29 June 2026

Trading conduct report 21-27 June 2026

Market monitoring weekly report

Trading conduct report 21-27 June 2026

1. Overview

1.1. This week the average spot price increased from $33/MWh to $44/MWh. Despite higher demand, high hydro storage has meant prices have only been slightly higher this week. National controlled storage has increased to 90% nominally full and is 130% of the historical average for this time of here.

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 21-27 June 2026:

(a) The average spot price for the week was $44/MWh, an increase of around $11/MWh compared to the previous week.

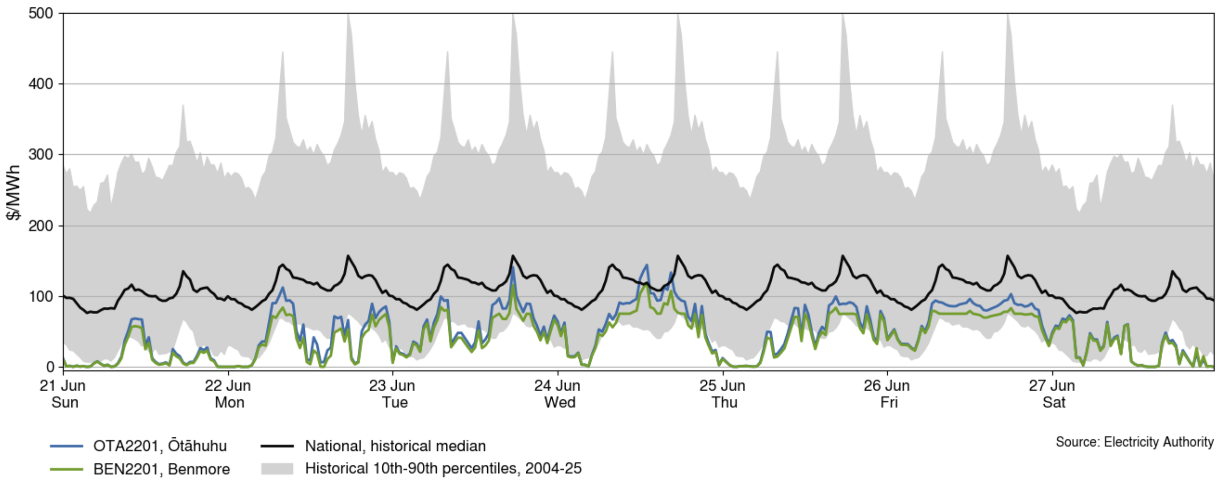
(b) 95% of prices fell between $0.03/MWh and $98/MWh.

2.3. Despite higher demand, prices have only been slightly higher this week due to high hydro storage.

2.4. The highest spot prices this week occurred on Wednesday at 1.00pm. At this time, the spot price at Ōtāhuhu was $144/MWh while the price at Benmore was $119/MWh.

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, however, this week there were none.

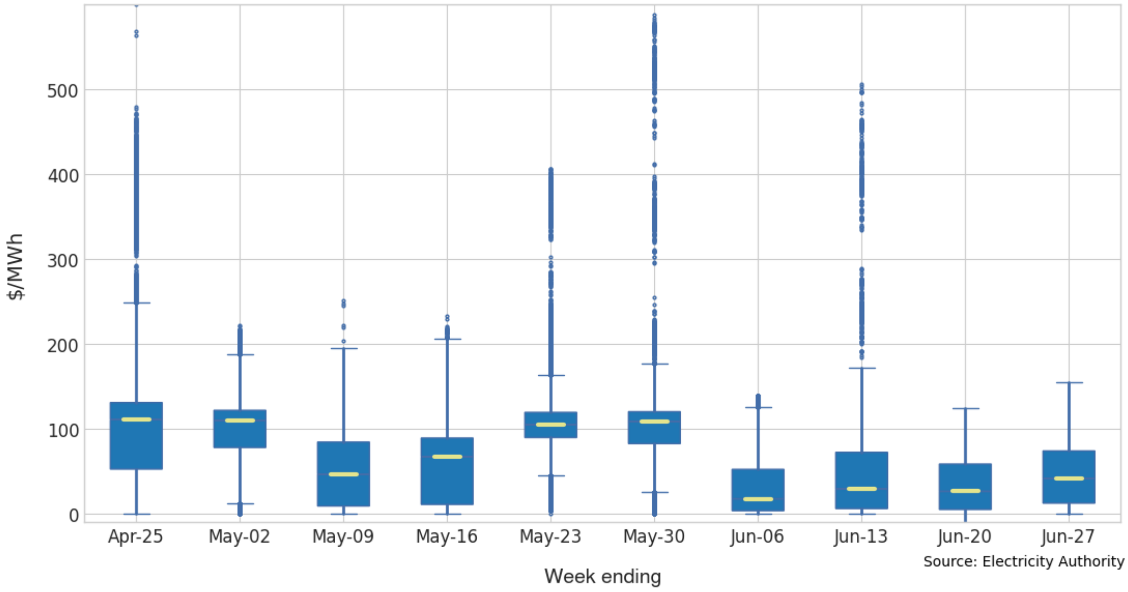
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 21-27 June 2026



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 similar to last week, with a slightly higher distribution. The median price was $42/MWh, and most prices (middle 50%) fell between $13/MWh and $75/MWh.

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

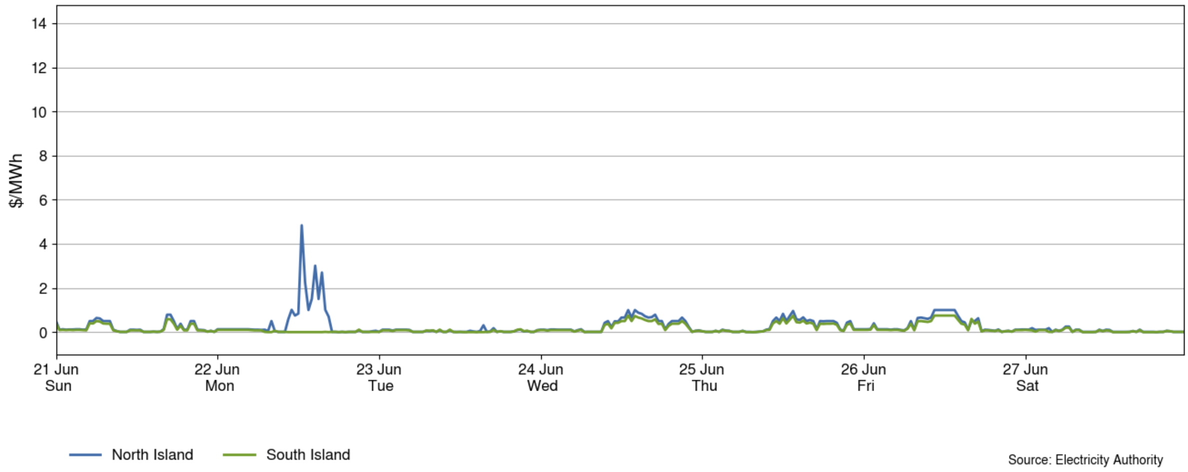


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices remained mostly below $1/MWh this week, with one series of spikes on Monday reaching just under $5/MWh in the North Island.

3.2. During the reserve price separation on Monday, the HVDC was relatively close to capacity, and was setting the risk for the North Island.

