25 August 2025

Trading conduct report 17-23 August 2025

Market monitoring weekly report

Trading conduct report 17-23 August 2025

1. Overview

1.1. The average price increased by $28/MWh this week to $216/MWh. This increase was likely driven by declining hydro generation and a rise in thermal generation. National hydro storage declined to ~ 47% nominally full and around 79% of the historical average. Thermal generation increased to meet demand when wind generation was also 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 17-23 August 2025:

(a) The average spot price for the week was $216/MWh, an increase of around $28/MWh compared to the previous week.

(b) 95% of prices fell between $187/MWh and $243/MWh.

2.3. Spot prices hovered between $150-$200/MWh on Sunday-Monday before rising on to between $200-$250/MWh from Tuesday. This is like due to a combination of to declining hydro storage and increased thermal generation. Wind generation also declined from Thursday.

2.4. A few price spikes occurred, up to $360/MWh, mostly during peaks. Overnight prices were high due to high thermal generation and/or low wind generation.

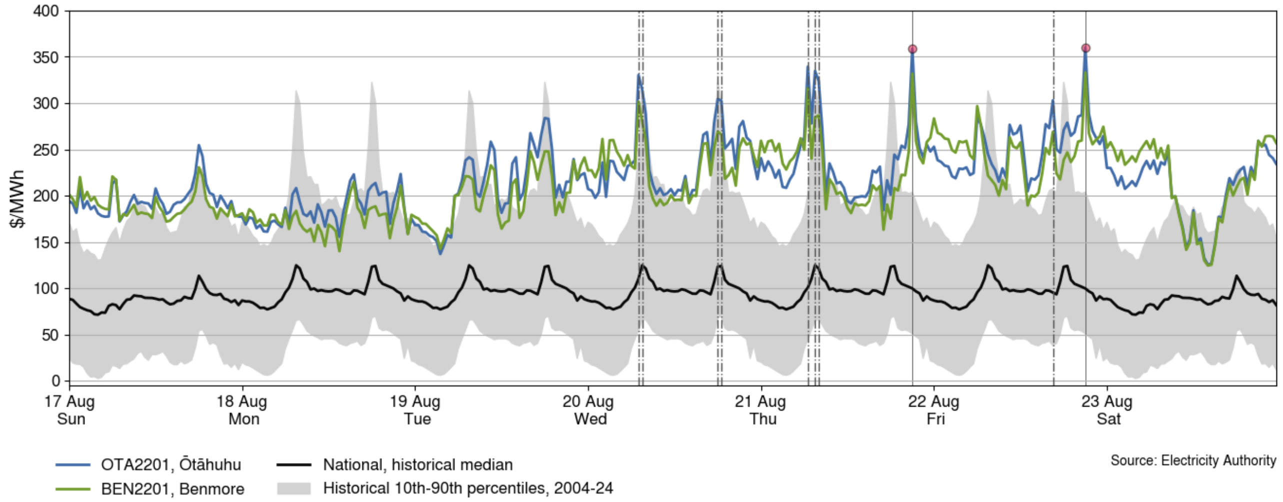
2.5. On Wednesday, during the morning peak (7.00am-7.30am), prices reached up to $330/MWh at Ōtāhuhu and $302/MWh at Benmore. During these times, wind was 125MW, and 79MW lower than forecast, respectively.

2.6. On Thursday, during the morning peak between 6.30am-8.00am, prices ranged from $278-$339/MWh at Ōtāhuhu and $240-$316/MWh at Benmore. Another price spike on Thursday occurred at 9.00pm, with prices of $359/MWh at Ōtāhuhu and $332/MWh at Benmore. Wind was 67MW lower than forecast at that time.

2.7. The highest price of the week occurred on Friday at 9.00pm, with prices of $360/MWh at Ōtāhuhu and $333/MWh at Benmore. Wind generation was low (69MW), and 44MW below the forecast.

2.8. 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 above $300/MWh are marked with black dashed lines.

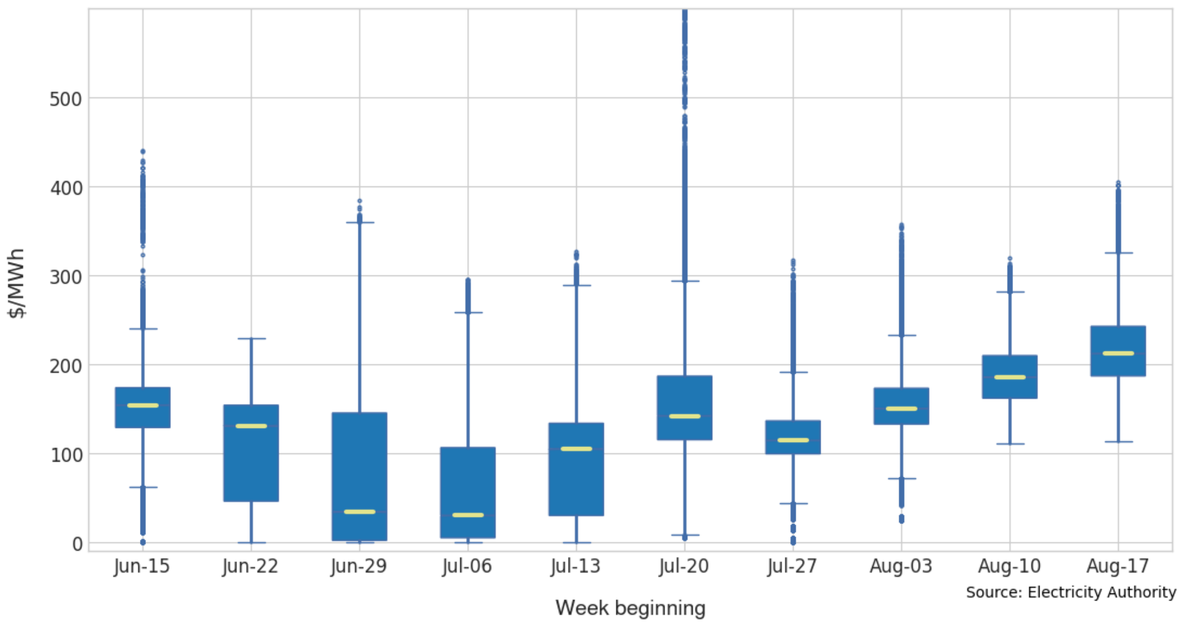
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 17-23 August 2025



2.9. 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.

2.10. The distribution of spot prices this week was similar to last week, with no significant high-priced outliers but high median prices. The median price was $212/MWh, and most prices (middle 50%) fell between $187/MWh and $243/MWh.

