6 July 2026

Trading conduct report 28 June-4 July 2026

Market monitoring weekly report

Trading conduct report 28 June-4 July 2026

1. Overview

1.1. This week the average spot price increased from $44/MWh to $67/MWh. Increased demand and lower wind generation have contributed to higher prices this week. National controlled storage has decreased to 85% nominally full and is 126% 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 28 June-4 July:

(i) The average spot price for the week was $67/MWh, an increase of around $23/MWh compared to the previous week.

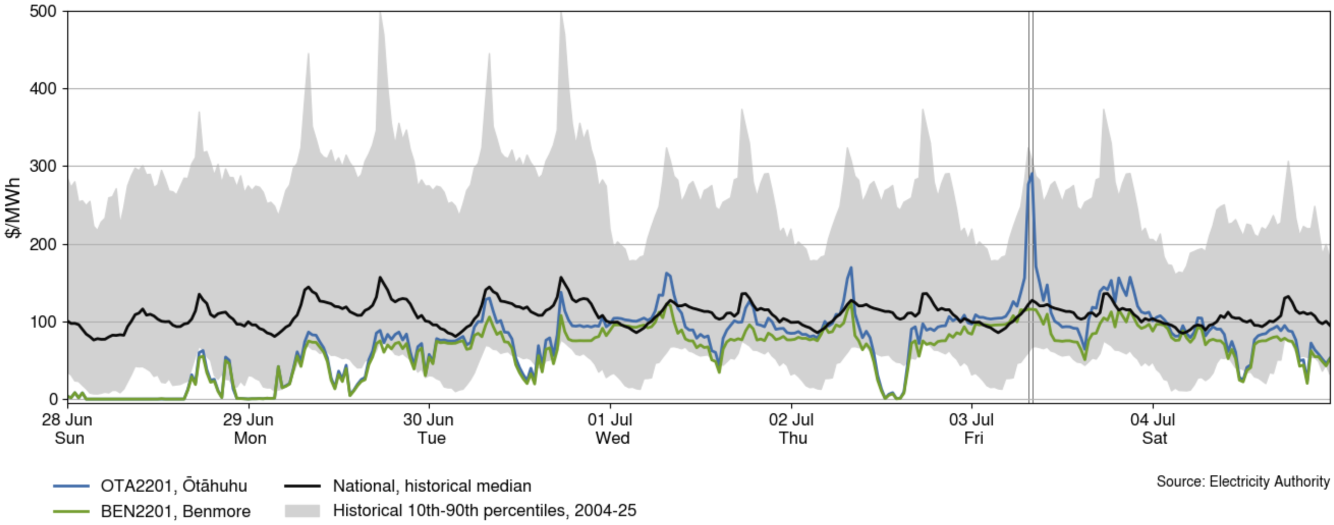
(ii) 95% of prices fell between $0.02/MWh and $134/MWh.

2.3. Prices have increased this week due to higher demand and lower wind generation.

2.4. Spot prices spiked on Friday at 7.30am and 8.00am, reaching $291/MWh at Ōtāhuhu and $116/MWh at Benmore. At this time, demand was between 28 and 60MW above forecast, and wind generation was between 40 and 52MW below forecast. At this time, SIR prices spiked to $87/MWh in the North Island, while they were $0/MWh in the South Island.

2.5. 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.

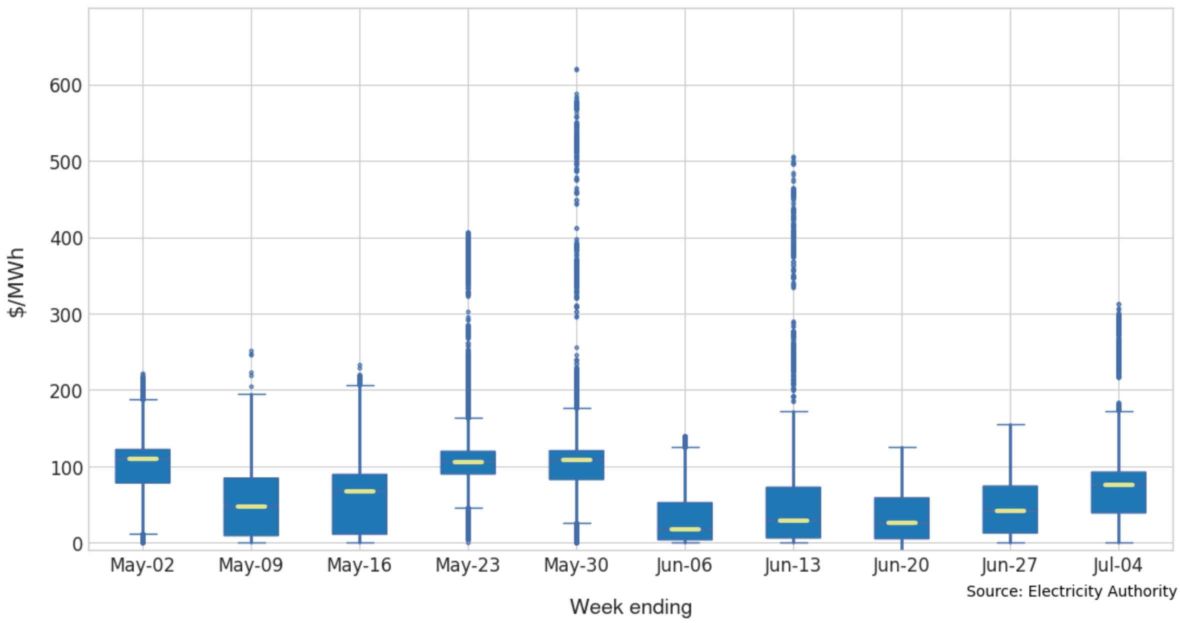
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 28 June-4 July



2.6. 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.

2.7. The distribution of spot prices this week was higher than last week. The median price was \$76/MWh and most prices (middle 50%) fell between \$39/MWh and \$92/MWh.

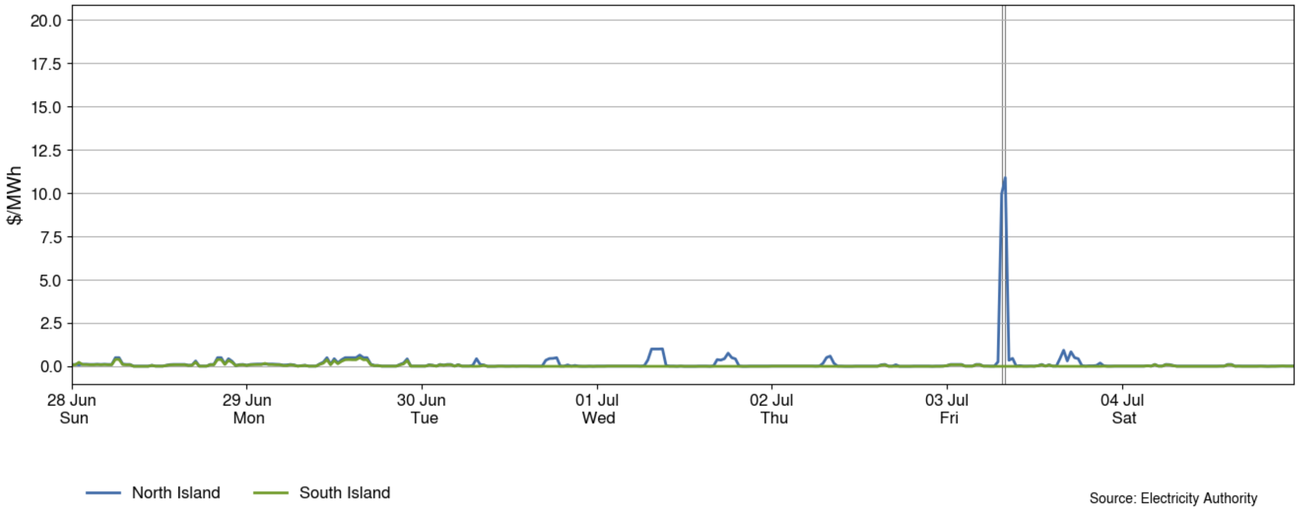
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



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, apart from a small spike in North Island FIR prices on Friday morning.

