21 July 2025

Trading conduct report 13-19 July 2025

Market monitoring weekly report

Trading conduct report 13-19 July 2025

1. Overview

1.1. The average price increased by $34/MWh this week to $90/MWh. National hydro storage remains stable at ~66% nominally full and ~102% of the historical average. Several high prices occurred on Tuesday, mainly due to the demand forecast errors. Total weekly demand increased, and hydro generation also increased compared to the previous week. Thermal generation remains low.

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 13-19 July 2025:

(a) The average spot price for the week was $90/MWh, an increase of around $34/MWh compared to the previous week.

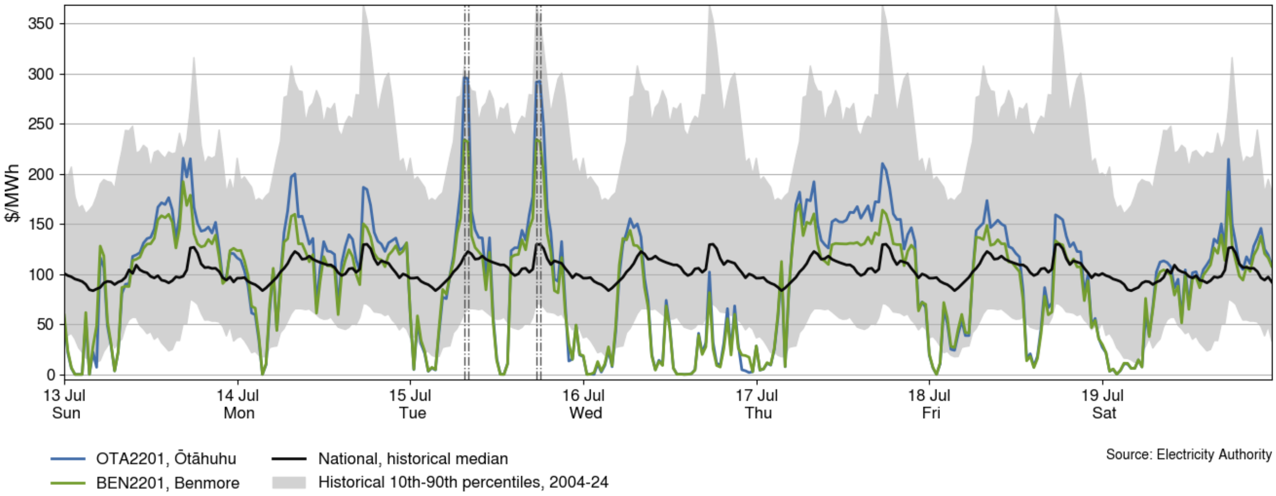
(b) 95% of prices fell between $0.06/MWh and $193/MWh.

2.3. Spot prices were mostly under $200/MWh with a few price spikes.

2.4. On Tuesday, during the morning peak (7.30am-8.00am), prices were $295/MWh at Ōtāhuhu and $234/MWh at Benmore. During these times, national demand was 95MW-98MW higher than forecast. On the same day in the evening, there were other price spikes during the evening peak (5.30pm-6.00pm), with prices of around $292/MWh at Ōtāhuhu and $234/MWh at Benmore. Demand was higher than forecast by 143MW at 5.30pm and by 70MW at 6.00pm. Sustained instantaneous reserve (SIR) prices also spiked during these times.

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. Other notable prices are marked with black dashed lines.

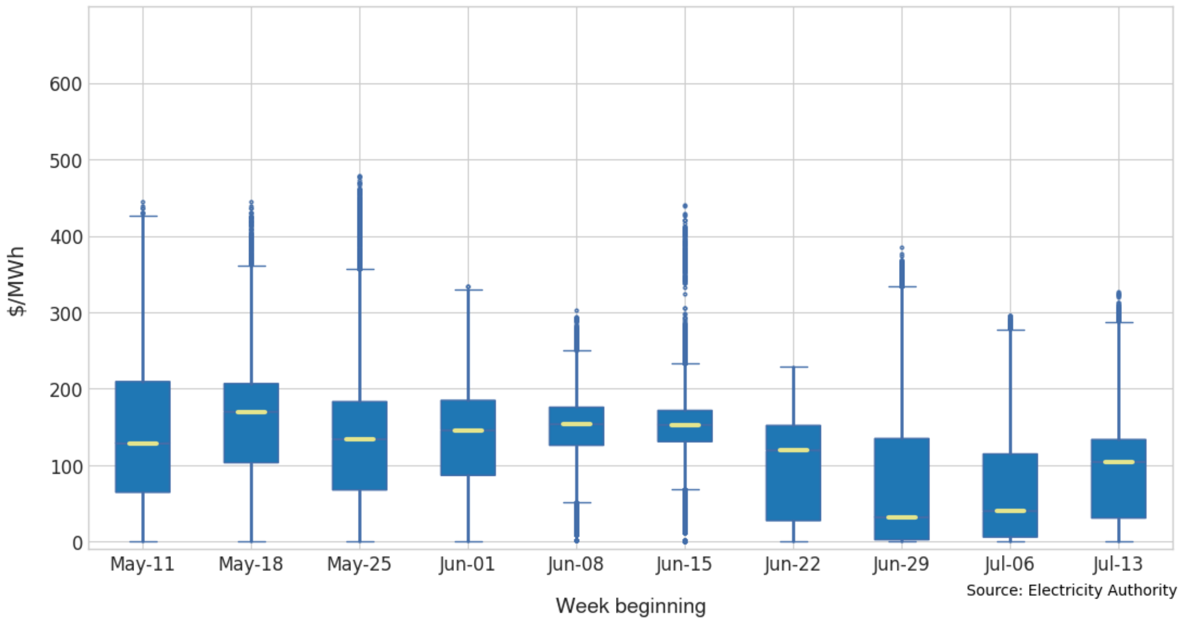
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 13-19 July 2025



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 moved up this week compared to the previous week, with no significant high-priced outliers. The median price was $104/MWh, which is higher compared to the previous week, and most prices (middle 50%) fell between $31/MWh and $134/MWh.

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

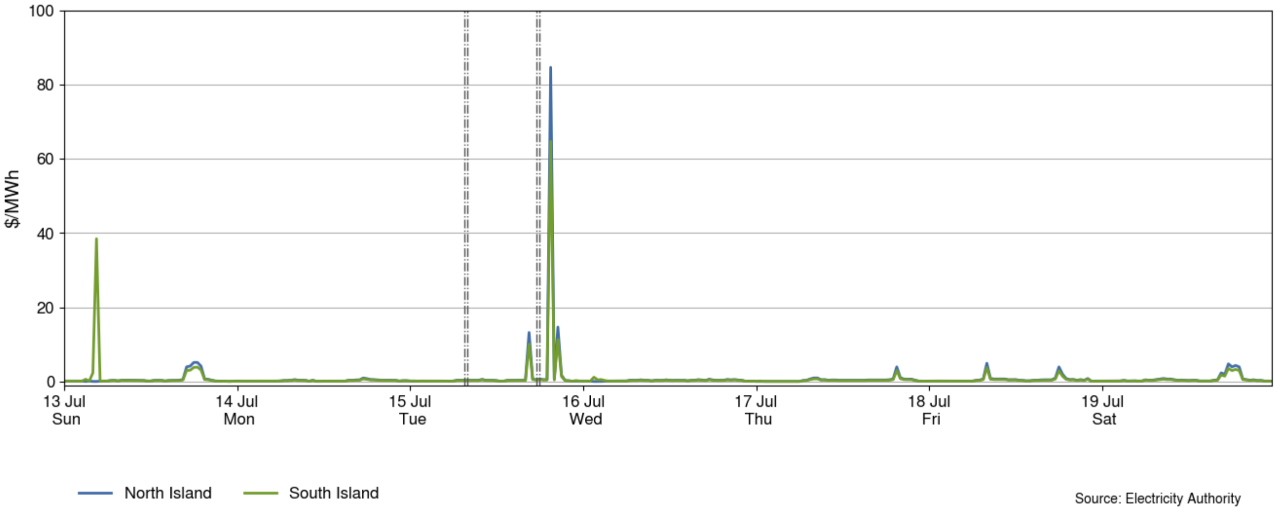


3. Reserve prices

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. On Sunday South Island FIR prices spiked when the HVDC was flowing South and setting the risk.

