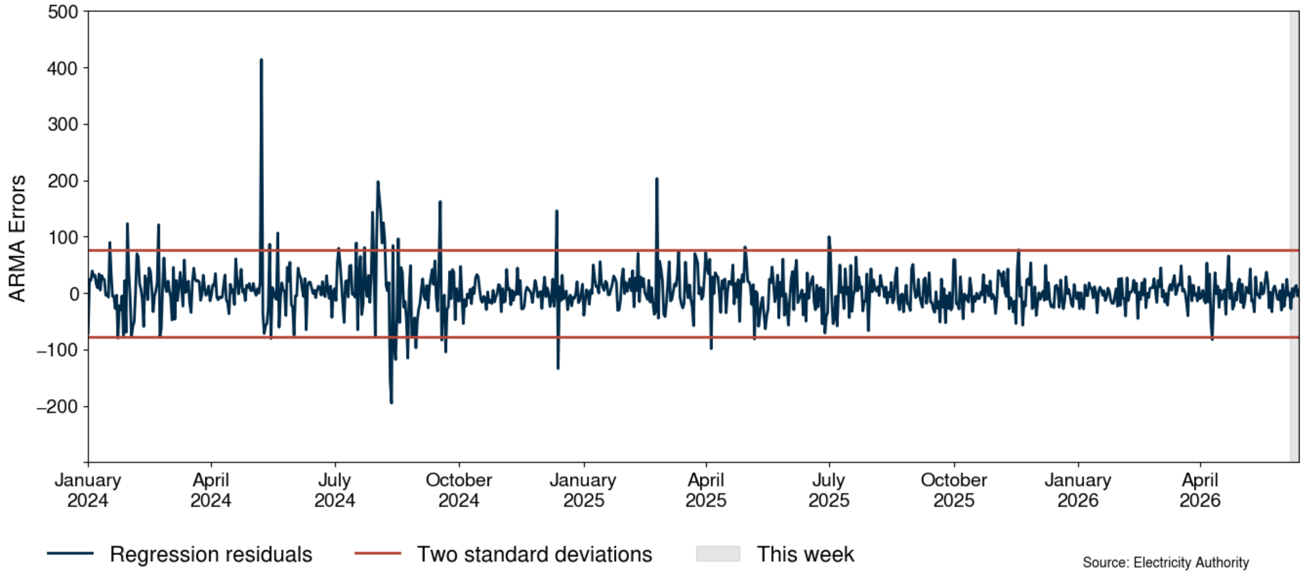
4. Regression residuals

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 or below two standard deviations, indicating that prices were similar to those predicted by the model.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 13 June 2026



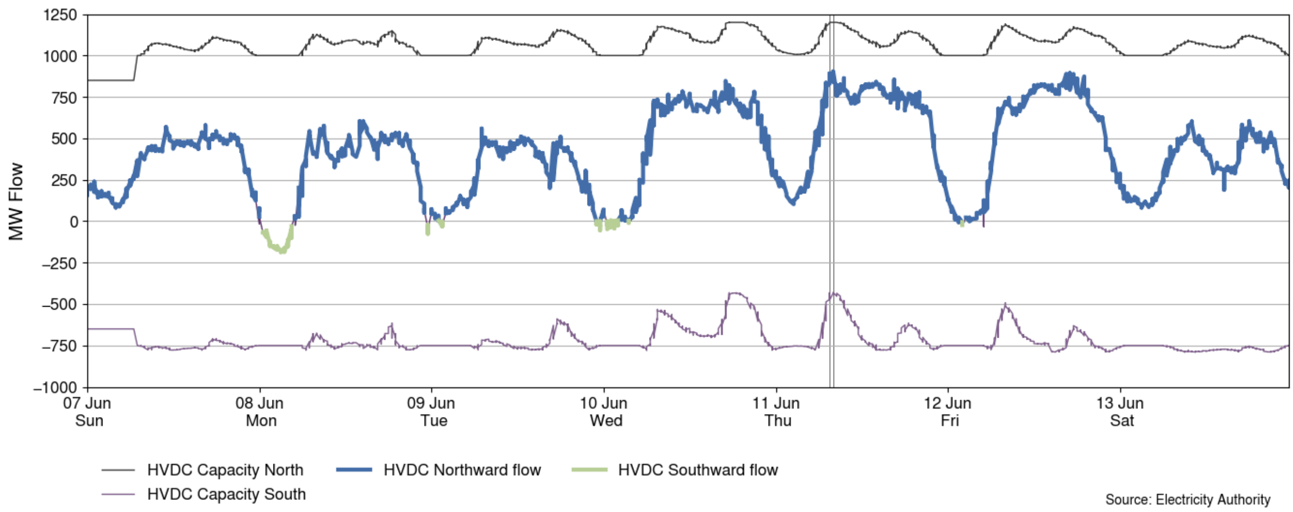
5. HVDC

5.1. Figure 6 shows the HVDC flow between 7-13 June. HVDC flow was mainly northward this week, due to lower wind generation and relatively high demand.

5.2. The highest northward flow of 905MW occurred on Thursday at 8.00am.

5.3. The highest southward flow of 189MW occurred on Monday at 3.00am.

Figure 6: HVDC flow and capacity, 7-13 June

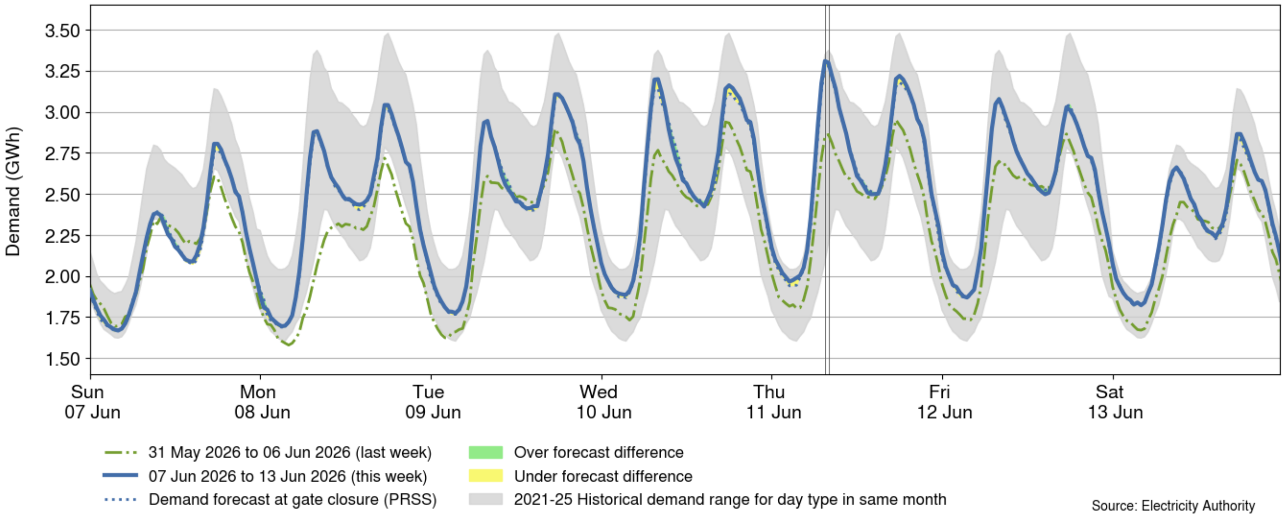


6. Demand

6.1. Figure 7 shows national demand between 7-13 June, compared to the historic range and the demand of the previous week. Demand was mostly higher than last week, likely due to King's Birthday last week and relatively colder temperatures this week.

