7 July 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

# Trading conduct report 29 June – 5 July 2025

Market monitoring weekly report

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## 1. Overview

1.1. The average price decreased by $29/MWh this week to $76/MWh. National hydro storage remains stable at ~68% nominally full and ~102% of the historical average. A few high prices were observed from Tuesday to Thursday, mainly due to lower wind generation and demand and wind forecast errors. Hydro generation increased and wind and thermal generation decreased compared to the previous week.

## 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 29 June – 5 July 2025:

(a) The average spot price for the week was $76/MWh, a decrease of around $29/MWh compared to the previous week.

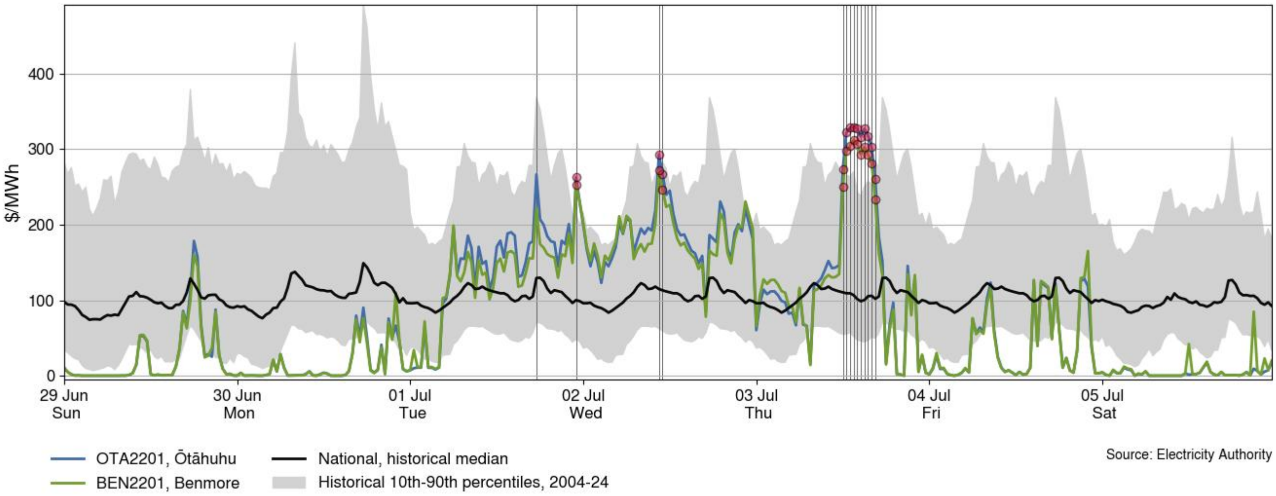
(b) 95% of prices fell between $0.02/MWh and $281/MWh.

2.3. Spot prices on Sunday and Monday were often below $1/MWh but increased from Monday afternoon, likely due to decreasing wind generation, with higher price spikes typically contributed to by wind and/or demand forecast errors.

2.4. Spot prices were elevated from 12.00pm-5.30pm on Thursday due to wind and demand forecast errors which saw higher priced hydro generation dispatched. The highest price of the week occurred on Thursday at 1.30pm, with prices of $329/MWh at Ōtāhuhu and $312/MWh at Benmore. During this time, demand was higher than forecast by 150MW and wind was 82MW lower than forecast.

2.5. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90$^{th}$ percentiles adjusted for inflation. Prices greater than $250/MWh are highlighted with a vertical black line.

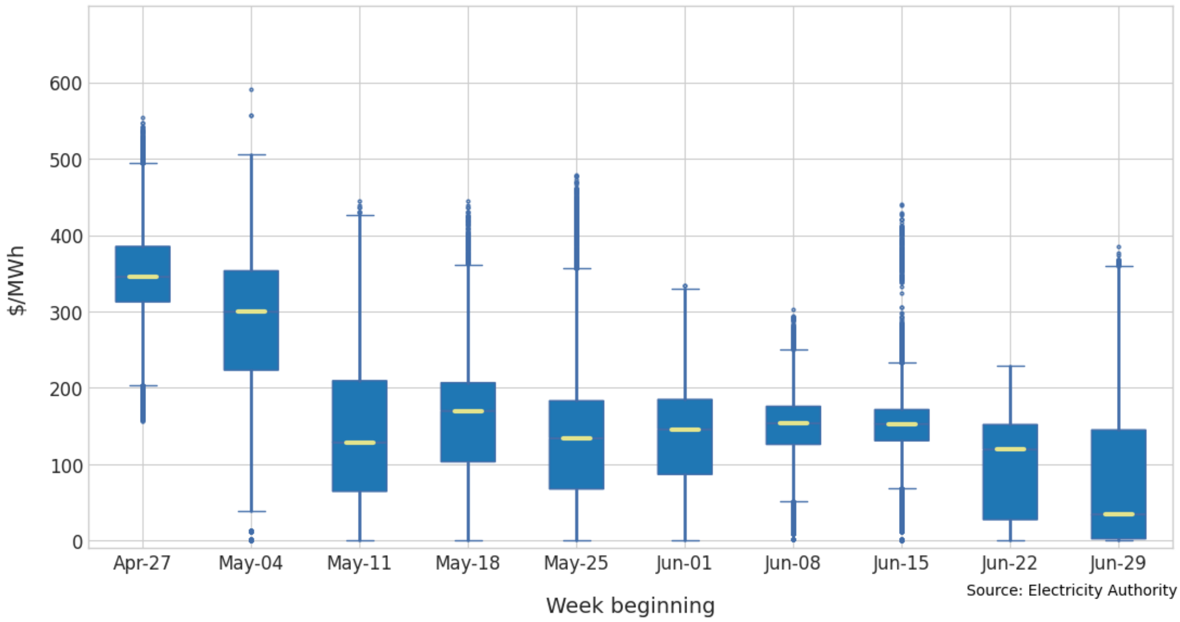
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 29 June – 5 July 2025**




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 wider compared to the previous week, with no significant high-priced outliers. The median price was $34/MWh and most prices (middle 50%) fell between $2/MWh and $145/MWh.

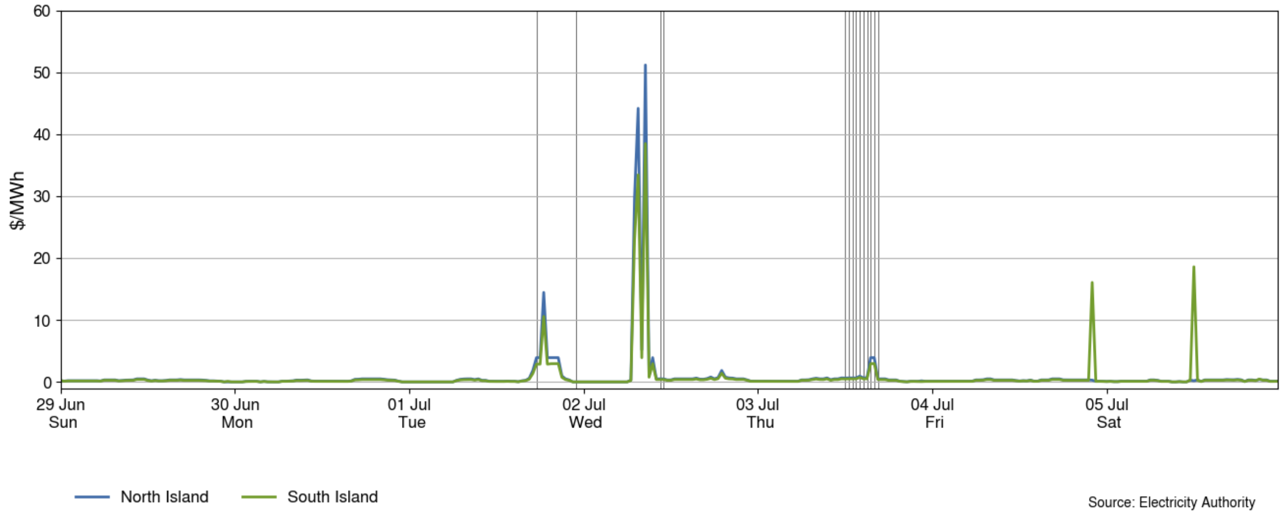
**Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks**



## 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 below $5/MWh with a few spikes. Significant FIR price spikes occurred on Wednesday at 7.30am and 8.30am, with prices reaching around $51/MWh in the North Island and $38/MWh in the South Island. At these times, Huntly 5 was the risk setter, and during co-optimisation cheaper reserve offers were dispatched as energy.