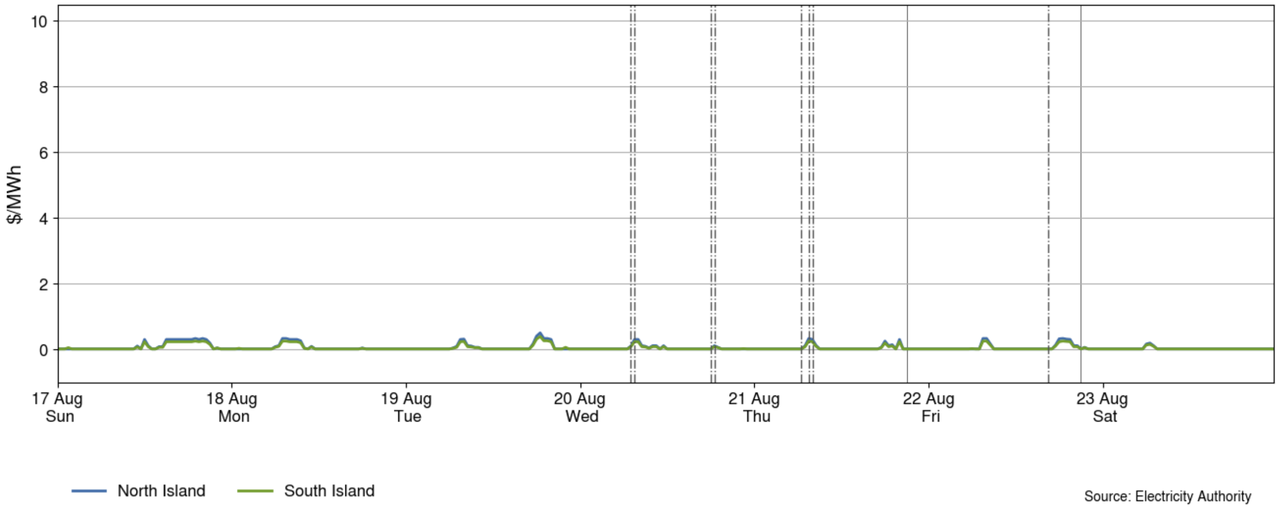
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

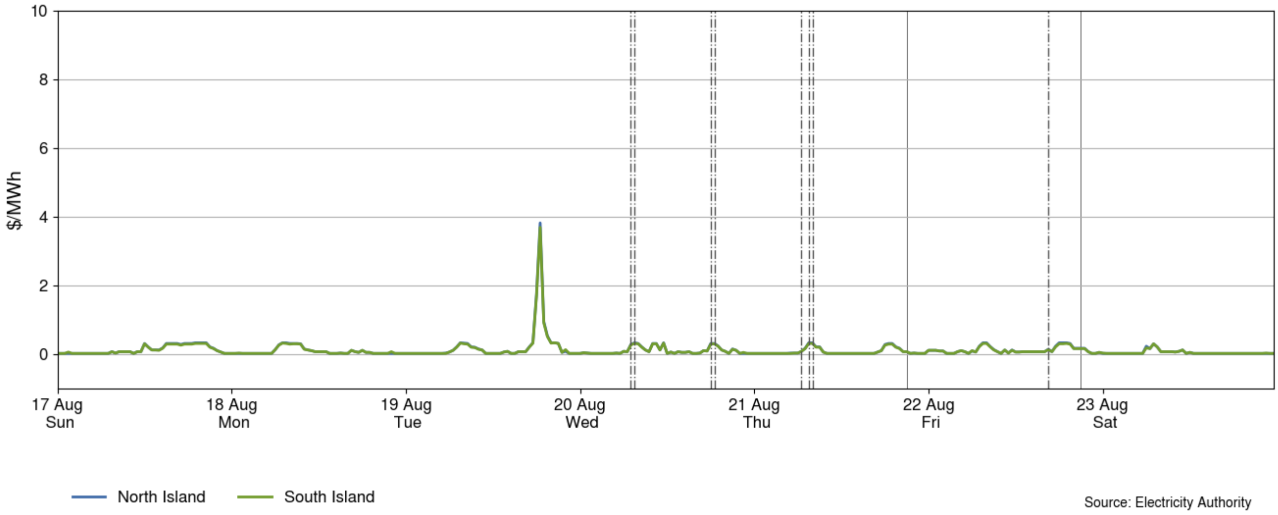
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices across both the North and South Island were below $1/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 17-23 August 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were below $5/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 17-23 August 2025



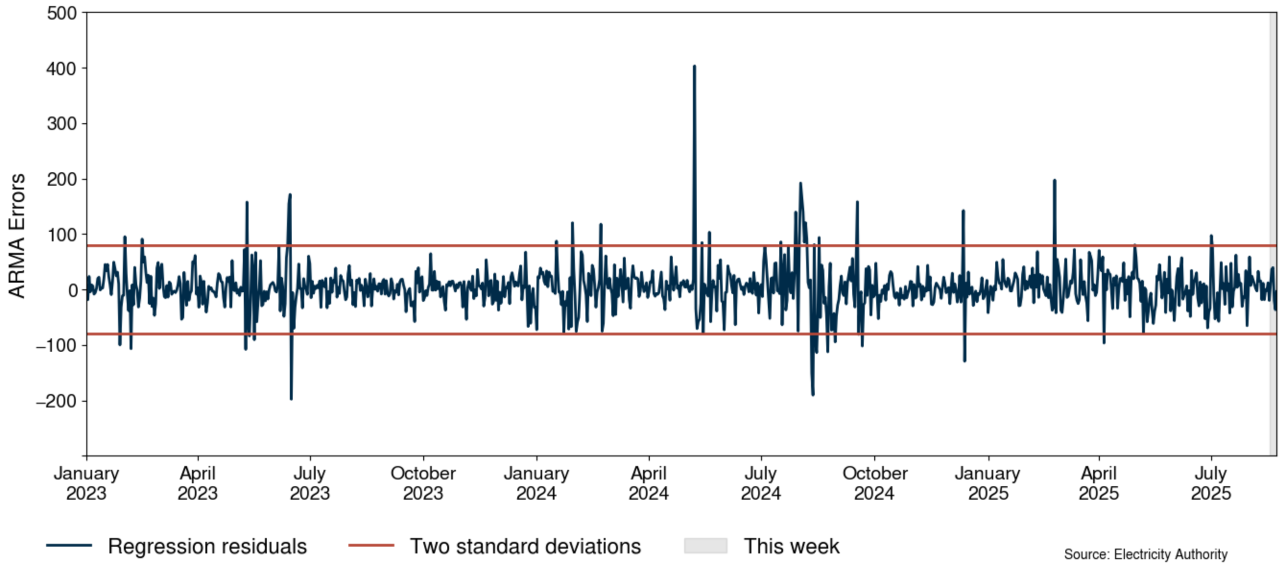
4. Regression residuals

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.

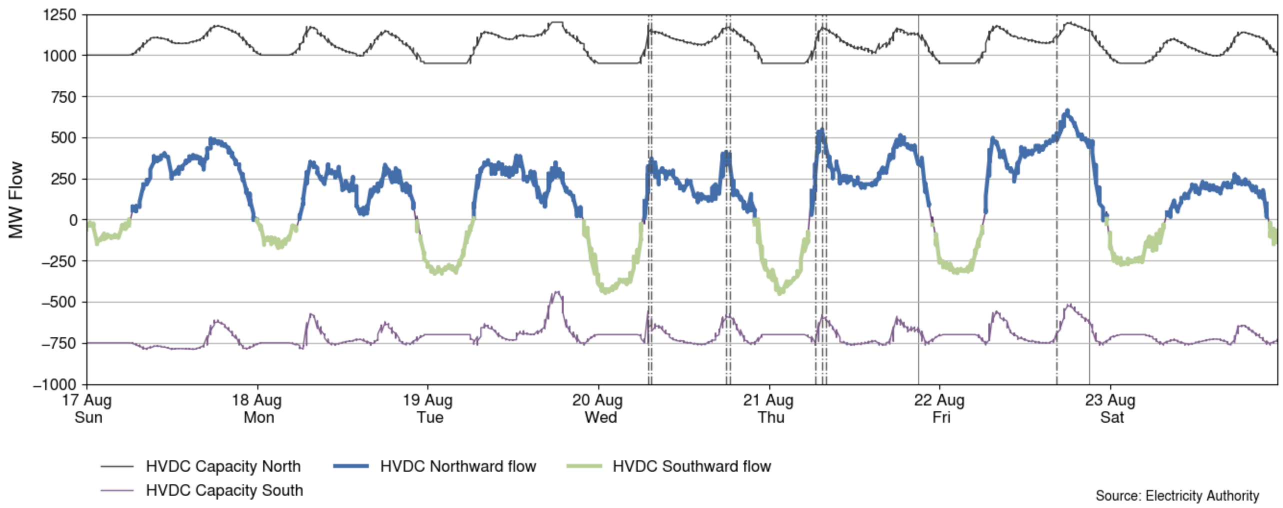
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 23 August 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 17-23 August 2025. HVDC flows were mostly northward during the day and southward overnight. Northward flow reduced likely due to decreasing hydro storage. Northward flows reached around 664MW on Friday at 6.00pm during the evening peak demand period.