Figure 3: Fast instantaneous reserve price by trading period and island, 21-27 June 2026

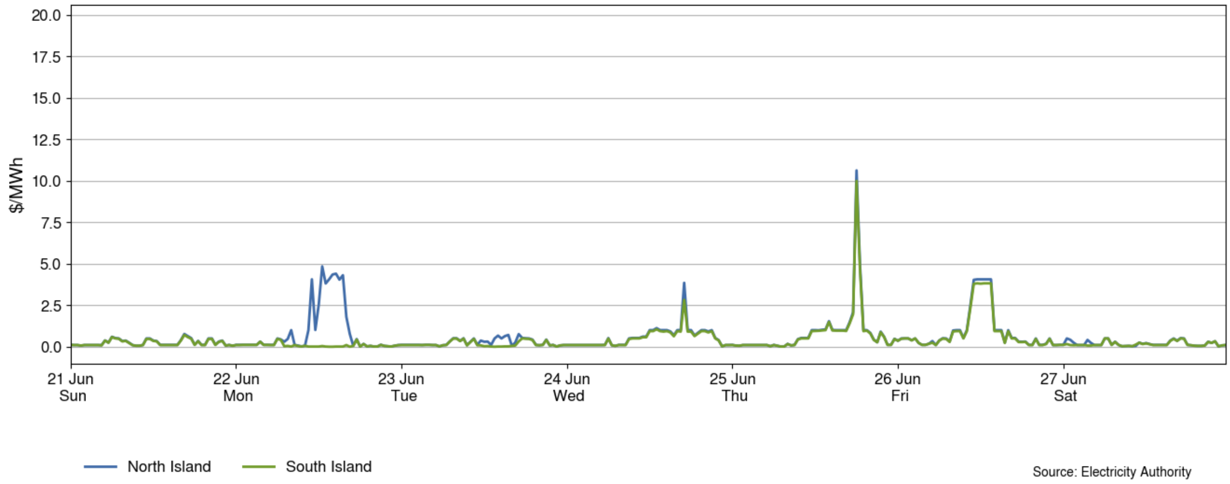


3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices remained mostly below $1/MWh this week, with a few small spikes reaching just below $5/MWh, and one spike reaching $10/MWh in the North Island and South Island.

3.4. On Thursday at 6.00pm, SIR prices reached $11/MWh in the North Island and $10/MWh in the South Island. At this time, Tararua wind farm and Turitea wind farm were risk setters for both islands, with Ōhau as an additional risk setter for the South Island.

3.5. During the reserve price separation on Monday, the HVDC was relatively close to capacity, and was setting the risk for the North Island.

Figure 4: Sustained instantaneous reserve by trading period and island, 21-27 June 2026



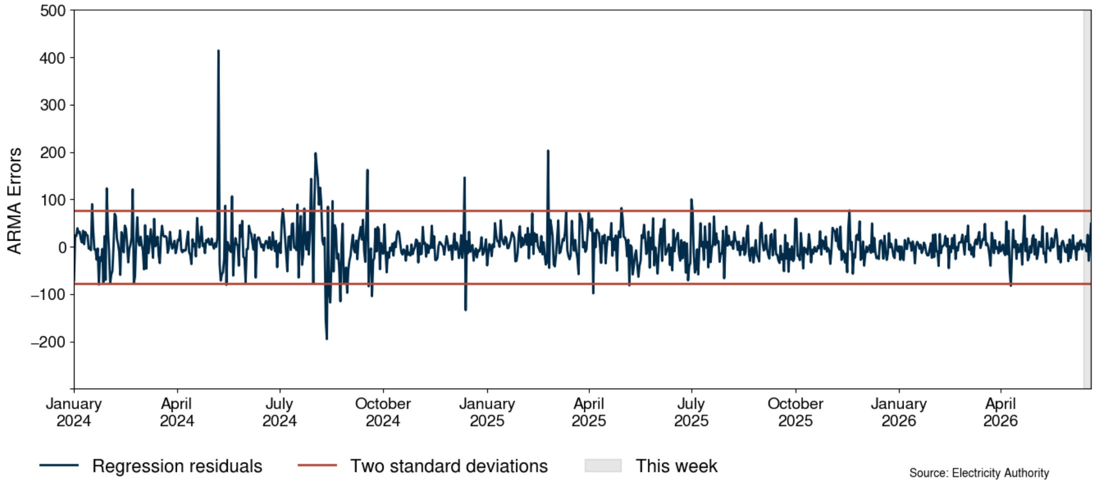
4. Regression residuals

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 - 27 June 2026



5. HVDC

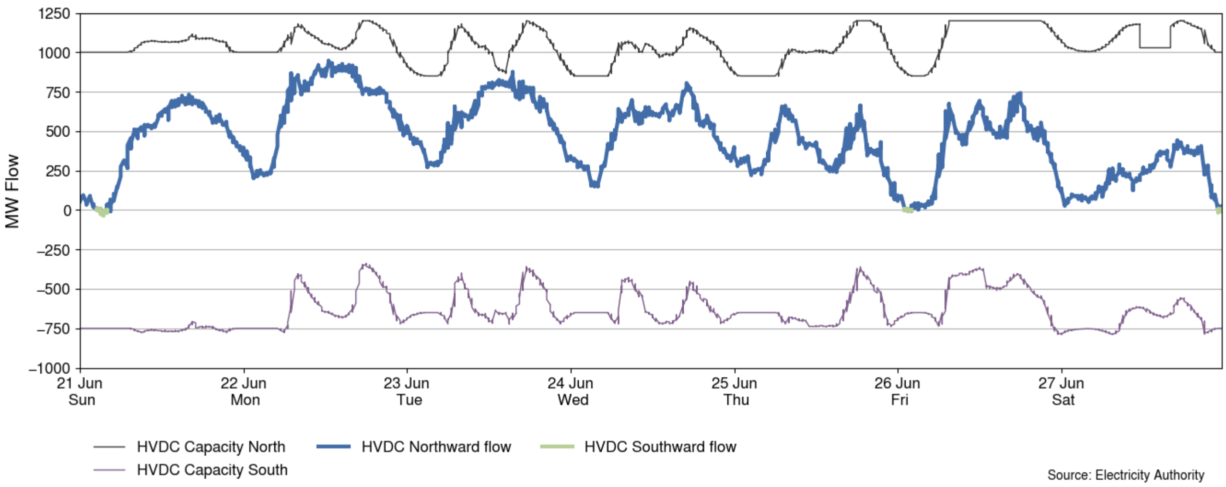
5.1. Figure 6 shows the HVDC flow between 21-27 June 2026. HVDC flows were mostly northward this week due to higher demand. In addition, Huntly 5 was on outage, so there was less North Island thermal generation available. Southward flow occurred briefly in the early mornings of Sunday, Friday and in the late night of Saturday.

5.2. The maximum southward flow of 37MW occurred on Sunday at 3.30am.

5.3. The maximum northward flow of 946MW occurred on Monday at 12.30pm. At this time, HVDC flow was within 131MW of capacity.