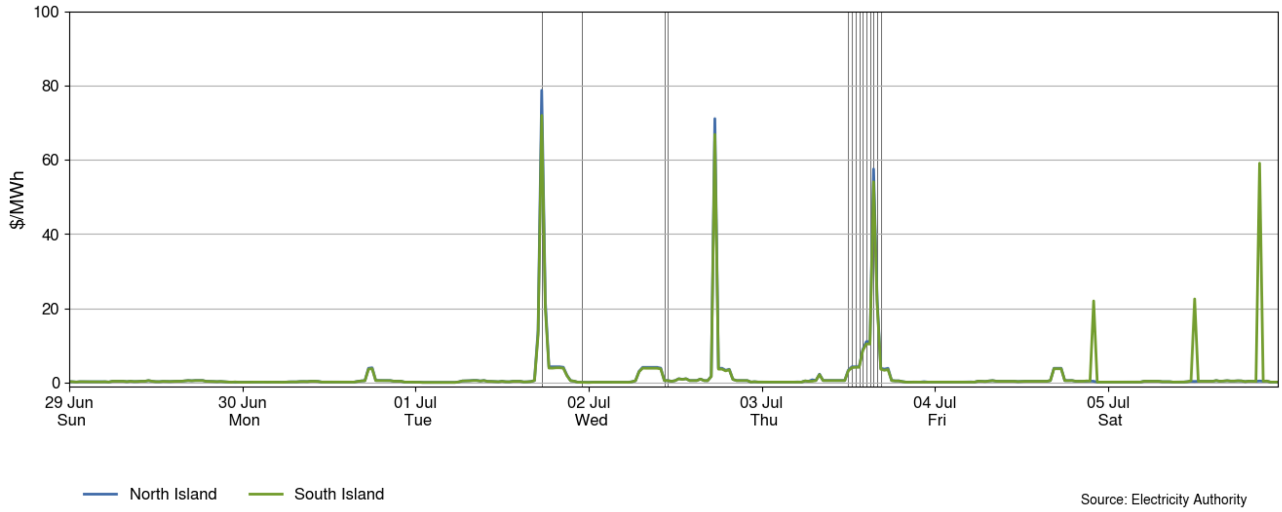
**Figure 3: Fast instantaneous reserve price by trading period and island, 29 June – 5 July 2025**




3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh with a few spikes. The highest SIR price was at 5.30pm on Tuesday with prices of $79/MWh in the North Island and $72/MWh in the South Island. At this time, Huntly 5 was the risk setter, and during co-optimisation cheaper reserve offers were dispatched as energy.

3.3. SIR prices also separated at 9.00pm on Saturday evening when the South Island SIR price was $59/MWh and the North Island SIR price was $0.39/MWh. At this time, the HVDC was contributing to setting the South Island SIR risk.

**Figure 4: Sustained instantaneous reserve by trading period and island, 29 June – 5 July 2025**



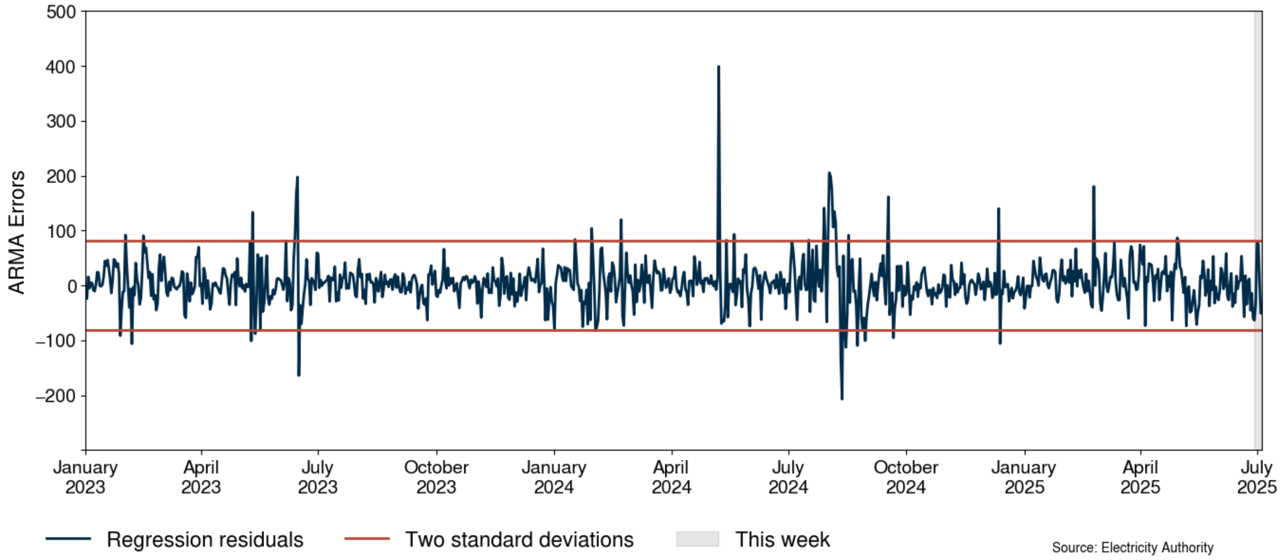
# 4. Regression residuals

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.

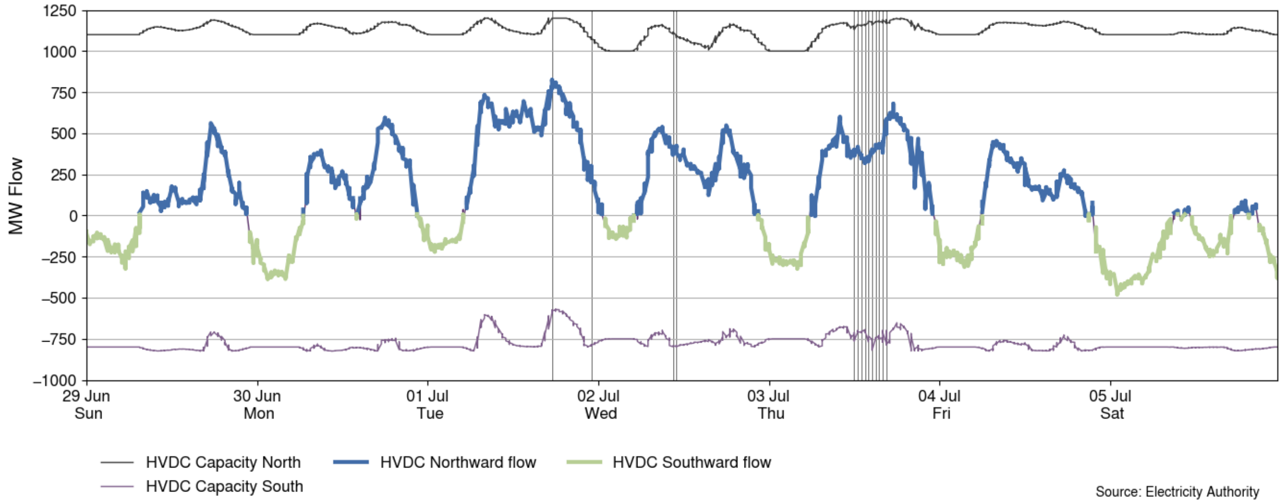
**Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 5 July 2025**




# 5. HVDC

5.1. Figure 6 shows the HVDC flow between 29 June – 5 July 2025. HVDC flows were mostly northward during the day and southward overnight. However, on Saturday, the flow was southward during the day due to higher wind generation. Northward flows reached around 825MW on Tuesday at 5.30pm during the evening demand peak when wind generation was low.