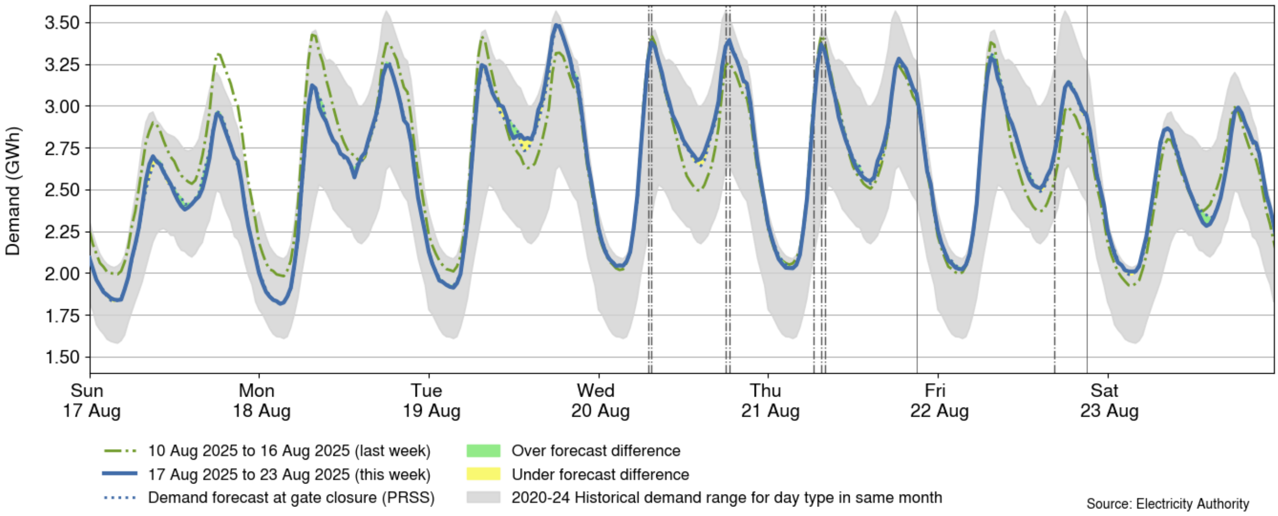
Figure 6: HVDC flow and capacity, 17-23 August 2025



6. Demand

6.1. Figure 7 shows national demand between 17-23 August 2025, compared to the historic range and the demand of the previous week. Demand on Sunday was lower when compared to the previous week, due to mild temperatures. Mid-day demand on Tuesday was high when apparent temperatures in Wellington and Christchurch were low. The highest demand of the week was 3.48GWh at 6.00pm on Tuesday during the evening peak.

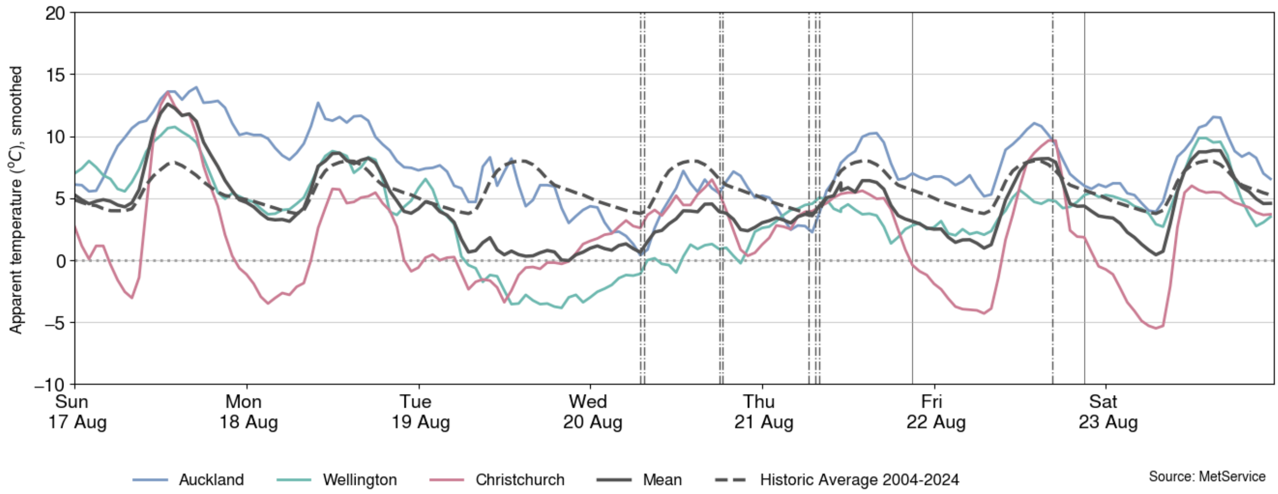
Figure 7: National demand, 17-23 August 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 17-23 August 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.

6.3. Apparent temperatures ranged from 0°C to 15°C in Auckland, -4°C to 11°C in Wellington, and -6°C to 14°C in Christchurch. Temperatures in Wellington were low on Tuesday and Wednesday, while Christchurch experienced frosty mornings throughout most of the week.

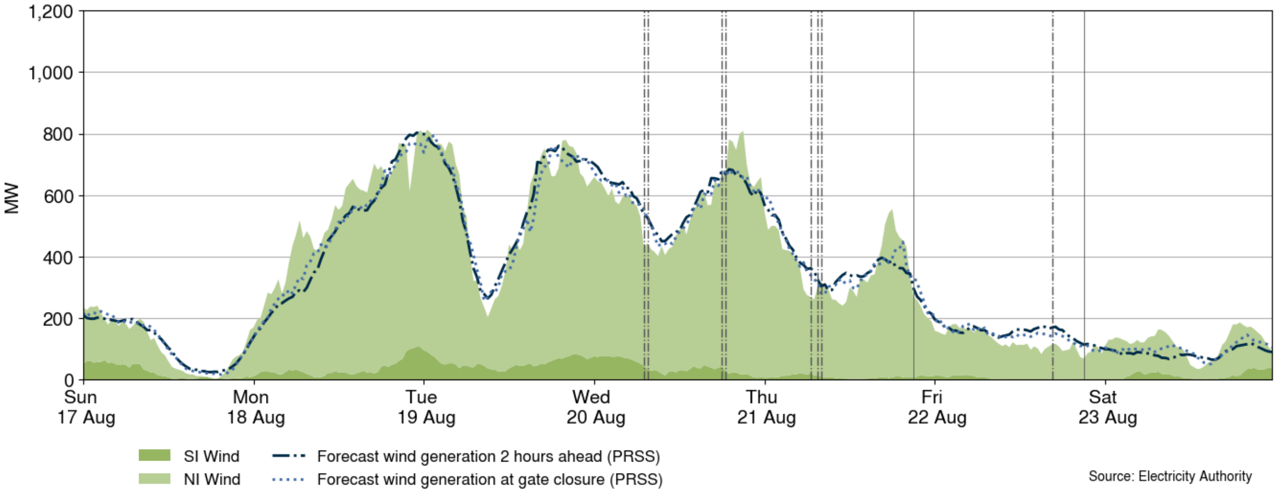
Figure 8: Temperatures across main centres, 17-23 August 2025



