25 August 2026

Trading conduct report 16-22 August 2026

Market monitoring weekly report

Trading conduct report 16-22 August 2026

1. Overview

1.1. Spot prices have increased slightly compared to the previous week, with higher demand at times due to some colder weather. However, intermittent generation was high, leading to overall low wholesale prices this week. There were two notable higher priced periods during Monday evening and Thursday morning peak demand, when reserve prices spiked.

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 16-22 August:

(a) The average spot price for the week was $82/MWh, an increase of around $11/MWh compared to the previous week.

(b) 95% of prices fell between $5/MWh and $154/MWh.

2.3. Colder weather this week meant that overall demand was higher than last week. As a result, prices increased compared to last week.

2.4. The highest price at Ōtāhuhu was $417/MWh at 7:00am on Thursday. At this time the price at Benmore was $90/MWh. Factors that may have contributed to this price spike are: North Island reserve prices spiked up to $260/MWh with low wind generation, national residual generation 256MW lower than forecast, demand 32MWh higher than forecast, and intermittent generation 64MW lower than forecast.

2.5. Prices at Ōtāhuhu spiked up to $186/MWh at 5:00pm on Monday. At this time the price at Benmore was $58/MWh. Factors that may have contributed to this price spike are: North Island reserve prices spiked up to $91/MWh with national residual generation 359MW lower than forecast, demand 57MWh higher than forecast, and intermittent generation 50MW lower than forecast.

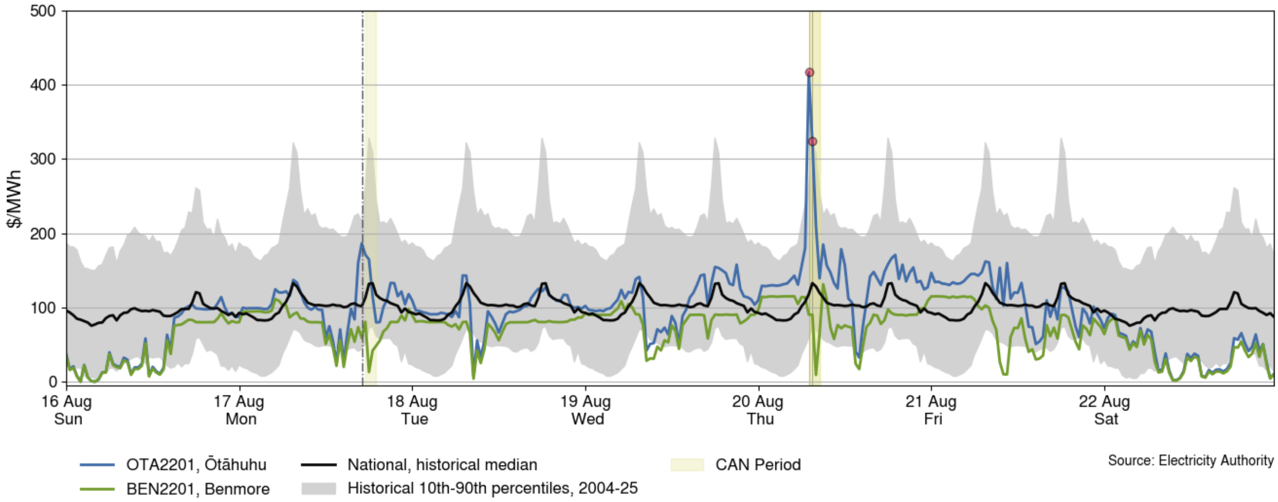
2.6. At 11.15am on Sunday the System Operator issued a Low Residual Situation Customer Advice Notice (CAN) for 5.30-7.00pm on Monday[1], as national residual generation was identified to be below 200MW during this period in the Long Non-Response Schedule (NRSL). In real-time the lowest residual that occurred during this period was 603MW.

2.7. At 2.56pm on Wednesday the System Operator issued a Low Residual Situation CAN for 7.00-8.30am on Thursday[2], as national residual generation was identified to be below 200MW during this period in the NRSL. In real-time the lowest residual that occurred during this period was 319MW.

[1] CAN Low Residual Situation 800000316.pdf
[2] CAN Low Residual Situation 800000321.pdf

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.

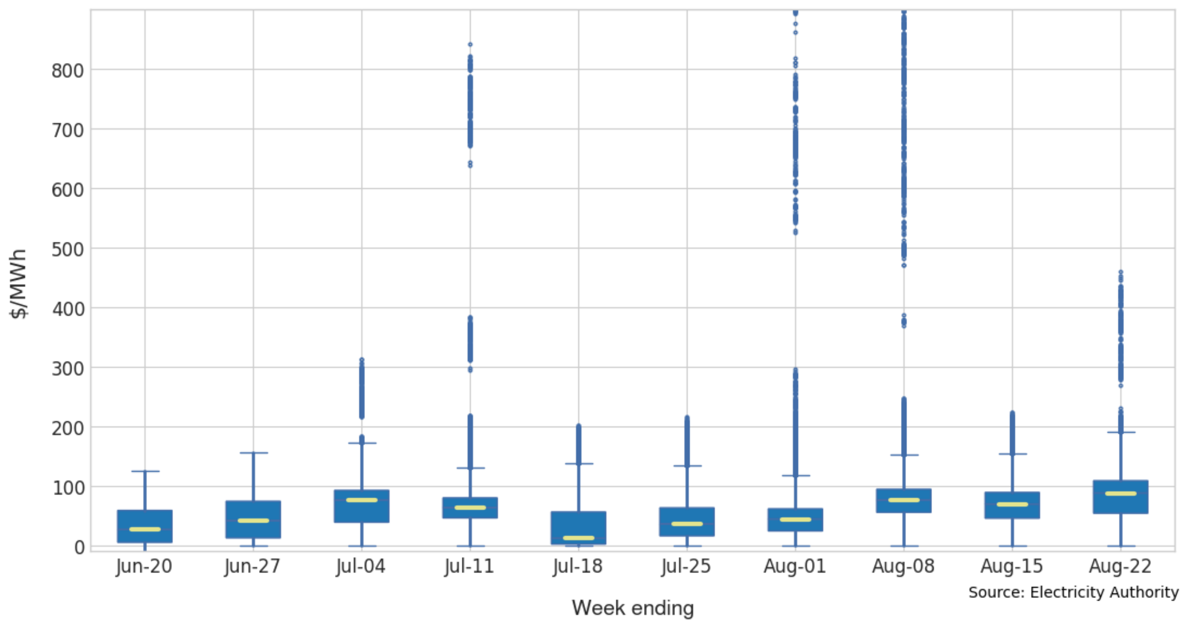
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 16-22 August



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 wider than last week with more high priced outliers. The median price was $82/MWh and most prices (middle 50%) fell between $54/MWh and $109/MWh.

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



3. Reserve prices

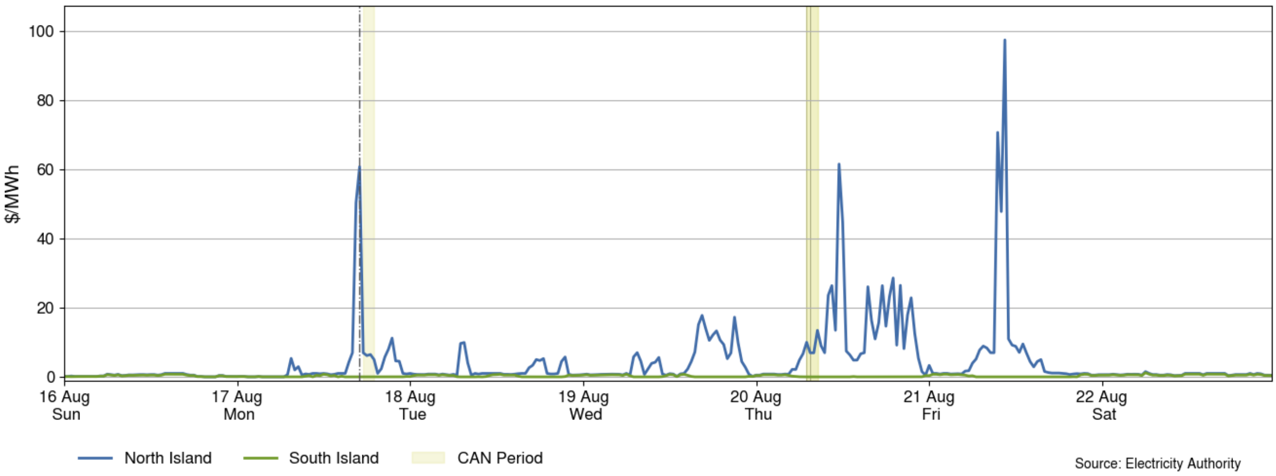
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $20/MWh this week.