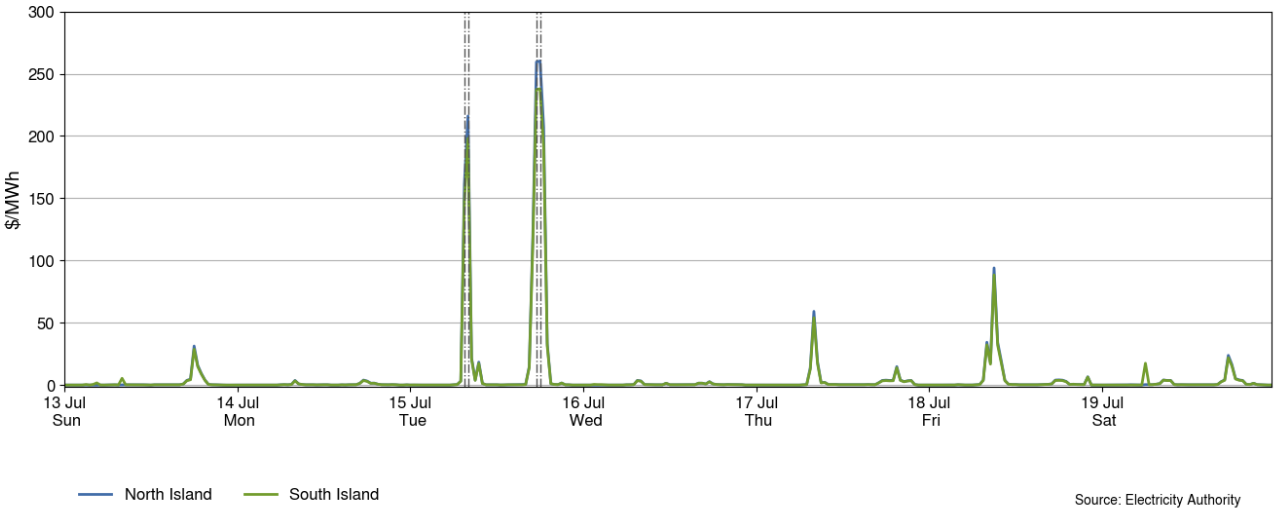
3.2. A significant FIR price spike occurred on Tuesday at 7.30pm, with prices reaching around $85/MWh in the North Island and $65/MWh in the South Island. At that time, Huntly 5 was the risk setter, and its generation increased, requiring more reserves to be cleared to cover the risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 13-19 July 2025



3.3. SIR prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh with a few spikes. Two significant price spikes occurred on Tuesday. The first spike occurred during the morning peak period at 8.00am when SIR prices reached $216/MWh in the North Island and $198/MWh in the South Island. Another spike appeared during the evening peak periods between 5.30pm-6.00pm, with SIR prices of around $260/MWh in the North Island and $238/MWh in the South Island. During both times, Huntly 5 was the risk setter, and energy and reserve were co-optimised. Due to current lower thermal commitment, there is an overall reduction in reserve available, so at times reserve prices can spike when higher amounts of reserve are needed.

Figure 4: Sustained instantaneous reserve by trading period and island, 13-19 July 2025



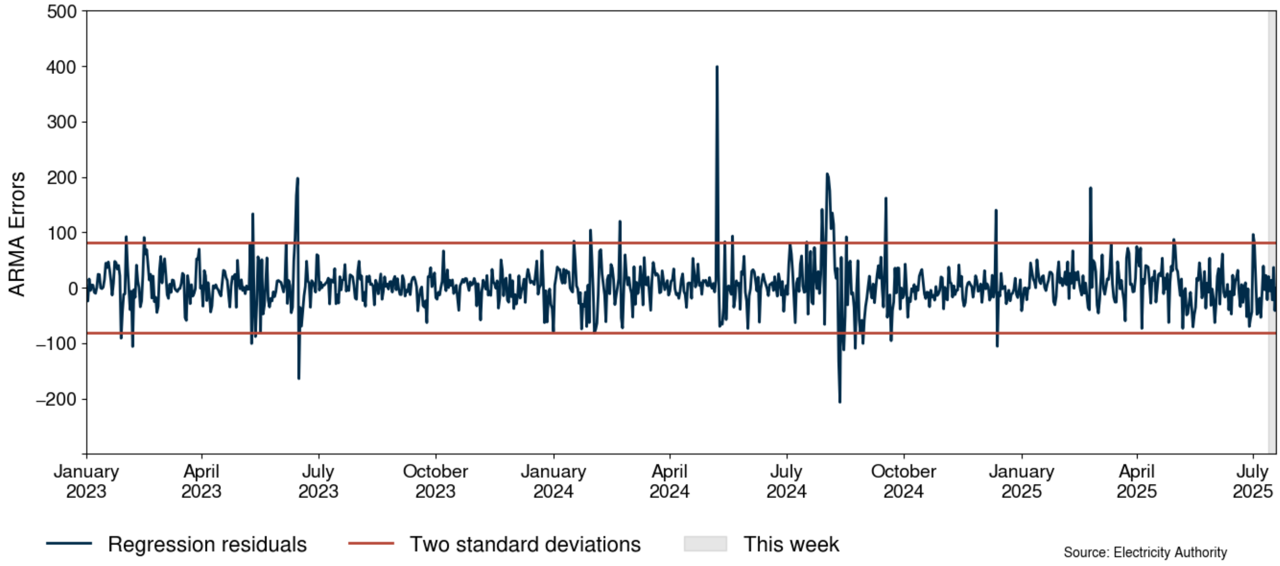
4. Regression residuals

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.

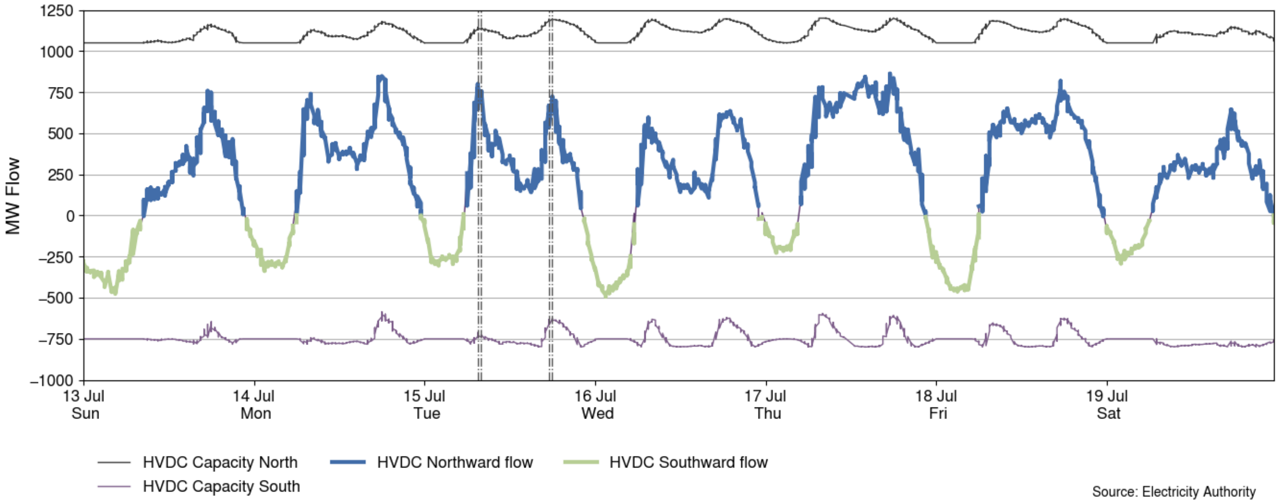
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 19 July 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 13-19 July 2025. HVDC flows were mostly northward during the day and southward overnight. Northward flows reached around 862MW on Thursday at 5.30pm during the evening demand peak when demand was high.