5.4. On Tuesday between 1.30pm and 2.30pm, HVDC northward flow was within 100MW of capacity.

Figure 6: HVDC flow and capacity, 21-27 June 2026



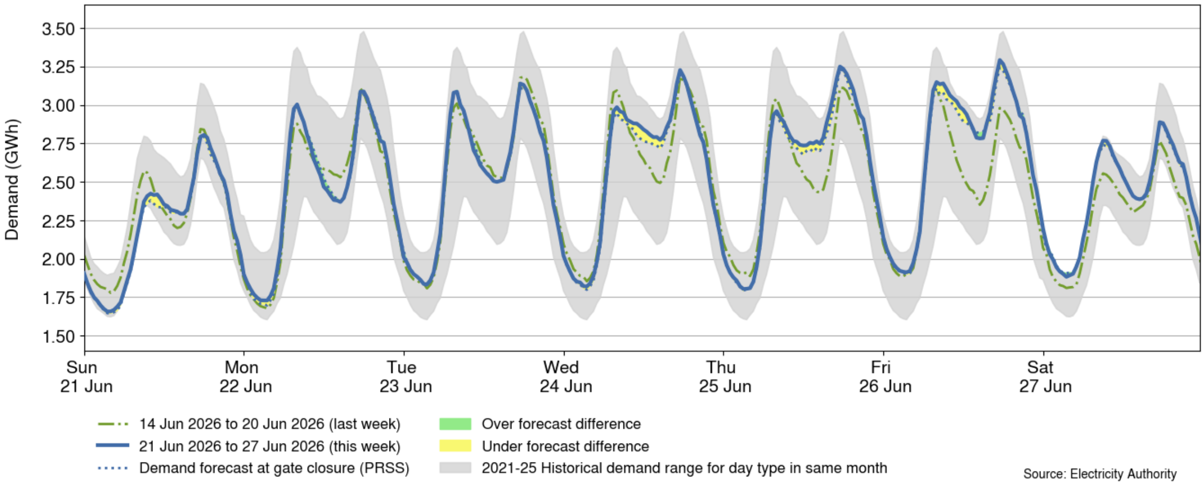
6. Demand

6.1. Figure 7 shows national demand between 21-27 June 2026, compared to the historic range and the demand of the previous week. Demand was similar to last week from Sunday to Tuesday, and higher than last week from Wednesday onwards, due to cooler temperatures.

6.2. The highest demand for the week was 6,580MW on Friday at 5.00pm.

6.3. On Sunday, Wednesday, Thursday and Friday there were notable forecasting errors, where demand was at least 100MW above forecast.

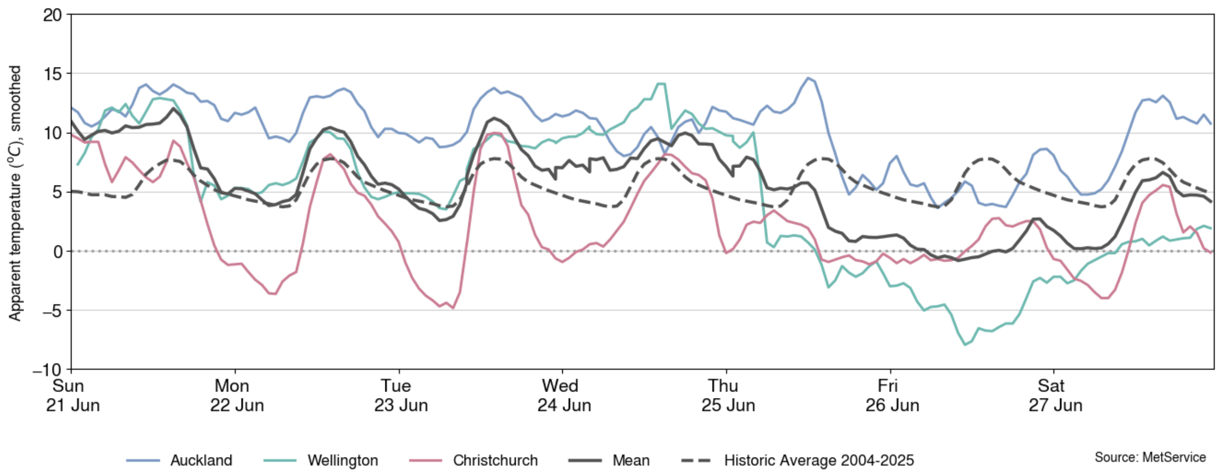
Figure 7: National demand, 21-27 June 2026 compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 21-27 June 2026. 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 3°C to 15°C in Auckland, -9°C to 14°C in Wellington, and -6°C to 10°C in Christchurch. Cool temperatures in the second half of the week likely contributed to higher demand.

Figure 8: Temperatures across main centres, 21-27 June 2026



7. Generation

7.1. Figure 9 shows wind generation and forecast from 21-27 June 2026. This week wind generation varied between 89MW and 940MW, with a weekly average of 446MW. Wind generation averaged above 400MW on Sunday, Thursday, Friday and Saturday but below 300MW on Monday and Tuesday.

7.2. Forecasting errors:

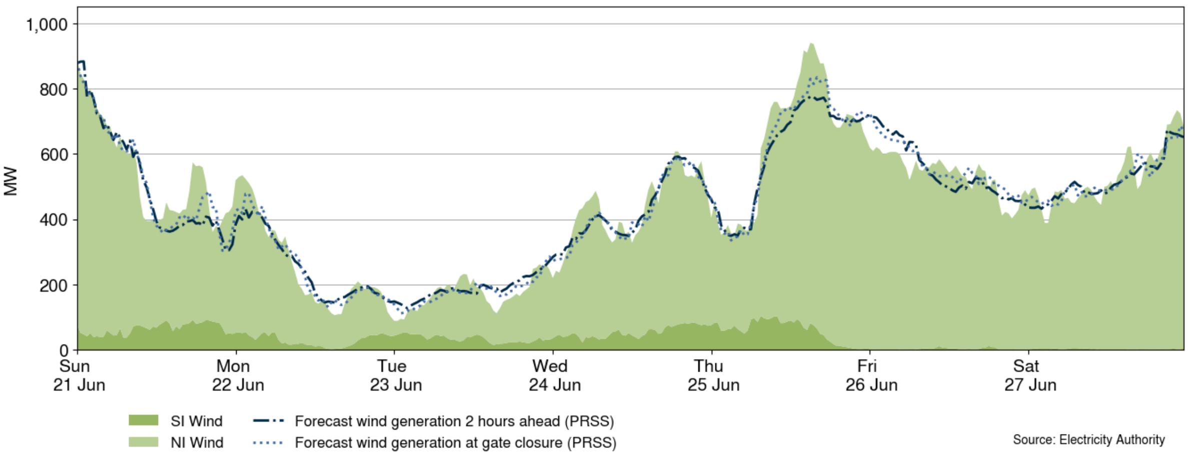
(a) on Sunday night and Monday morning were mainly a result of forecasting errors at Mill Creek, Tararua, Te Āpiti, and Turitea wind farms.

(b) on Thursday resulted from an amalgamation of errors at many wind farms.

(c) on Friday and Saturday were mainly a result of forecasting errors at Waipipi and Te Uku.

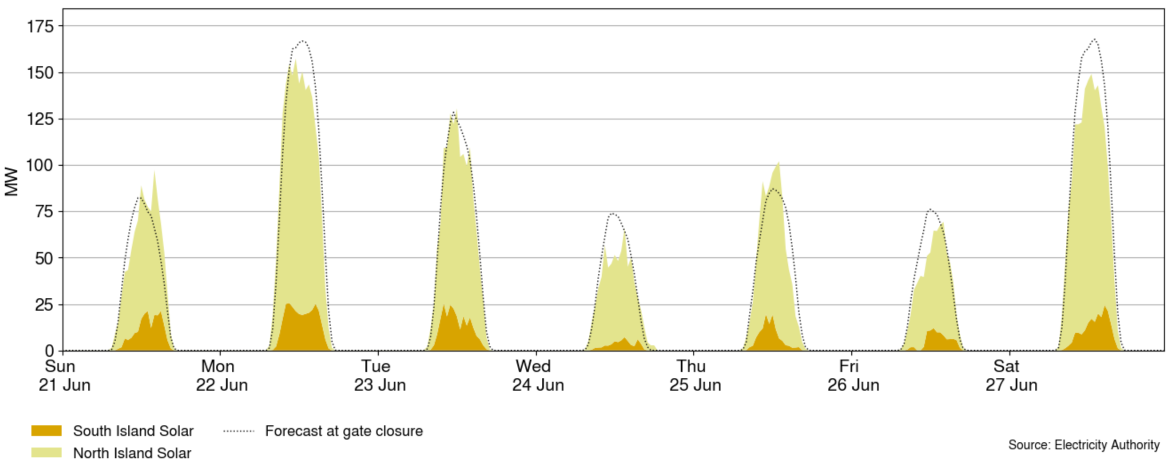
7.3. During times of high winds, which could have damaged the turbines, Meridian offered all of West Wind's generation at high prices so that turbines would only be turned on if the generation was needed.