3.2. At 5.00pm on Monday, North Island FIR prices spiked up to $60/MWh. At this time, the HVDC was setting the risk and northward HVDC transfer increased.

3.3. At 11.30am on Thursday, North Island FIR prices spiked up to $61/MWh. During this trading period Huntly 2 tripped off while generating at 140MW. The HVDC was setting the risk at the time.

3.4. At 9.30am on Friday, North Island FIR prices spiked up to $70/MWh and increased again to $97/MWh at 10.30am. At 9.30am the HVDC flow rapidly increased over the course of one trading period while the HVDC was setting the risk, with transfer decreasing again following the 10.30am trading period.

Figure 3: Fast instantaneous reserve price by trading period and island, 16-22 August

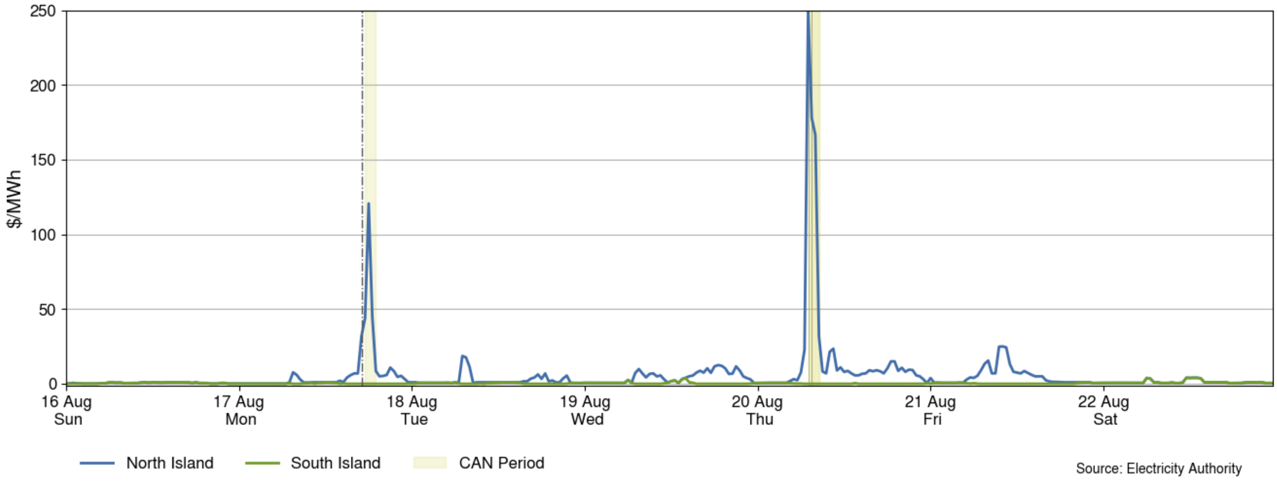


3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $25/MWh this week.

3.6. At 6.00pm on Monday, North Island SIR prices spiked up to $120/MWh. At this time the HVDC was setting the risk, and some battery reserve offers were dispatched for energy, reducing reserves available.

3.7. At 7.00am on Thursday, North Island SIR prices spiked up to $250/MWh. The HVDC was setting the risk with northward HVDC flow increasing at the time.

Figure 4: Sustained instantaneous reserve by trading period and island, 16-22 August



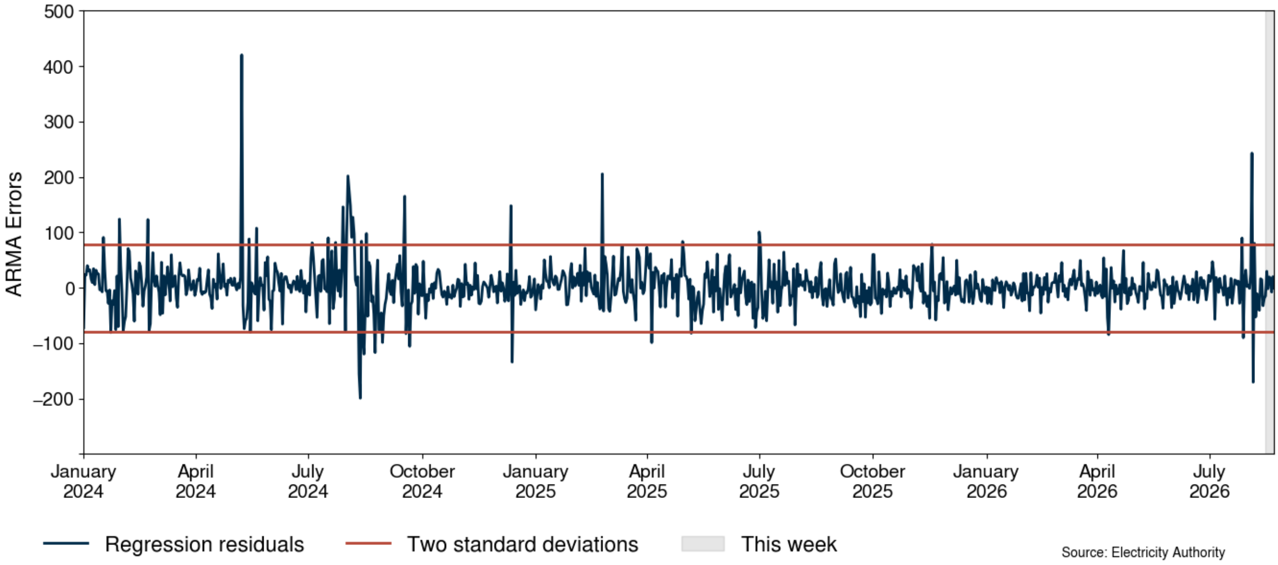
4. Regression residuals

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 - 22 August 2026



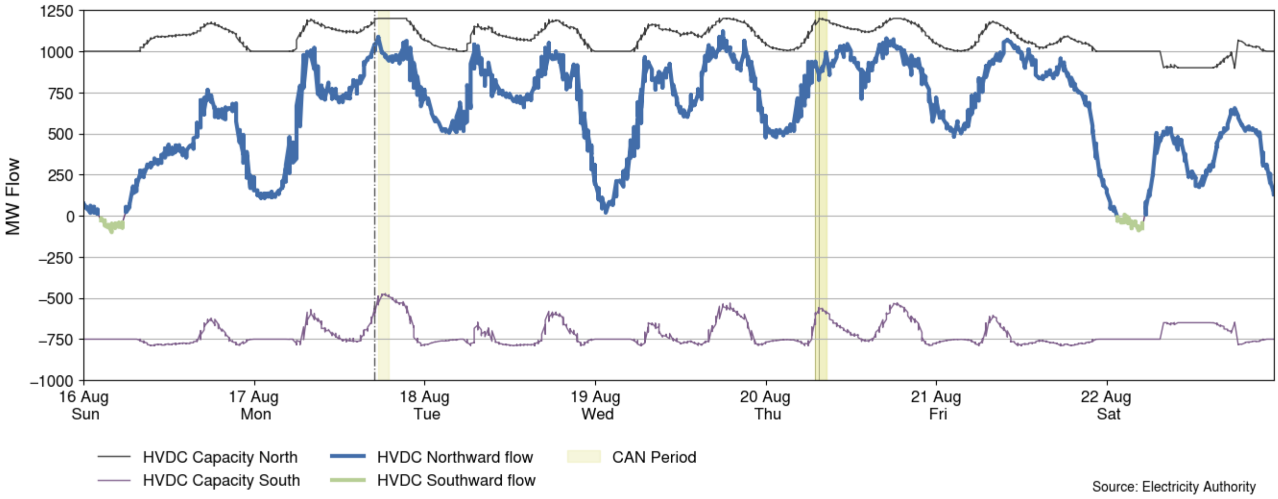
5. HVDC

5.1. Figure 6 shows the HVDC flow between 16-22 August. HVDC[3] flows were almost entirely northward this week. Southward flow occurred overnight on Sunday and Friday, during periods of high wind generation and low demand.