Figure 6: HVDC flow and capacity, 13-19 July 2025

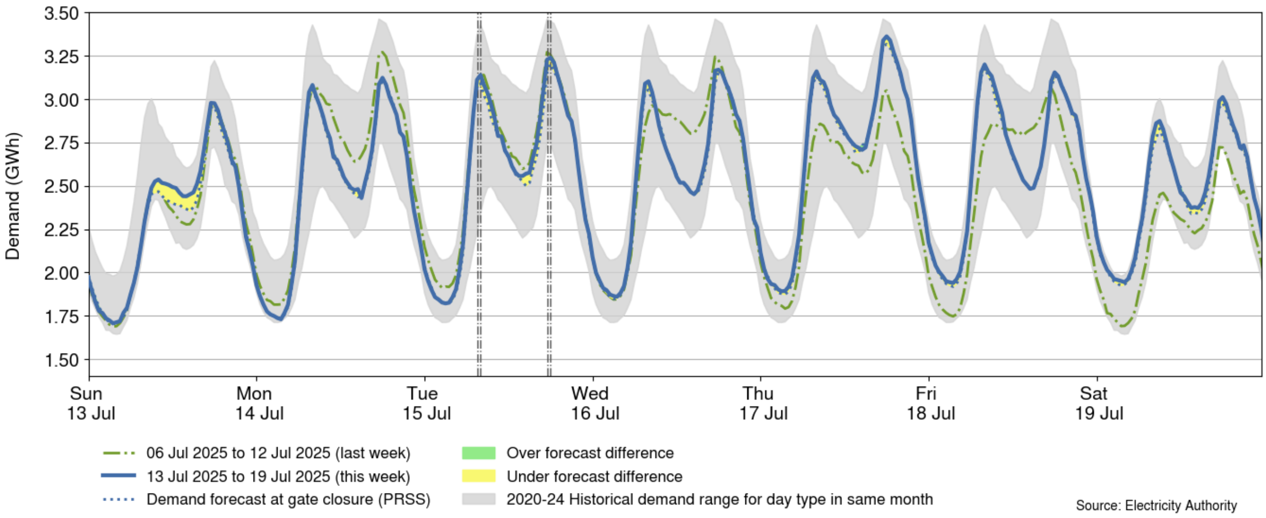


6. Demand

6.1. Figure 7 shows national demand between 13-19 July 2025, compared to the historic range and the demand of the previous week. Overall, demand was high this week compared to the previous week due to end of school holidays and colder temperatures. The highest demand of the week was 3.36GWh at 6.00pm on Thursday.

6.2. This week, demand was higher than forecast for a few trading periods. The maximum demand error occurred on Tuesday at 4.30pm, when demand was 218MW higher than forecast. Demand was consistently higher than forecast on Sunday morning and early afternoon, however, prices remained mostly below $150/MWh.

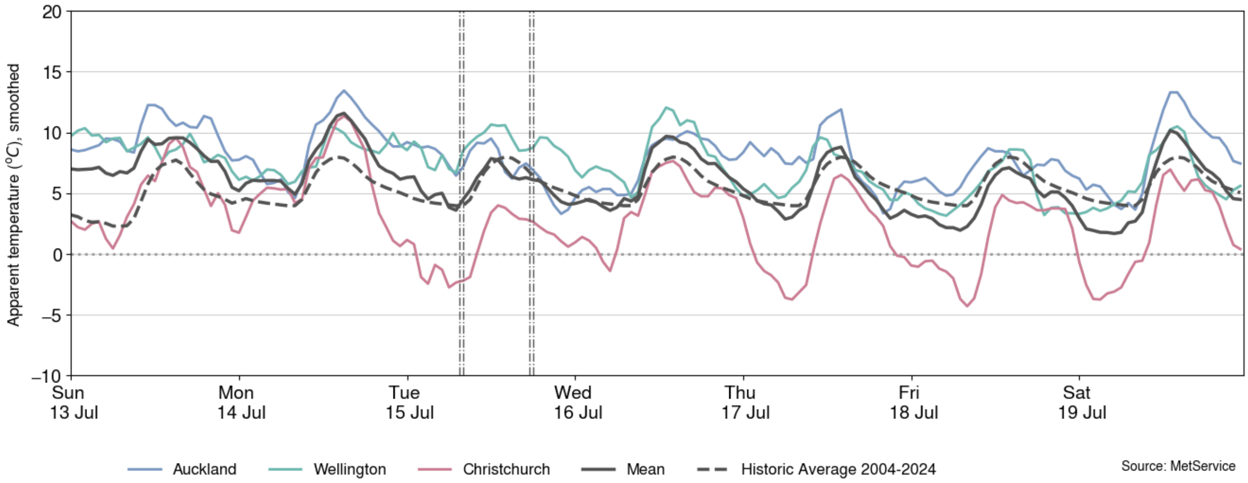
Figure 7: National demand, 13-19 July 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 13-19 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.

6.4. Apparent temperatures ranged from 3°C to 14°C in Auckland, 3°C to 13°C in Wellington, and -5°C to 12°C in Christchurch. Christchurch experienced freezing mornings most of the week.

Figure 8: Temperatures across main centres, 13-19 July 2025

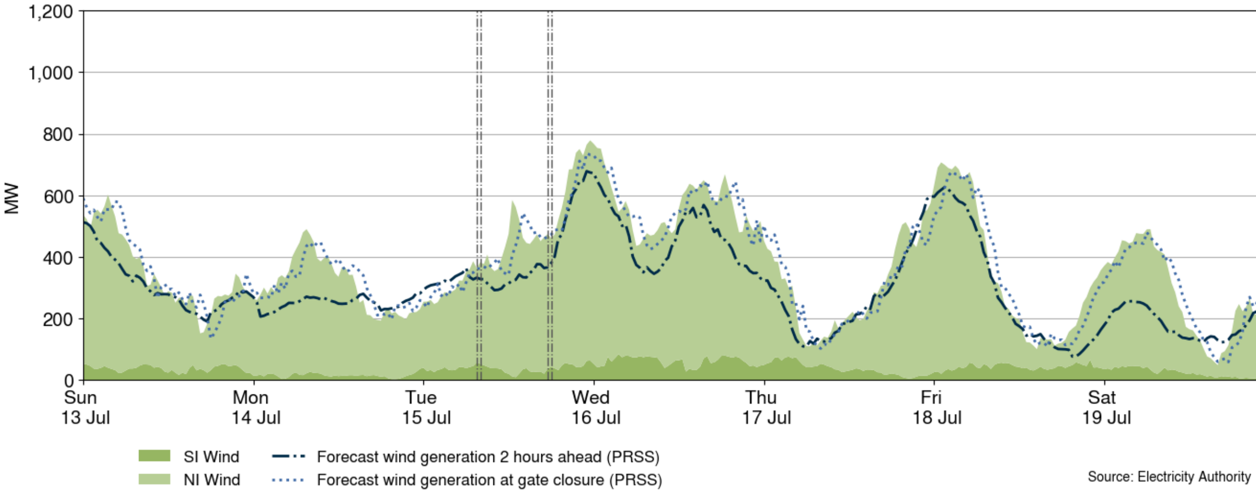


7. Generation

7.1. Figure 9 shows wind generation and forecast from 13-19 July 2025. This week wind generation varied between 49MW and 779MW, with a weekly average of 372MW.