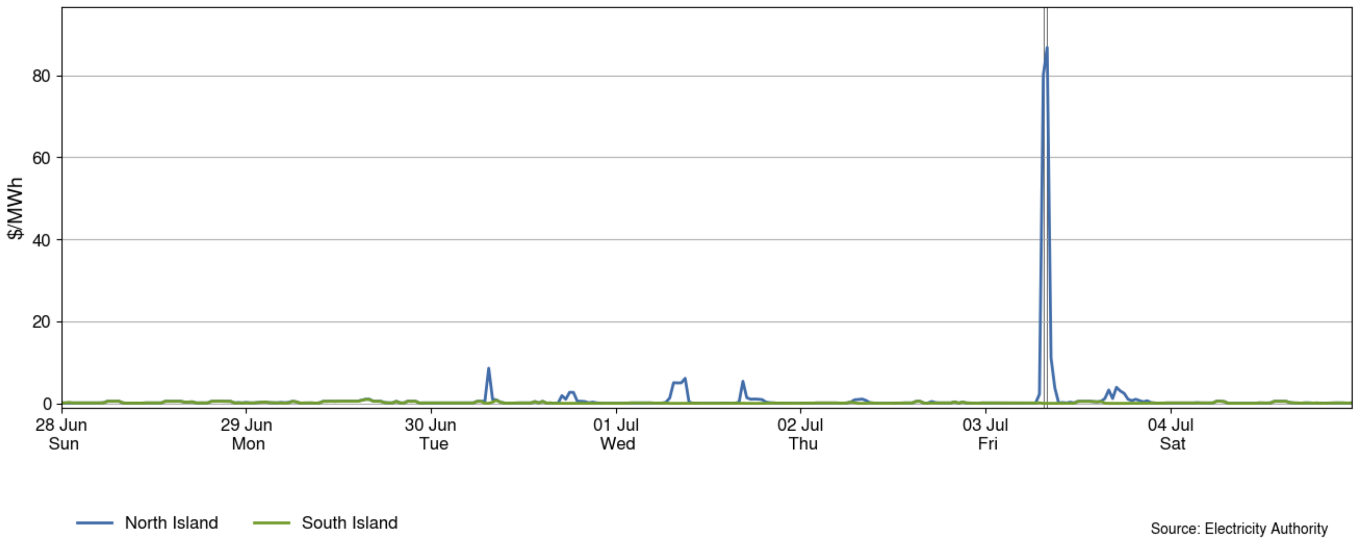
Figure 3: Fast instantaneous reserve price by trading period and island, 28 June-4 July



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, apart from a spike in North Island SIR prices on Friday morning.

3.3. On Friday at 7.30am and 8.00am, SIR prices spiked, reaching $87/MWh in the North Island while it was $0/MWh in the South Island. The highest 5-minute SIR price was $395/MWh. At this time, the risk setter changed from Tauhara to the HVDC, due to northward HVDC flow increasing with demand. This meant that more reserve was needed to cover this risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 28 June-4 July



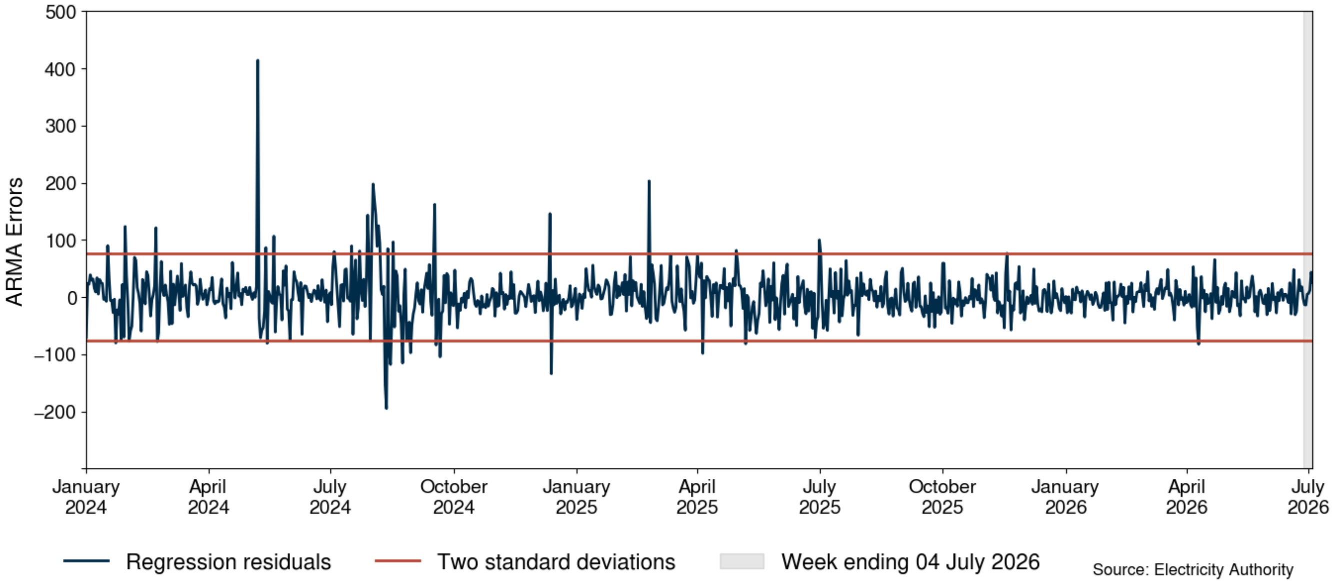
4. Regression residuals

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 - 4 July 2026



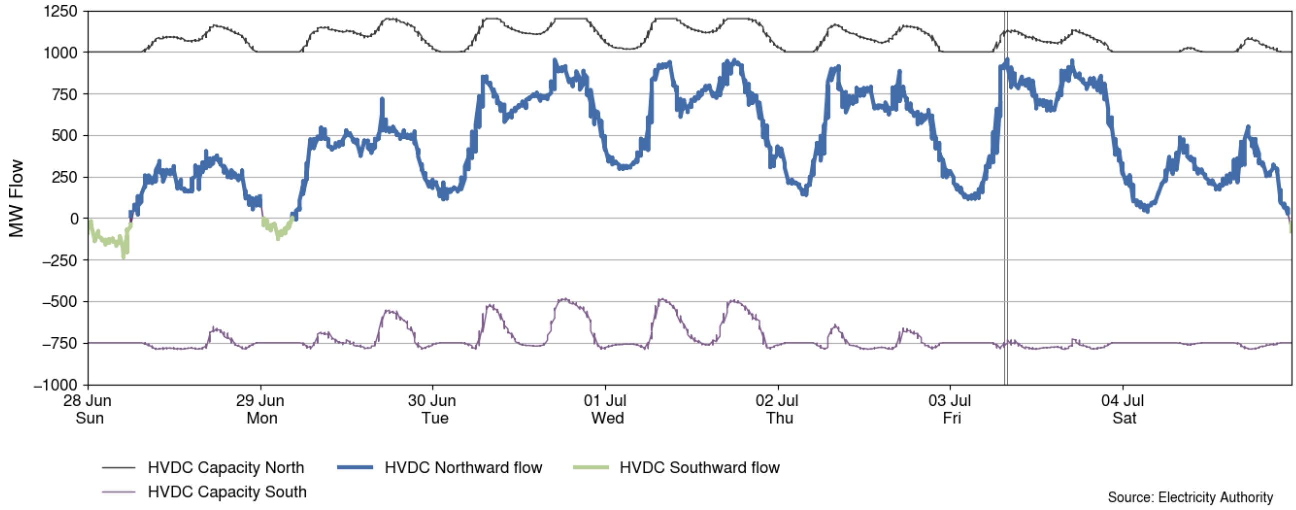
5. HVDC

5.1. Figure 6 shows the HVDC flow between 28 June-4 July. HVDC flows were mainly northward this week, due to high demand and high hydro generation.