6.2. The maximum demand this week was around 3.31GWh (6.62GW) at 7.30am on Thursday. This was near to top of the 2021-25 June morning peak range.

Figure 7: National demand, 7-13 June compared to the previous week

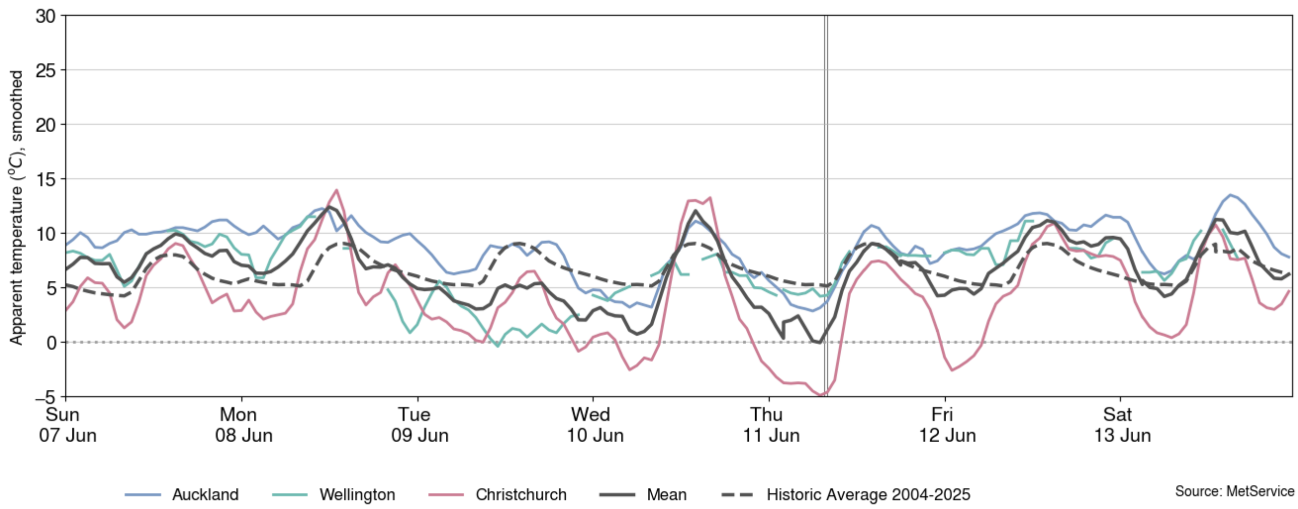


6.3. Figure 8 shows the hourly apparent temperature at main population centres from 7-13 June. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Apparent temperatures ranged from 4°C to 13°C in Auckland, 0°C to 12°C in Wellington, and -1°C to 14°C in Christchurch.

6.5. Note that temperature data is missing at times throughout the week for Wellington.

Figure 8: Temperatures across main centres, 7-13 June

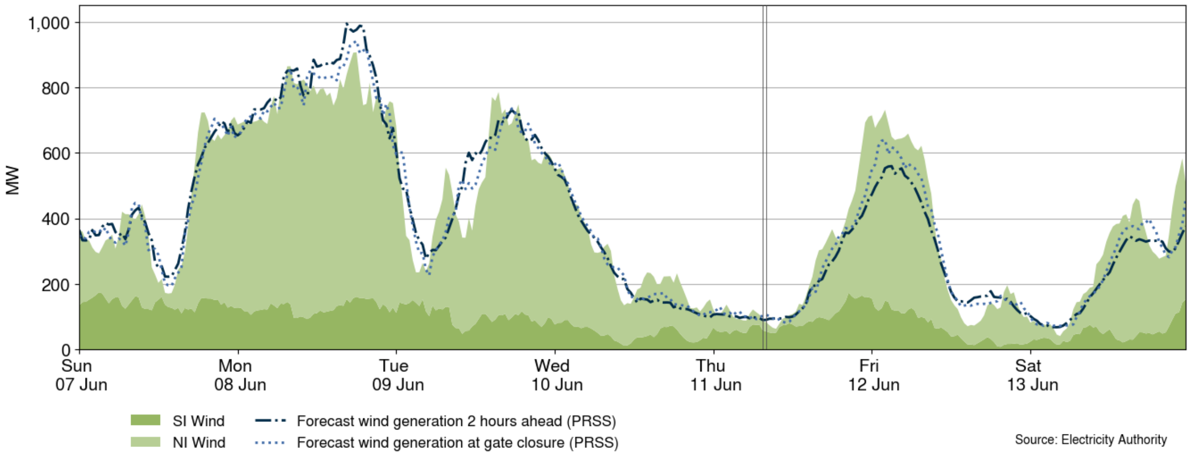


7. Generation

7.1. Figure 9 shows wind generation and forecast from 7-13 June. This week wind generation varied between 41MW and 906MW, with a weekly average of 399MW. Wind generation was high on Monday, Tuesday, and overnight between Thursday and Friday, and was otherwise relatively low.

7.2. Forecasting errors on Thursday evening and Friday morning are the result of an amalgamation of errors at Kaiwera Downs, Mill Creek, Tararua, and Te Āpiti wind farms.

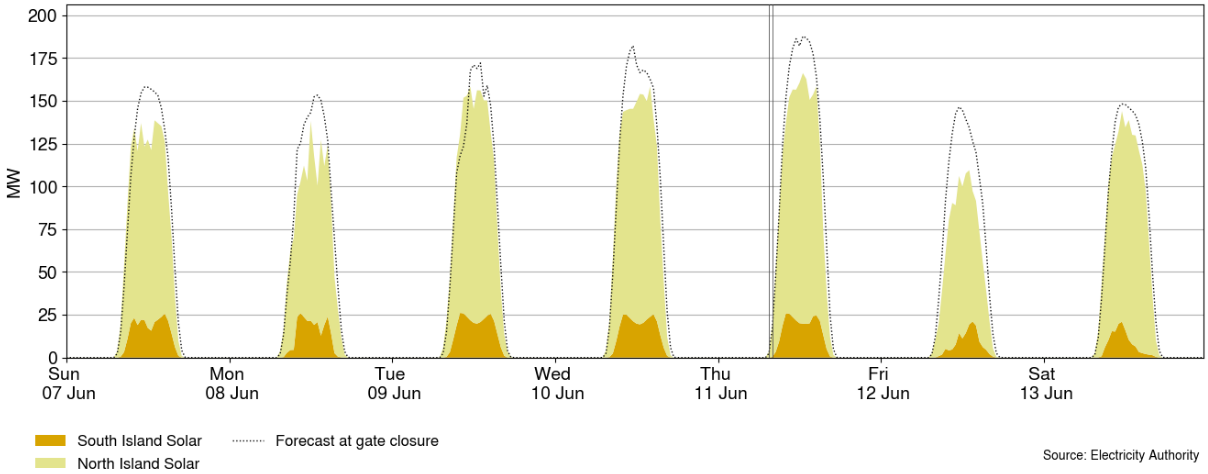
Figure 9: Wind generation and forecast, 7-13 June