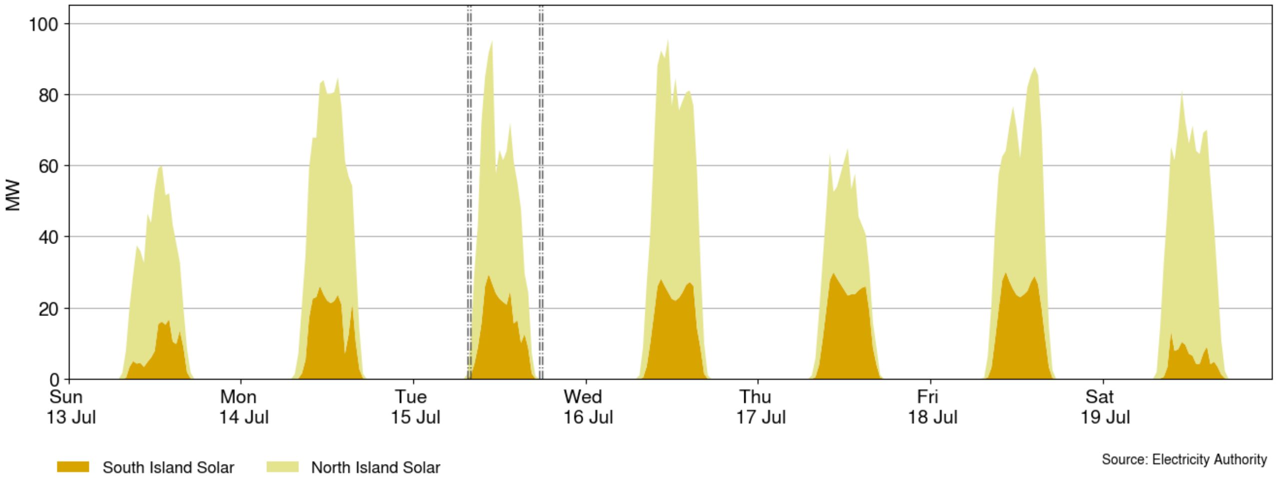
7.2. Wind generation was highest between Tuesday night and Wednesday, but dropped on Thursday night. Wind generation then increased to 607 MW on Friday night, before decreasing again. On Saturday, wind reached its lowest value of 49 MW.

Figure 9: Wind generation and forecast, 13-19 July 2025



7.3. Figure 10 shows grid connected solar generation from 13-19 July 2025. Solar generation typically peaked above 60MW, with a maximum of 96MW at 11.30am on Wednesday.

Figure 10: Grid connected solar generation, 13-19 July 2025



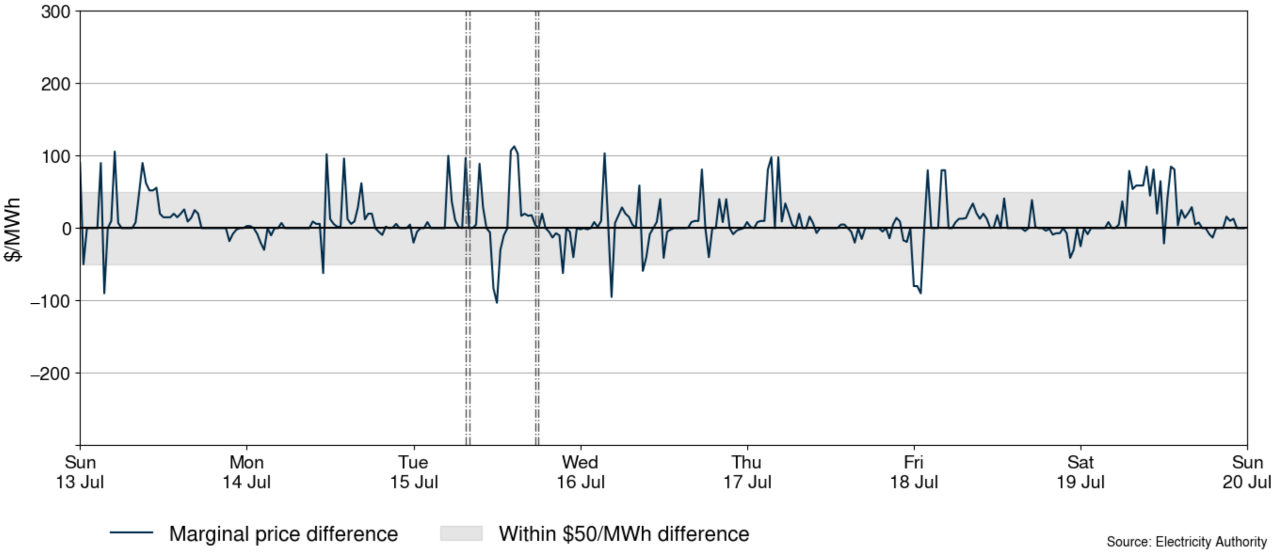
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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. Many trading periods throughout the week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$112/MWh occurred at 2.30pm on Tuesday when demand was over 141MW higher than forecast, and wind was 77MW lower than forecast.

7.6. During the price spike on Tuesday morning, the final price was higher than the simulated price by ~$100/MWh. However, during the Tuesday evening price spike the price was similar to the simulation price. However, when compared to the prices in the forecast schedules, both instances had prices higher than forecast.

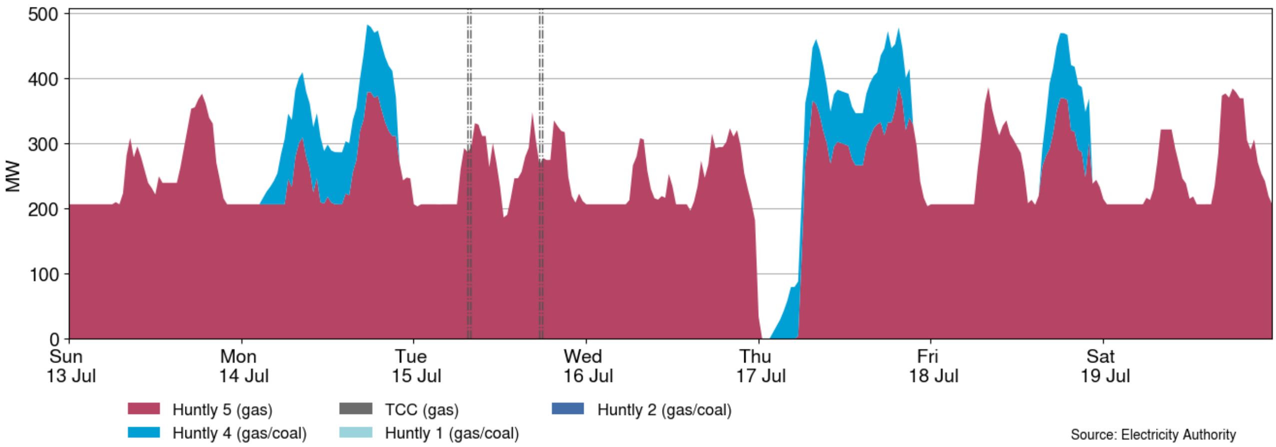
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 13-19 July 2025