5.2. The highest northward HVDC flow this week was 1,121MW which occurred at 6.00pm on Wednesday.

5.3. The highest southward HVDC flow this week was 100MW which occurred at 4.00am on Sunday.

Figure 6: HVDC flow and capacity, 16-22 August



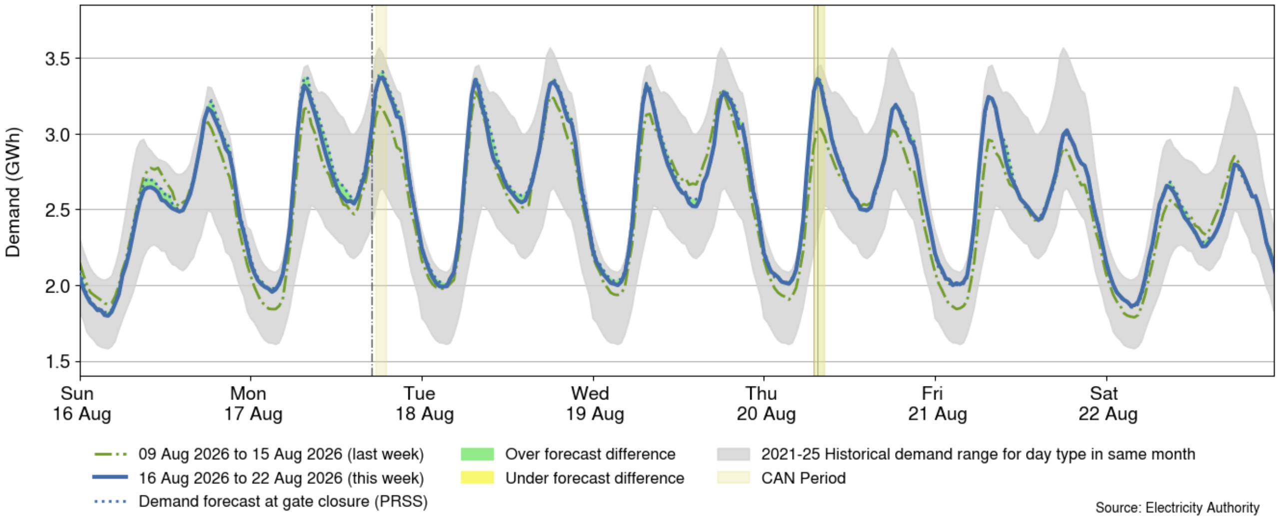
6. Demand

6.1. Figure 7 shows national demand between 16-22 August, compared to the historic range and the demand of the previous week. Demand was overall higher than last week with some periods where demand dropped below last week, such as Sunday morning, and midday Wednesday.

6.2. The maximum demand this week was around 3.37GWh (6.75GW) at 6:30pm on Monday.

[3] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South Islands. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD (scheduling, pricing and dispatch) co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

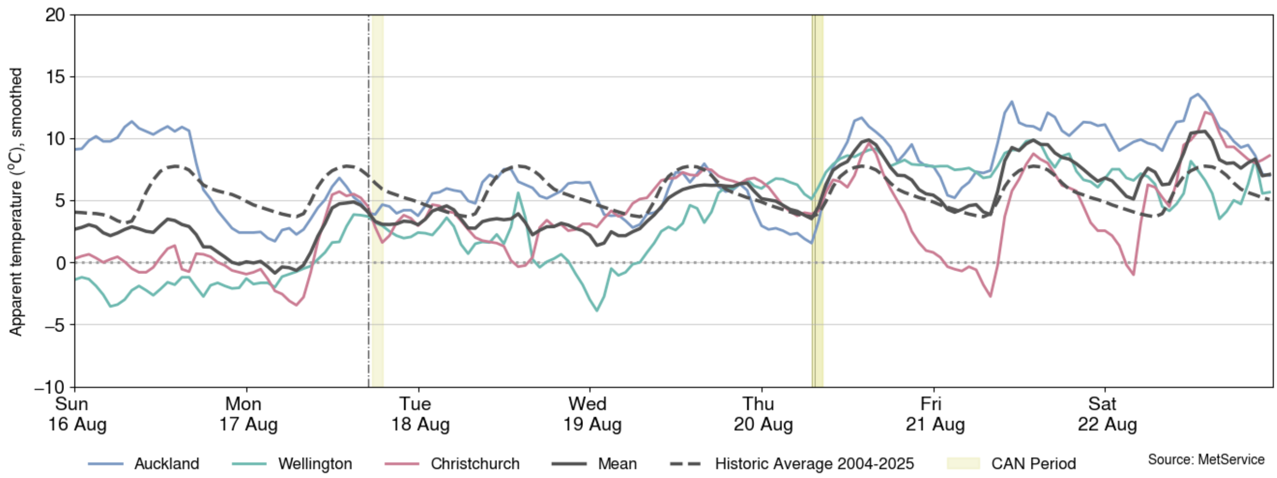
Figure 7: National demand, 16-22 August compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 16-22 August. 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 1°C to 14°C in Auckland, -5°C to 10°C in Wellington, and -4°C to 12°C in Christchurch.

Figure 8: Temperatures across main centres, 16-22 August



7. Generation

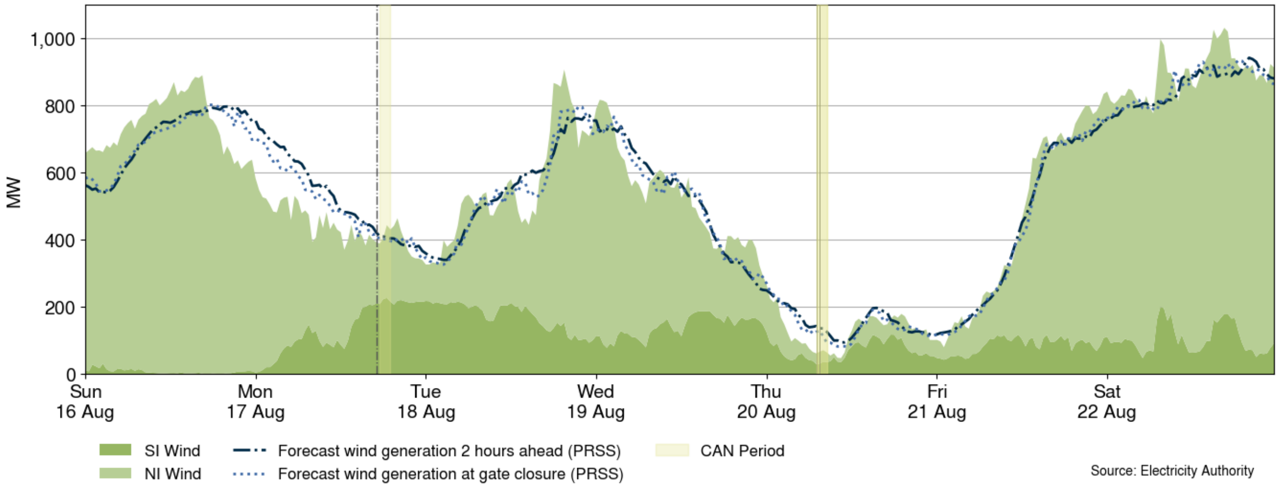
7.1. Figure 9 shows wind generation and forecast from 16-22 August. This week wind generation varied between 48MW and 1,032MW, with a weekly average of 536MW. Wind generation was below 200MW from 1.00am on Thursday to 6.00am on Friday, and high throughout the rest of the week, though lower on Monday and Tuesday morning.

7.2. Wind generation forecasting errors from 5.30pm Sunday to 6.00pm Monday were on average 111MW lower than forecast and ranged between 5MW and 209MW lower than forecast. These errors were due to West Wind 1, Harapaki, and Waipipi wind farms.

7.3. Generation was 123MW lower than forecast at 1.30pm on Tuesday. Harapaki wind farm contributed 94MW to this difference, and Waipipi contributed the next largest error of 25MW. The remainder was an accumulation of errors at other wind farms.

7.4. Wind generation forecasting errors from 2.00am to 11.00am Thursday were on average 49MW lower than forecast and ranged between 18MW and 89MW lower than forecast. These errors were due to Harapaki and Kaiwera Downs Stage 1 wind farms.