7.3. Figure 10 shows grid connected solar generation from 7-13 June. Solar generation was relatively high this week, reaching above 125MW every day except Friday. Overall, solar generation peaked at 166MW at 12.30pm on Thursday.

7.4. Solar forecasting errors are due to Omeheu solar farm, which is still commissioning and generating below forecast.

Figure 10: Grid connected solar generation, 7-13 June

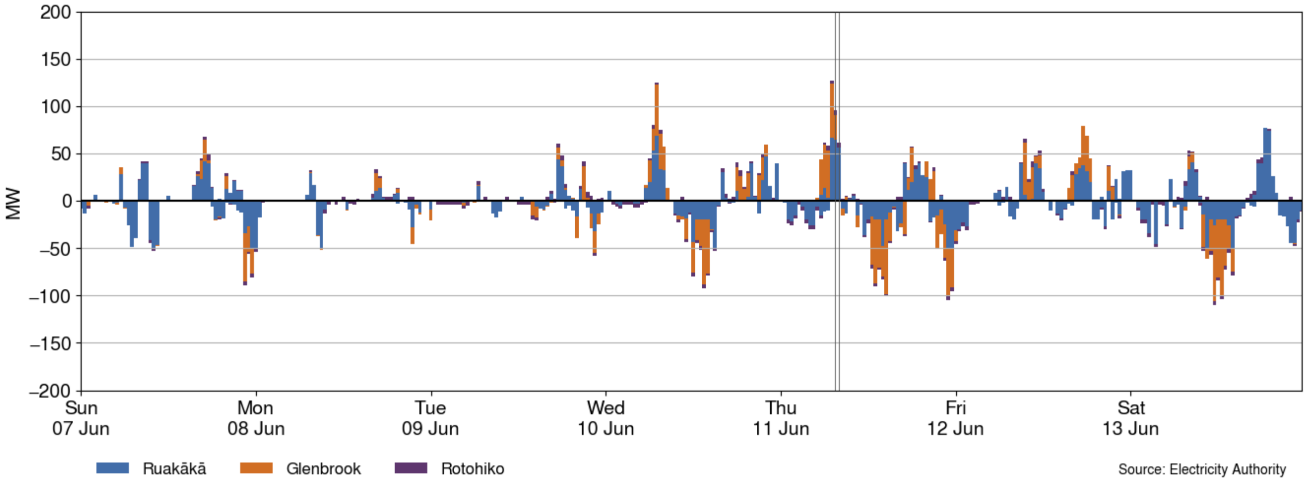


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.6. This week, the batteries generally charged when prices were lower, and discharged when prices were higher. From Sunday to Tuesday, the batteries generally charged when prices were below ~$5/MWh, and discharged when prices were above ~$10/MWh. From Wednesday onwards, the batteries generally charged when prices were below ~$70/MWh, and discharged when prices were above ~$70/MWh.

7.7. Glenbrook discharged much of its energy between 7.00am and 7.30am on Thursday, so could not discharge as much during the price spike at 7.30am and 8.00am.

Figure 11: Grid scale battery charge and discharge, 7-13 June



7.8. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation 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 intermittent generation is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and intermittent generation forecasting, the 1-hour ahead and the RTD intermittent generation 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.

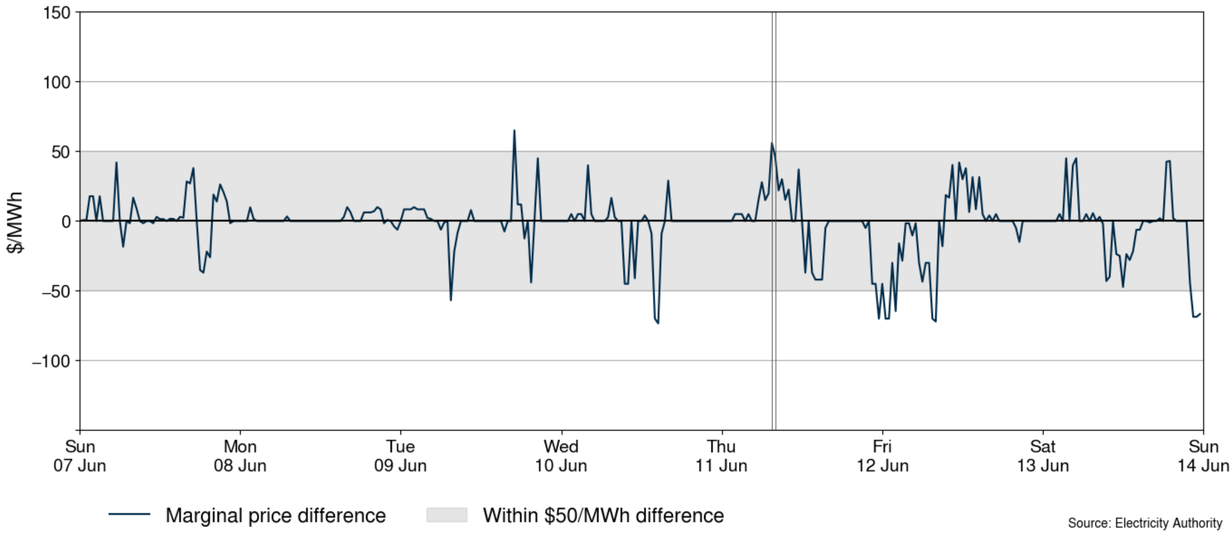
7.9. There were some marginal price differences over $50/MWh this week.

7.10. The maximum positive difference of $65/MWh occurred on Tuesday at 5.00pm. At this time, wind generation was 37MW below forecast, and demand was 98MW above forecast.

7.11. The maximum negative difference of $73/MWh occurred on Wednesday at 2.30pm. At this time, wind generation was 73MW above forecast, and demand was 55MW below forecast.