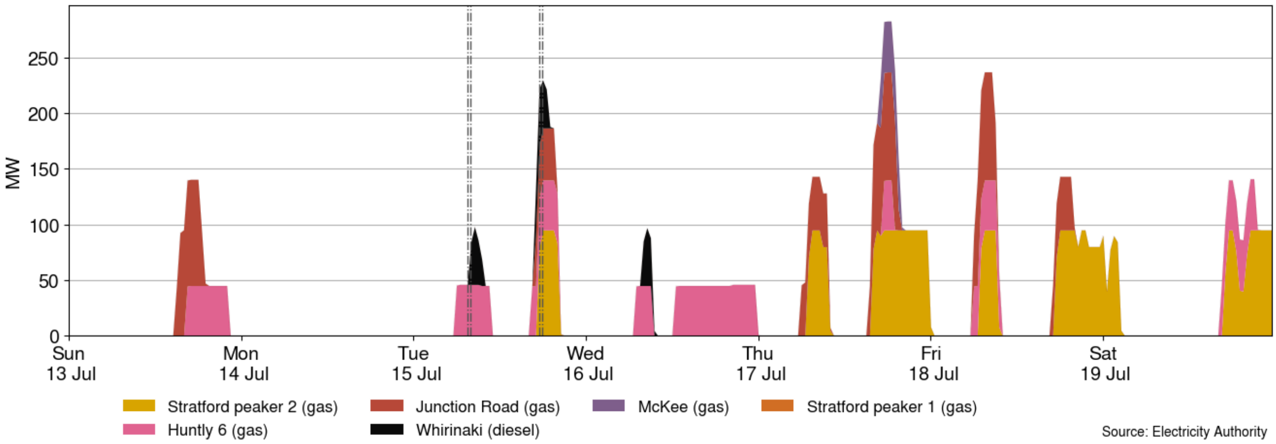
7.7. Figure 12 shows the generation of thermal baseload between 13-19 July 2025. Huntly 5 ran as baseload this week, turning off overnight on Friday. Huntly 2 ran on Monday and Thursday, and on Friday during the evening peak period.

Figure 12: Thermal baseload generation, 13-19 July 2025



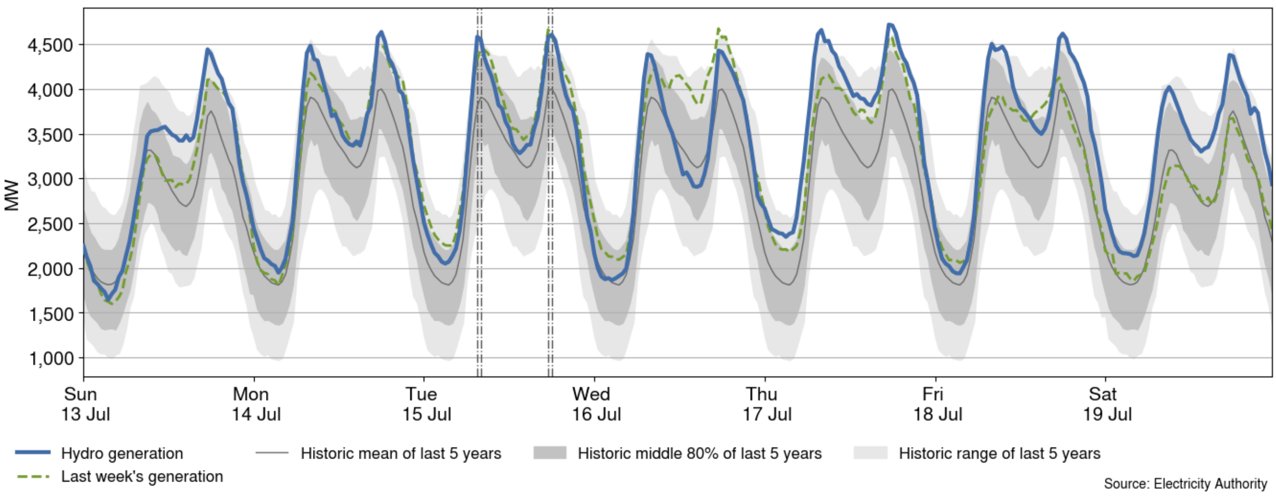
7.8. Figure 13 shows the generation of thermal peaker plants between 13-19 July 2025. On Monday no peaker was running. Junction Road generated during the evening peaks on Sunday and Tuesday, and also ran during the morning and evening peak periods on Thursday and Friday. Huntly 6 generated during peak periods, except on Monday. Stratford Peaker 2 generated during the evening peaks on Tuesday, and from Thursday to Saturday. Whirinaki also generated on Tuesday and Wednesday, however, during this time it was offering generation below $1/MWh.

Figure 13: Thermal peaker generation, 13-19 July 2025



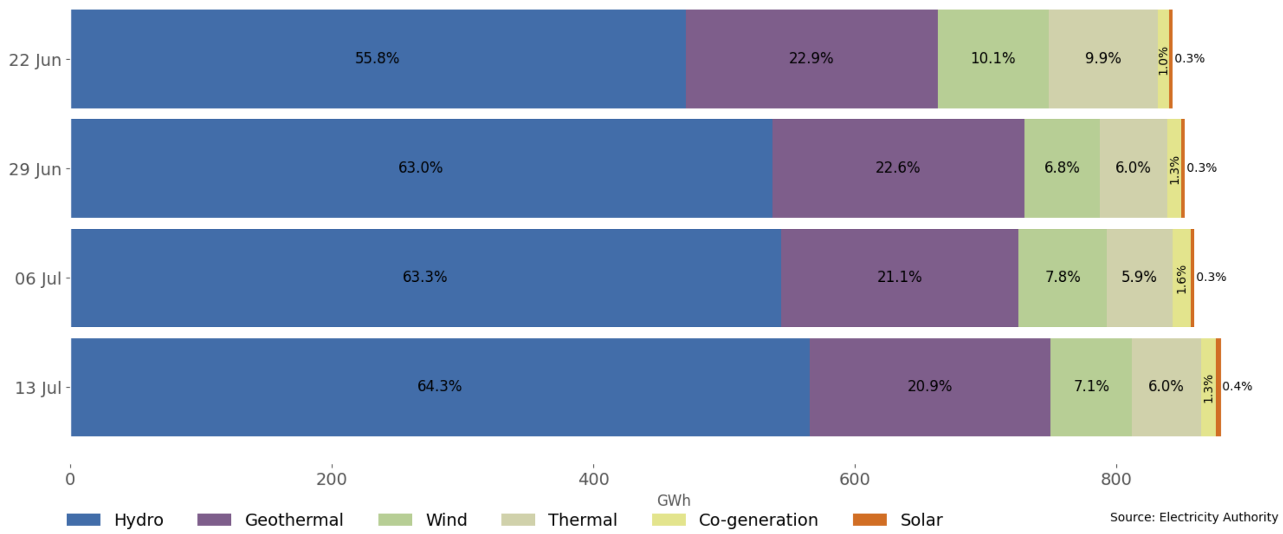
7.9. Figure 14 shows hydro generation between 13-19 July 2025. Overall, hydro generation was higher than the historic mean. On Tuesday, during the price spikes, hydro generation increased to meet elevated demand. From Thursday to Saturday, hydro generation was significantly higher than both the historical average and the previous week.