Figure 9: Wind generation and forecast, 21-27 June 2026



7.4. Figure 10 shows grid connected solar generation from 21-27 June 2026. Solar generation varied throughout the week, peaking at 157MW on Monday, but only reaching 66MW on Wednesday.

Figure 10: Grid connected solar generation, 21-27 June 2026

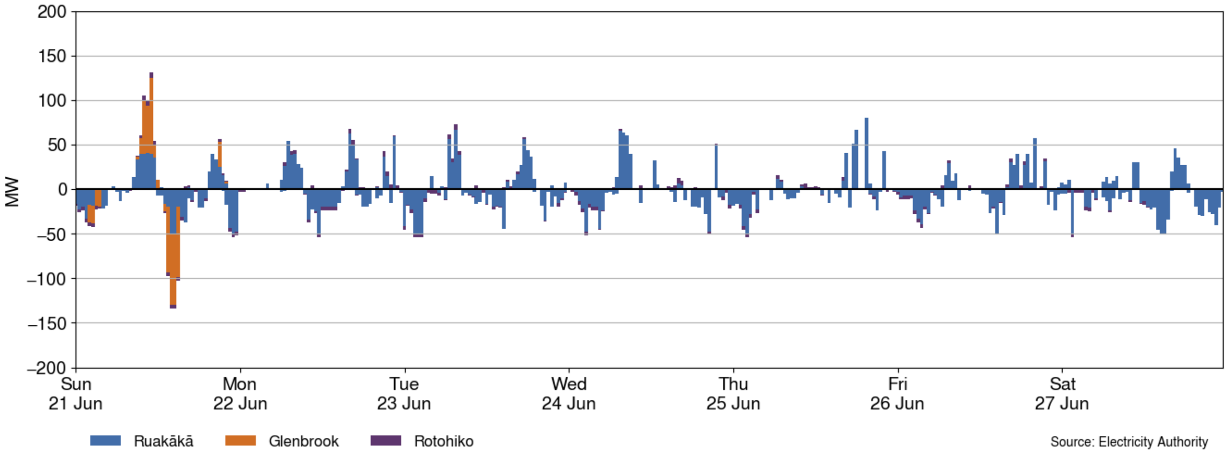


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are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

7.6. Glenbrook battery was on outage from Monday onwards.

7.7. This week, the batteries generally charged when prices were lower, and discharged when prices were higher. On weekdays, the batteries generally charged when prices were below ~$80/MWh, and discharged when prices were above ~$80/MWh. On weekends, the batteries generally changed when prices were below ~$20/MWh, and discharged when prices were above ~$20/MWh.

Figure 11: Grid scale battery charge and discharge, 21-27 June 2026



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.

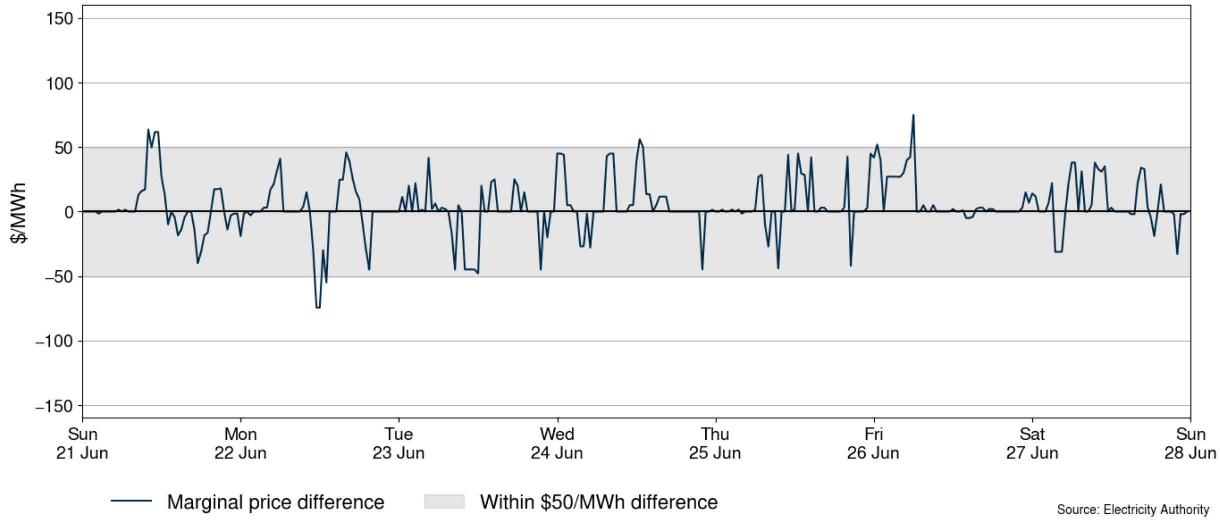
7.9. There were a few periods with a marginal price difference over $50/MWh.

7.10. The maximum positive difference of $75/MWh occurred on Friday at 6.00am. At this time, demand was 80MW above forecast, and wind generation was 98MW below forecast.

7.11. The maximum negative difference of $75/MWh occurred on Monday at 11.30am. At this time, demand was 86MW below forecast, and wind generation was 1MW below forecast.

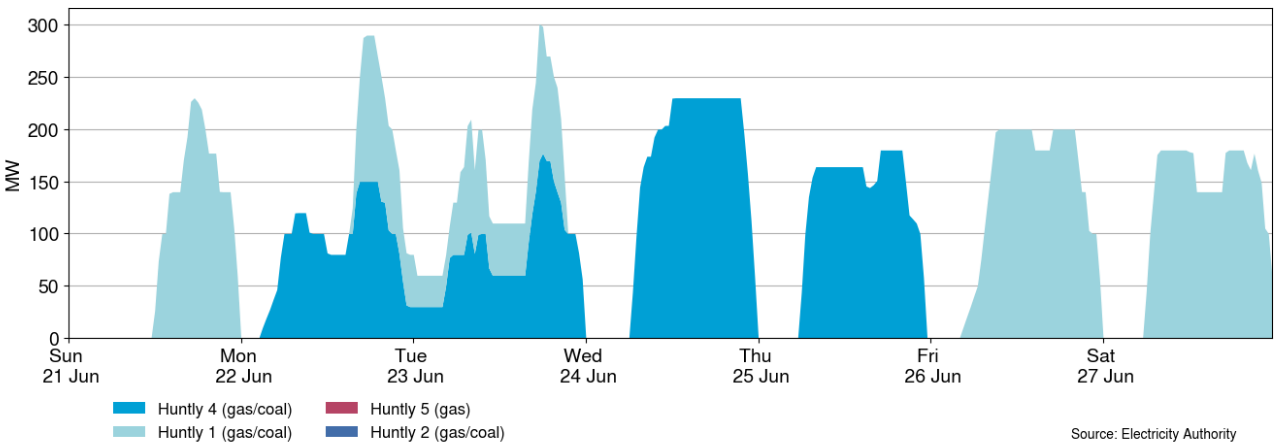
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 21-27 June 2026



7.12. Figure 13 shows the generation of thermal baseload between 21-27 June 2026. Huntly 1 ran at times from Sunday to Tuesday and on Friday and Saturday, while Huntly 4 ran continuously on Monday and Tuesday and at times on Wednesday and Thursday.