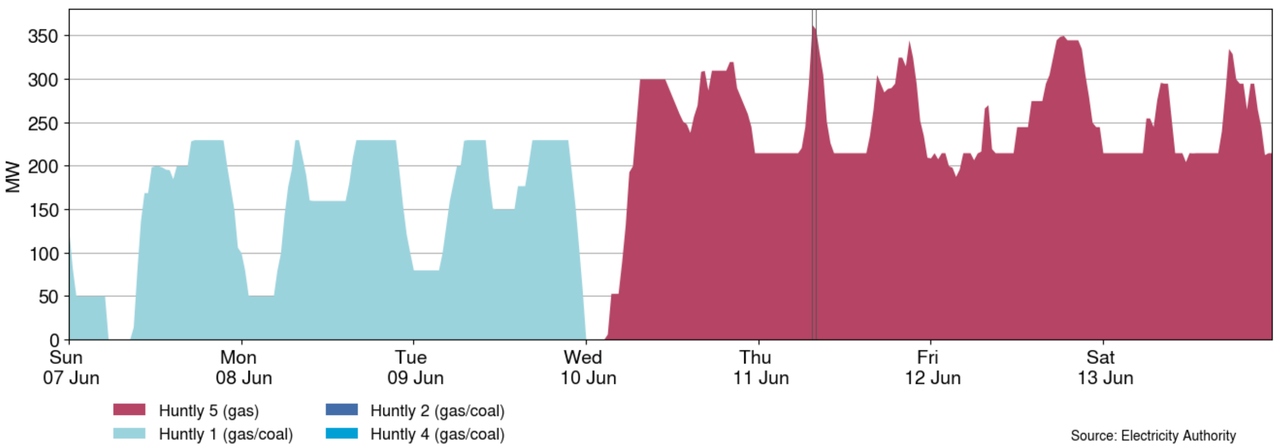
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 7-13 June



7.12. Figure 13 shows the generation of thermal baseload between 7-13 June. This week, Huntly 1 ran mostly continuously from Sunday to Tuesday, and Huntly 5 ran continuously from Wednesday onwards. Huntly 5 generation peaked during the Thursday morning price spike.

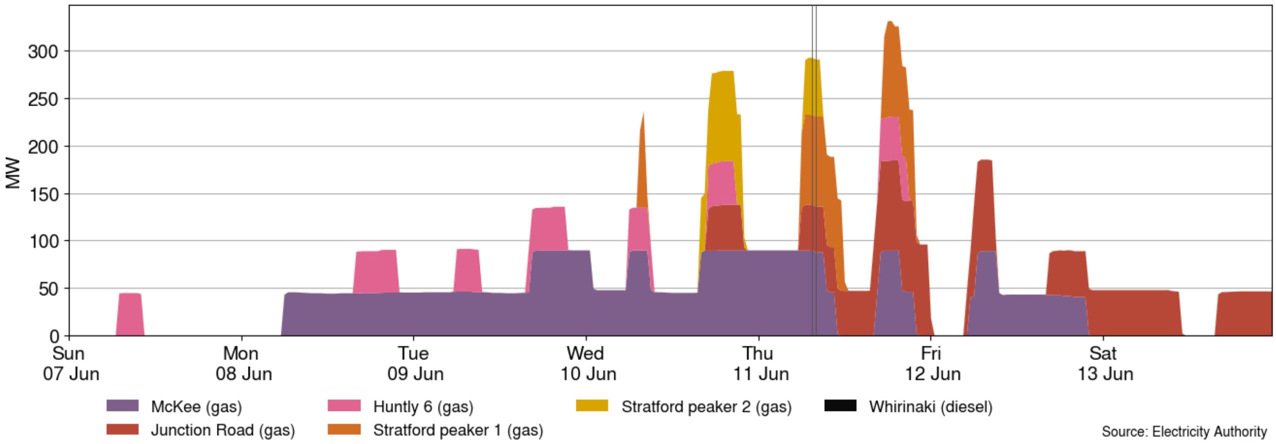
Figure 13: Thermal baseload generation, 7-13 June



7.13. Figure 14 shows the generation of thermal peaker plants between 7-13 June. This week, McKee ran mostly continuously from Monday to Friday, and Junction Road ran at times from Wednesday to Saturday. Huntly 6 ran at times from Sunday to Thursday, and the Stratford peakers ran at times on Wednesday and Thursday.

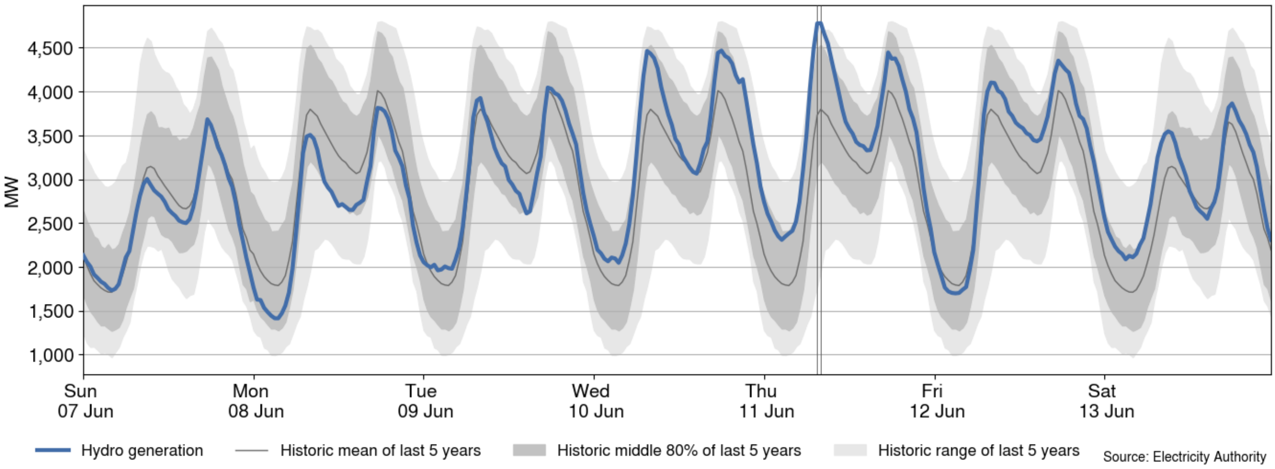
7.14. On Thursday from 8.00am to 3.00pm, Huntly 6 was on outage, so it did not generate during the 8:00am price spike.

Figure 14: Thermal peaker generation, 7-13 June



7.15. Figure 15 shows hydro generation between 7-13 June. Hydro generation was similar to the historic mean on Sunday and Tuesday, lower than the historic mean on Monday, and mostly higher than the historic mean from Wednesday onwards, due to relatively high demand.