Figure 9: Wind generation and forecast, 16-22 August

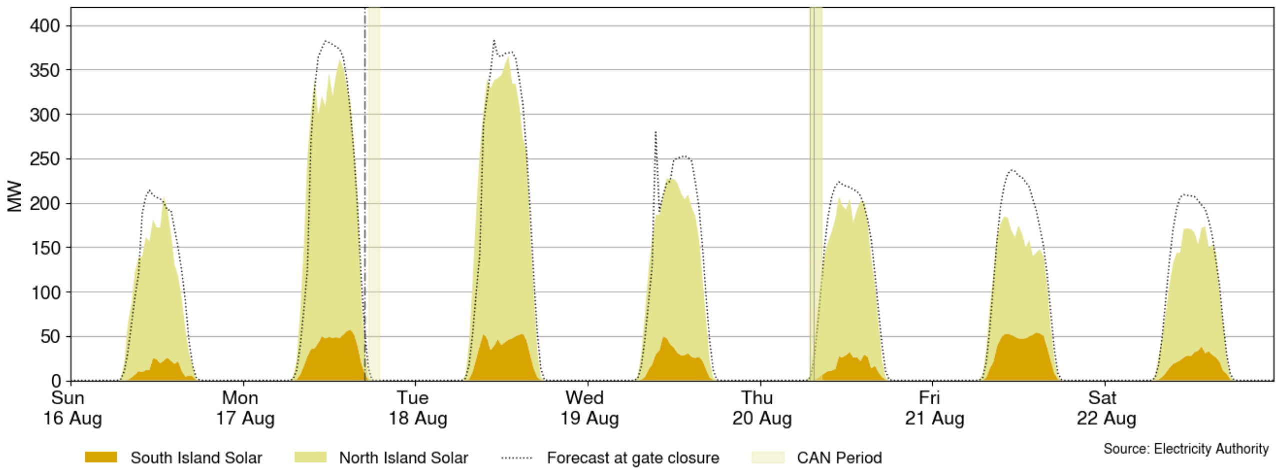


7.5. Figure 10 shows solar generation from 16-22 August. Solar generation was high at times this week when Tauhei solar farm was generating.

7.6. Forecasting errors this week being largely caused by Tauhei up to 8.00am on Wednesday, when the farm had to be disconnected due to a voltage stability issue while commissioning.[4] Errors after this are due to an accumulation of errors at other farms.

7.7. Solar generation this week peaked at 365MW on Tuesday at 1.00pm.

Figure 10: Solar generation, 16-22 August



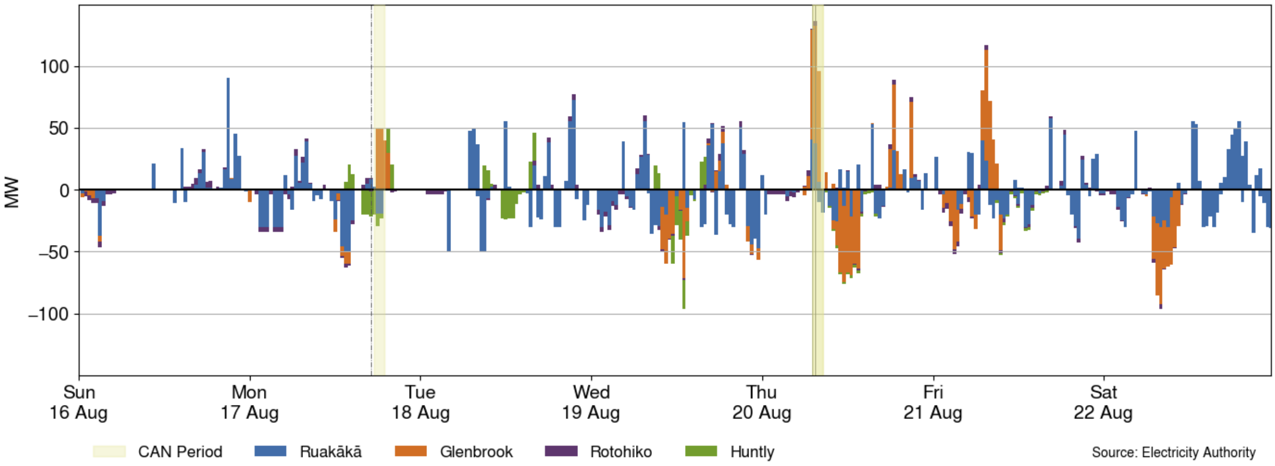
7.8. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh, commissioning) charged (negative values) and discharged (positive values). Typically, a

[4] GEN RPT for Voltage Stability Event Waihou 800000322.pdf

grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.9. This week batteries generally charged overnight and during the middle of the day and discharged during the morning and evening peaks.

Figure 11: Grid scale battery charge and discharge, 16-22 August



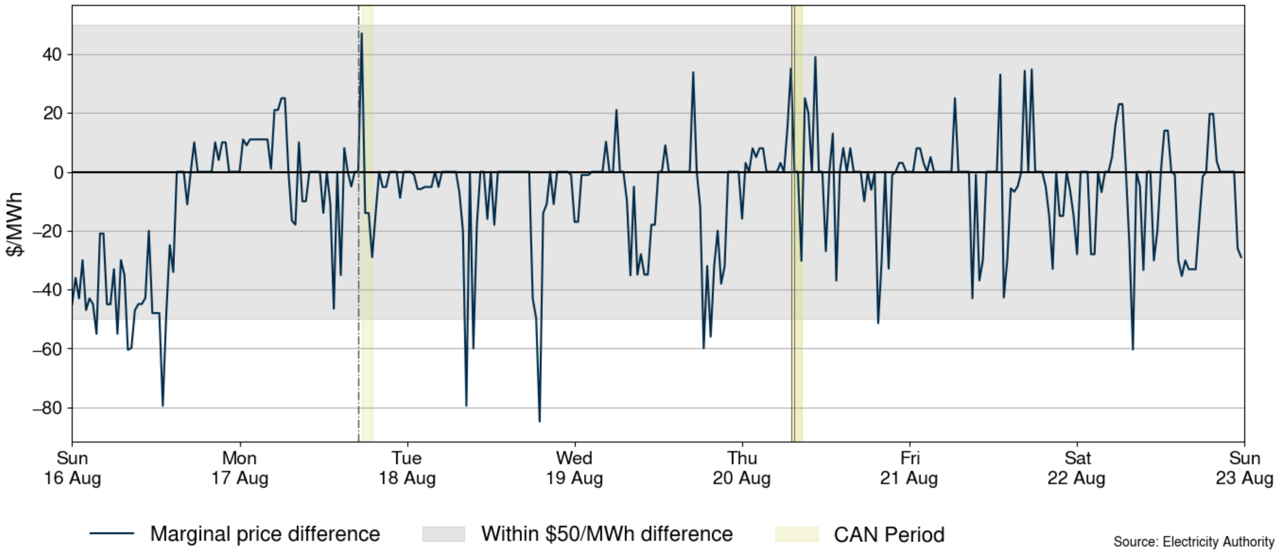
7.10. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[5]) projections. The figure highlights when forecasting inaccuracies are causing 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.

7.11. There are 12 periods with price differences greater than $50/MWh this week. These are all negative differences.

7.12. The largest negative price forecast difference was $84/MWh which occurred at 7.00pm on Tuesday. At this time demand was 40MW lower than forecast and intermittent generation was 126MW higher than forecast.

[5] 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, 16-22 August

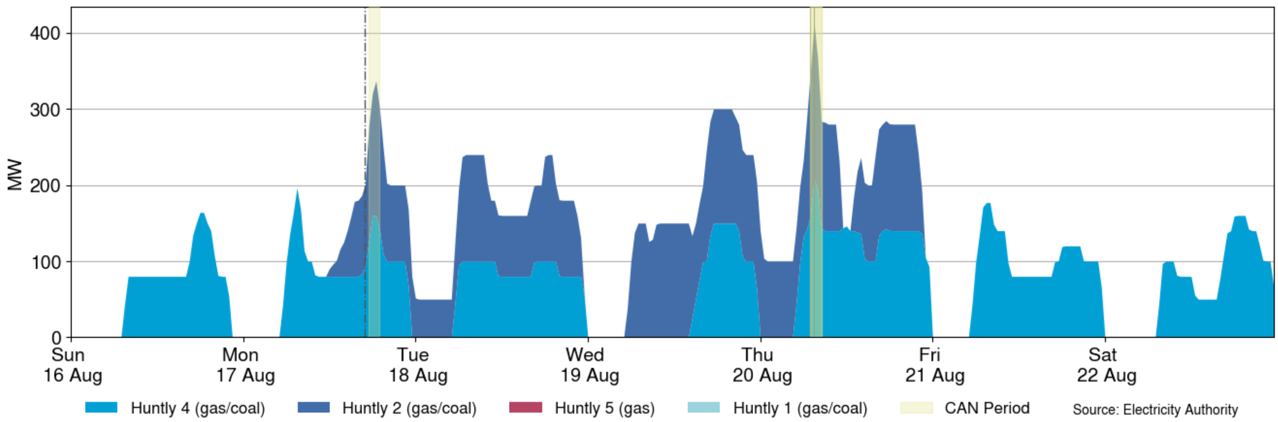


7.13. Figure 13 shows the generation of thermal baseload between 16-22 August.

7.14. Baseload thermal generation was provided by Huntly 2 and 4 this week, with both units generating during the high priced periods on Monday and Thursday.