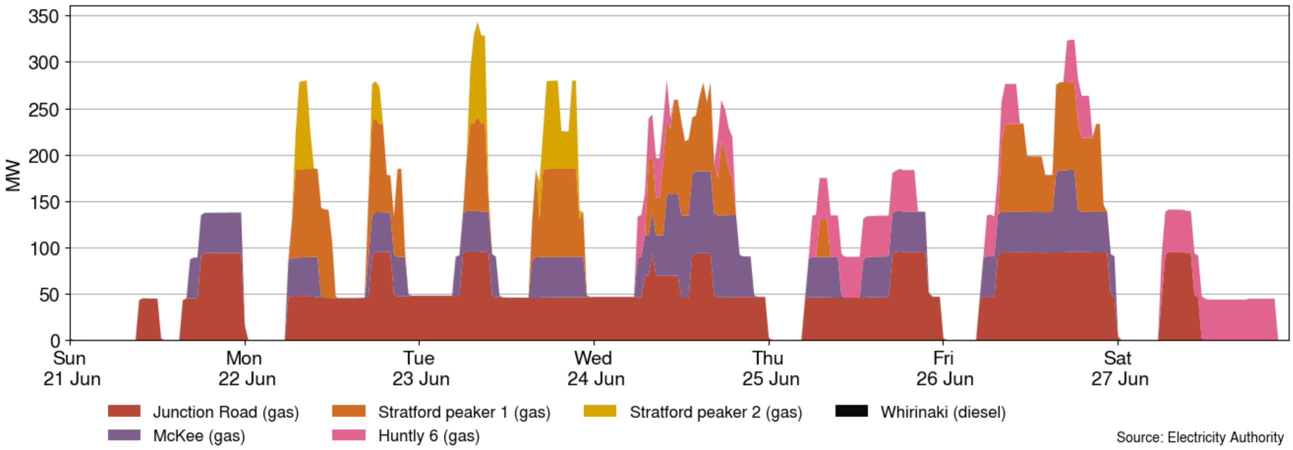
Figure 13: Thermal baseload generation, 21-27 June 2026



7.13. Figure 14 shows the generation of thermal peaker plants between 21-27 June 2026. Junction Road ran at times every day this week, while McKee ran at times every day except for Saturday. The Stratford peakers ran at times every day this week, while Huntly 6 ran at times from Thursday to Saturday.

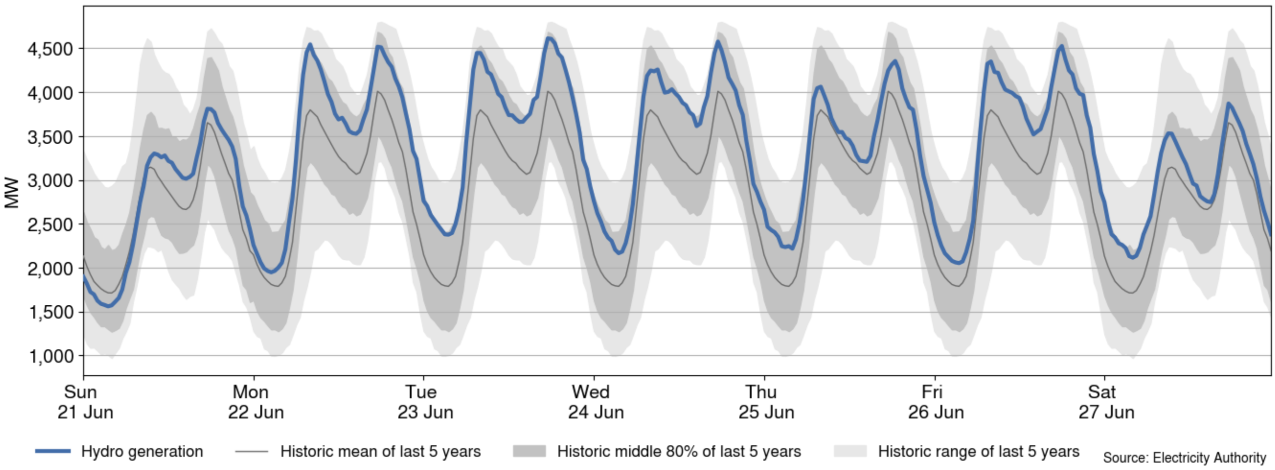
7.14. On Wednesday, the Stratford peakers varied the amount of energy priced between $0-0.99/MWh throughout the day. The monitoring team is looking into these offers further.

Figure 14: Thermal peaker generation, 21-27 June 2026



7.15. Figure 15 shows hydro generation between 21-27 June 2026. Hydro generation has been above the historic mean for most of the week.

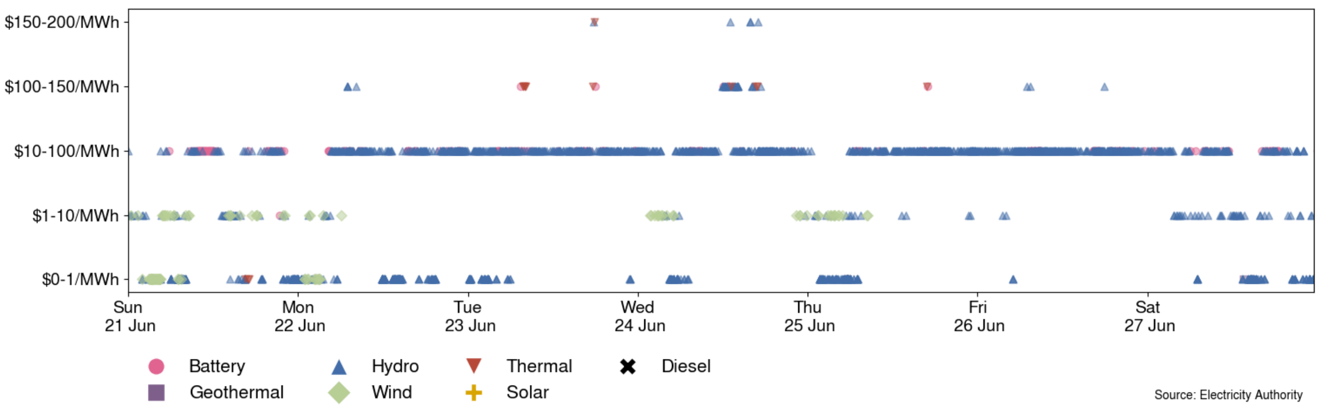
Figure 15: Hydro generation, 21-27 June 2026



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.

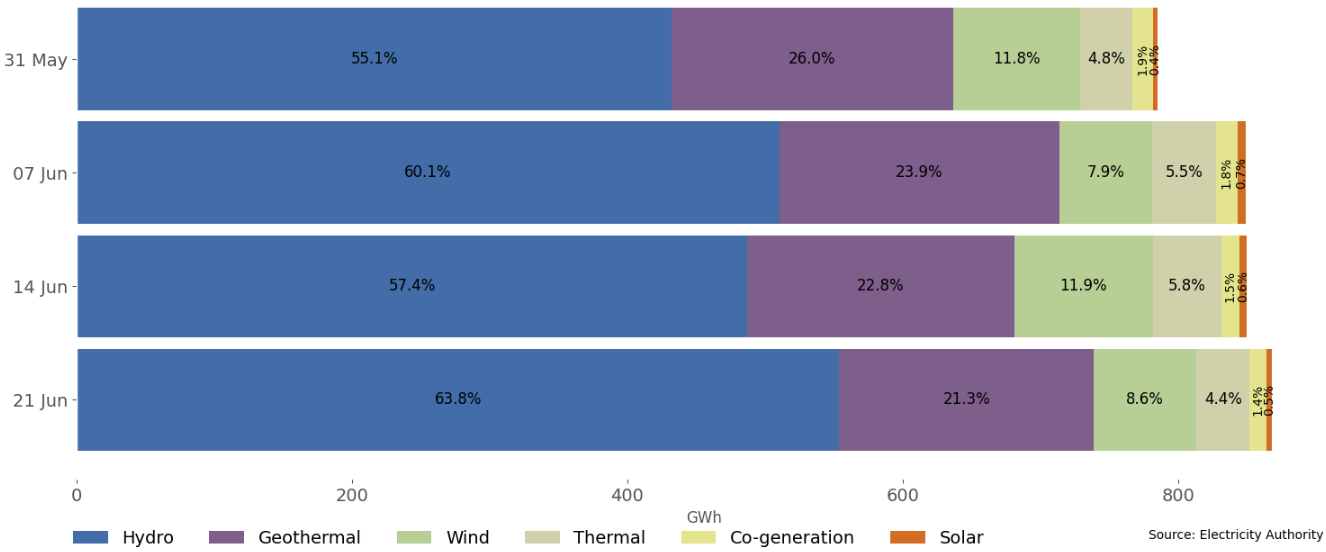
7.17. The highest prices were set by Huntly 1. The most common technology setting prices was hydro, with wind the second most common. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 21-27 June 2026