**Figure 6: HVDC flow and capacity, 29 June – 5 July 2025**



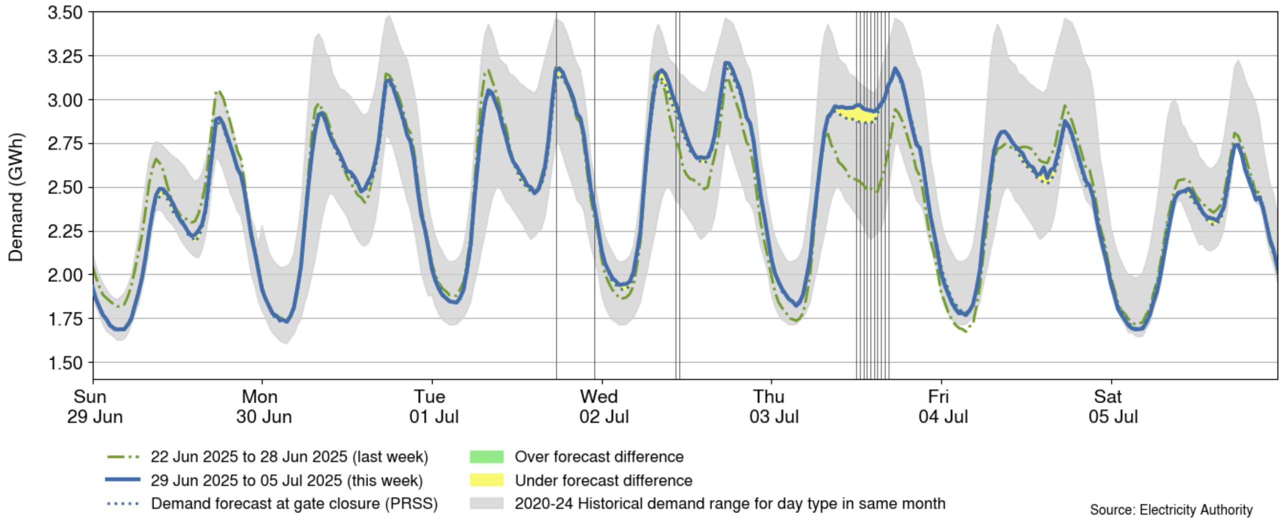

# 6. Demand

6.1. Figure 7 shows national demand between 29 June – 5 July 2025, compared to the historic range and the demand of the previous week. At the start of the week, demand was similar to last week. On Wednesday and Thursday demand was higher than the previous week.

6.2. The highest demand of the week was 3.21GWh at 5.30pm on Wednesday.

6.3. On Thursday, demand was 112MW-195MW higher than forecast between 10.00am-2.30pm.

**Figure 7: National demand, 29 June – 5 July 2025 compared to the previous week**

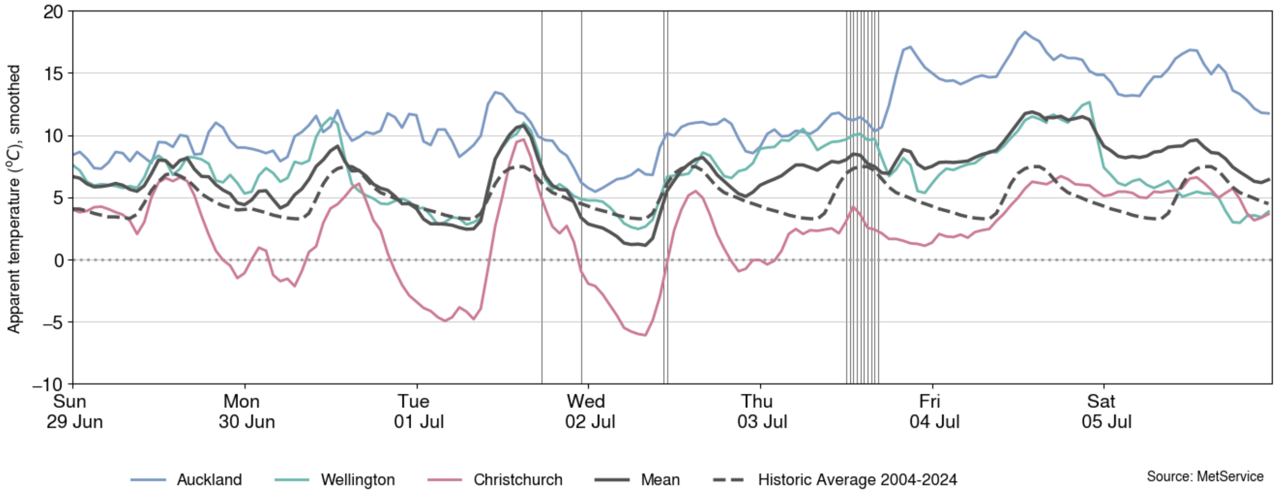



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 29 June – 5 July 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean 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. Christchurch experienced freezing mornings at the start of the week. Wellington temperatures were mostly steady, and Auckland temperatures increased from Thursday afternoon.

6.6. Apparent temperatures ranged from 5°C to 18°C in Auckland, 2°C to 13°C in Wellington, and -6°C to 10°C in Christchurch.

**Figure 8: Temperatures across main centres, 29 June – 5 July 2025**

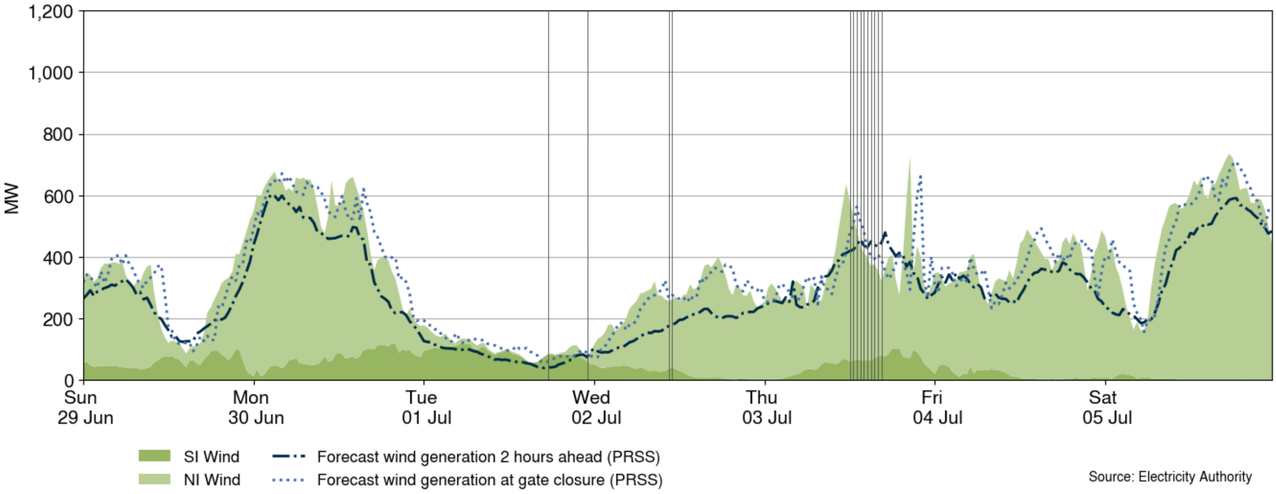



# 7. Generation

7.1. Figure 9 shows wind generation and forecast from 29 June – 5 July 2025. This week wind generation varied between 54MW and 735MW, with a weekly average of 345MW. Wind generation was relatively low throughout the week, contributing to elevated prices at times. On Tuesday, wind was mostly low (below 180MW), with a minimum of 54MW at 3.00pm.