7. Generation

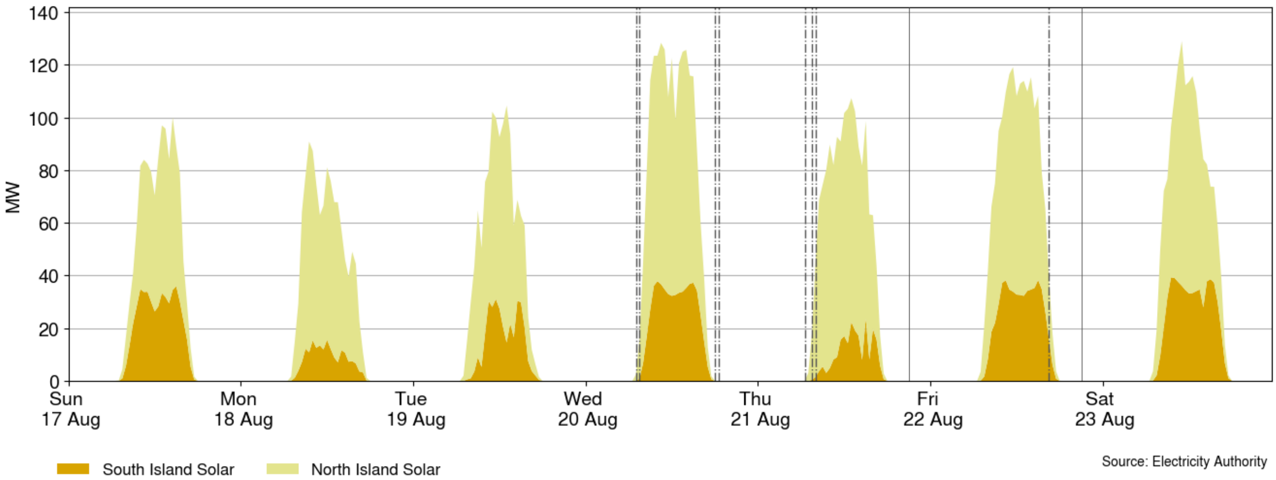
7.1. Figure 9 shows wind generation and forecast from 17-23 August 2025. This week wind generation varied between 3MW and 812MW, with a weekly average of 343MW. Wind generation was high on Monday but fell sharply on Tuesday night. Wind generation began increasing again on Tuesday morning and peaked around 780MW. Wind remained mostly below 200MW between Friday and Saturday.

Figure 9: Wind generation and forecast, 17-23 August 2025



7.2. Figure 10 shows grid connected solar generation from 17-23 August 2025. Solar generation typically peaked above 80MW, with a maximum of 129MW at 11.00am on Saturday.

Figure 10: Grid connected solar generation, 17-23 August 2025



7.3. 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.

7.4. A few trading periods this week had positive marginal price differences slightly above $50/MWh which were driven by wind and demand forecasting errors. The largest negative price difference of -$265/MWh occurred at 8.00am on Thursday, when demand was 33MW

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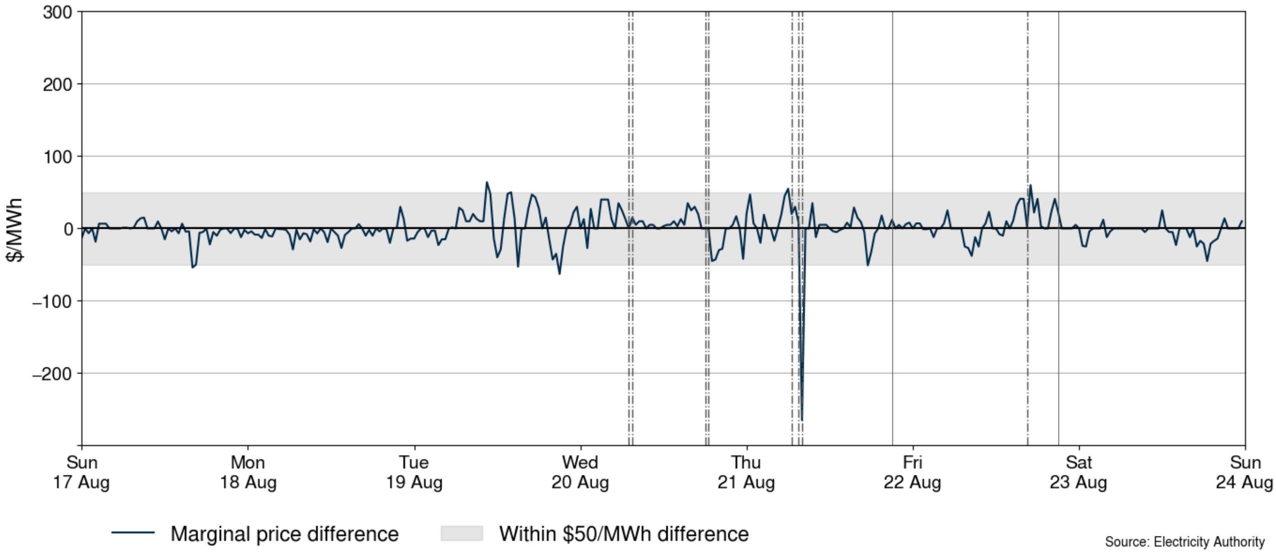
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

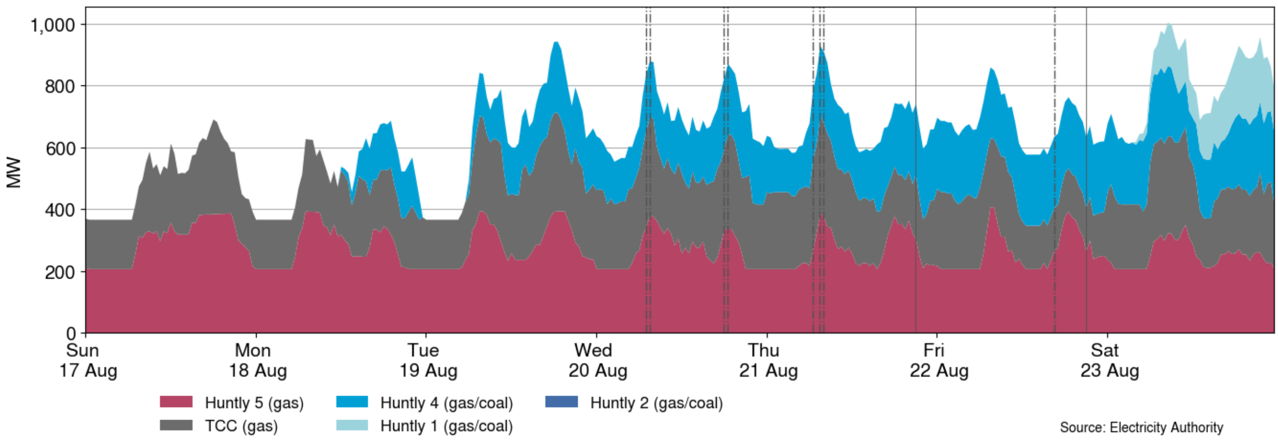
lower than forecast, and wind was 40MW higher than forecast. If demand and wind had matched the forecast, prices at that time would likely have been much higher.