5.2. The maximum northward flow of 958MW occurred on Friday at 8.00am.

5.3. The maximum southward flow of 235MW occurred on Sunday at 5.00am.

Figure 6: HVDC flow and capacity, 28 June-4 July



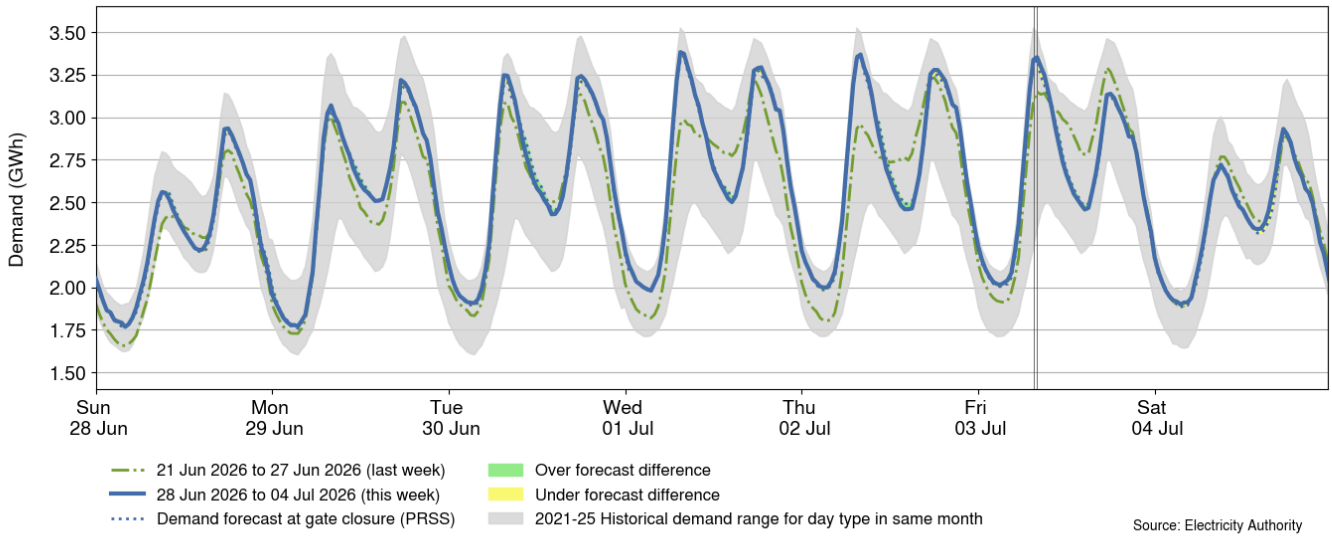
6. Demand

6.1. Figure 7 shows national demand between 28 June-4 July, compared to the historic range and the demand of the previous week. Demand was slightly higher than last week from Sunday to Tuesday, much higher than last week on Wednesday, Thursday, and Friday morning, and similar to last week on Friday afternoon and Saturday.

6.2. The maximum demand this week was around 3.38GWh (6.76GW) at 7:30am on Wednesday.

6.3. The morning peak demand on Wednesday and Thursday were the highest of the year so far.

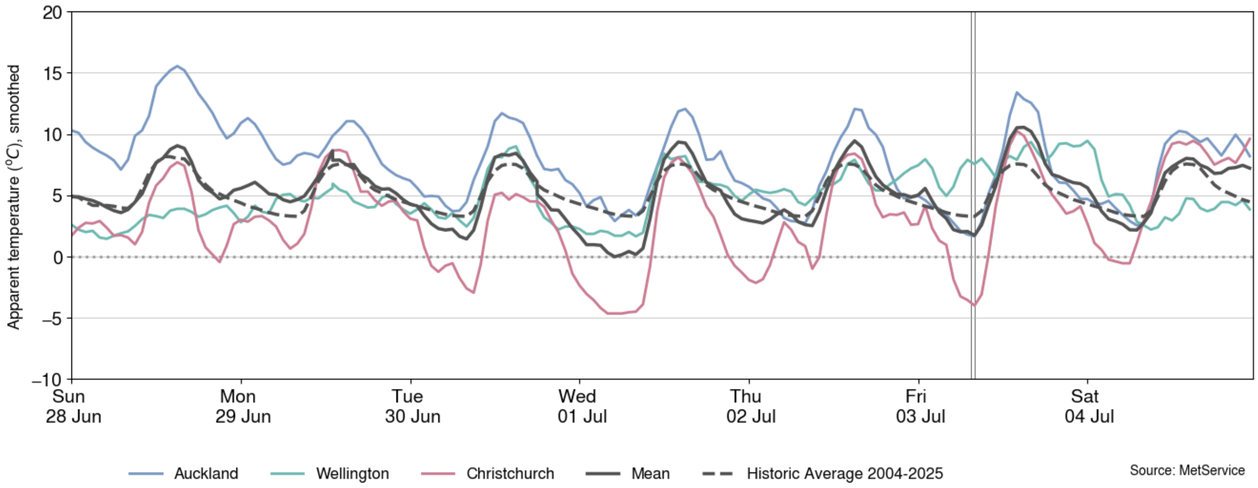
Figure 7: National demand, 28 June-4 July compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 28 June-4 July. 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.

6.5. Apparent temperatures ranged from 1°C to 16°C in Auckland, 1°C to 10°C in Wellington, and -5°C to 10°C in Christchurch.

Figure 8: Temperatures across main centres, 28 June-4 July



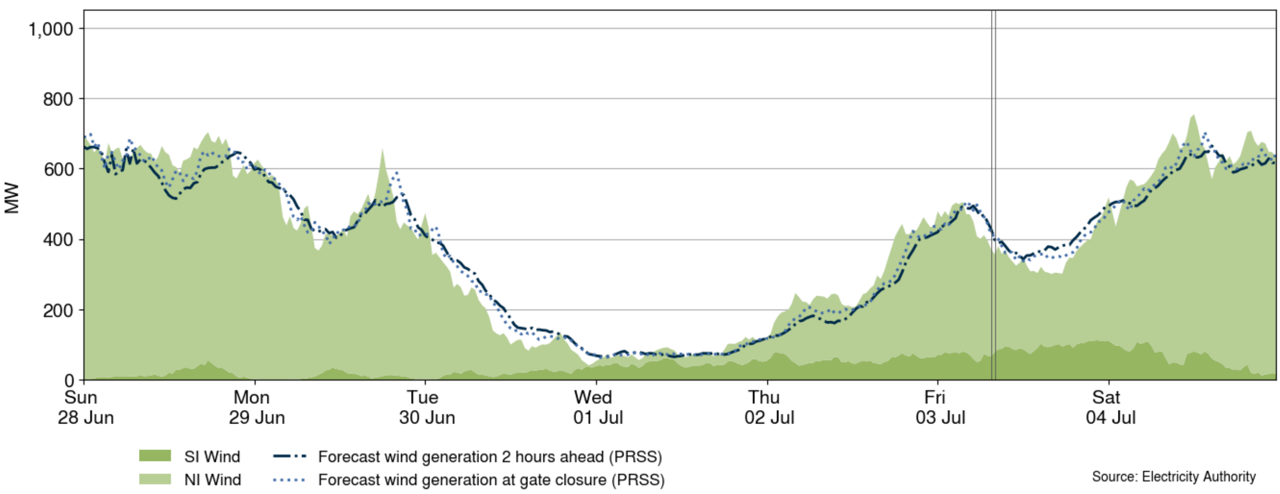
7. Generation

7.1. Figure 9 shows wind generation and forecast from 28 June-4 July. This week wind generation varied between 41MW and 754MW, with a weekly average of 382MW. Wind generation was higher on Sunday, Monday, Friday, and Saturday, and lower from Tuesday to Thursday.

7.2. Wind forecasting errors on Thursday resulted from forecasting errors at Mill Creek and West Wind 1.

7.3. Other forecasting errors throughout the week mainly resulted from forecasting errors at Harapaki, Te Āpiti, Tararua, and Turitea wind farms.