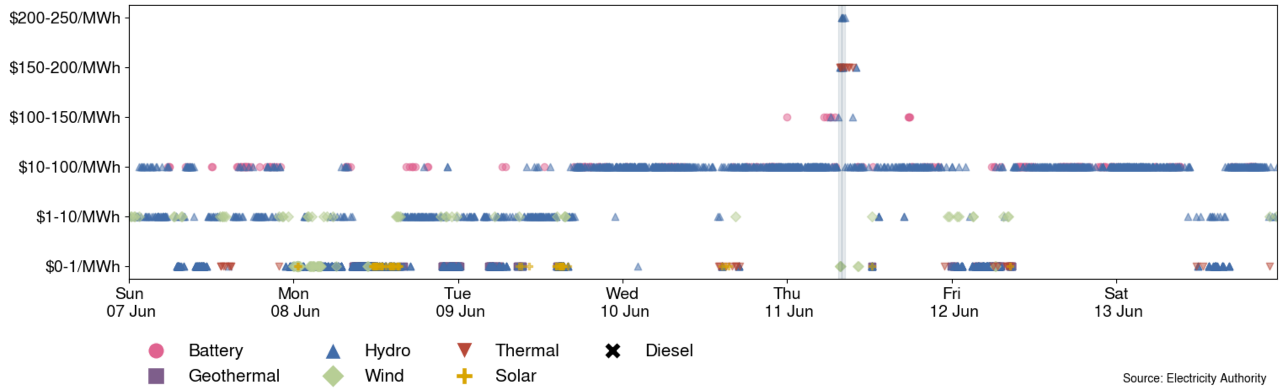
Figure 15: Hydro generation, 7-13 June



7.16. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.

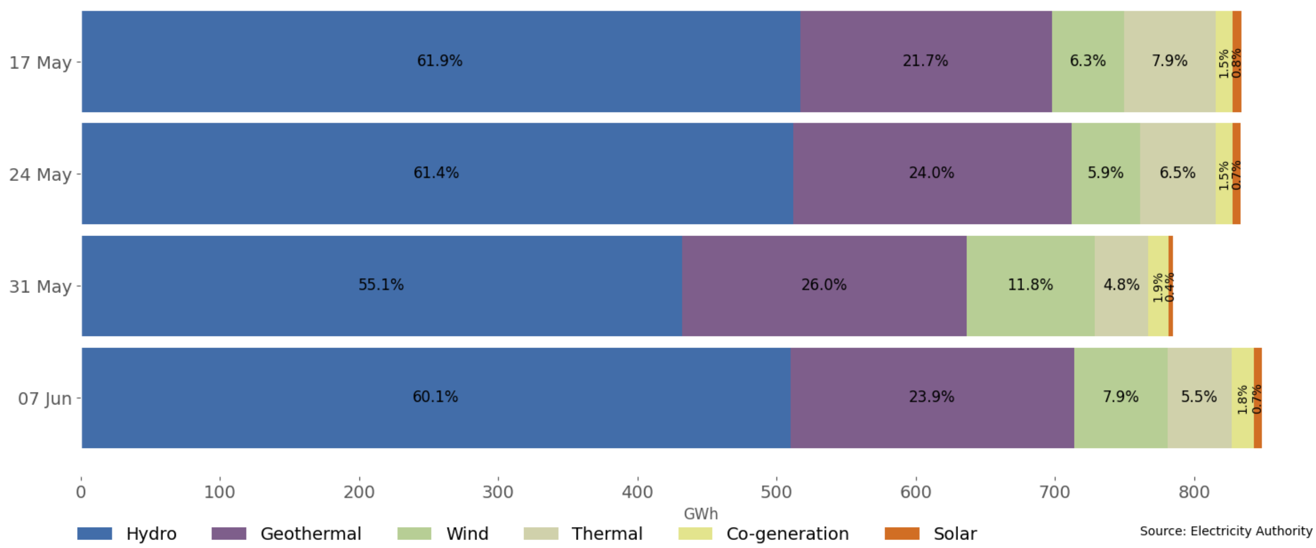
7.17. The highest prices this week were set by Contact hydro. The most common technology setting prices was hydro, with geothermal the second most common. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 7-13 June



7.18. As a percentage of total generation, between 7-13 June, total weekly hydro generation was 60.1%, geothermal 23.9%, wind 7.9%, thermal 5.5%, co-generation 1.8%, and solar (grid connected) 0.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 17 May and 13 June



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 7-13 June ranged between ~597MW and ~1,353MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 7-13 June

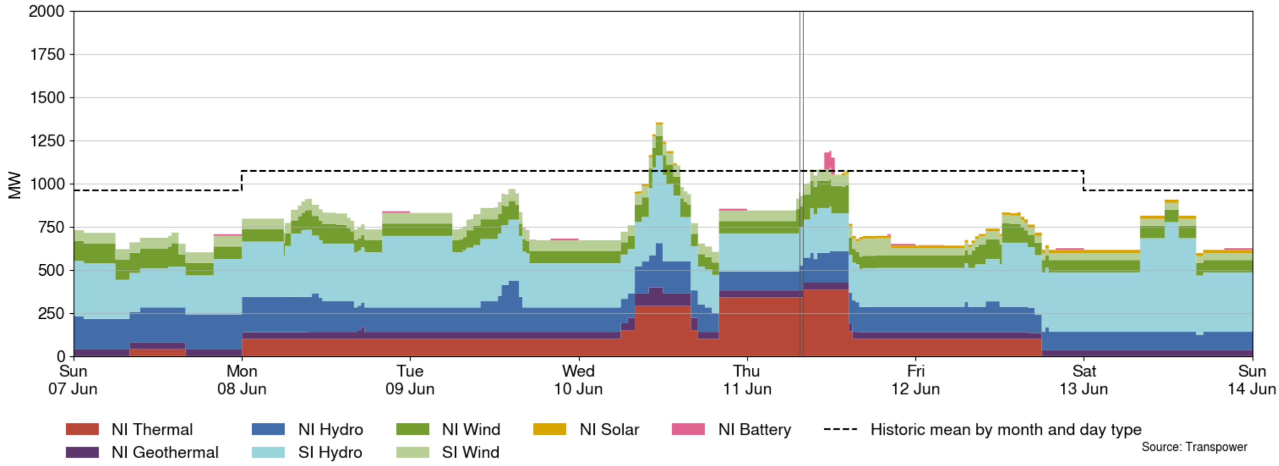
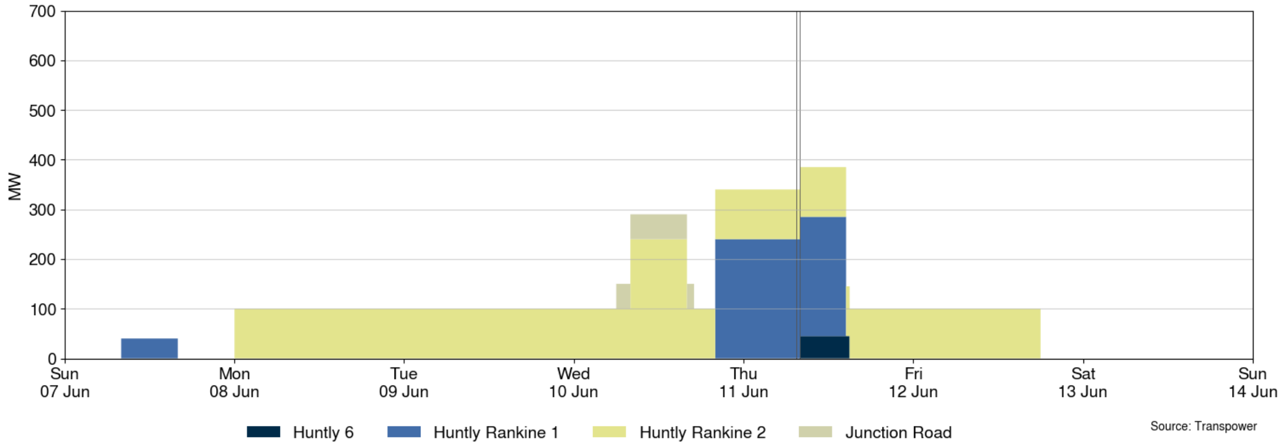