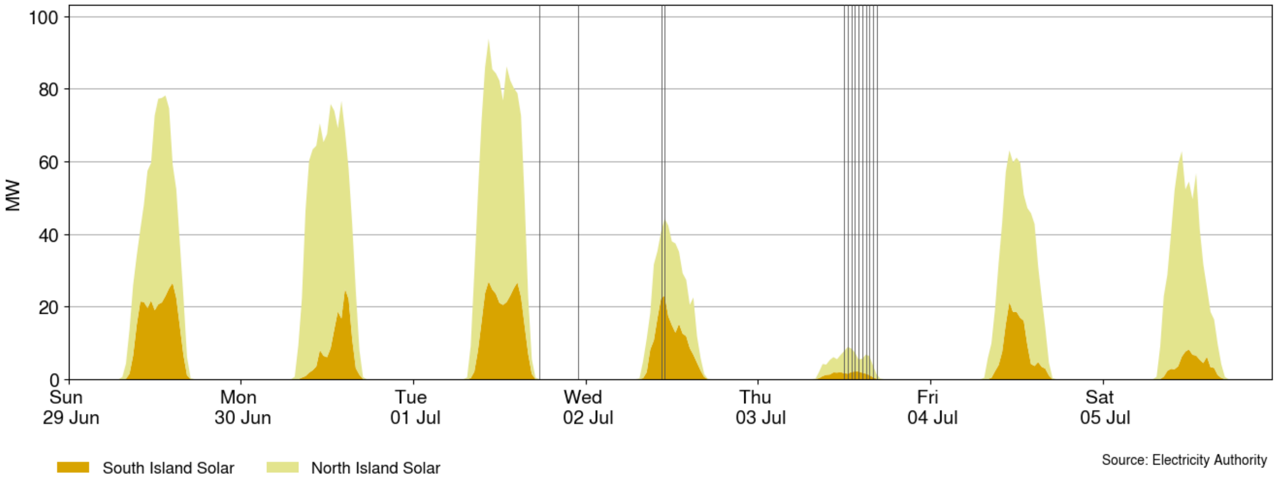
7.2. Wind generation increased sharply to 728MW at 8.30pm on Thursday evening and was 434MW higher than forecast. Wind generation then fell quickly to 400MW and 261MW lower than forecast at 10.00pm.

**Figure 9: Wind generation and forecast, 29 June – 5 July 2025**



7.3. Figure 10 shows grid connected solar generation from 29 June – 5 July 2025. Solar generation was lowest on Thursday. Except for Wednesday and Thursday, solar generation typically peaked above 50MW, with a maximum of 94MW at 10.30am on Tuesday.

**Figure 10: Grid connected solar generation, 29 June – 5 July 2025**

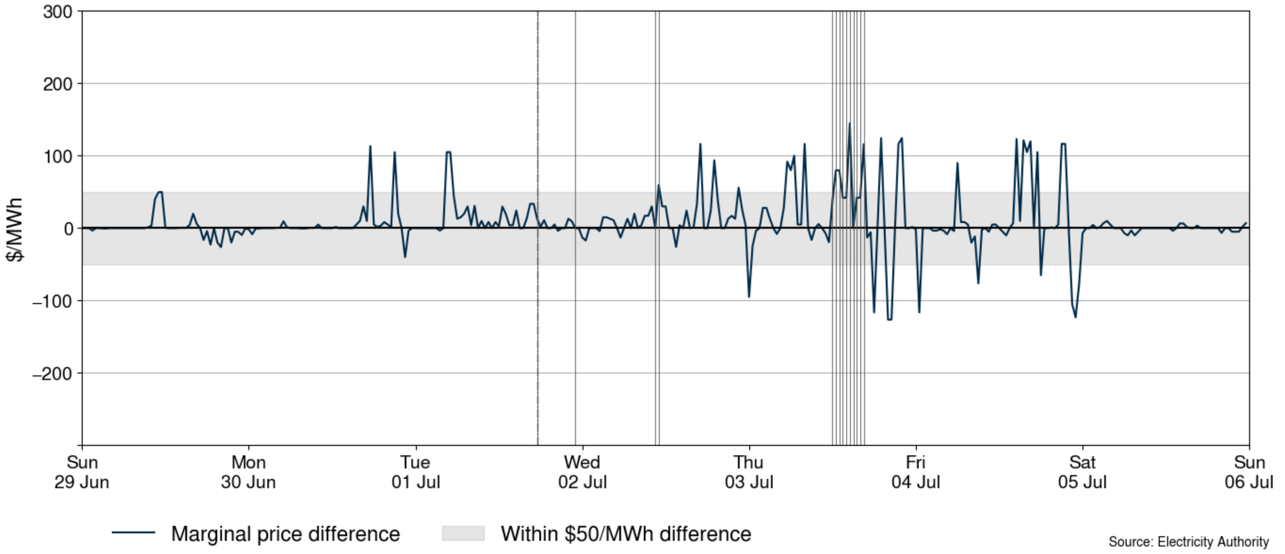



7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

7.5. A few trading periods between Monday and Friday had positive marginal price differences which were driven by wind and demand forecasting errors. The largest positive price difference of +$145/MWh occurred at 2.30pm on Thursday when demand was over 133MW higher than forecast, and wind was 26MW lower than expected.

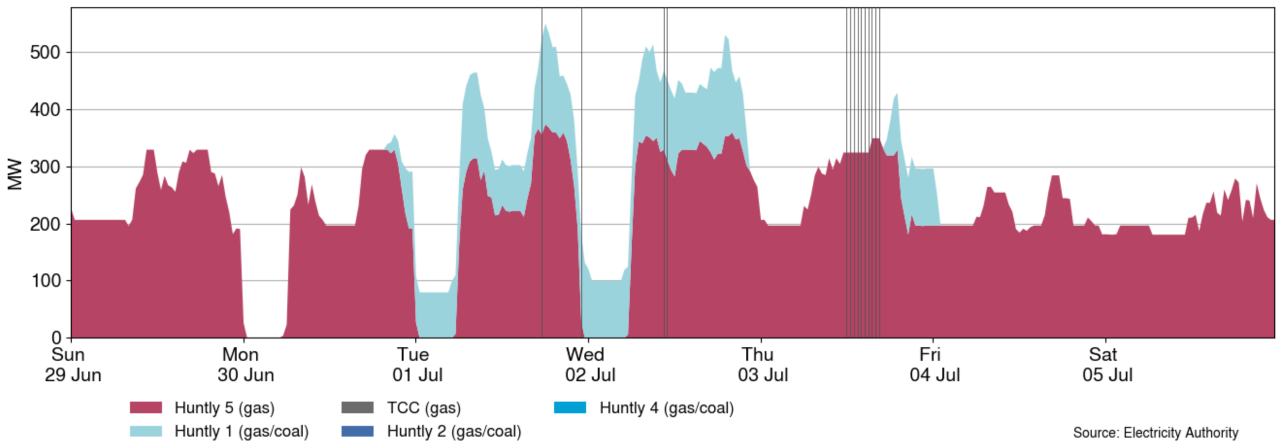
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