Figure 9: Wind generation and forecast, 28 June-4 July



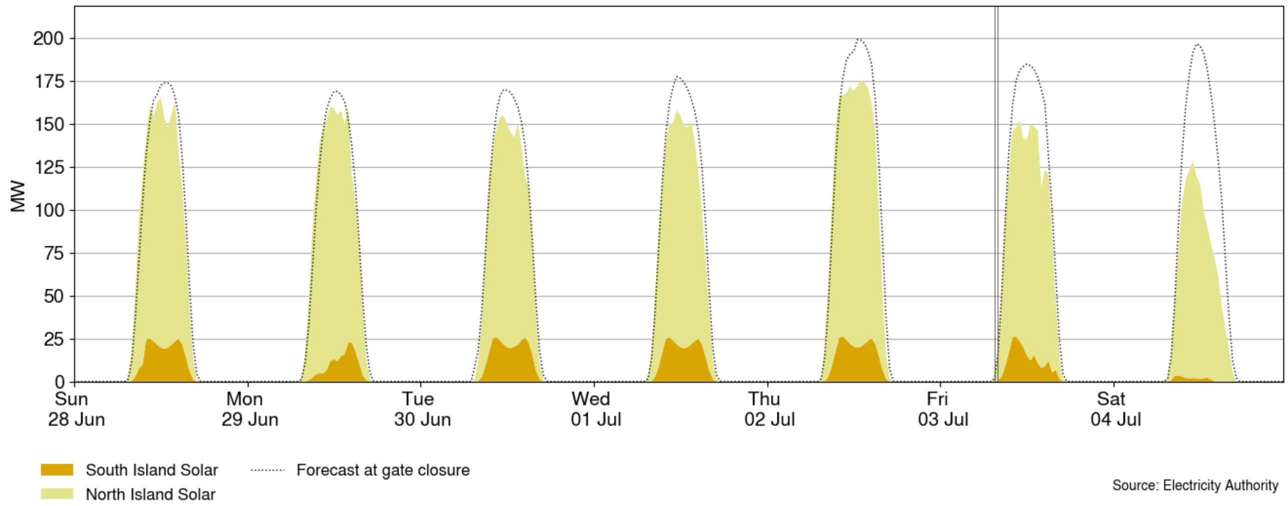
7.4. Figure 10 shows grid connected solar generation from 28 June-4 July. Solar generation was relatively high this week, reaching above 150MW every day except Saturday. Solar generation peaked at 175MW at 1.00pm on Thursday.

7.5. Forecasting errors on Friday and Saturday resulted from Omeheu and Tauhei solar farms.

(i) Omeheu did not generate on Saturday despite being forecast.

(ii) Tauhei, which is newly commissioning, did not generate on Friday and Saturday despite being forecast.

Figure 10: Grid connected solar generation, 28 June-4 July

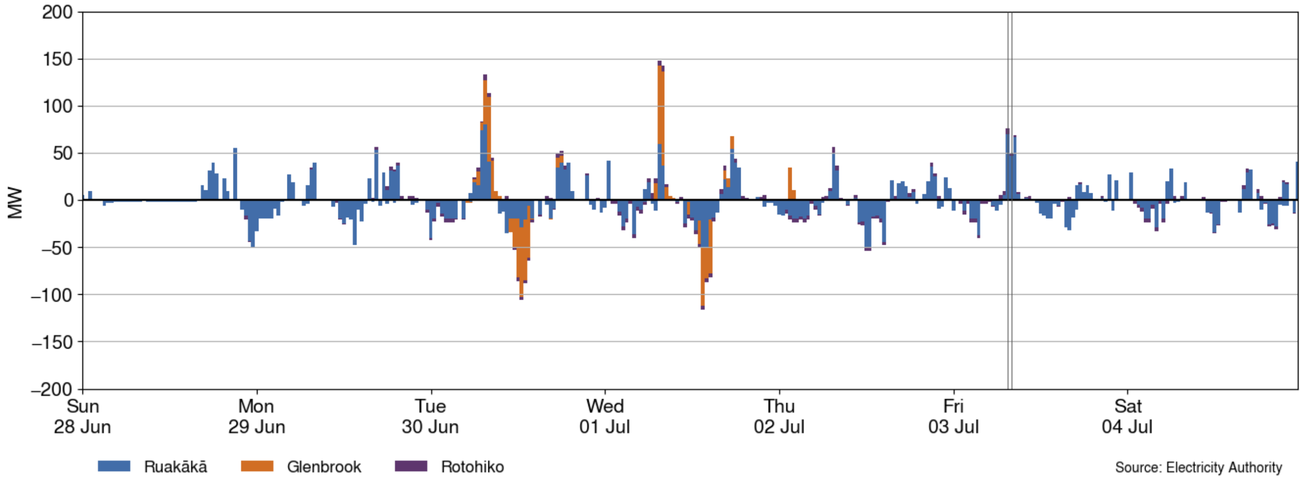


7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are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

7.7. This week, the batteries have generally charged overnight and near midday, when prices are lower, and discharged during the morning and evening peaks, when prices are higher.

7.8. Glenbrook was on outage until Monday, and from Thursday onwards.

Figure 11: Grid scale battery charge and discharge, 28 June-4 July



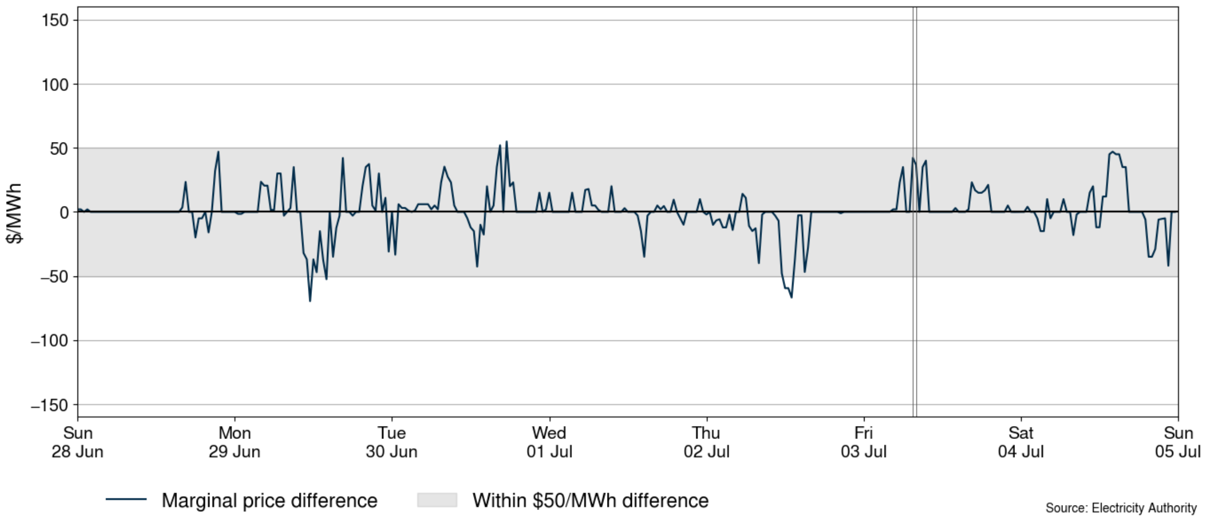
7.9. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing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

7.10. This week, there were a few trading periods with a marginal price difference over $50/MWh.

7.11. The highest positive difference of $55/MWh occurred on Tuesday at 5.30pm. At this time, demand was 143MW above forecast, and wind generation was 20MW below forecast.

7.12. The highest negative difference of $70/MWh occurred on Monday at 11.30am. At this time, demand was 111MW below forecast, and total intermittent generation was 15MW below forecast.

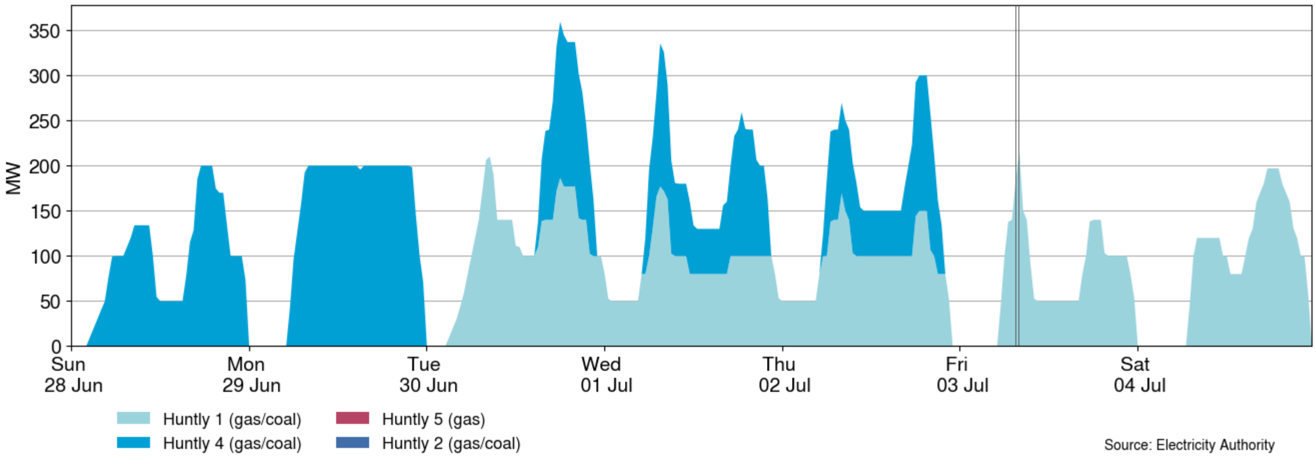
Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 28 June-4 July



7.13. Figure 13 shows the generation of thermal baseload between 28 June-4 July. Huntly 4 ran at times from Sunday to Thursday, and Huntly 1 ran at times from Tuesday to Saturday.