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, 17-23 August 2025



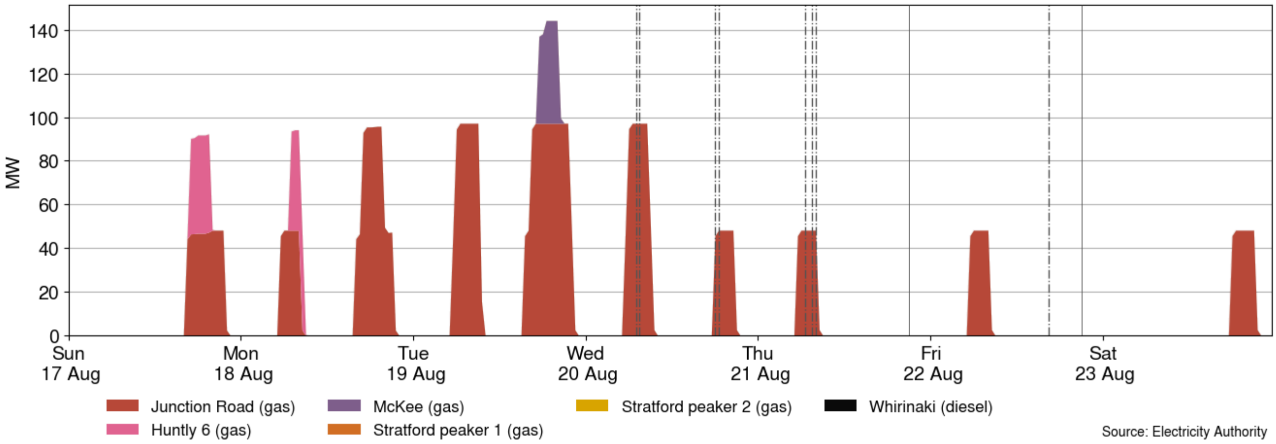
7.5. Figure 12 shows the generation of thermal baseload between 17-23 August 2025. Huntly 5 and TCC ran as baseload this week. Huntly 4 ran on Monday evening and continuously ran from Tuesday to Saturday. Huntly 1 ran on Saturday when wind generation was low.

Figure 12: Thermal baseload generation, 17-23 August 2025



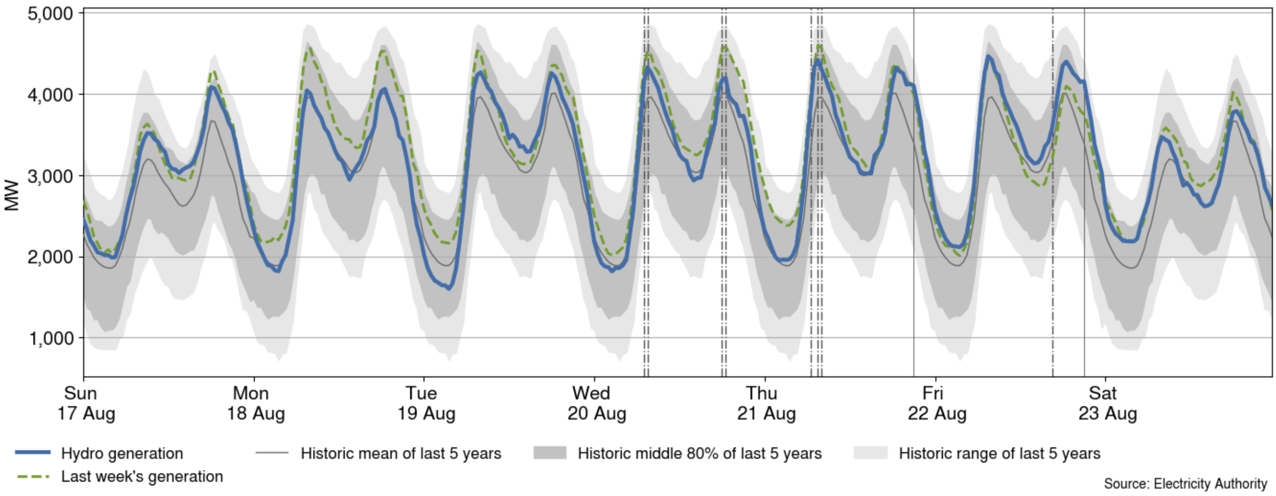
7.6. Figure 13 shows the generation of thermal peaker plants between 17-23 August 2025. Junction Road ran daily this week during peak demand periods. McKee ran on Tuesday during the evening peak. Huntly 6 also generated during the evening peak on Sunday and during the morning peak on Monday.

Figure 13: Thermal peaker generation, 17-23 August 2025



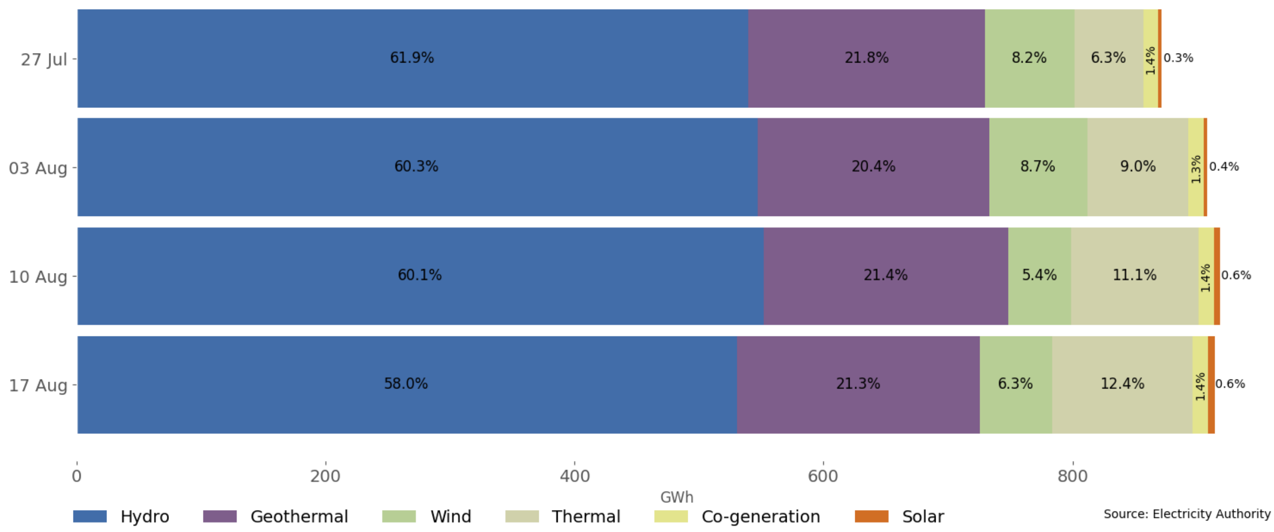
7.7. Figure 14 shows hydro generation between 17-23 August 2025. Overall, hydro generation was around the historic mean this week but was lower compared to the previous week. During the times of high demand, hydro generation increased to meet elevated demand.

Figure 14: Hydro generation, 17-23 August 2025



7.8. As a percentage of total generation, between 17-23 August 2025, total weekly hydro generation was 58.0%, geothermal 21.3%, wind 6.3%, thermal 12.4%, co-generation 1.4%, and solar (grid connected) 0.6%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 27 July 2025 and 23 August 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 17-23 August 2025 ranged between ~710MW and ~1,439MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage between 13-31 August 2025.