Figure 19: Total MW loss from thermal outages, 7-13 June



8.2. Notable outages include:

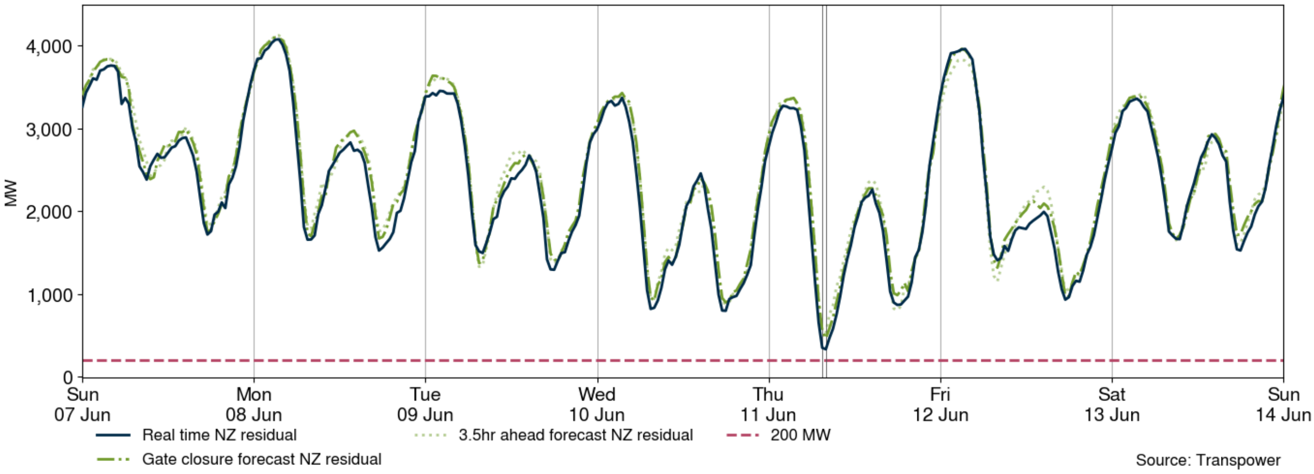
Plant	Partial or Full	End Date
Huntly 1	Full	11 June 2026
Kaiwera Downs	Partial	11 June 2026
Huntly 2	Partial	12 June 2026
Ōhau A	Full	13 June 2026
Manapōuri unit 2	Full	30 June 2026
Manapōuri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 7-13 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 forecast 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 national residual has neared the 200MW threshold this week. The minimum residuals this week occurred on Thursday from 7.30am to 8.30am, where it ranged from 334MW to 468MW. The minimum South Island residual was 55MW at 7.30am, and the minimum North Island residual was 261MW at 8.00am.

Figure 20: National generation balance residuals, 7-13 June



10. Storage/fuel supply

10.1. Figure 21 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. As of 13 June, national controlled storage was 85% nominally full and ~120% of the historical average for this time of the year.

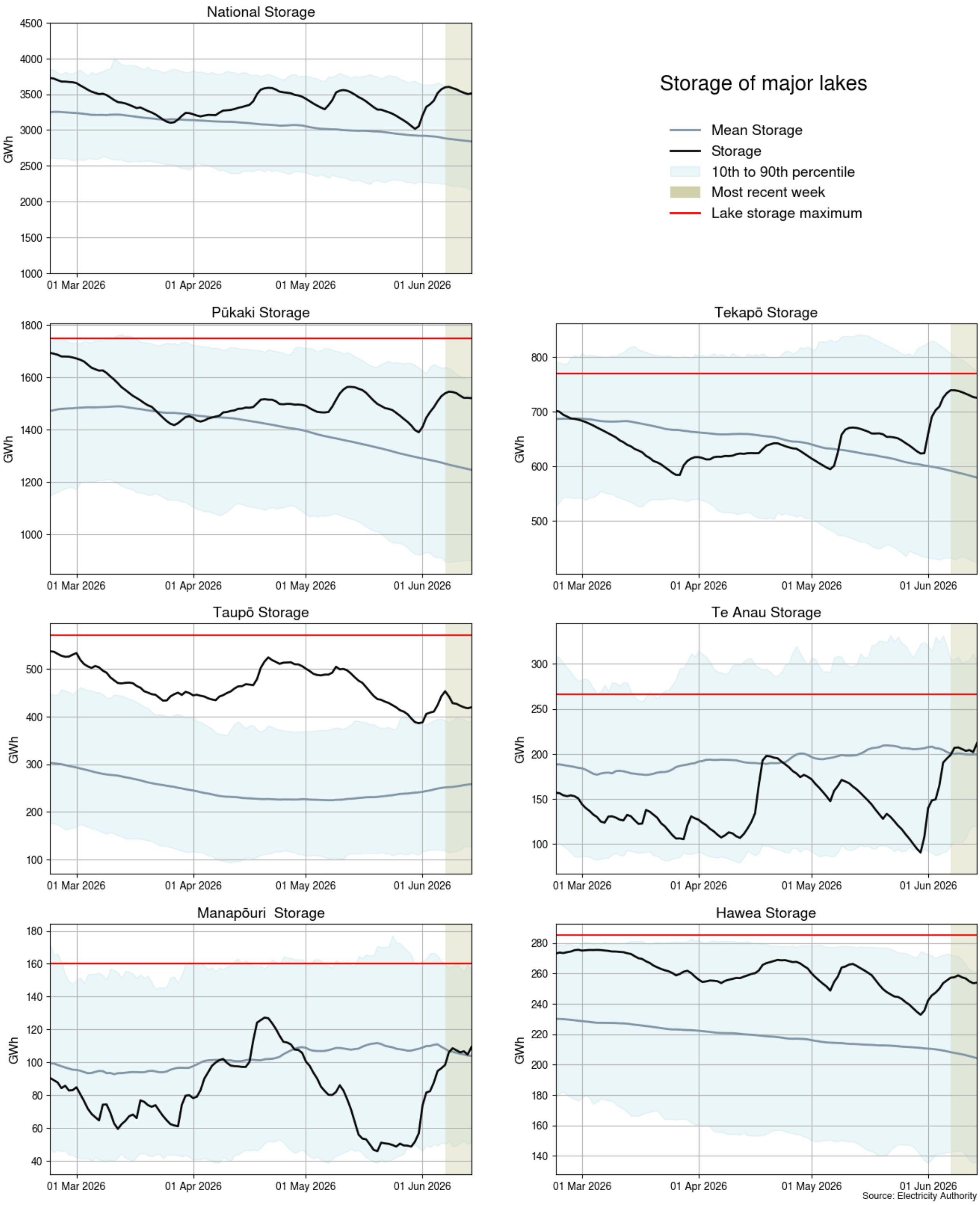
10.3. Storage at Lake Pūkaki (84% full) and Lake Tekapō (81% full) remain well above their historic mean.