**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, 29 June – 5 July 2025**



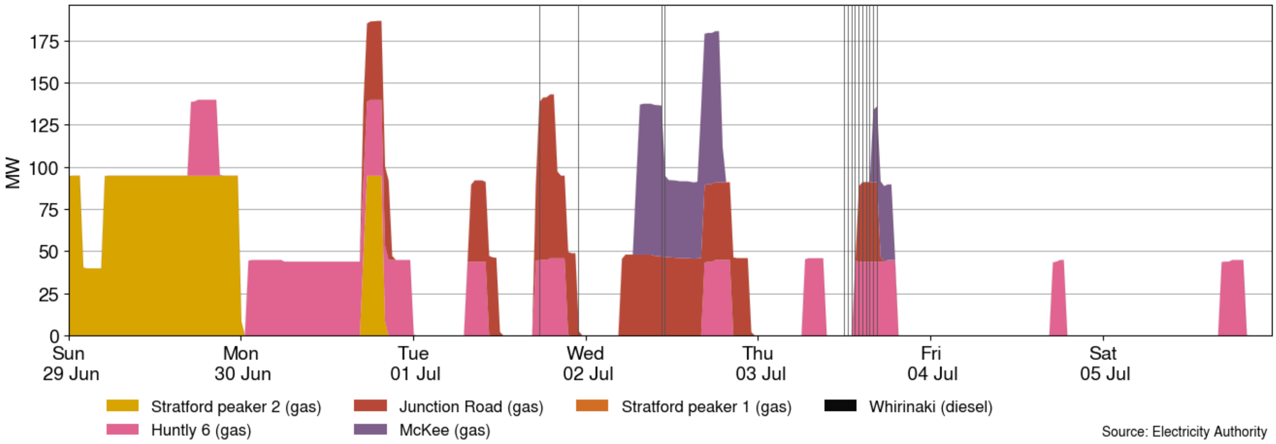

7.6. Figure 12 shows the generation of thermal baseload between 29 June – 5 July 2025. Huntly 5 ran as baseload this week, turning off overnight from Sunday to Tuesday. Huntly 1 ran between Monday and Thursday.

**Figure 12: Thermal baseload generation, 29 June – 5 July 2025**




7.7. Figure 13 shows the generation of thermal peaker plants between 29 June – 5 July 2025. Junction Road ran between Monday and Thursday during peak periods, and on Wednesday for the whole day. Huntly 6 ran daily during most peak periods, and continuously on Monday. Stratford peaker 2 ran on Sunday and on Monday during the evening peak. McKee ran on Wednesday and on Thursday during the evening peak.

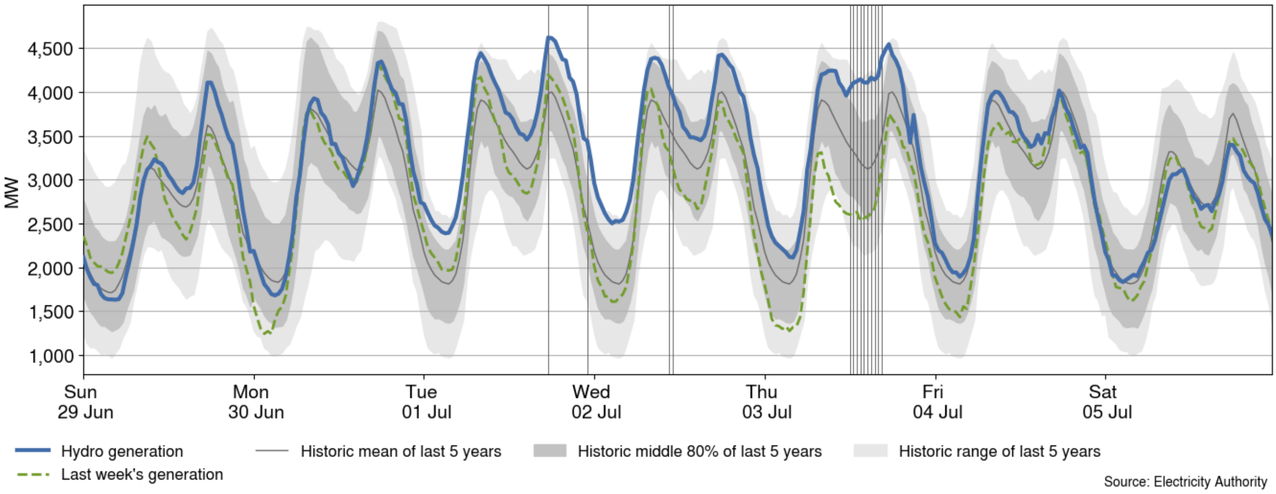
**Figure 13: Thermal peaker generation, 29 June – 5 July 2025**




7.8. Figure 14 shows hydro generation between 29 June – 5 July 2025. Overall, hydro generation was high compared to the previous week and higher overnight during off-peak periods. Between Tuesday and Thursday, hydro generation was higher than the historic mean.

7.9. Hydro generation was high during the day on Thursday when demand was higher than forecast.

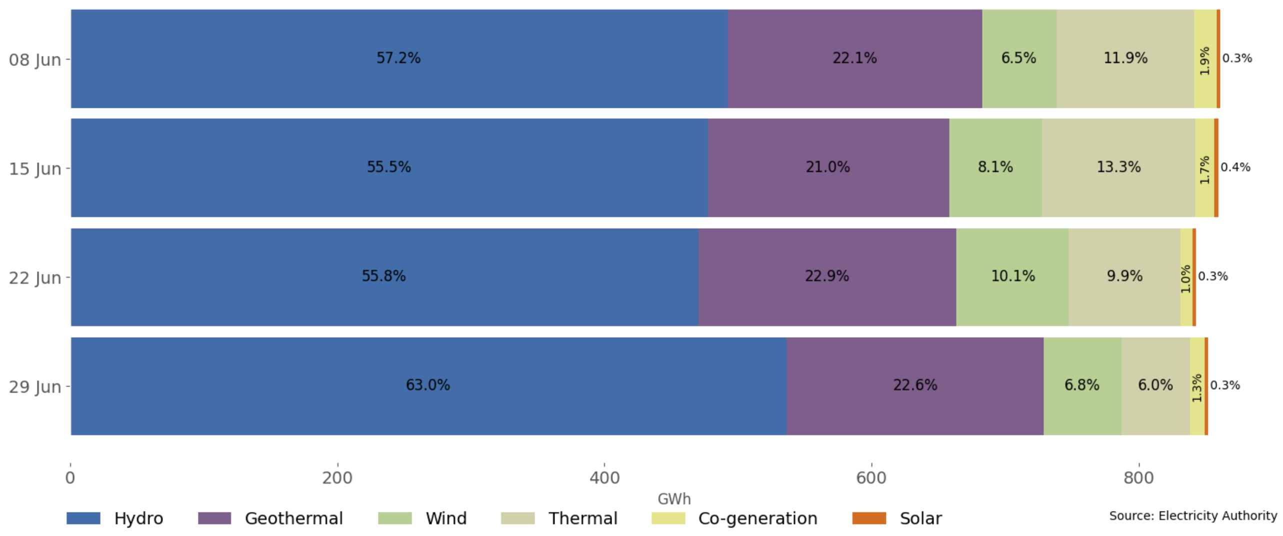
**Figure 14: Hydro generation, 29 June – 5 July 2025**




7.10. As a percentage of total generation, between 29 June – 5 July 2025, total weekly hydro generation was 63.0%, geothermal 22.6%, wind 6.8%, thermal 6.0%, co-generation 1.3%, and solar (grid connected) 0.3%, as shown in Figure 15.

7.11. Hydro generation increased significantly in the last week, making up for lower wind and thermal generation.

**Figure 15: Total generation by type as a percentage each week, between 8 June 2025 and 5 July 2025**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 29 June – 5 July 2025 ranged between ~691MW and ~1,981MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford peaker 1 is on outage until 31 July 2025.