7.15. Huntly 2 tripped off at 11.30am on Thursday after ramping down from generating at 140MW.

Figure 13: Thermal baseload generation, 16-22 August

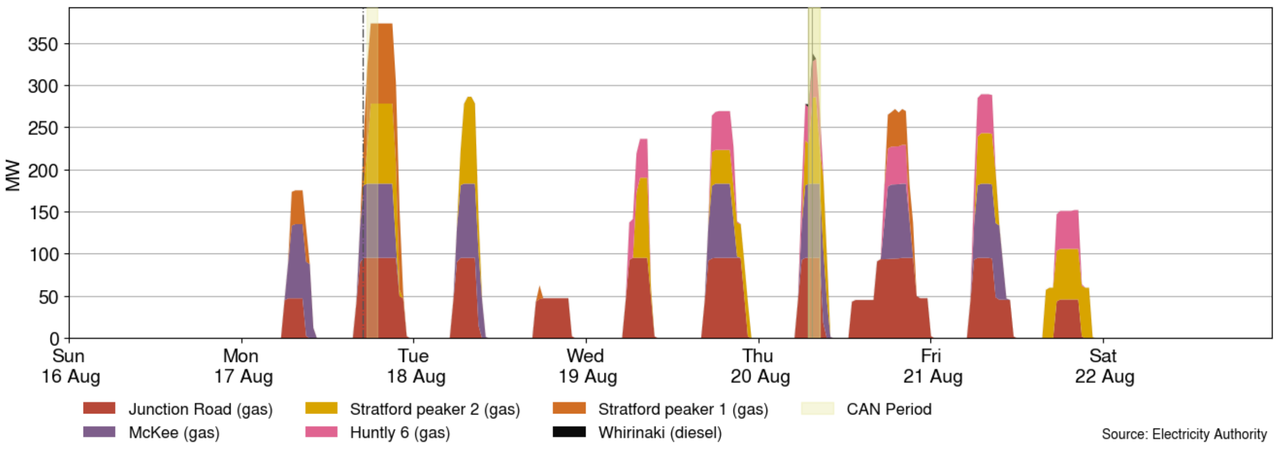


7.16. Figure 14 shows the generation of thermal peaker plants between 16-22 August. Peakers generated during the morning and evening peaks on weekdays this week, and did not generate on the weekend.

7.17. During the Thursday morning peak, Whirinaki was constrained on and did not clear in the energy market.

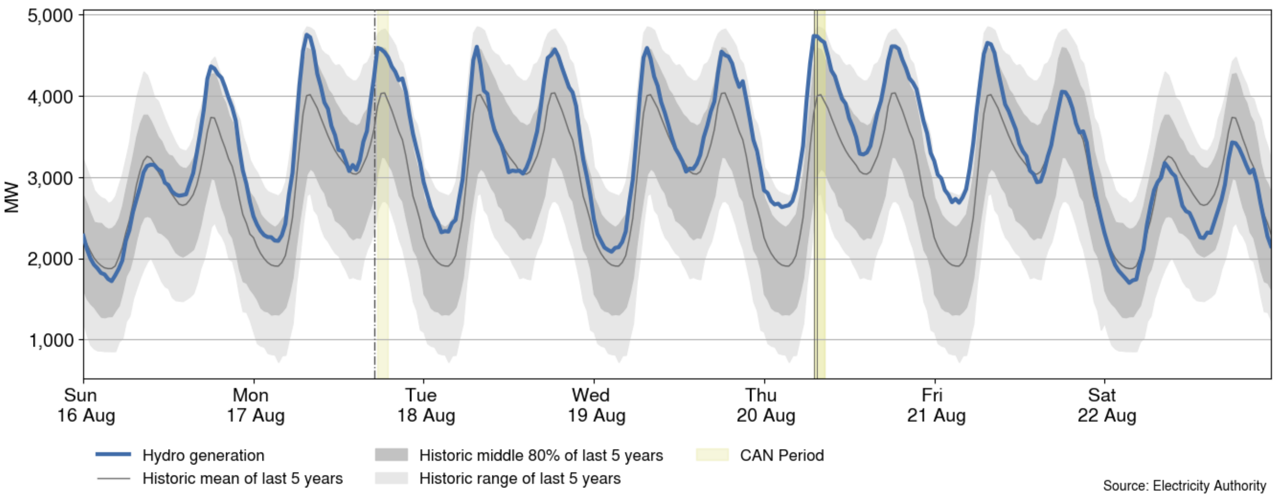
7.18. Stratford peaker 1 tripped off at 10.30pm on Monday and went on outage until 3.00pm on Tuesday. It attempted to run at 5.00pm on Tuesday but was shut down at 5.30pm as a metal chip was detected in the machine, and was subsequently on outage until Thursday.

Figure 14: Thermal peaker generation, 16-22 August



7.19. Figure 15 shows hydro generation between 16-22 August. Hydro generation was high this week, sitting around the top of the middle 80% of the historic range from Monday to Friday morning.

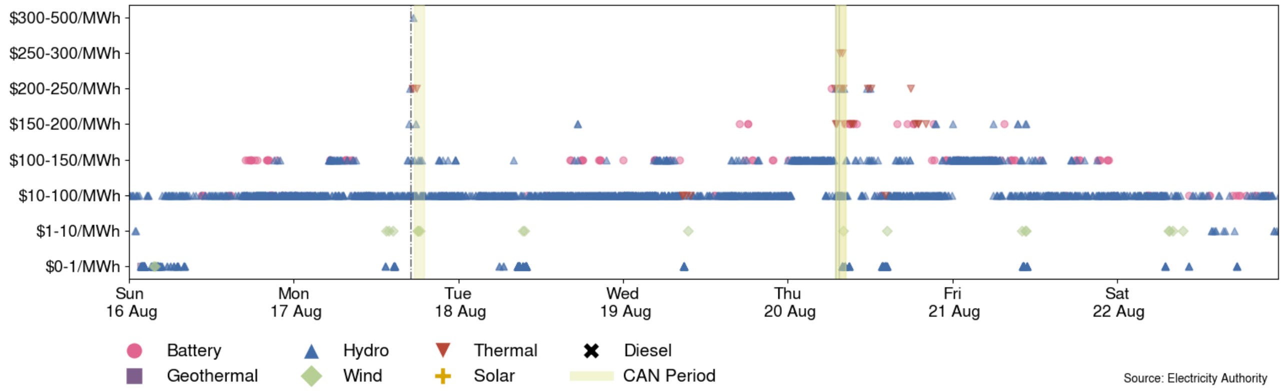
Figure 15: Hydro generation, 16-22 August



7.20. 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.