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

Figure 13: Thermal baseload generation, 28 June-4 July



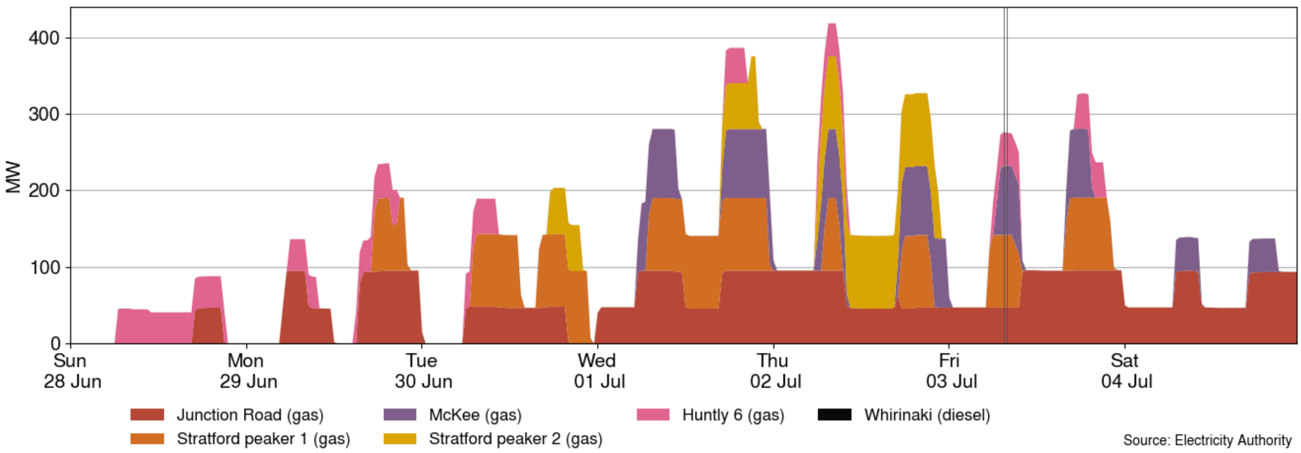
7.14. Figure 14 shows the generation of thermal peaker plants between 28 June-4 July. Junction Road ran at times every day this week, while the Stratford Peakers ran at times every weekday. McKee ran at times from Wednesday to Saturday, and Huntly 6 ran at times from Sunday to Friday.

7.15. During the price spike on Friday:

(i) Only one of the Stratford Peakers was being offered below $1000/MWh.

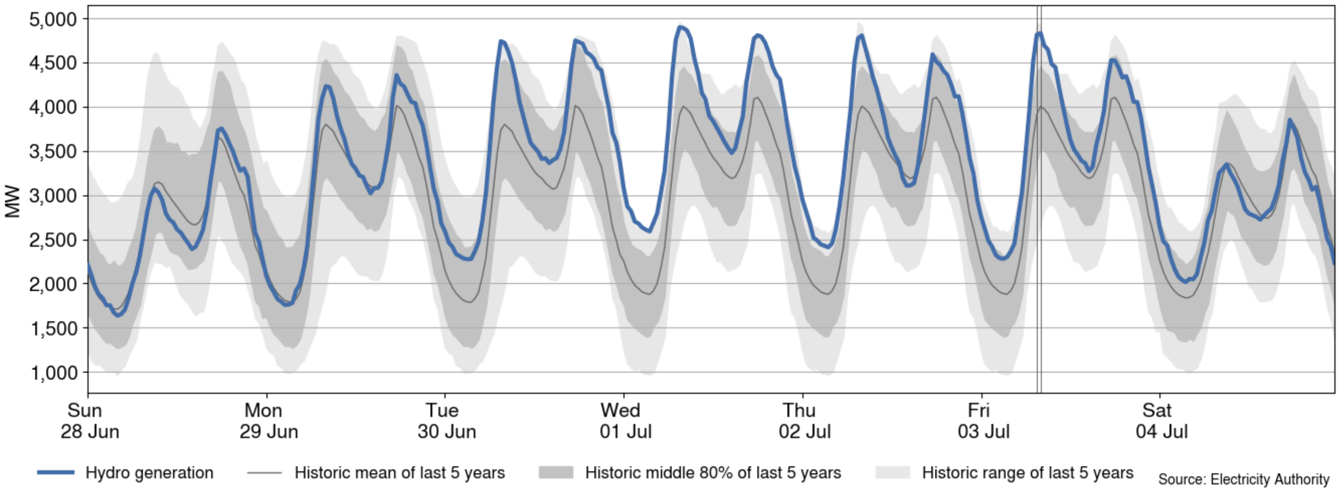
(ii) Junction road was only offering about half of its capacity. The other half was removed in pre-dispatch offers from Thursday 8.00pm onwards. The monitoring team is looking further into this.

Figure 14: Thermal peaker generation, 28 June-4 July



7.16. Figure 15 shows hydro generation between 28 June-4 July. Hydro generation has been higher than the historic mean from Monday to Friday, nearing or surpassing the historic range during peak periods.

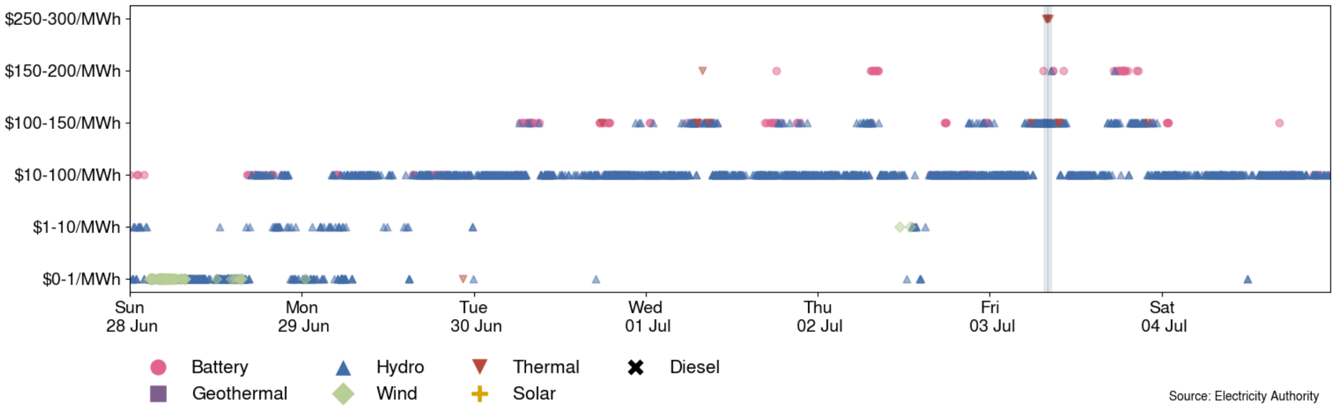
Figure 15: Hydro generation, 28 June-4 July



7.17. 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.