7.18. As a percentage of total generation, between 21-27 June 2026, total weekly hydro generation was 63.8%, geothermal 21.3%, wind 8.6%, thermal 4.4%, co-generation 1.4%, and solar (grid connected) 0.5%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 31 May and 27 June



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 21-27 June 2026 ranged between ~922MW and ~1,704MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 21-27 June 2026

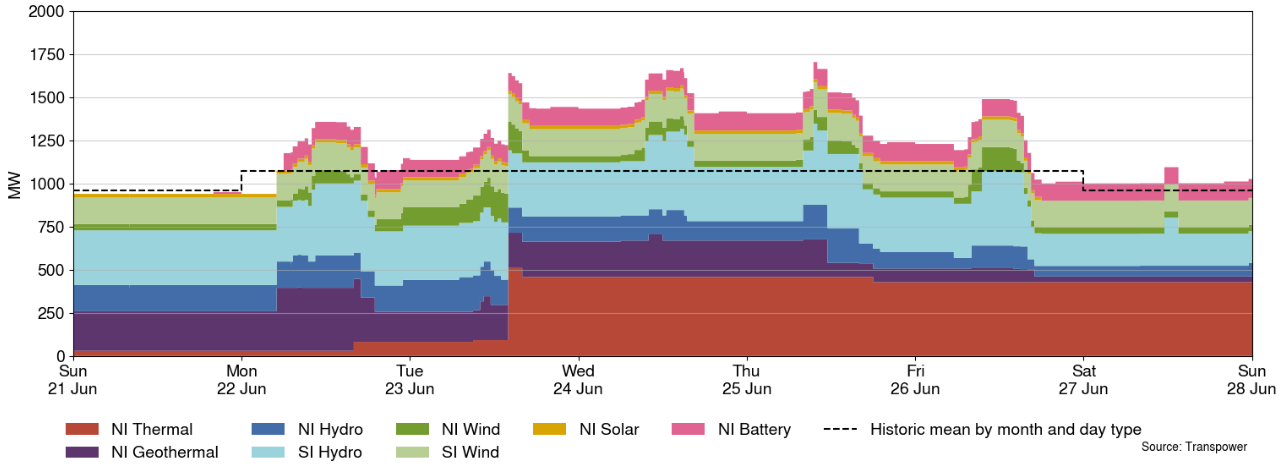
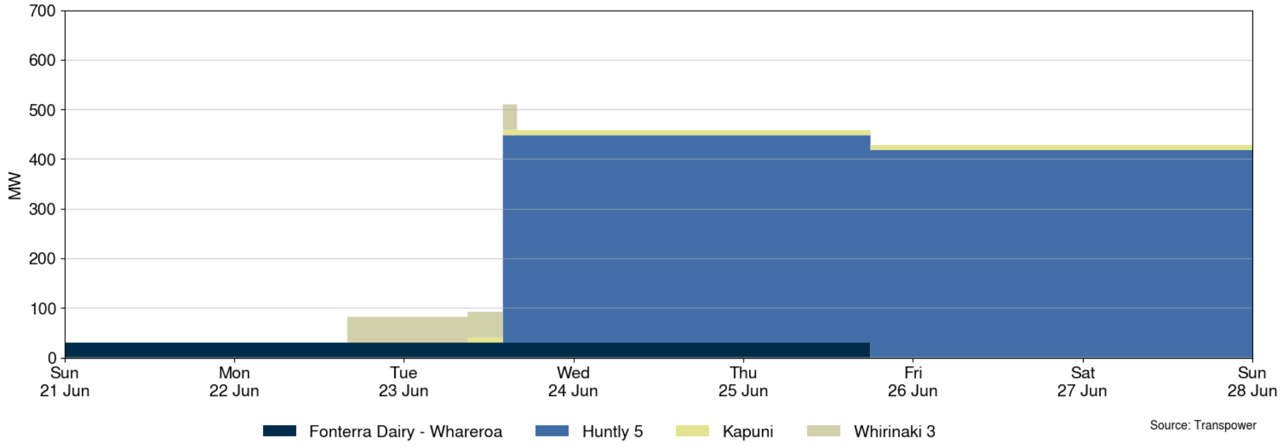


Figure 19: Total MW loss from thermal outages, 21-27 June 2026



8.2. Notable outages include:

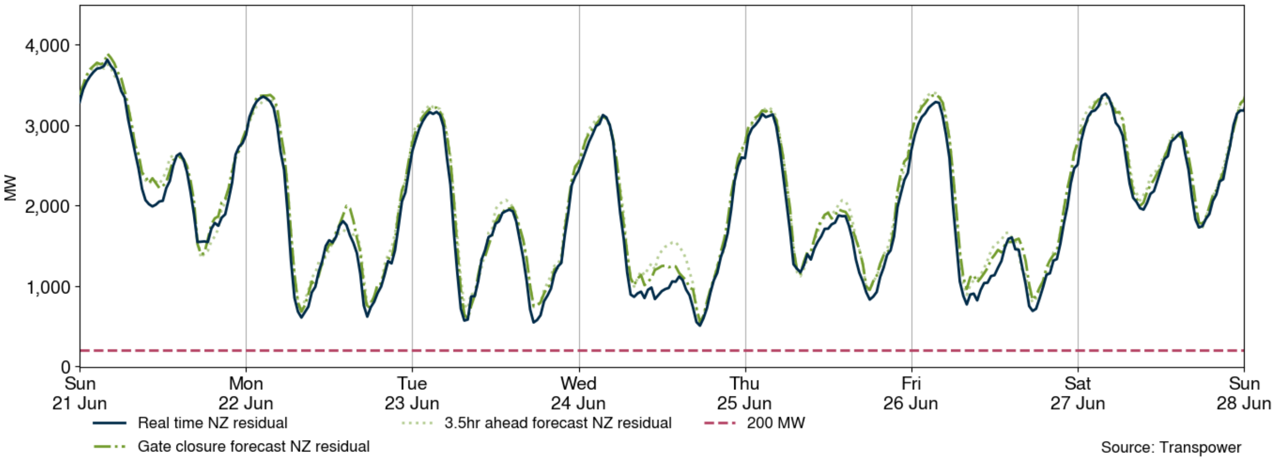
Plant	Partial or Full	End Date
Ngā Awa Pūrua	Full	25 June 2026
Manapōuri unit 2	Full	26 June 2026
Glenbrook	Full	29 June 2026
Huntly 5	Full	30 June 2026
Manapōuri unit 4	Full	8 July 2026
Kaiwera Downs	Full	31 July 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 21-27 June 2026. 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 been healthy this week. The lowest national residual of 507MW occurred at 5.30pm on Wednesday.

Figure 20: National generation balance residuals, 21-27 June 2026



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 27 June, national controlled storage was 90% nominally full and ~130% of the historical average for this time of the year.