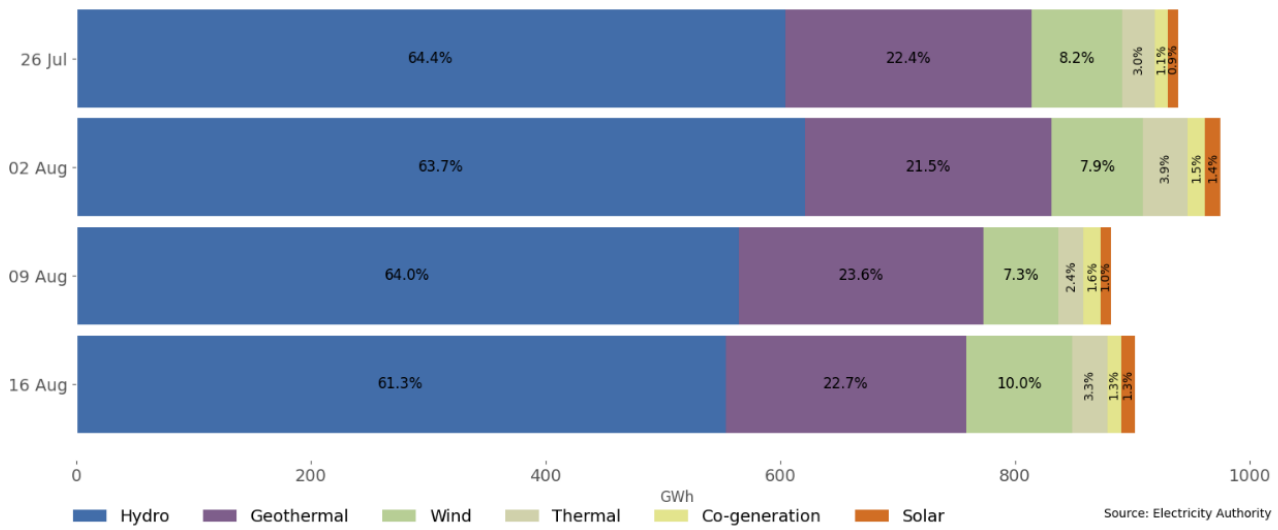
7.21. The highest marginal price of $310/MWh was set by Karāpiro during the 5:00pm trading period on Monday. The most common marginal technology was hydro and the second most common technology was battery. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 16-22 August



7.22. As a percentage of total generation, between 16-22 August, total weekly hydro generation was 61.3%, geothermal 22.7%, wind 10%, thermal 3.3%, co-generation 1.3%, and solar (grid connected) 1.3%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 26 July and 16 August



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 16-22 August ranged between ~447MW and ~1,467MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 16-22 August

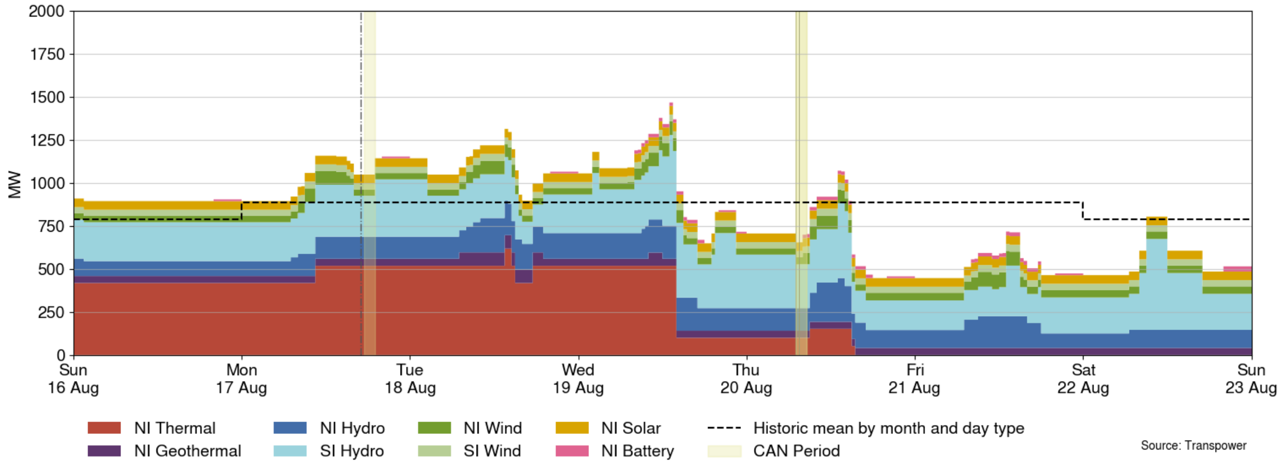
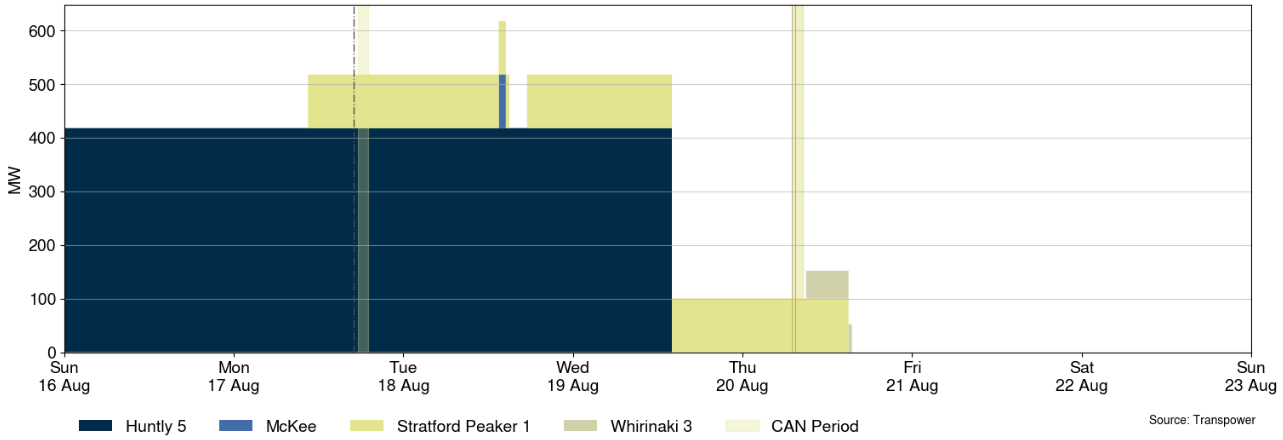


Figure 19: Total MW loss from thermal outages, 16-22 August



8.2. Notable outages include:

Plant	Partial or Full	End Date
Huntly 5	Full	19 August 2026
Manapōuri unit 3	Full	19 August 2026
Manapōuri unit 4	Full	20 August 2026
Stratford Peaker 1	Full	20 August 2026
Manapōuri unit 7	Full	21 August 2026
Tauhei Solar Farm	Full	28 August 2026
Kaiwaikawe Wind Farm	Partial	30 November 2026
Roxburgh unit 8	Full	24 September 2026

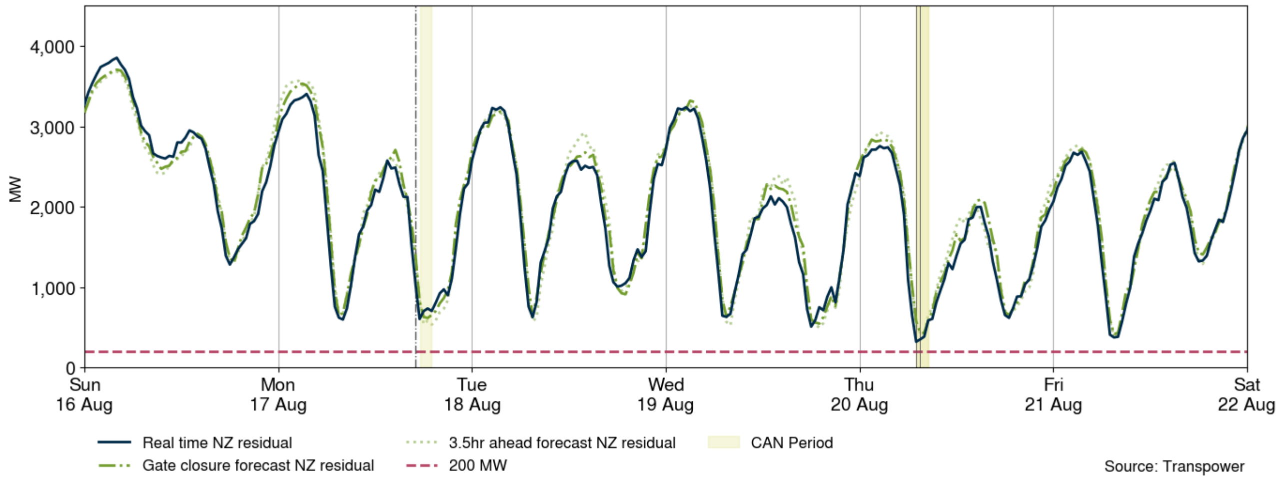
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 16-22 August. 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. At 11.15am on Sunday the System Operator issued a Low Residual Situation CAN for 5.30-7.00pm on Monday[6], as national residual generation was identified to be below 200MW during this period in the NRSL. In real-time the lowest residual that occurred during this period was 603MW.