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

(c) Clyde unit 4 was on outage between 19-20 August 2025.

(d) West wind farm (88.6MW) was on outage between 18-19 August, and on partial outage (44.6MW) between 20-21 August 2025. From 22 August, a small amount of MW has remained on outage.

Figure 16: Total MW loss from generation outages, 17-23 August 2025

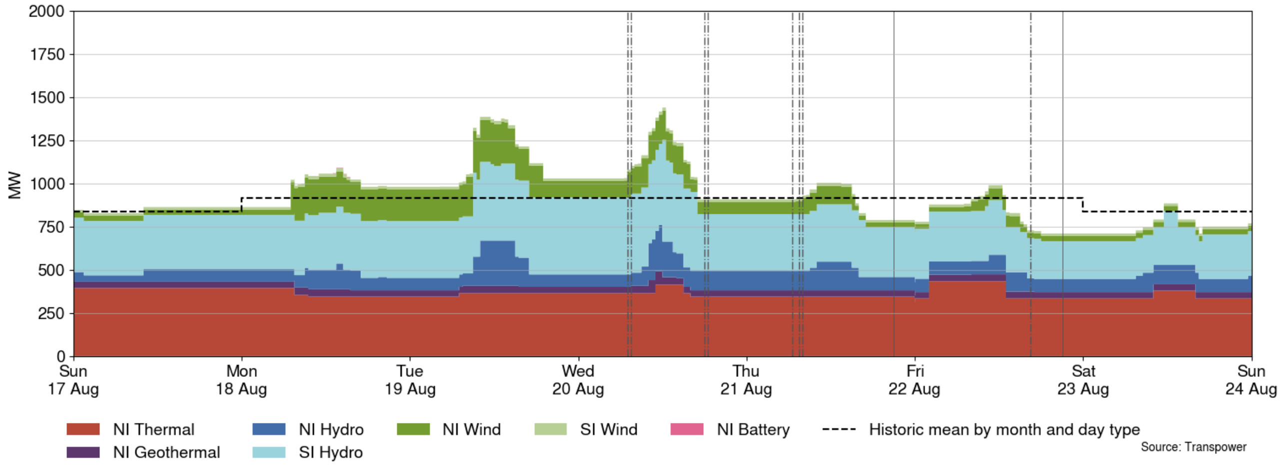
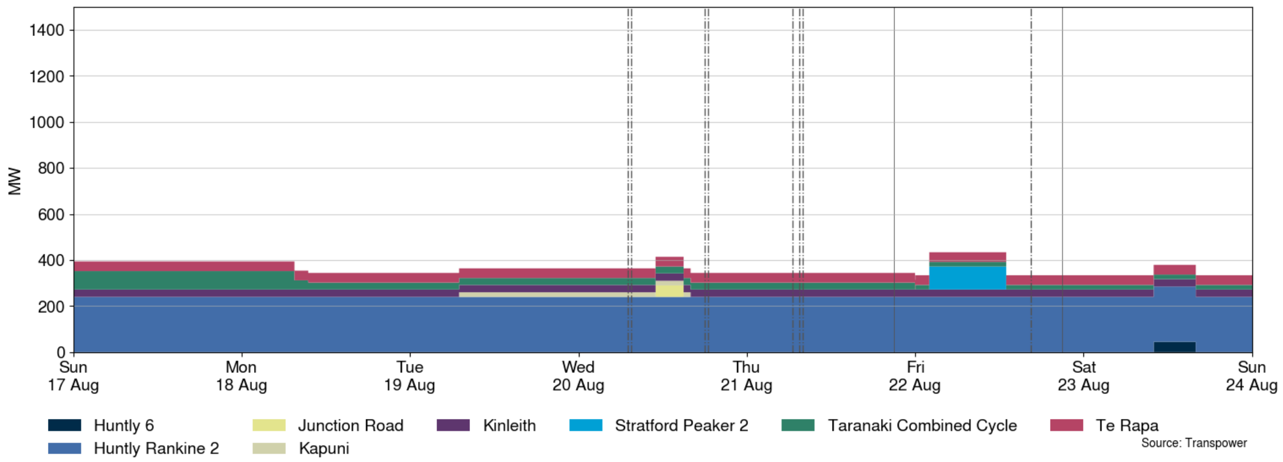


Figure 17: Total MW loss from thermal outages, 17-23 August 2025

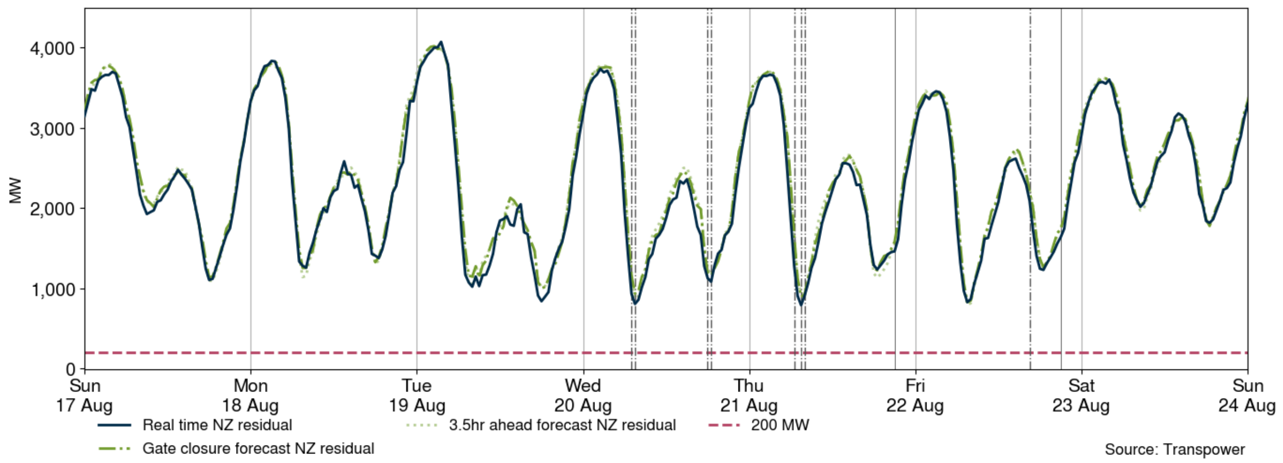


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 17-23 August 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 790MW on Thursday at 7.30am

Figure 18: National generation balance residuals, 17-23 August 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 23 August 2025, national controlled hydro storage had decreased to 47% of nominal full and ~79% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (38% full[2]) is slightly above its historic 10th percentile, while storage at Lake Takapō (27% full) is below its historic 10th percentile.