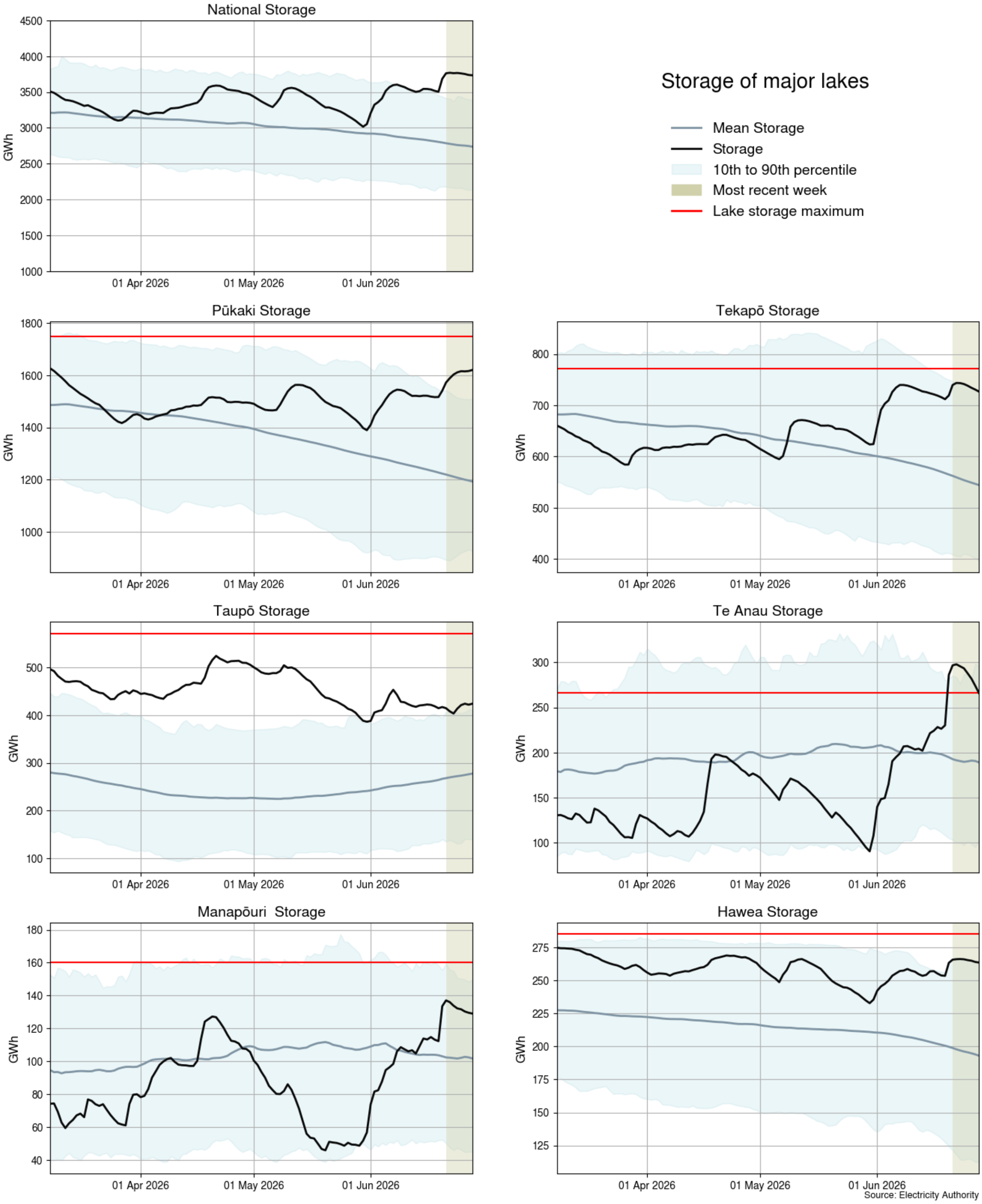
10.3. Storage at Lake Pūkaki (89% full) is above its 90th percentile, while storage at Lake Tekapō (81% full) is at its 90th percentile.

10.4. Storage at Lake Te Anau (100% full) and Lake Manapōuri (82% full) remain well above their historic mean.

10.5. Storage at Lake Taupō (74% full) remains above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (92% 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 June 2026. The SRMCs for gas generation has decreased, with SRMCs for coal and diesel fuelled generation remaining steady.

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

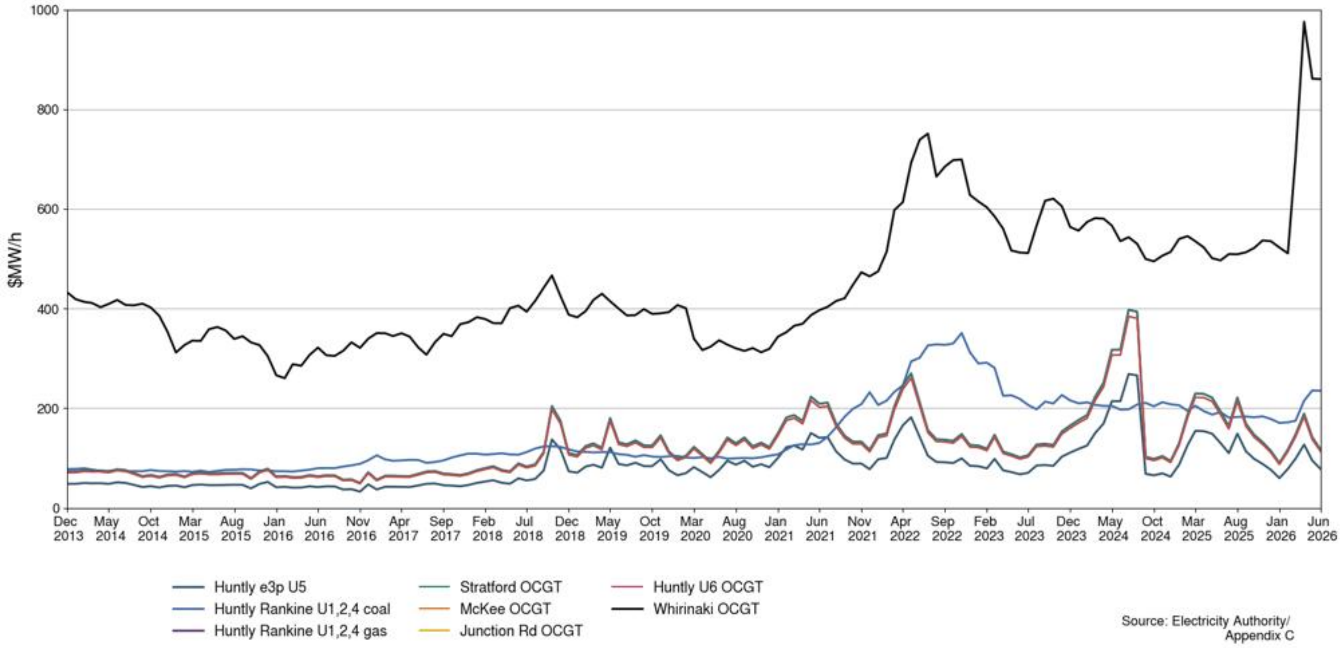
11.5. The SRMC of gas fuelled thermal plants is currently between $78/MWh and $116/MWh.