9.3. At 2.56pm on Wednesday the System Operator issued a Low Residual Situation CAN for 7.00-8.30am on Thursday[7], as national residual generation was identified to be below 200MW during this period in the NRSL. In real-time the lowest residual that occurred during this period was 319MW.

Figure 20: National generation balance residuals, 16-22 August



10. Storage/fuel supply

10.1. As of 22 August, national controlled storage was 68% nominally full and ~113% of the historical average for this time of the year.

10.2. Storage at Lake Pūkaki (80% full) is significantly higher than the historic 90th percentile for this time of year.

10.3. Storage at Lake Tekapō (58% full) is below the historic 90th percentile but above average for this time of year.

10.4. Storage at Lake Taupō is (42% full) is below average for this time of year.

10.5. Storage at Lake Te Anau (70% full) is just above average for this time of year.

10.6. Storage at Lake Manapōuri (58% full) is below the historic 90th percentile for this time of year but above average.

10.7. Storage at Lake Hawea (45% full) is below average for this time of year.

10.8. Figure 21 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10^{th} to 90^{th} percentiles.

10.9. As of 22 August, national controlled storage was 68% nominally full and ~113% of the historical average for this time of the year.

[6] CAN Low Residual Situation 800000316.pdf
[7] CAN Low Residual Situation 800000321.pdf

10.10. Storage at Lake Pūkaki (80% full[8]) is significantly higher than the historic 90th percentile for this time of year.

10.11. Storage at Lake Tekapō (58% full) is below the historic 90th percentile but above average for this time of year.

10.12. Storage at Lake Taupō is (42% full) is below average for this time of year.

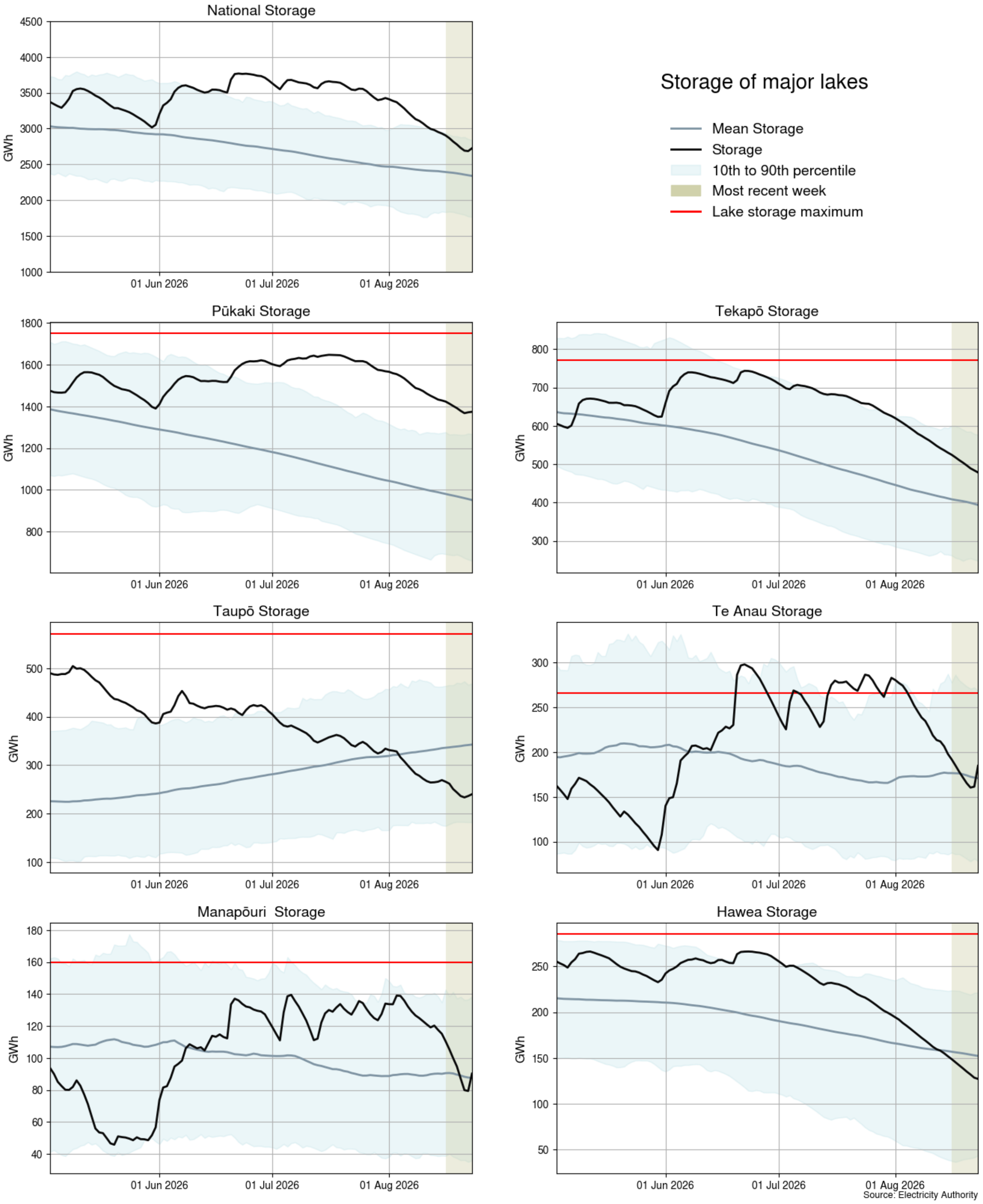
10.13. Storage at Lake Te Anau (70% full) is just above average for this time of year.

10.14. Storage at Lake Manapōuri (58% full) is below the historic 90th percentile for this time of year but above average.

10.15. Storage at Lake Hawea (45% full) is below average for this time of year.

[8] Percentage full values sourced from NZX Hydro.

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 23 shows an estimate of thermal SRMCs as a monthly average up to 1 August 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 ~$203/MWh.

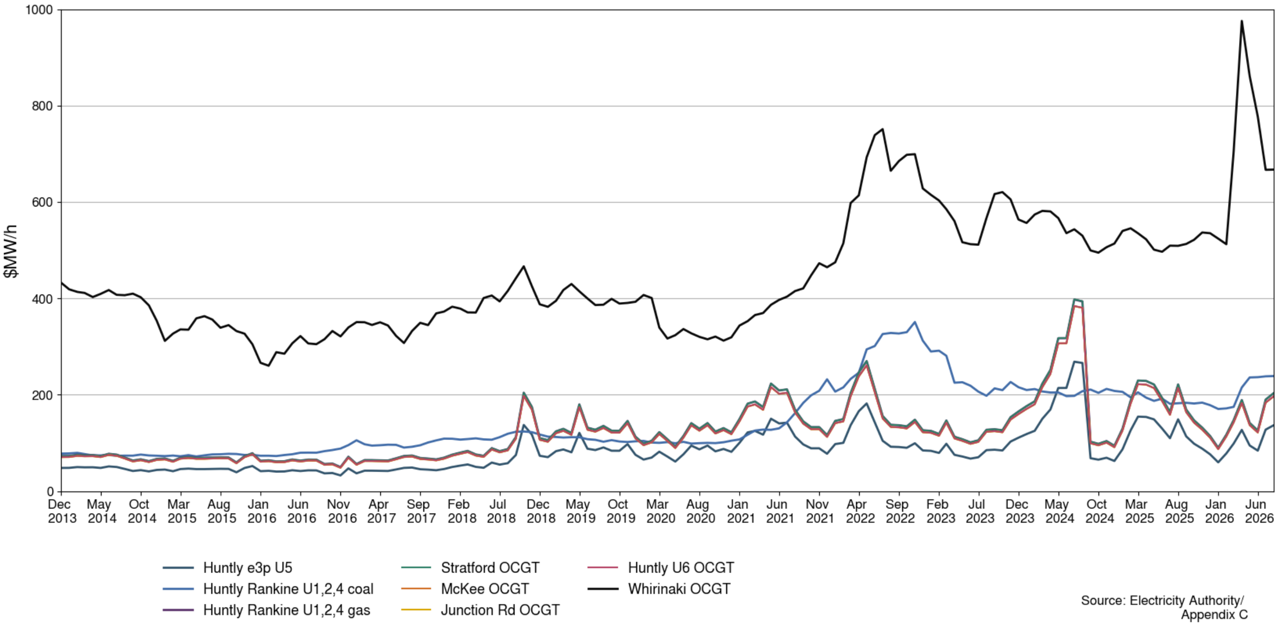
11.5. The SRMC of gas fuelled thermal plants is currently between $136/MWh and $203/MWh.