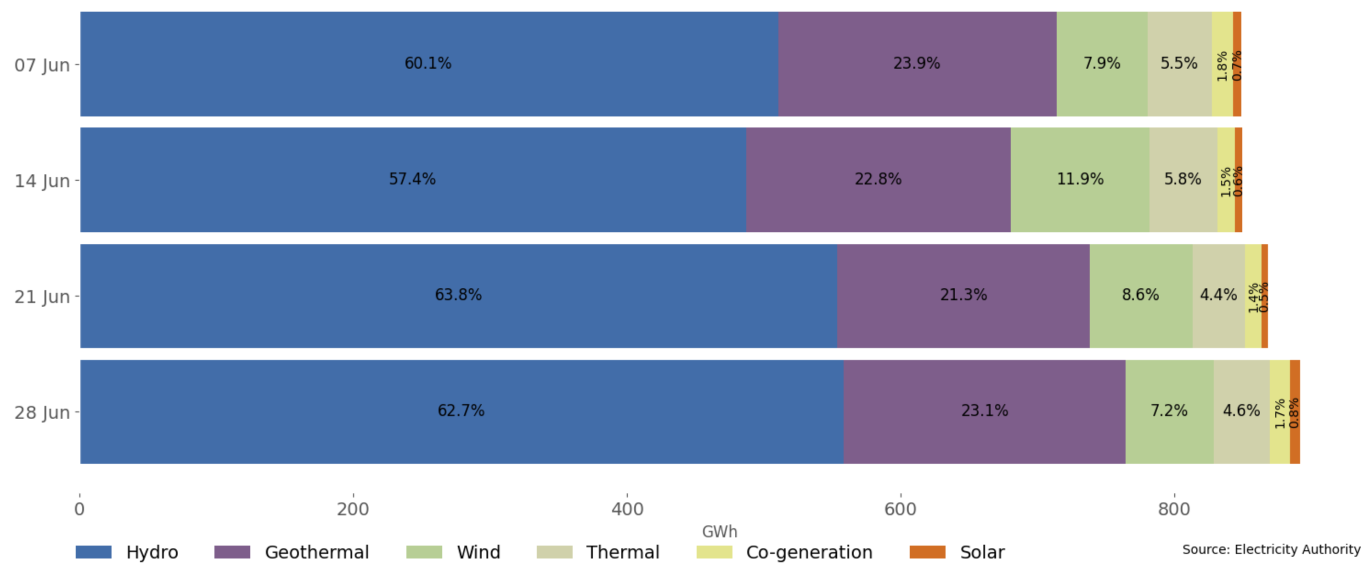
7.18. The highest prices were set by Huntly 1. The most common technology setting prices was hydro, with wind the second most common. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 28 June-4 July



7.19. As a percentage of total generation, between 28 June-4 July, total weekly hydro generation was 62.7%, geothermal 23.1%, wind 7.2%, thermal 4.6%, co-generation 1.7%, and solar (grid connected) 0.8%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 7 June and 4 July



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 28 June-4 July ranged between ~913MW and ~1,322MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 28 June-4 July

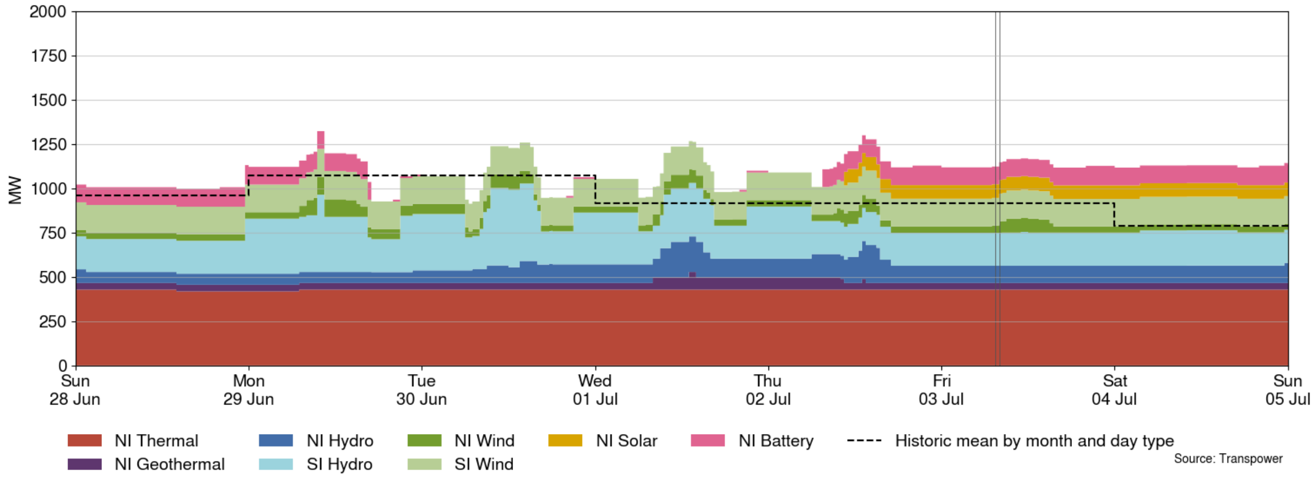
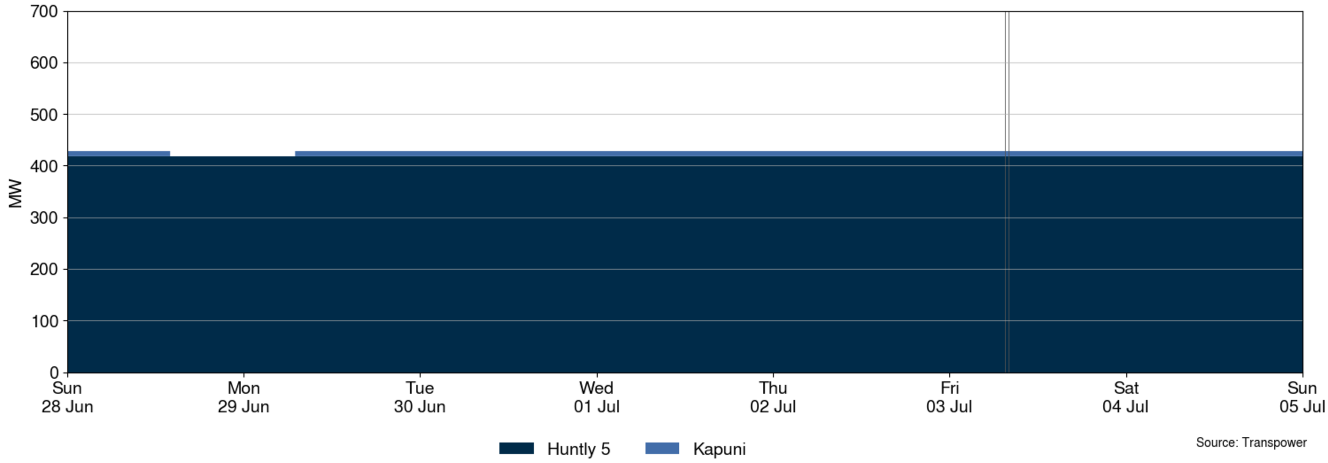


Figure 19: Total MW loss from thermal outages, 28 June-4 July



8.2. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 5	Full	29 June 2026
Clyde unit 3	Full	1 July 2026
Manapōuri unit 4	Full	8 July 2026
Glenbrook	Full	9 July 2026
Huntly 5	Full	10 July 2026
Tauhei Solar Farm	Full	18 July 2026
Kaiwera Downs	Full	20 July 2026
Roxburgh unit 8	Full	2 September 2026

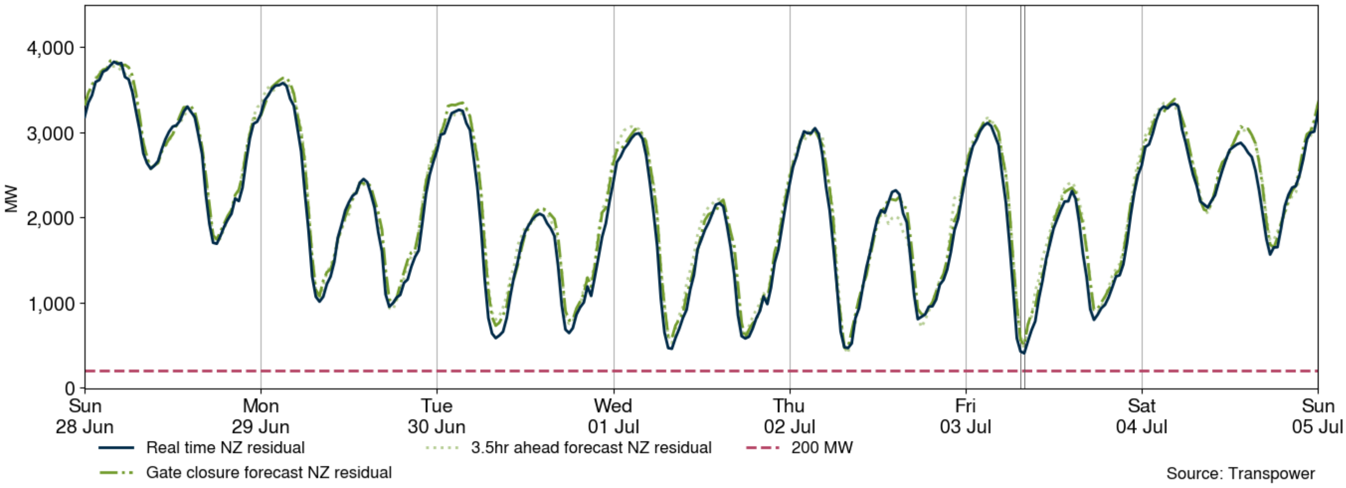
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 28 June-4 July. 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. This week, the national residual dropped below 500MW at 7.30am and 8.00am on Wednesday, Thursday, and Friday.