11.6. The SRMC of Whirinaki is ~$861/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



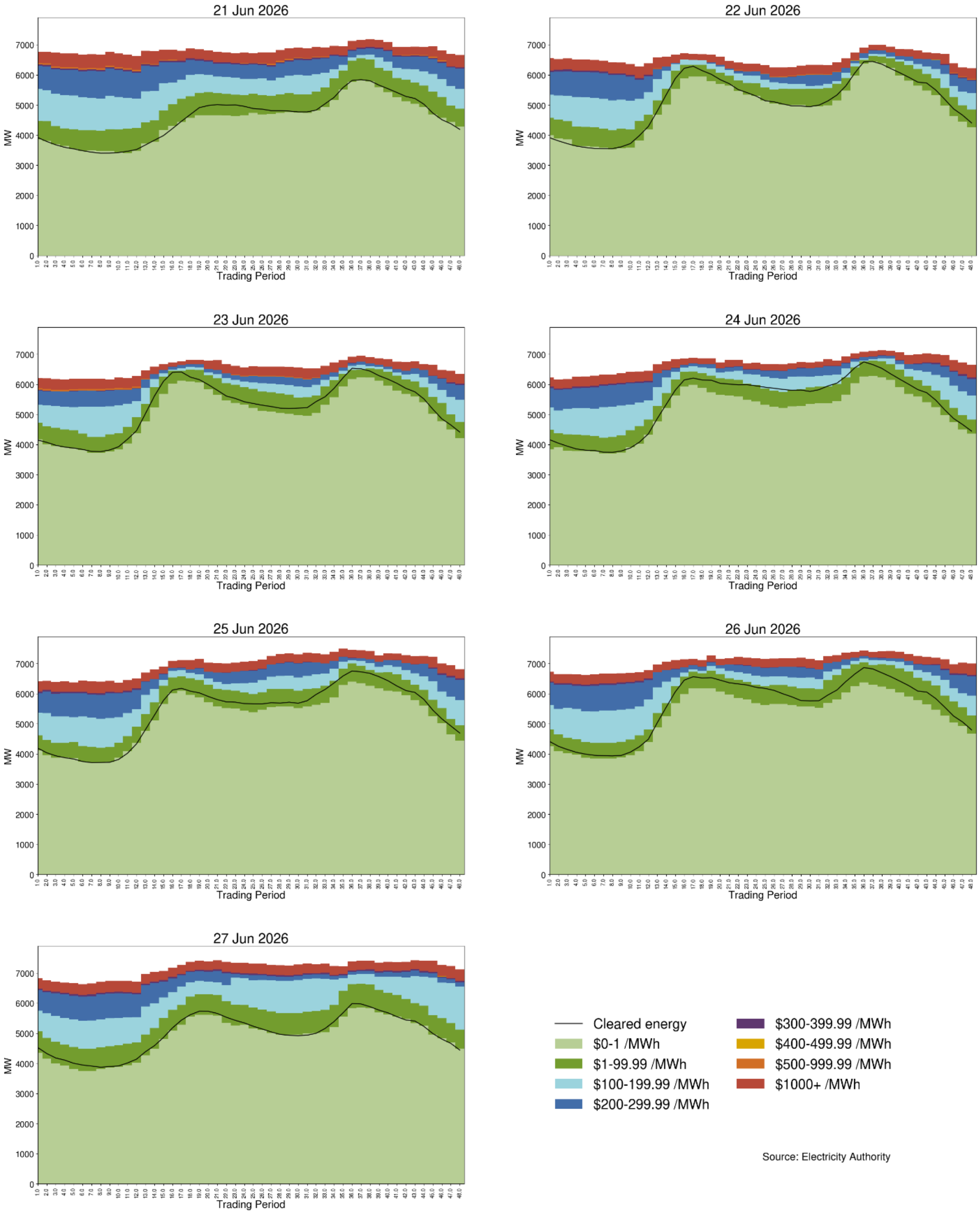
12. Offer behaviour

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. On weekdays during the day, Meridian hydro priced down offers from $100-199/MWh to $0-0.99/MWh, and Mercury hydro priced down offers from $200-299/MWh to $0-0.99/MWh.

12.3. On Saturday from 11am, Mercury hydro priced down offers from $200-299/MWh to $100-199/MWh.

Figure 23: Daily offer stacks

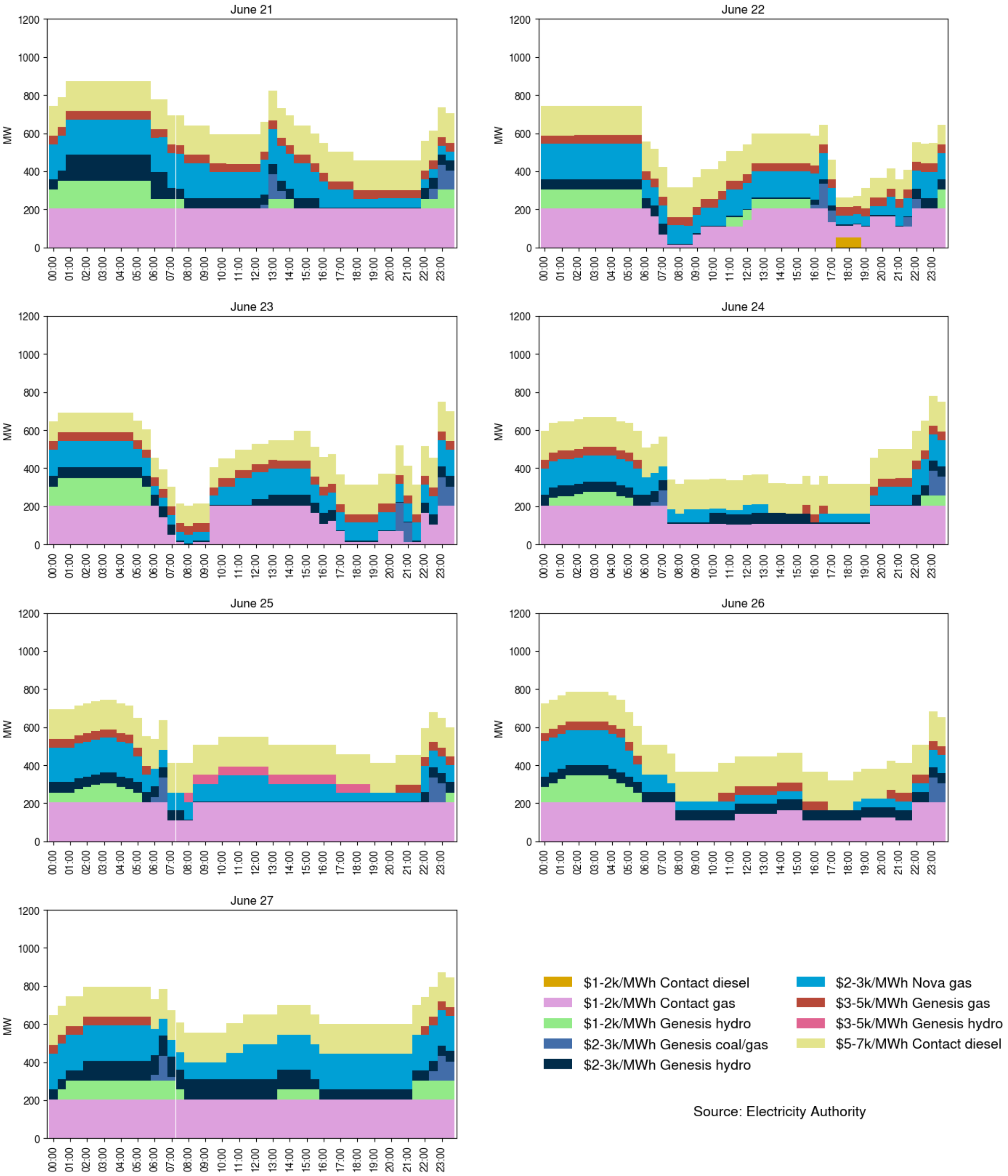


12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.5. 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.

12.6. On average 558MW per trading period was priced above $1,000/MWh this week, which is roughly 10% 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. The monitoring team is looking into Stratford peaker offers this week.

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