(b) Huntly 4 outage was extended until 4 July 2025.

(c) Huntly 2 was on outage until 1 July 2025.

(d) TCC was on outage on 2 July between 7.00am and 4.00pm.

(e) Manapōuri unit 2 was on outage between 2-3 July 2025.

(f) Manapōuri unit 4 is on outage until 12 June 2026.

(g) Clyde unit 2 was on outage between 1-2 July. Clyde unit 4 was also on outage on 2 July between 12.00pm-5.00pm.

(h) Ruakākā battery outage has been extended to end on 11 July 2025.

**Figure 16: Total MW loss from generation outages, 29 June – 5 July 2025**

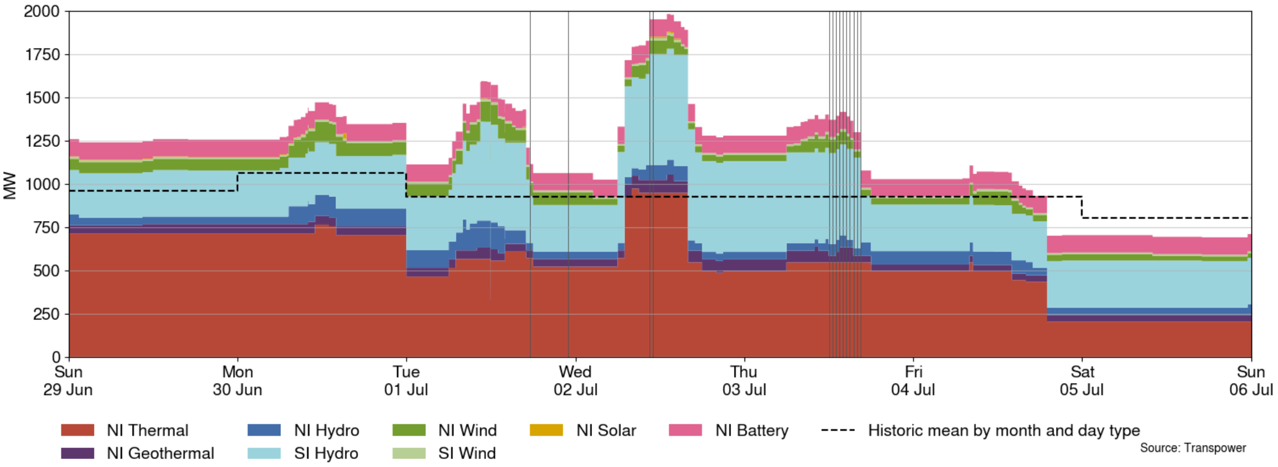
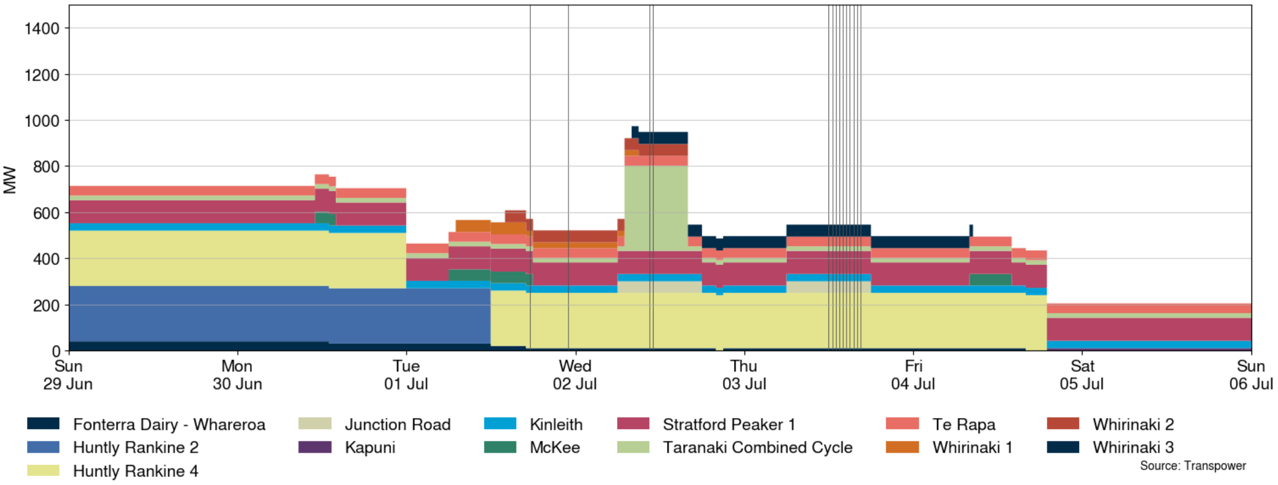



**Figure 17: Total MW loss from thermal outages, 29 June – 5 July 2025**

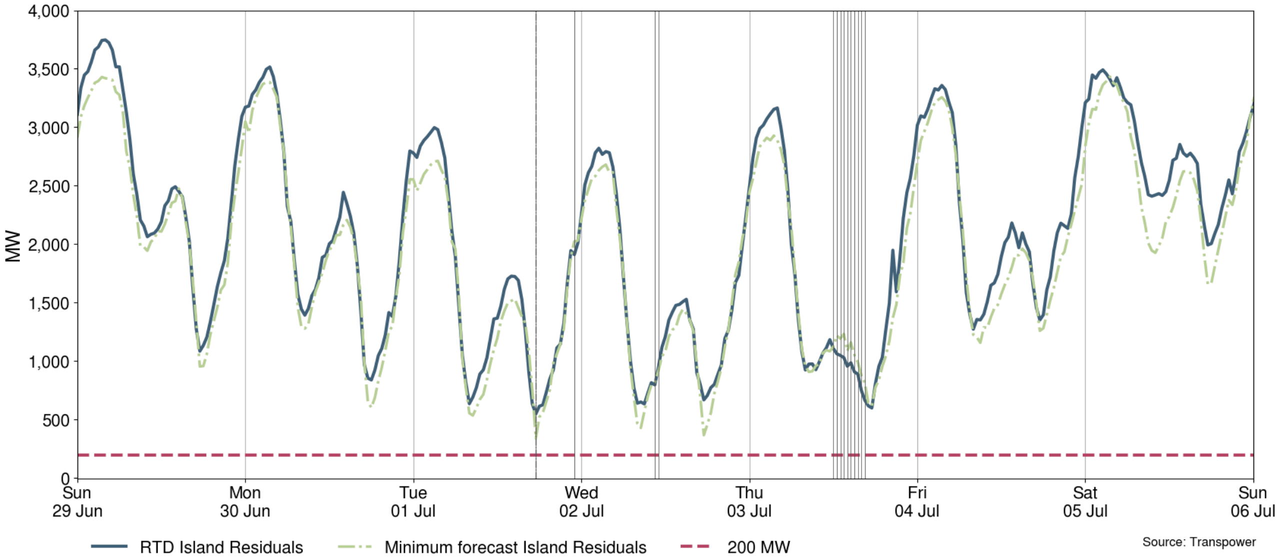



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 29 June – 5 July 2025. 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. Residuals were healthy this week. The lowest national residual was 549MW on Tuesday at 5.30pm.

Figure 18: National generation balance residuals, 29 June – 5 July 2025




# 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. As of 5 July 2025, national controlled storage was 68% nominally full and ~102% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (62% full)[2] and Lake Takapō (46% full) is between their respective historic means and 10th percentiles.