Figure 14: Hydro generation, 13-19 July 2025



7.10. As a percentage of total generation, between 13-19 July 2025, total weekly hydro generation was 64.3%, geothermal 20.9%, wind 7.1%, thermal 6.0%, co-generation 1.3%, and solar (grid connected) 0.4%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 22 June 2025 and 19 July 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 13-19 July 2025 ranged between ~679MW and ~1,348MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford peaker 1 is on outage until 10 August 2025.

(b) Huntly 2 was on outage between 15-18 June 2025.

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

(d) Roxburgh unit 4 is on outage until 30 July 2025.

(e) Tauhara geothermal was on outage until 14 July 2025.

(f) Ruakākā battery outage has been extended to end on 25 July 2025.

Figure 16: Total MW loss from generation outages, 13-19 July 2025

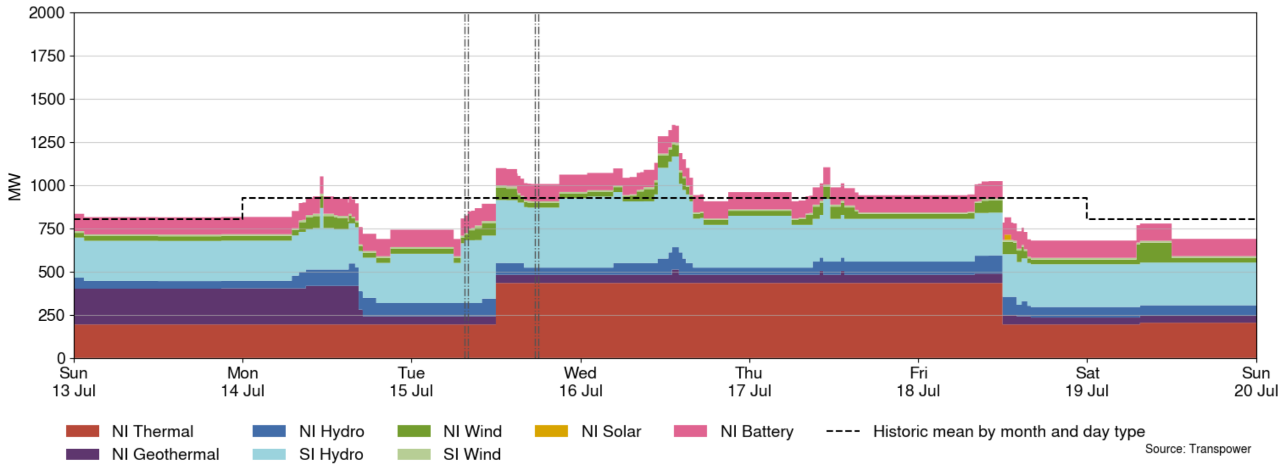
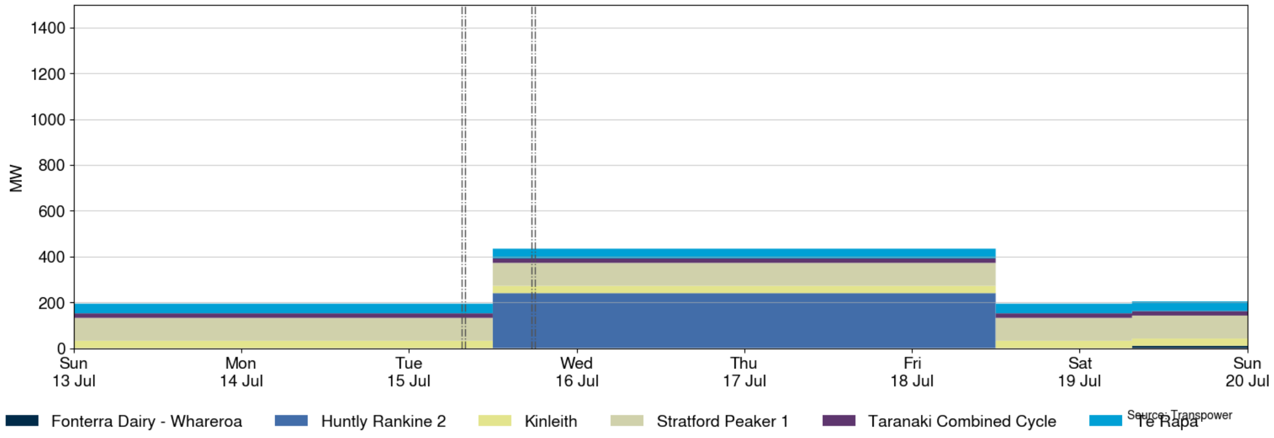


Figure 17: Total MW loss from thermal outages, 13-19 July 2025

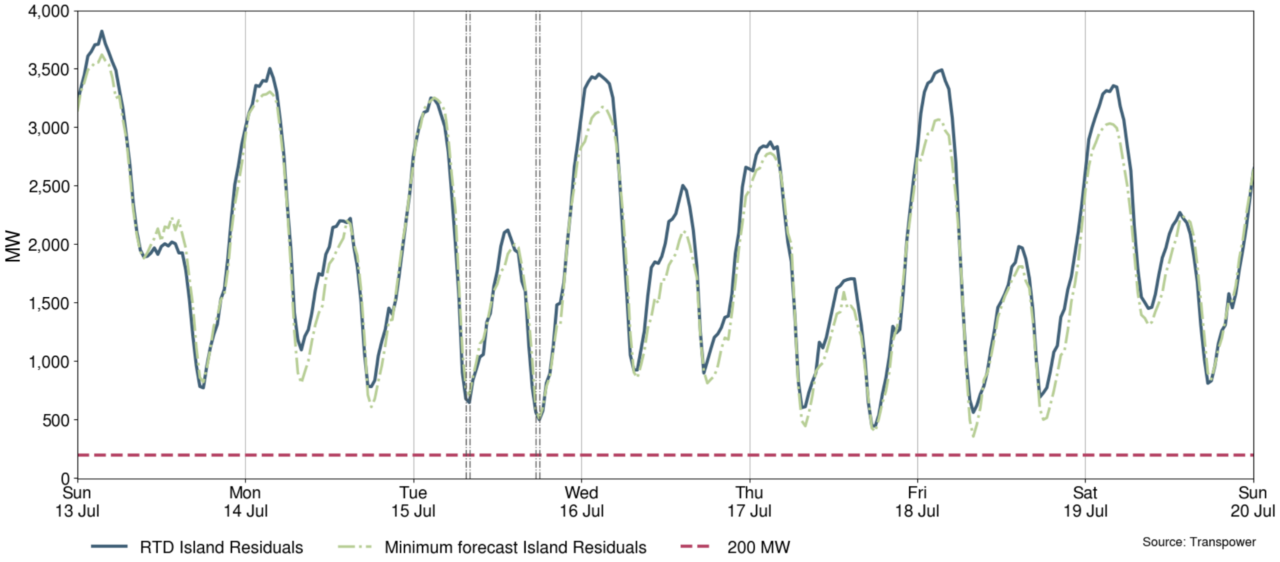


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 13-19 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 446MW on Thursday at 6.00pm.

Figure 18: National generation balance residuals, 13-19 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 19 July 2025, national controlled storage was 66% nominally full and ~102% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (61% full[2]) is close to its historical average, and storage at Lake Takapō (43% full) is between its historic mean and 10th percentile.