9.3. The minimum national residual of 406MW occurred on Friday at 8.00am. At this time, the North Island residual was 255MW, and the South Island residual was 151MW.

Figure 20: National generation balance residuals, 28 June-4 July



10. Storage/fuel supply

10.1. Storage at Lake Pūkaki (89% full) remains above its 90th percentile, while storage at Lake Tekapō (78% full) is just below its 90th percentile.

10.2. Storage at Lake Te Anau (101% full) and Lake Manapōuri (88% full) remain well above their historic mean.

10.3. Storage at Lake Taupō (66% full) is well above its historic mean.

10.4. Storage at Lake Hawea (88% full) remains at its historic 90th percentile for this time of year.

10.5. 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.

10.6. As of 4 July, national controlled storage was 85% nominally full, and ~126% of the historic average for this time of year.

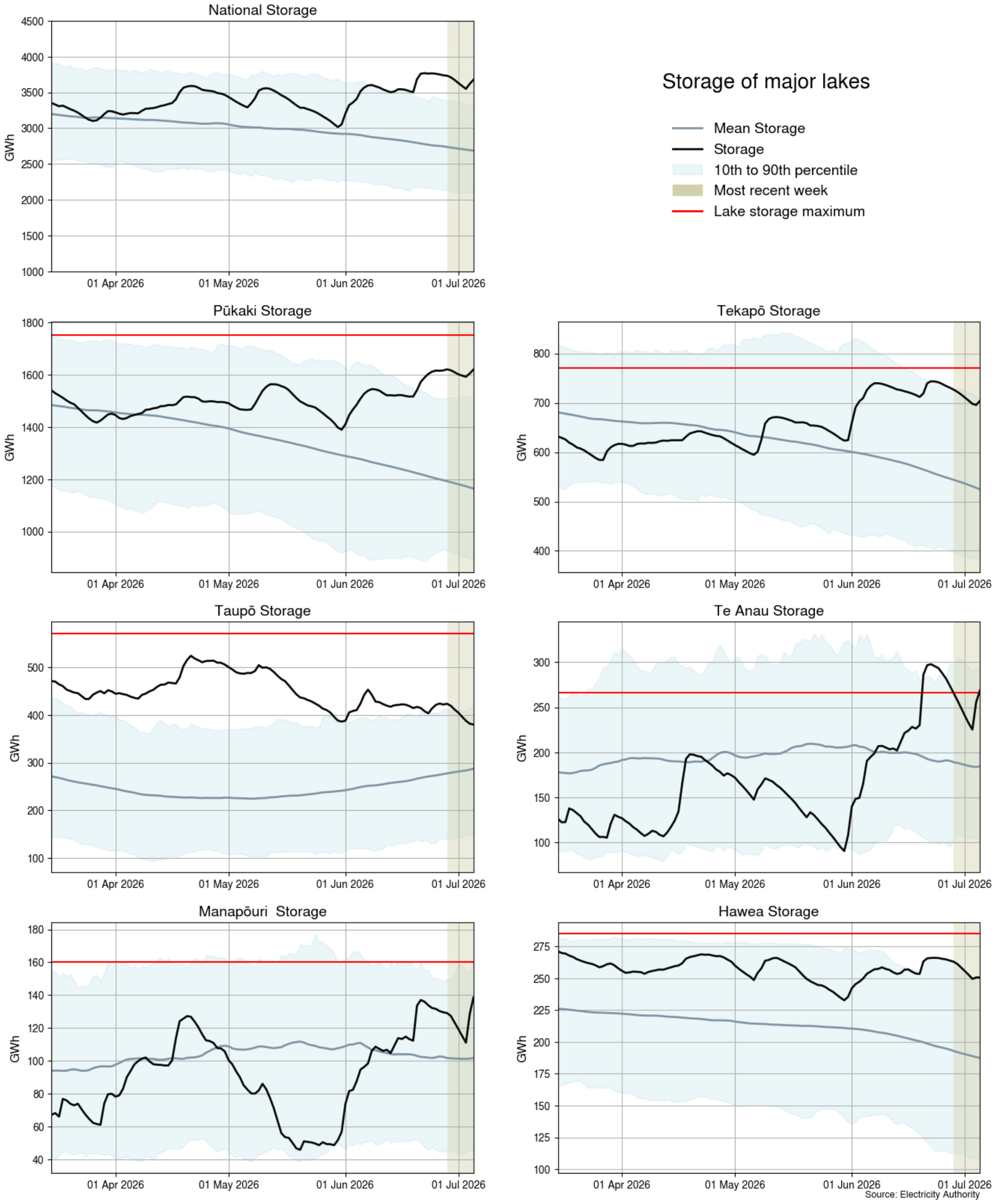
10.7. Storage at Lake Pūkaki (89% full) remains above its 90th percentile, while storage at Lake Tekapō (78% full) is just below its 90th percentile.

10.8. Storage at Lake Te Anau (101% full) and Lake Manapōuri (88% full) remain well above their historic mean.

10.9. Storage at Lake Taupō (66% full) is well above its historic mean.

10.10. Storage at Lake Hawea (88% full) remains at its historic 90th percentile for this time of year.

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. 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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 July 2026. The SRMCs for gas generation have increased, with SRMCs for coal and diesel fuelled generation remaining steady.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$238/MWh, while the cost of running the Rankines on gas is ~$181/MWh.

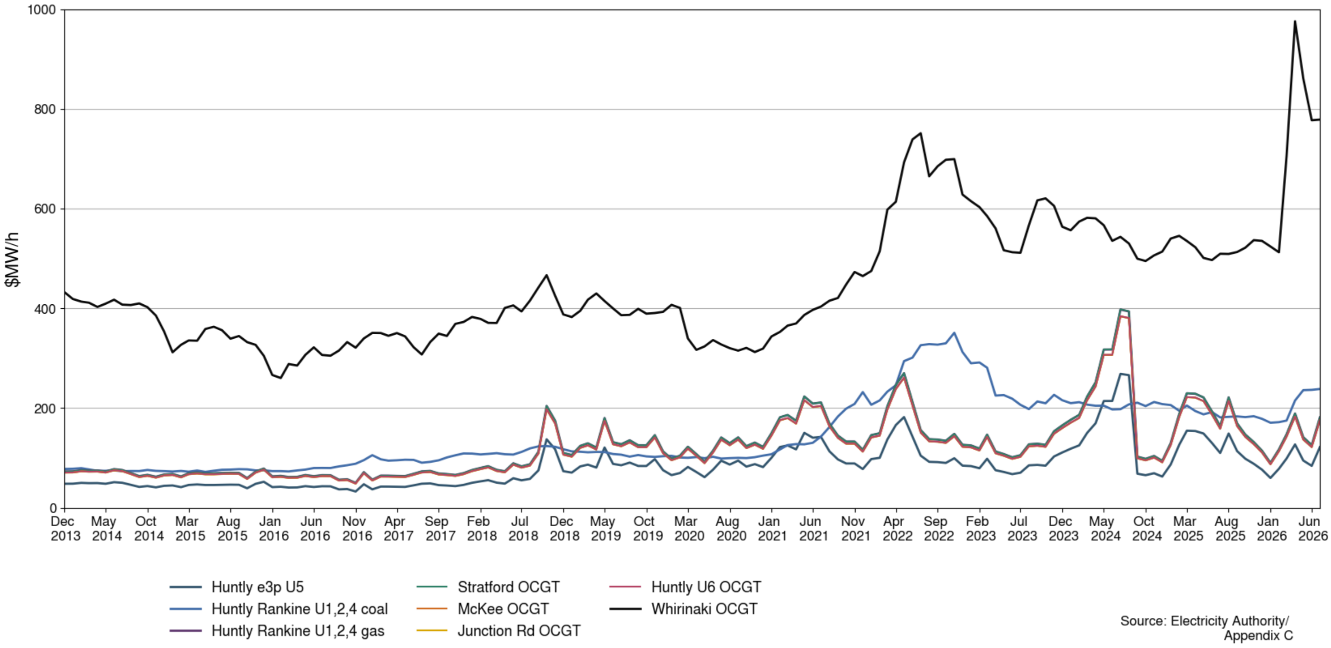
11.5. The SRMC of gas fuelled thermal plants is currently between $122/MWh and $181/MWh.