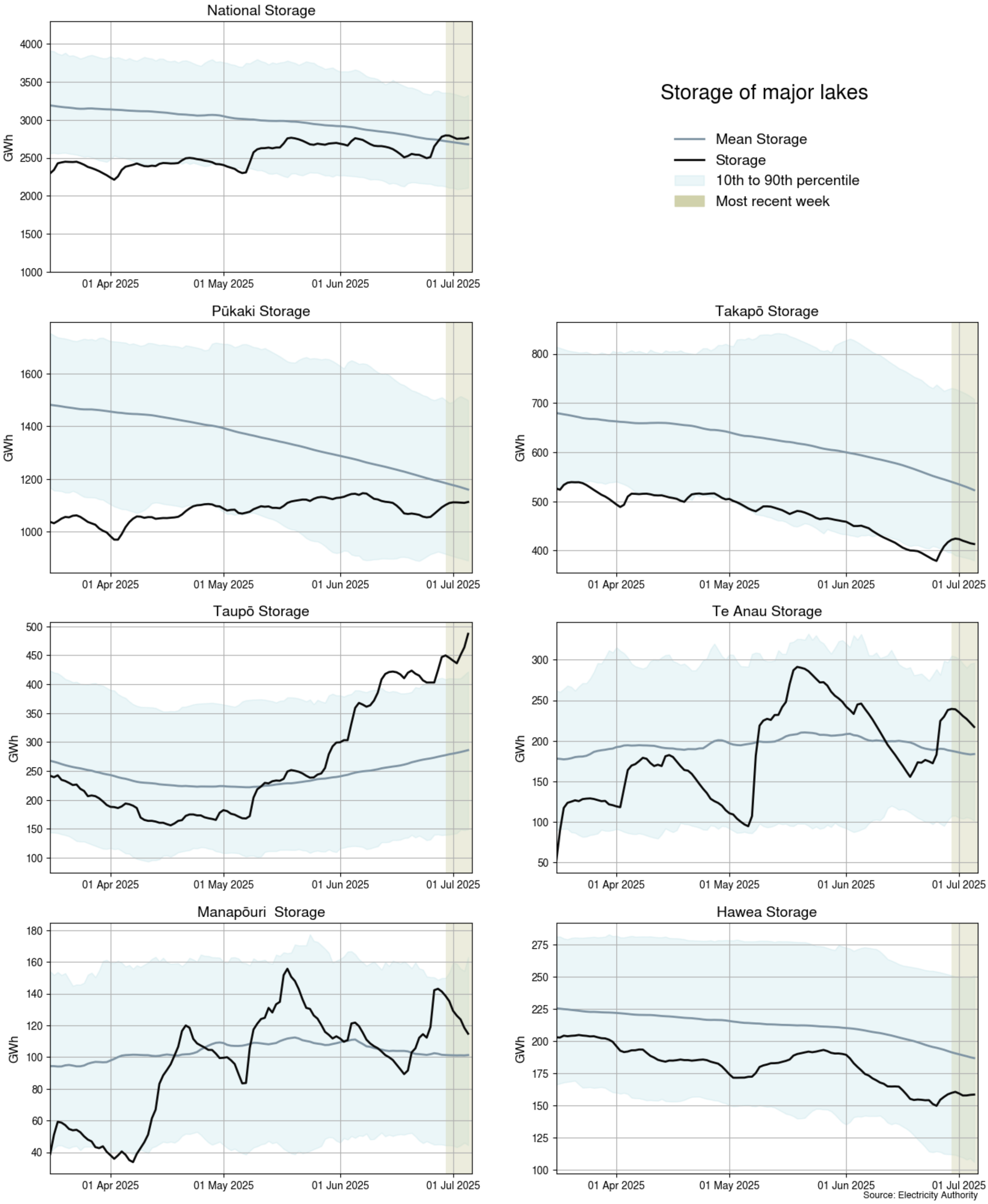
10.4. Storage at lakes Te Anau (79% full) and Manapōuri (70% full) decreased during the week. Both lakes remain above their historical means.

10.5. Storage at Lake Taupō (86% full) increased and remains above its 90th percentile.

10.6. Storage at Lake Hawea (56% full) remains between its historical 10th percentile and mean.

[2] Percentage full values sourced from NZX hydrological summary 7 July 2025.

**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 June 2025. The SRMCs for gas powered generation have decreased slightly while coal and diesel fuelled generation slightly increased.

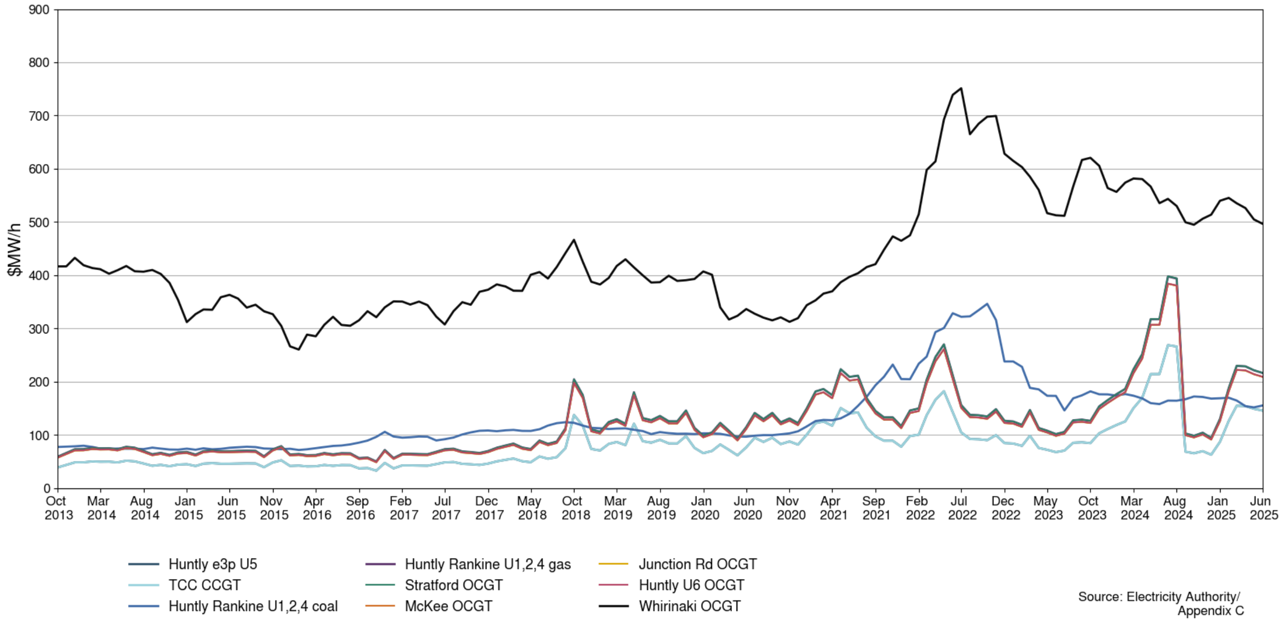
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$155/MWh. The cost of running the Rankines on gas is ~$216/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $145/MWh and $216/MWh.