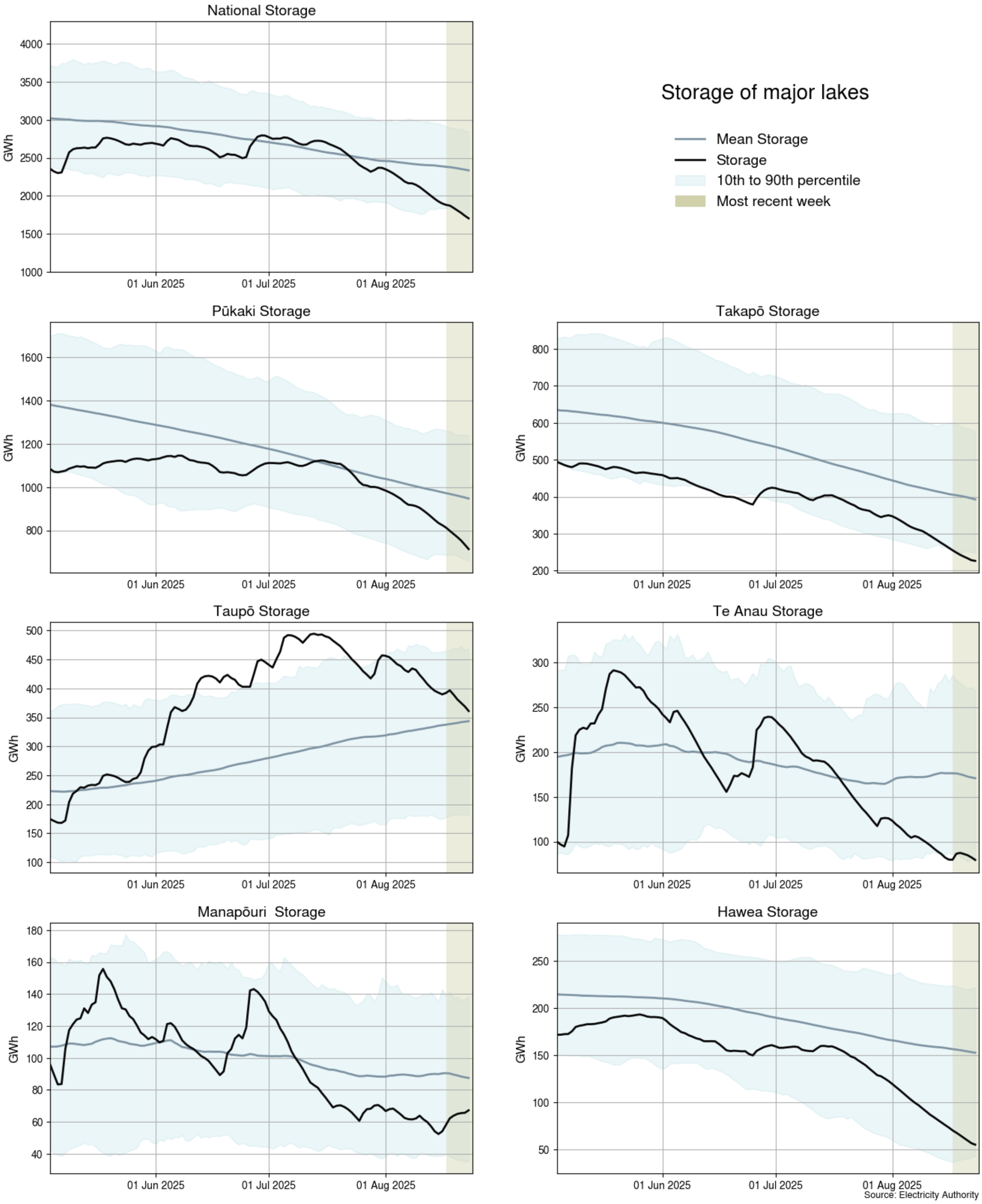
10.4. Storage at Lake Te Anau (29% full) is touching its historic 10th percentile, and storage at Lake Manapōuri (44% full) is below its historic mean.

10.5. Storage at Lake Taupō (62% full) is slightly above its historic mean.

10.6. Storage at Lake Hawea (18% full) remains close to its historic 10th percentile.

[2] Percentage full values sourced from NZX hydrological summary 24 August 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 August 2025. The SRMCs for gas powered generation have increased, while the SRMC for diesel fuelled generation has remained stable.

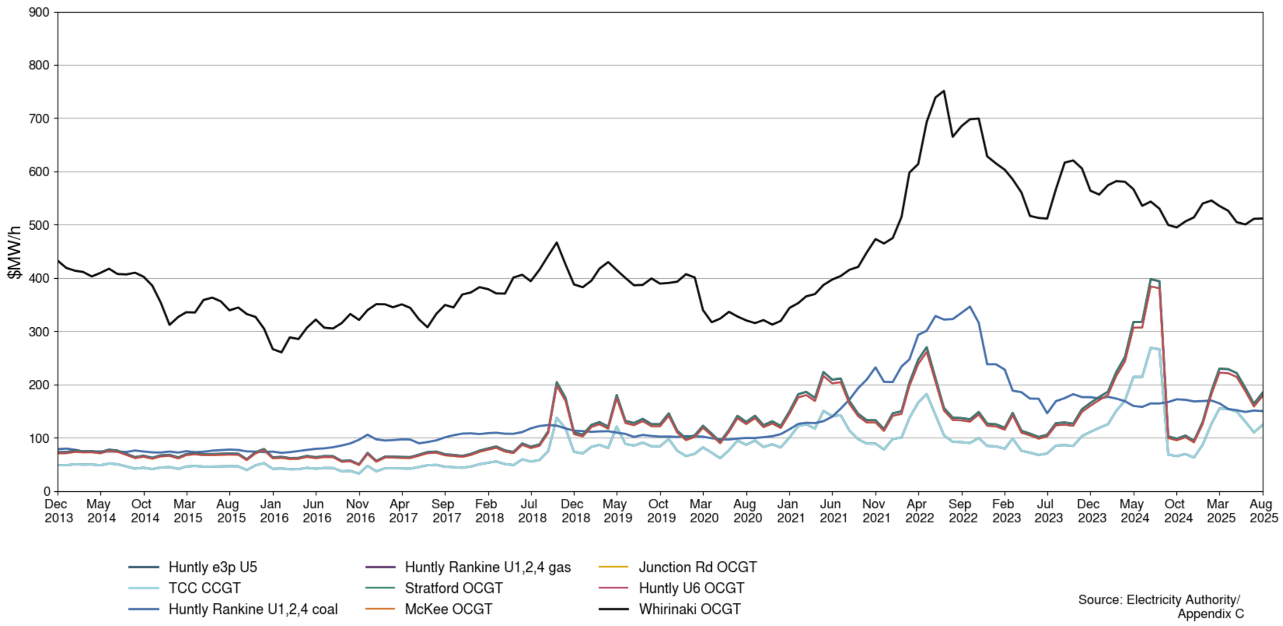
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $124/MWh and $184/MWh.