11.6. The SRMC of Whirinaki is ~$778/MWh.

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

11.8. 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

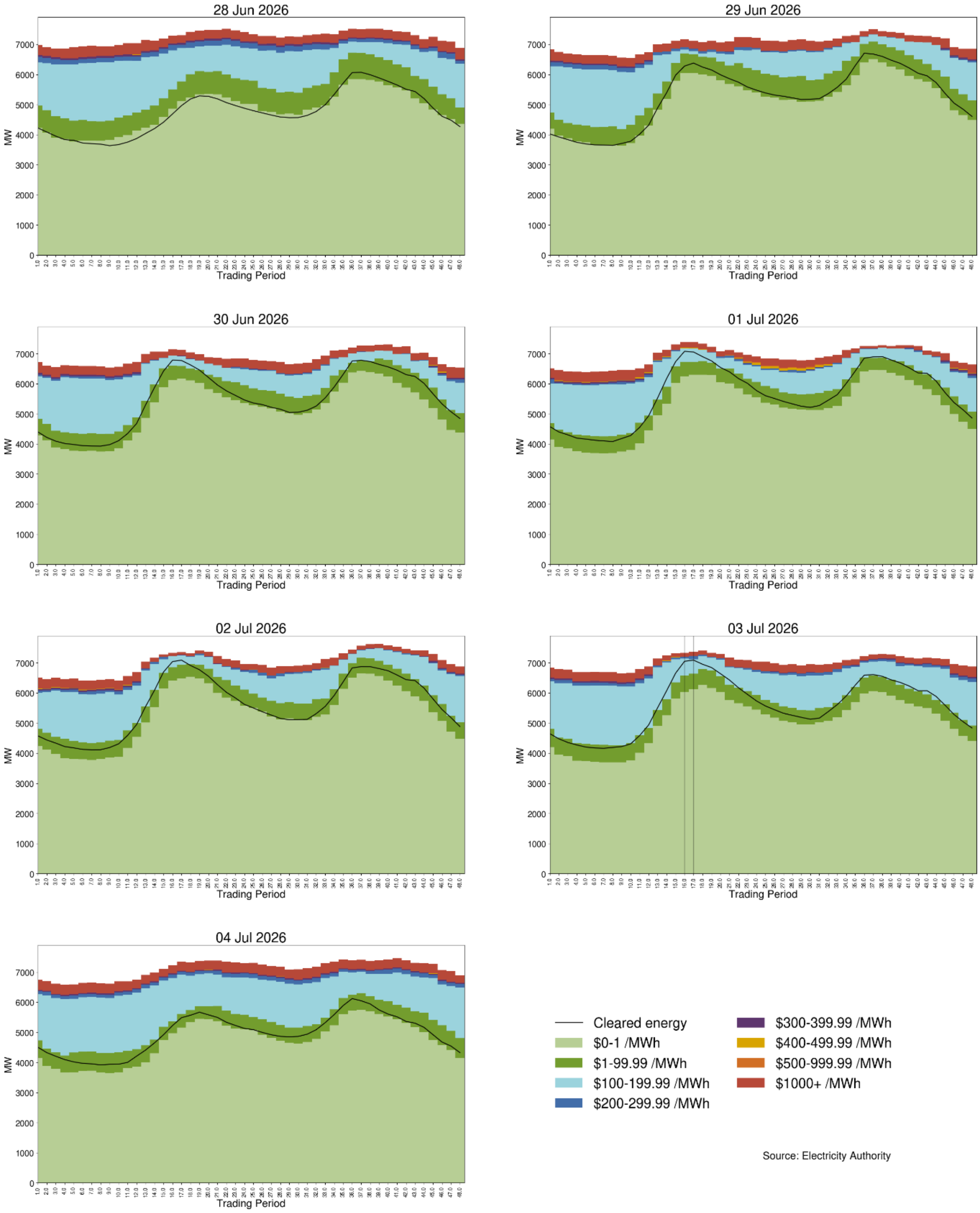


12. Offer behaviour

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 Monday to Friday, Meridian hydro and Mercury hydro priced down offers from $100-199/MWh to $0-1/MWh.

Figure 23: Daily offer stacks



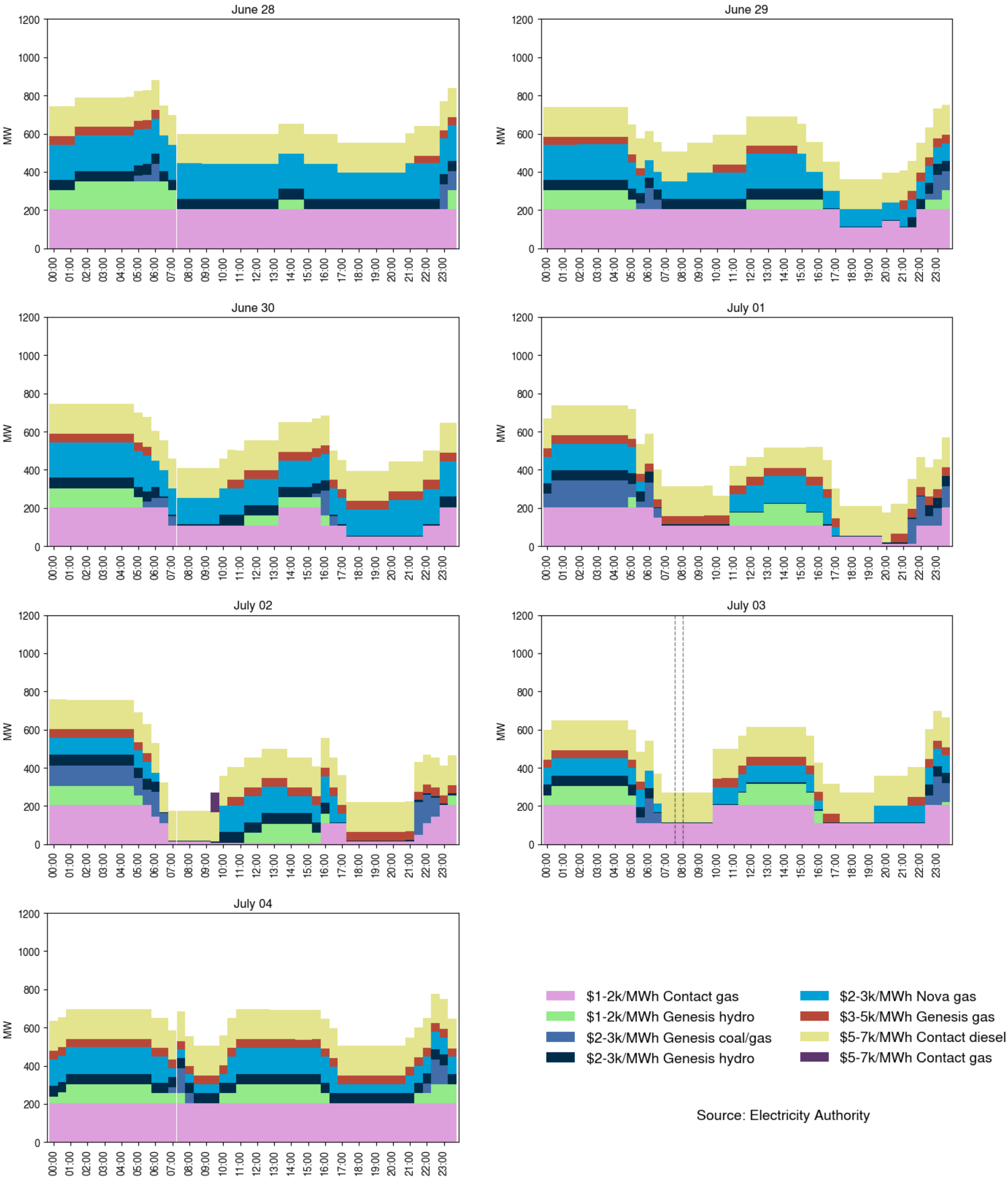
Source: Electricity Authority

12.3. 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.

12.4. 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.

12.5. On average 549MW per trading period was priced above $1,000/MWh this week, which is roughly 9.6% 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
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
24/06/2026	Several	Further analysis	Contact	Stratford peakers	Offers
3/07/2026	Several	Further analysis	Nova	Junction Road	Offers