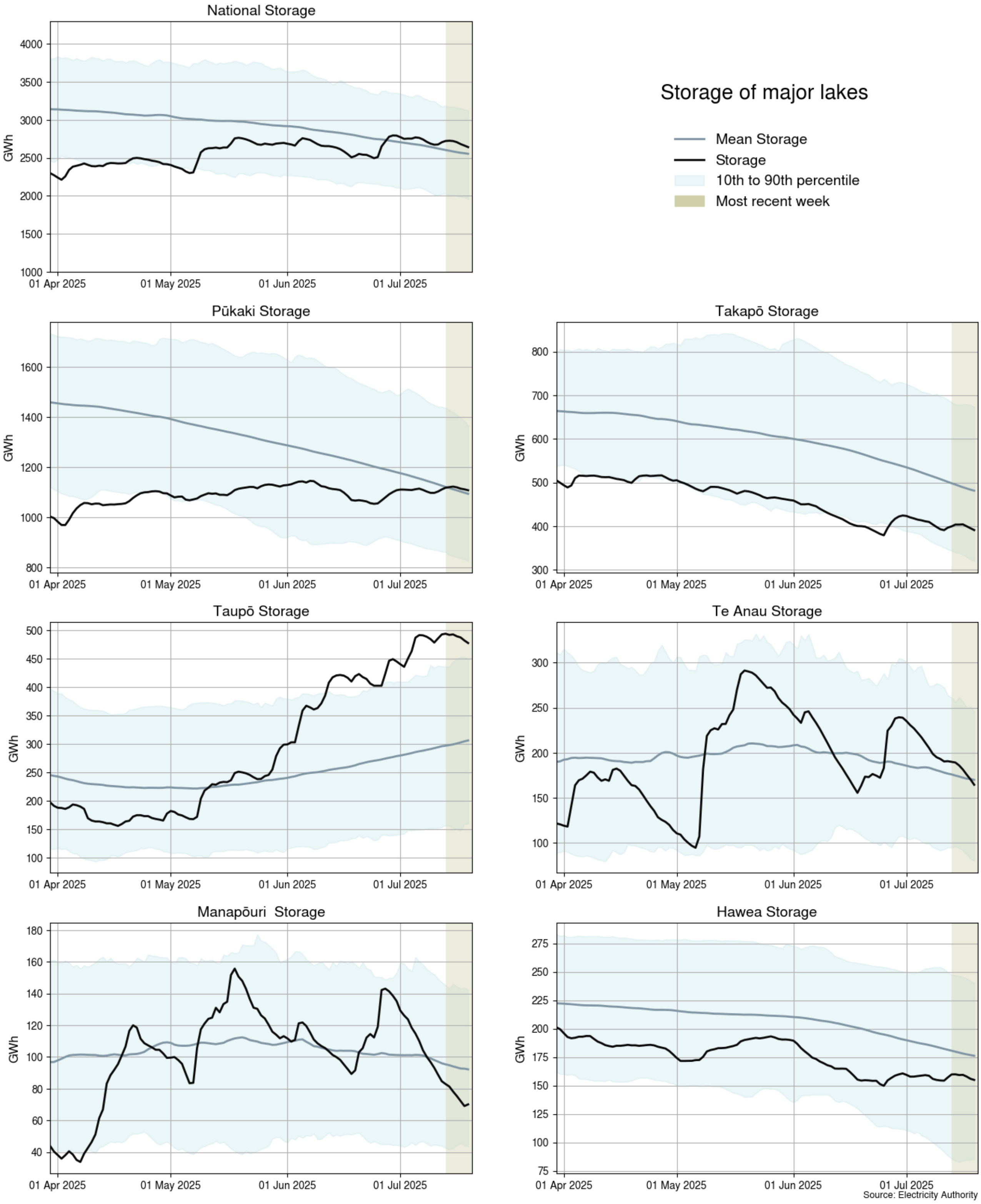
10.4. Storage at Lake Te Anau (60% full) and Lake Manapōuri (45% full) has decreased, with both currently below their respective historical mean.

10.5. Storage at Lake Taupō (82% full) remains above its historical 90th percentile.

10.6. Storage at Lake Hawea (53% full) remains between its historical 10th percentile and mean.

[2] Percentage full values sourced from NZX hydrological summary 20 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 July 2025. The SRMCs for gas powered generation have decreased, while the SRMC for diesel fuelled generation slightly increased.

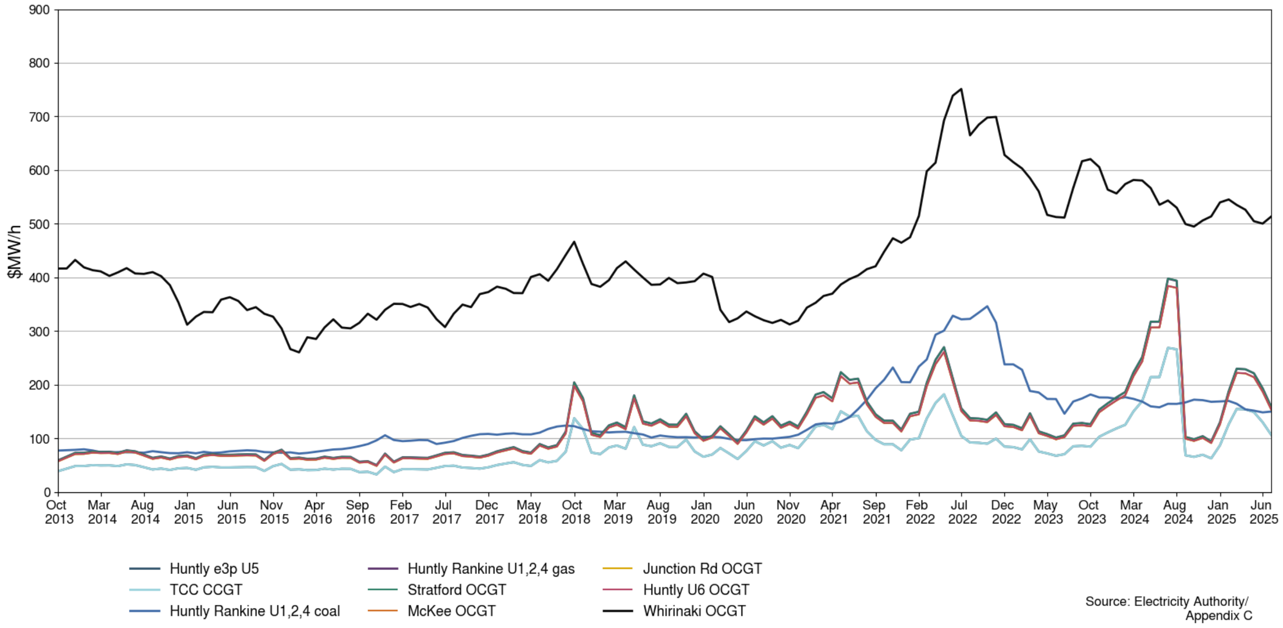
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$159/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $106/MWh and $159/MWh.