10.4. Storage at Lake Te Anau (80% full) remains above its historic mean, while storage at Lake Manapōuri (69% full) has increased to above its historic mean.

10.5. Storage at Lake Taupō (73% full) remains above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (89% full) is below its historic 90th percentile but remains above its historic mean.

Figure 21: 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. Figure 22 shows an estimate of thermal SRMCs as a monthly average up to 1 June 2026. The SRMCs for gas generation has decreased, with SRMCs for coal and diesel fuelled generation remaining steady.

11.3. The latest SRMC of coal-fuelled Rankine generation is ~$235/MWh, while the cost of running the Rankines on gas is ~$116/MWh.

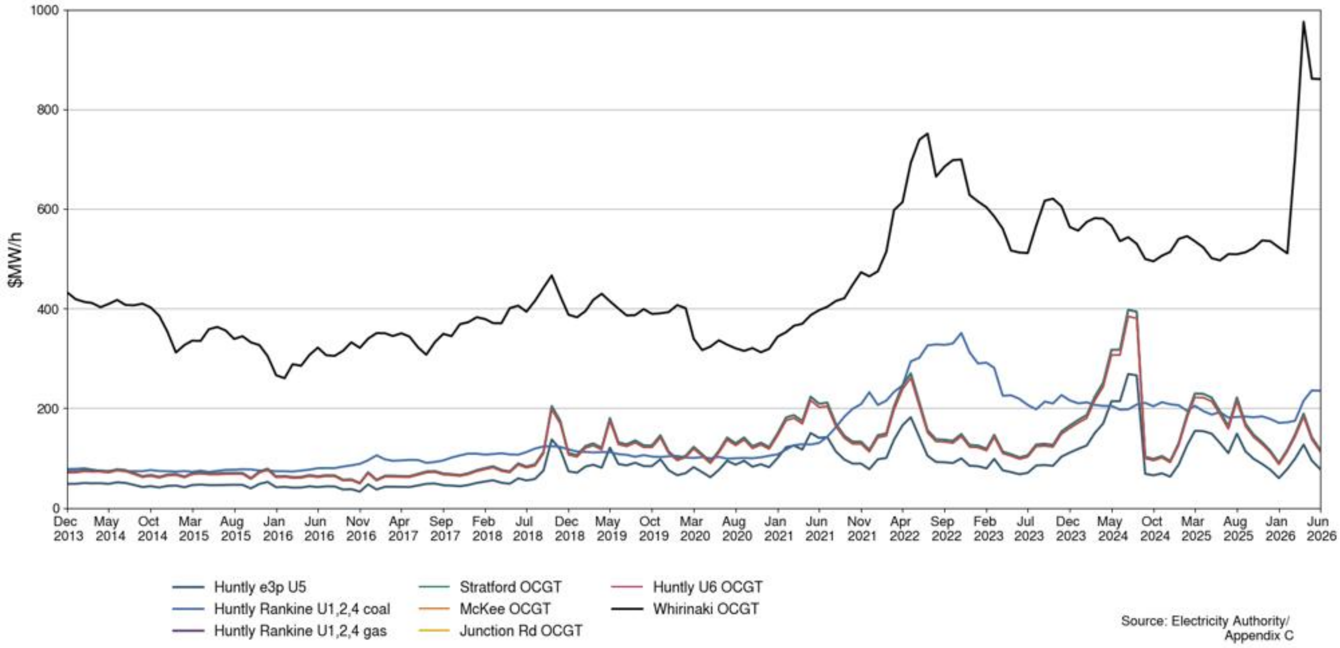
11.4. The SRMC of gas fuelled thermal plants is currently between $78/MWh and $116/MWh.

11.5. The SRMC of Whirinaki is ~$861/MWh.

11.6. Note that coal prices have been rolled forward from May.

11.7. 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



12. Offer behaviour

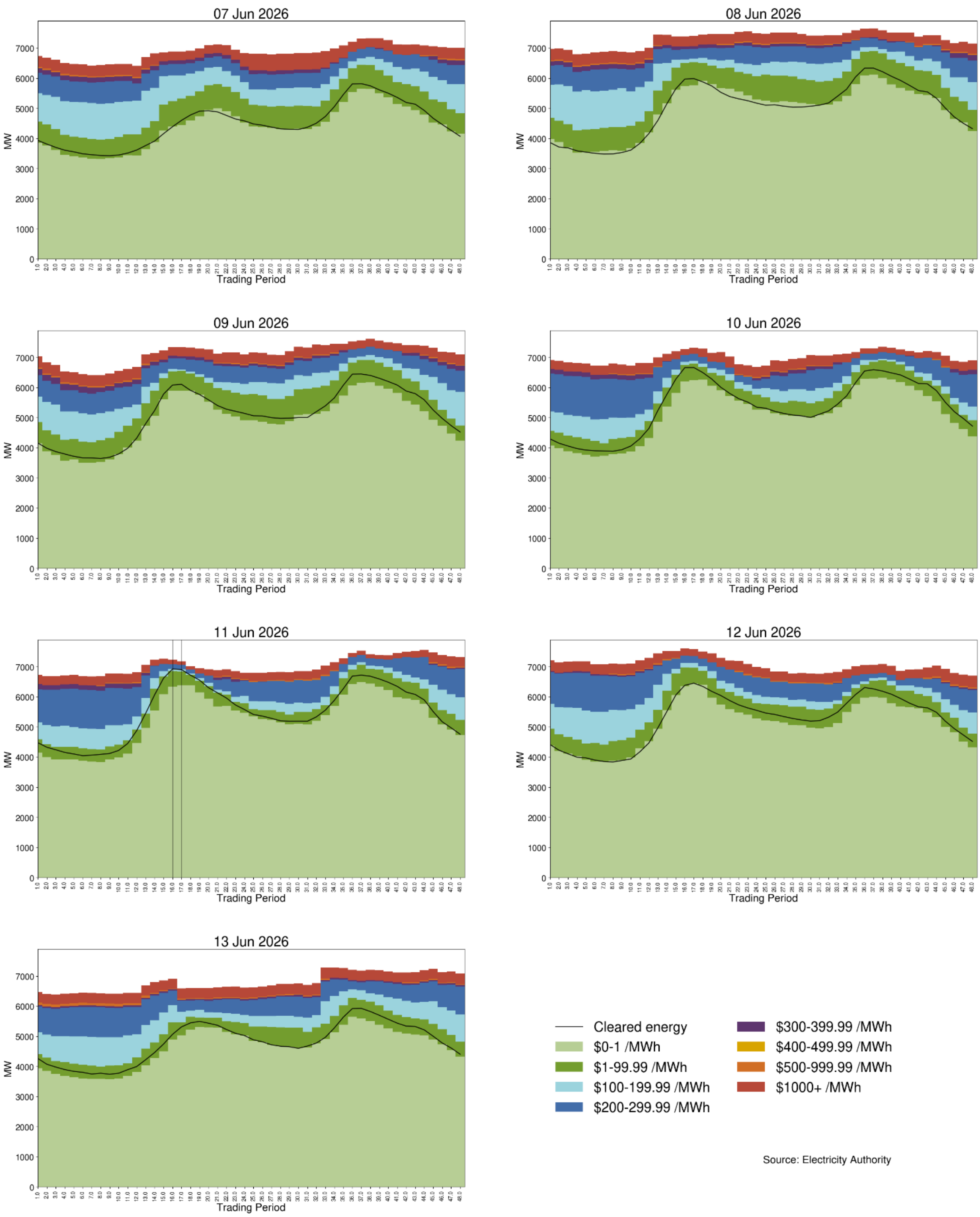
12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. From Wednesday, Mercury hydro priced up offers from between $1-199/MWh to between $200-299/MWh.