11.6. The SRMC of Whirinaki is ~$512/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

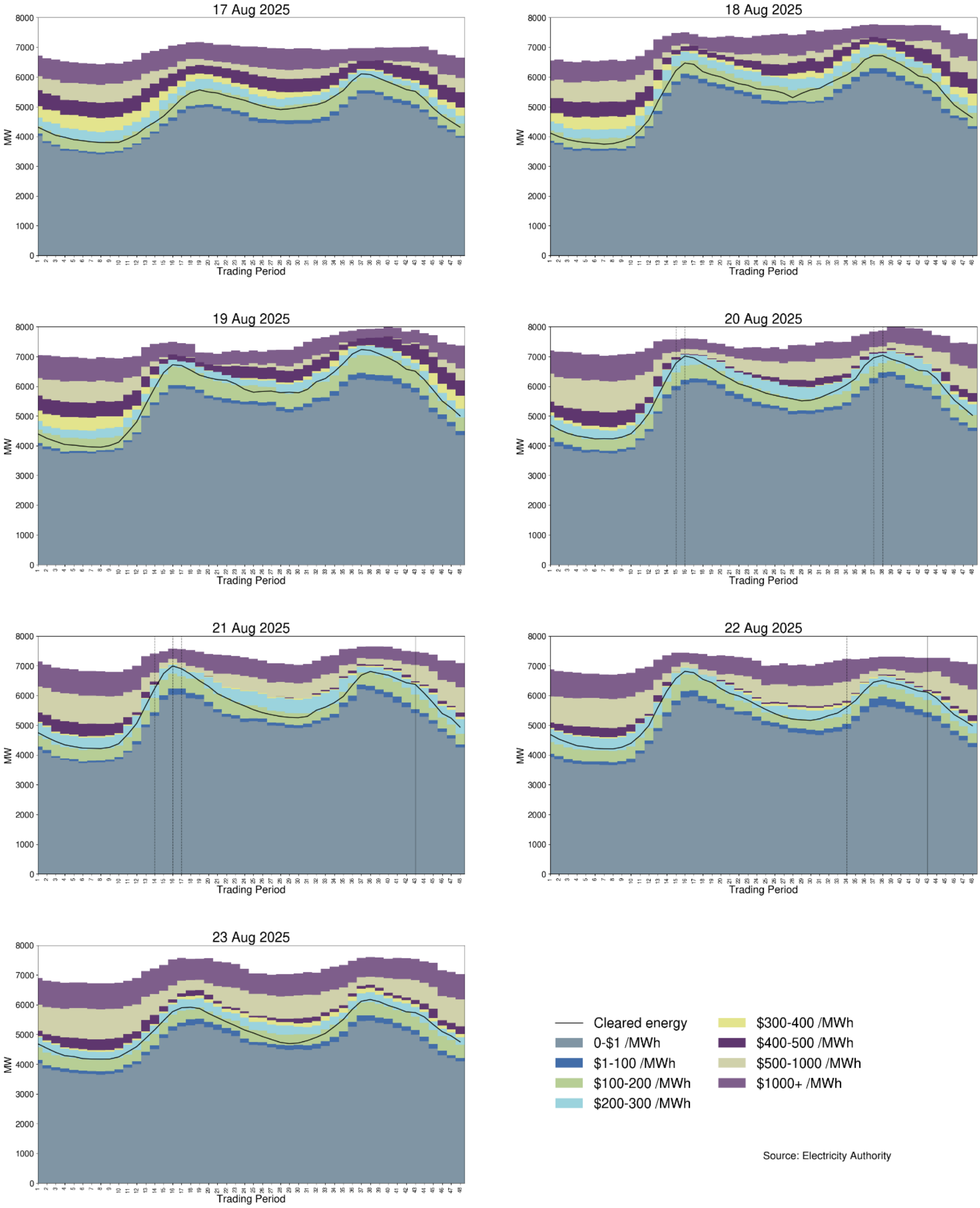


12. Offer behaviour

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 $100-$300/MWh range. During a few trading periods, a combination of peak demand, forecast inaccuracies, and low wind generation contributed to cleared energy shifting into higher price bands. Hydro generation continues to be shifted into higher priced tranches to signal the increasing value of stored water.

Figure 21: Daily offer stacks



Source: Electricity Authority

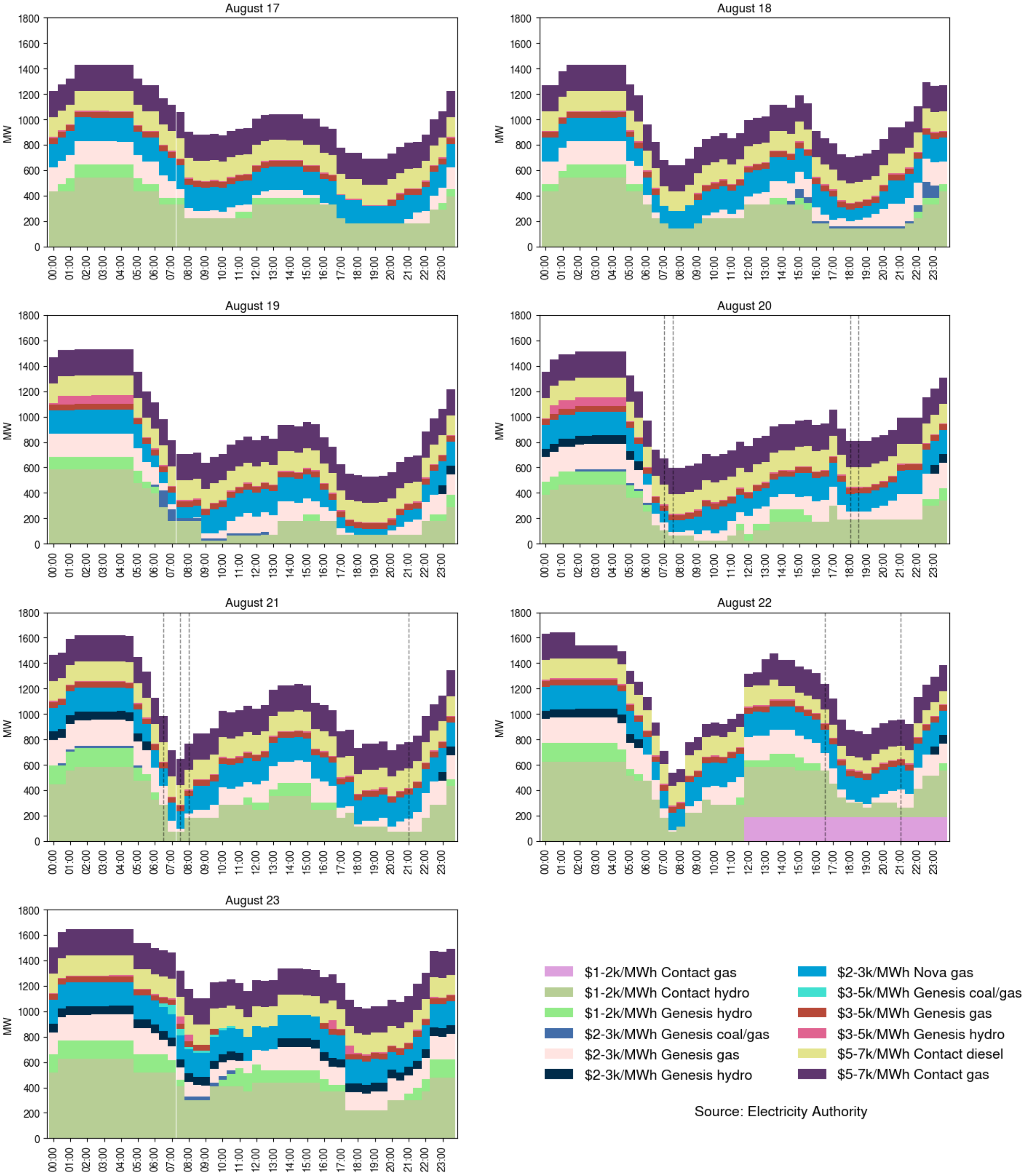
12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 1,096MW per trading period was priced above $1,000/MWh this week, which is roughly 17% of the total energy available. This is the highest of the year so far, which has occurred as hydro storage has also reached its lowest point.

12.6. A high proportion of Contact's energy along the Clutha is priced high as the scheme has continued low hydro storage from controlled (Hawea 19% full) and uncontrolled lakes (Wakatipu 11% and Wanaka 17% full). The monitoring team has engaged with Contact regarding these offers.

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
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
1/08/2025-9/08/2025	Several	Further analysis	Mercury	Waikato	Hydro offers
14/08/2025-16/08/2025	Several	Further analysis	Contact	Clutha scheme	Hydro offers