11.6. The SRMC of Whirinaki is ~$513/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

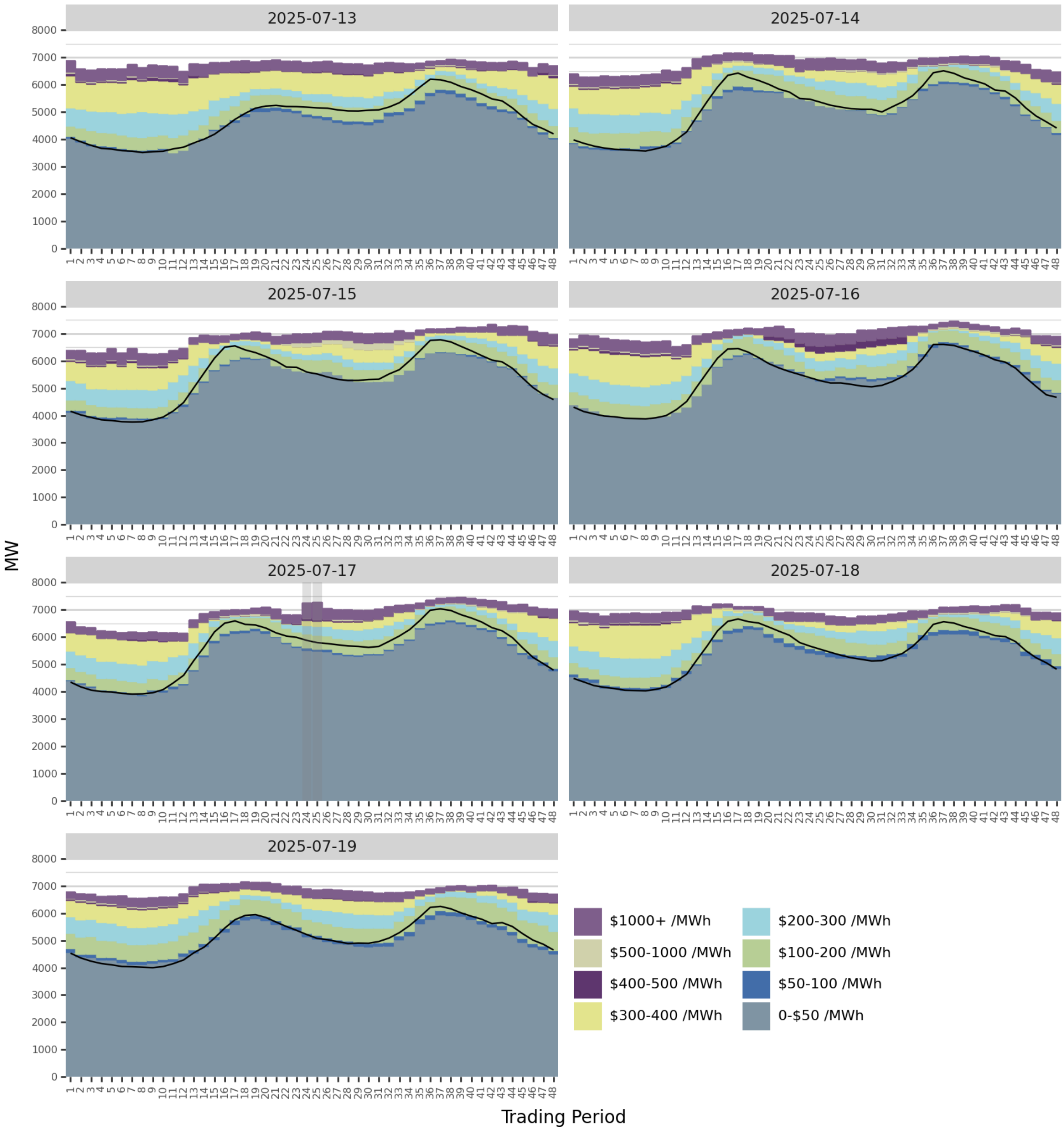


12. Offer behaviour

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. On Tuesday, energy cleared into the $200-300/MWh band due to demand forecast errors.

Figure 21: Daily offer stacks[3]



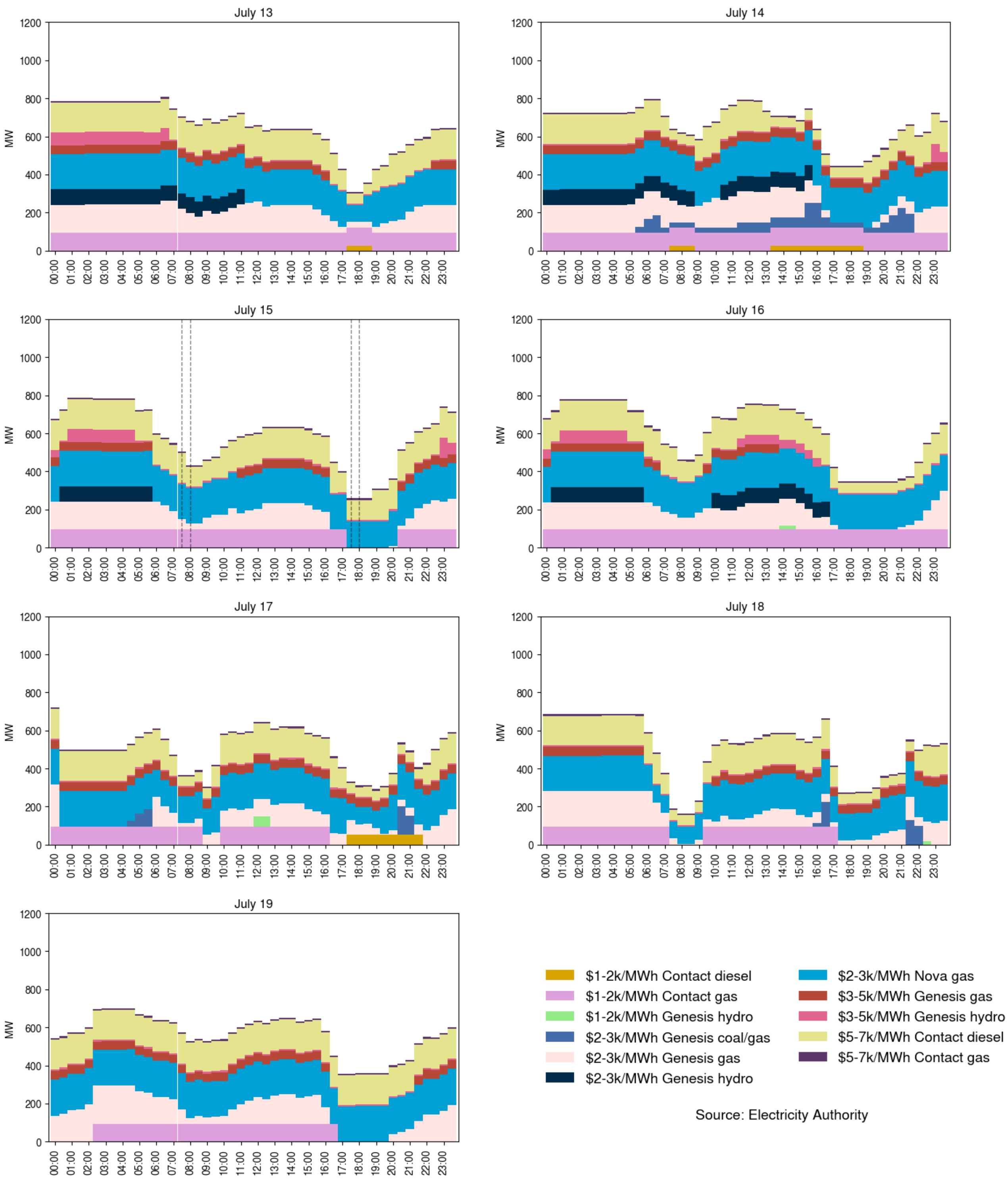
12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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.

[3] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

12.5. On average 574MW per trading period was priced above $1,000/MWh this week, which is roughly 9.8% 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- 15/06/2023	15-17/ 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
15/07/2025- 16/07/2025	Several	Further analysis	Contact	Stratford and Whirinaki	Offers