12.3. From Friday afternoon, Contact hydro priced down offers from between $200-399/MWh to between $100-199/MWh.

12.4. On Saturday, 198MW of Ōhau A was on a planned outage from 8.00am to 4.00pm.

Figure 23: Daily offer stacks

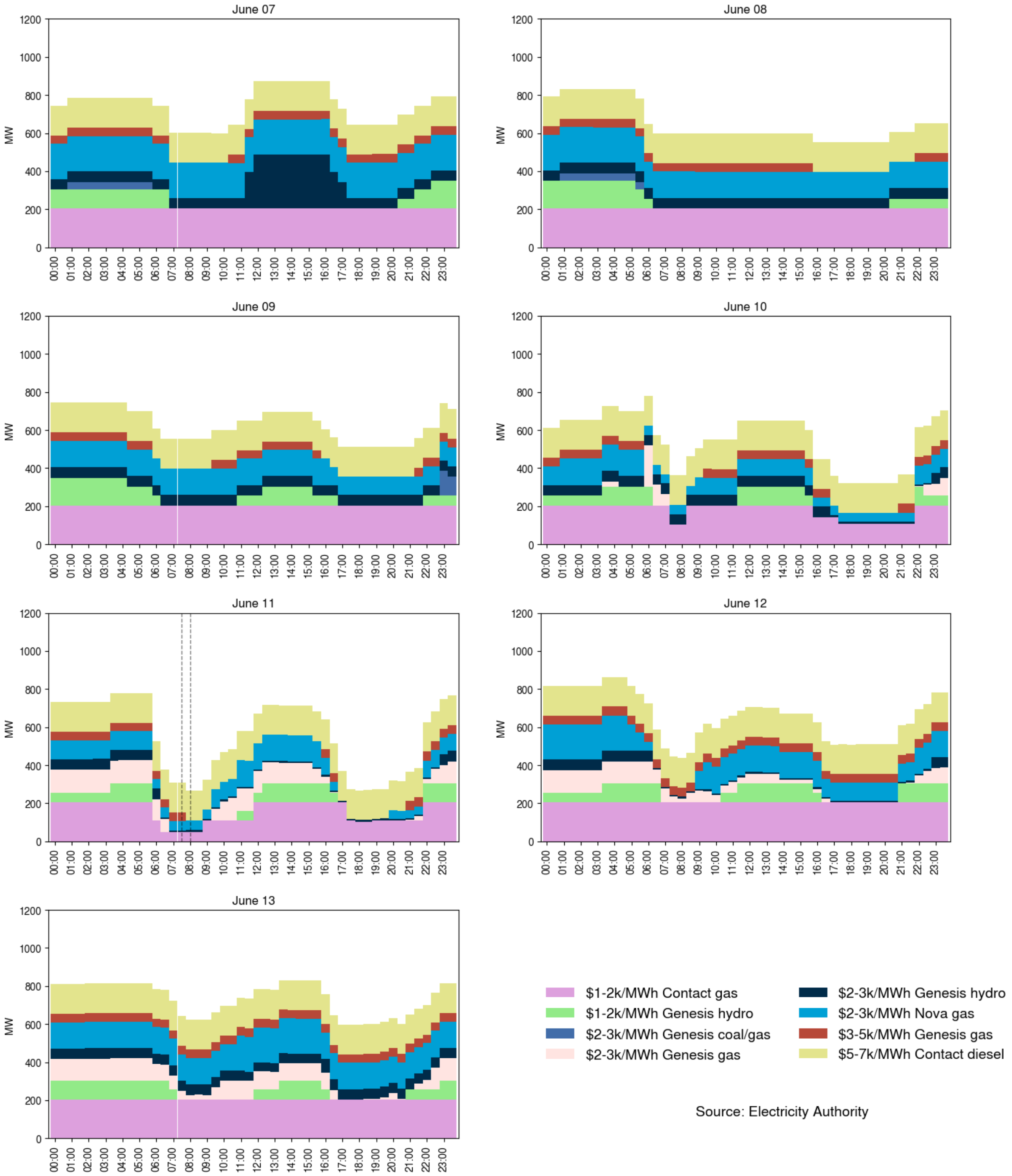


12.5. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.6. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren't expecting to run. These high prices reflect increased operating costs of running for only a short time. So, if demand is unexpectedly high, intermittent generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.7. On average 647MW per trading period was priced above $1,000/MWh this week, which is roughly 11.4% of the total energy available.

Figure 24: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

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
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers
26/04/2026-02/05/2026	Several	Further analysis	Contact	Roxburgh	Offers
r02/05/2026	Several	Further analysis	Genesis	Tokaanu	Offers
07/05/2026-08/05/2026	Several	Further analysis	Genesis	Tekapō	Offers
27/05/2026	Several	Further analysis	Genesis	Huntly 5	Offers
04/06/2026-05/06/2026	Several	Further analysis	Harbour Infrastructure	Papareireiā solar farm	Reason for no generation