11.6. The SRMC of Whirinaki is ~$496/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**

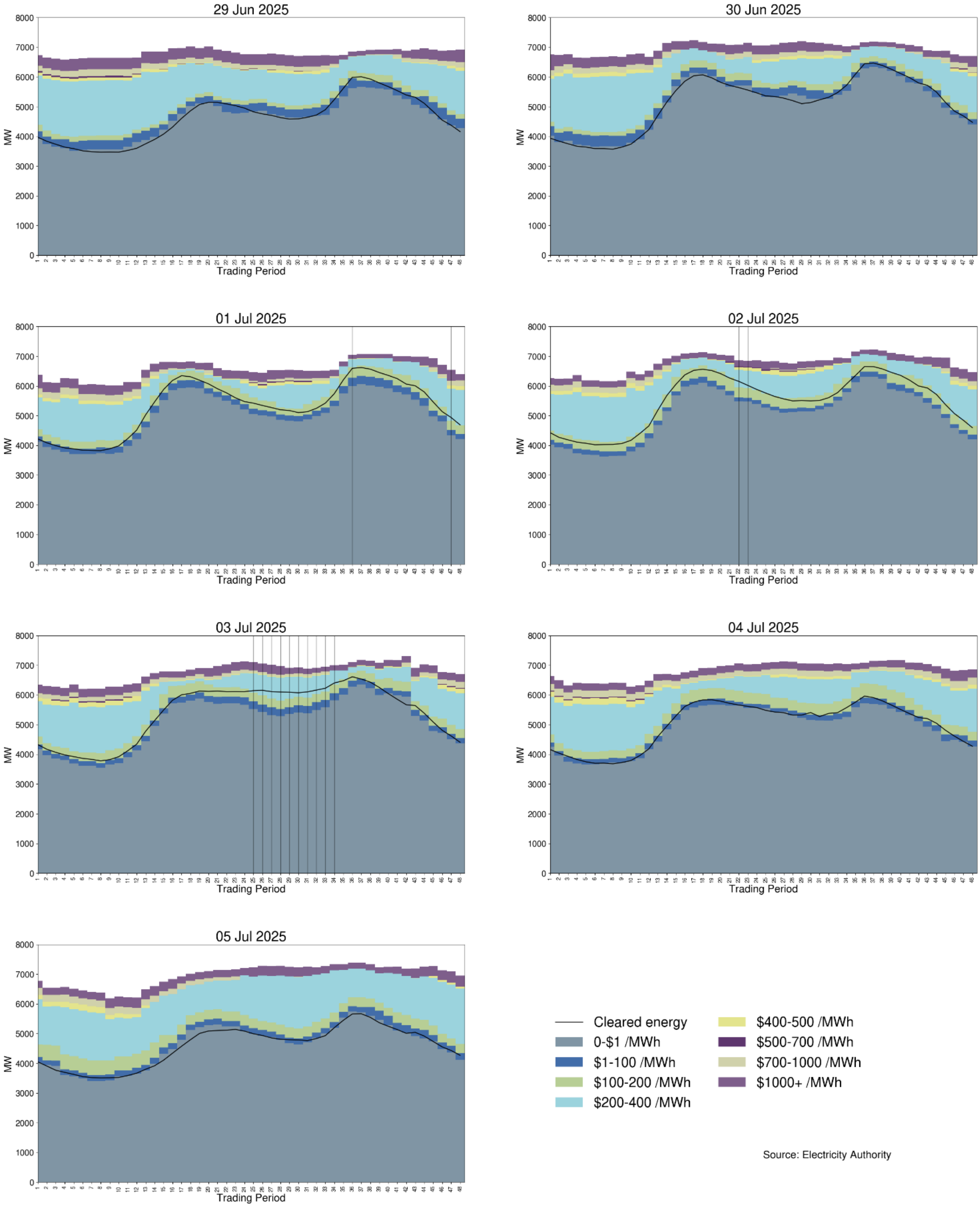



# 12. Offer behaviour

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. This week most offers cleared in the $1-$200/MWh range. The volume of offers in the $200-$400/MWh range remains notably high. On Thursday afternoon, energy cleared into the $200-400/MWh band due to demand and wind forecast errors.

**Figure 21: Daily offer stacks**

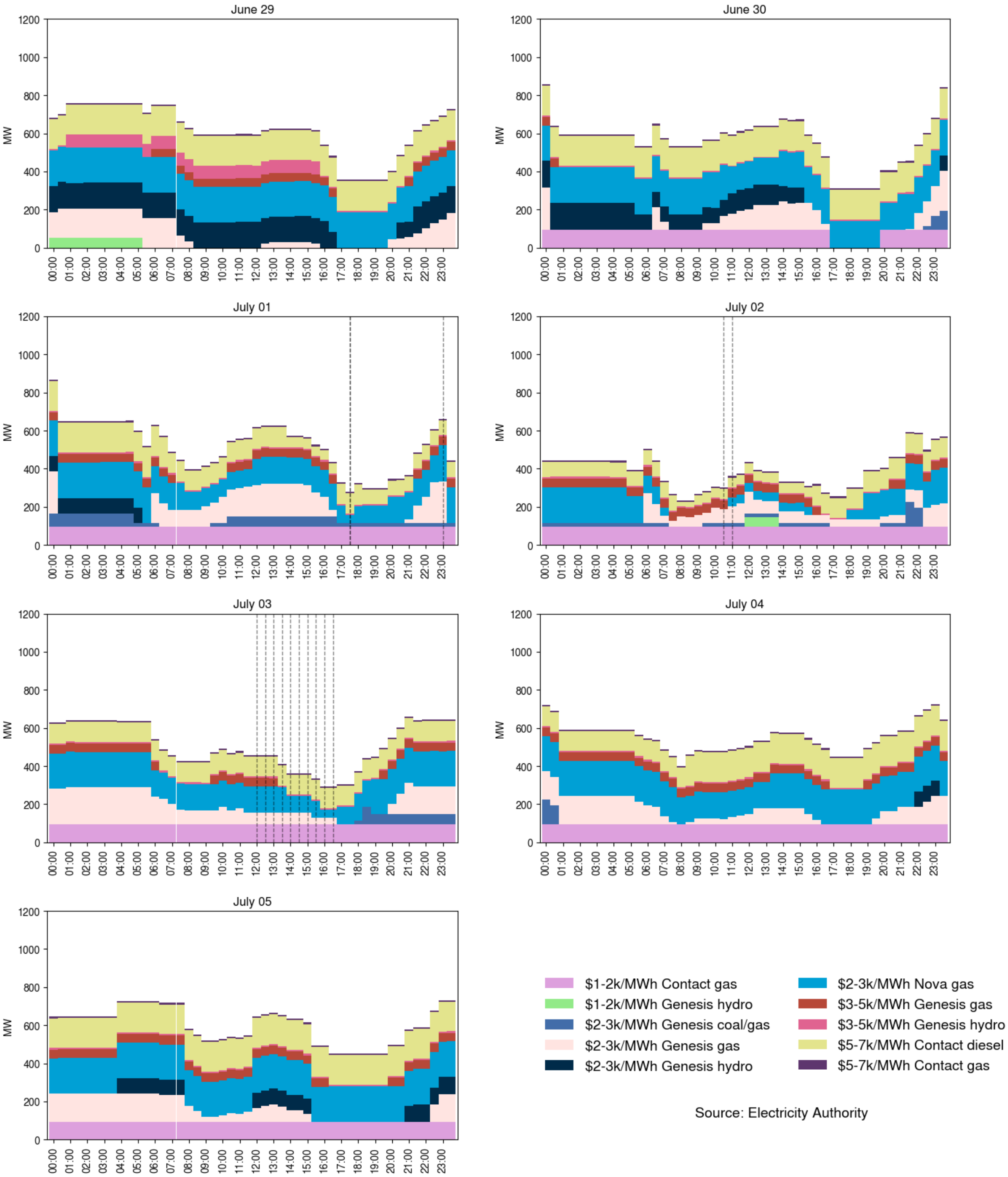



12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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, wind 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 535MW per trading period was priced above $1,000/MWh this week, which is roughly 9.2% of the total energy available.

**Figure 22: 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 |
|---|---|---|---|---|---|
| 14/06/2023-<br>15/06/2023 | 15-17/<br>15-19 | Back with monitoring for analysis | Genesis | Multiple | High energy prices associated with high energy offers |
| 22/09/2023-30/09/2023 | Several | Back with monitoring for analysis | Contact | Multiple | High hydro offers |
| 3-4/09/2024 and 13-18/09/2024 | Several | Further analysis | Contact | Clutha scheme | Hydro offers |
| 8/05/2025-9/05/2025 | Several | Further analysis | Genesis | Waikaremoana | Offers |