11.6. The SRMC of Whirinaki is ~$667/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

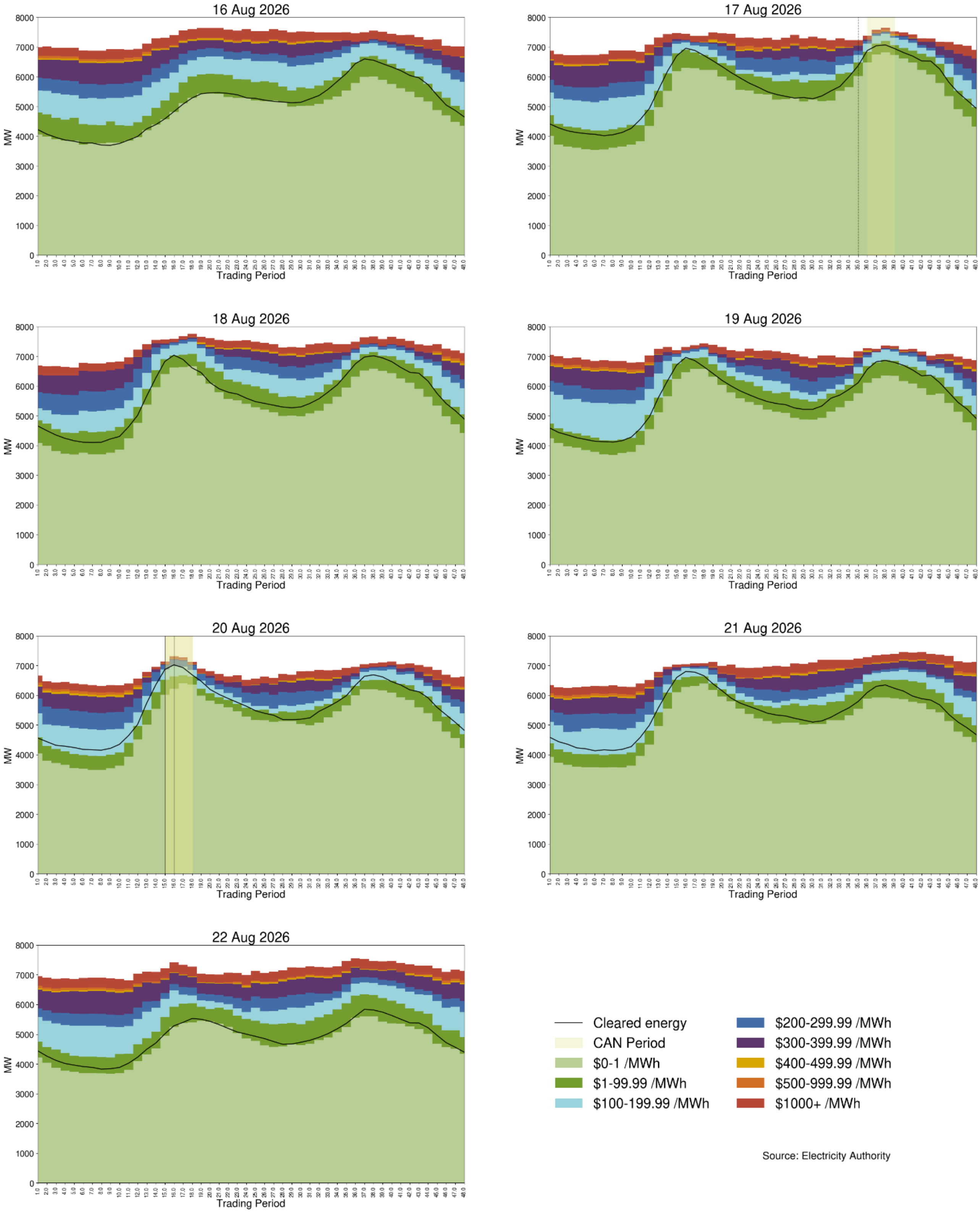


12. Offer behaviour

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. Most offers cleared below $100/MWh with some clearing above $200/MWh during the high-priced periods on Monday and Thursday.

Figure 23: Daily offer stacks



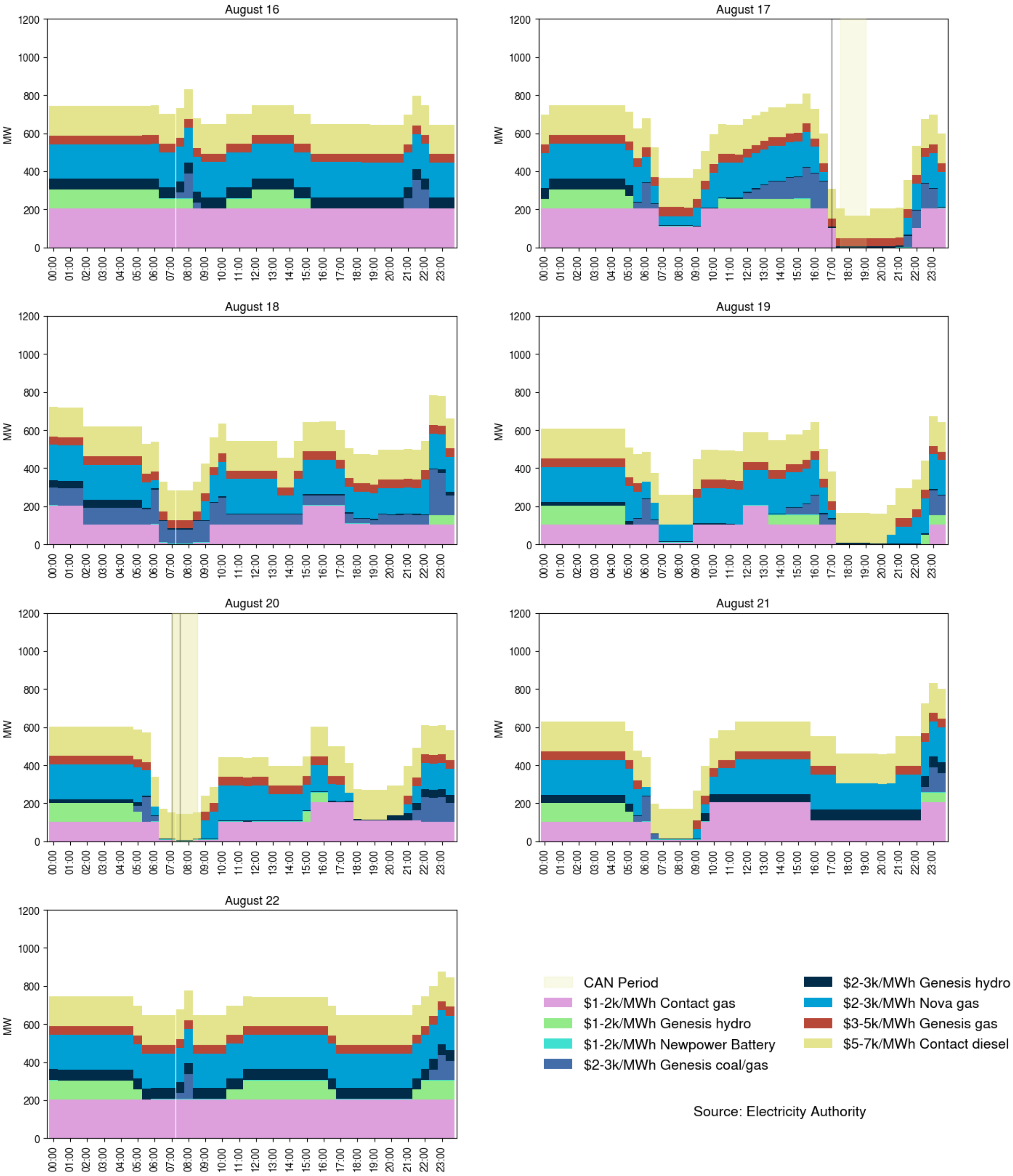
Source: Electricity Authority

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 564MW 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
07/05/2026-08/05/2026	Several	Further analysis	Genesis	Tekapō	Offers
27/05/2026	Several	Further analysis	Genesis	Huntly 5	Offers
02/08/2026-08/08/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers