11 August 2026

Trading conduct report 2-8 August 2026

Market monitoring weekly report

Trading conduct report 2-8 August 2026

1. Overview

1.1. This week is characterised by high hydro generation and high demand contributing to entirely northward HVDC flows, which caused frequent North Island price separation. There were also three high-priced periods during peak demand on Tuesday evening and Thursday morning when temperatures were low. Prices reached over $1000/MWh at these times.

1.2. As a result, the average spot price for the week was $123/MWh, an increase of around $60/MWh compared to the previous week. National hydro storage has decreased to 77% nominally full and ~124% of the historical average.

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 2-8 August:

(a) The average wholesale spot price across all nodes was $123/MWh, an increase of around $60/MWh.

(b) 95% of prices fell between $18/MWh and $222/MWh.

2.3. The highest price at Ōtāhuhu was $4,320/MWh at 7.30pm on Tuesday. At this time prices at Benmore were $3,351/MWh. This is due to high priced thermal generation, including Whirinaki station, setting the prices at the time following the tripping of Huntly 4 at 7.45pm and Stratford peaker 2 being unable to start from 7.30-8.30pm. Additionally, at 7.45pm the Scheduling, Pricing, and Dispatch model (SPD) identified energy scarcity at the Wiri node (WIR0331) in Auckland. Energy scarcity sets the price at the node to $21,000/MWh. This state lasted for just over 3 minutes until the next SPD run at 7.49pm.

2.4. Earlier on Tuesday at 6.30pm the price at Ōtāhuhu spiked to $1,517/MWh and prices at Benmore spiked to $1,190/MWh. At this time the national reserve dropped to 255MW, which was 236MW lower than forecast at gate closure. Additionally, wind generation was 55MW lower than forecast.

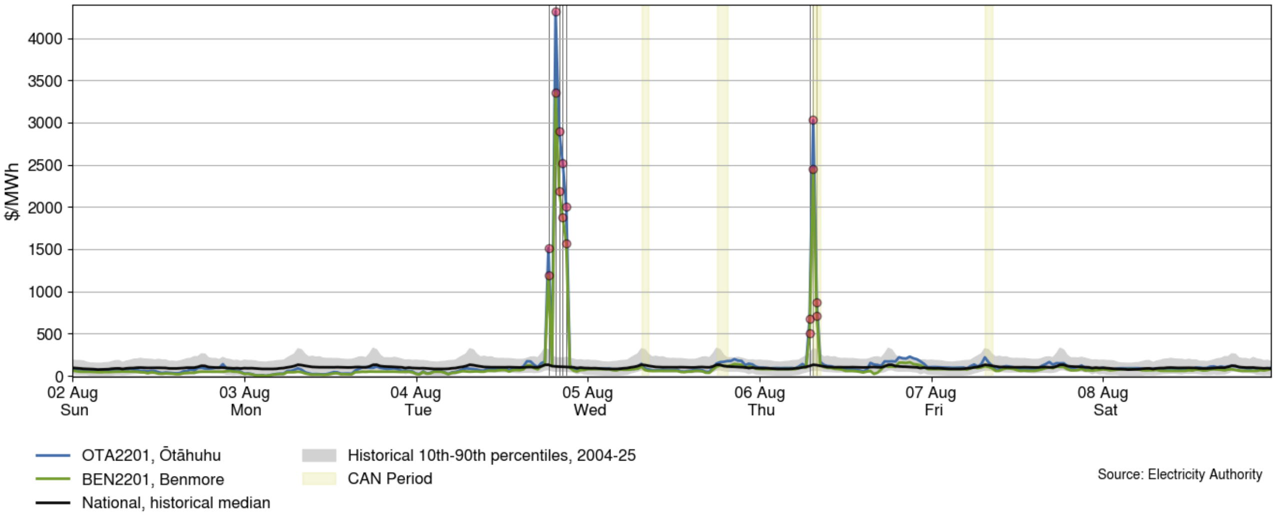
2.5. Ōtāhuhu prices also spiked up to $3,029/MWh at 7.30am on Thursday. At this time prices at Benmore were $2,447/MWh. The highest demand ever recorded occurred during this time. At this time batteries priced at $1,200/MWh were setting the price. Additionally, one five-minute dispatch had a RTD price at ~$6,628/MWh, which resulted when Whirinaki energy dispatch was increased. SIR prices were at their highest for the week ($166/MWh at Ōtāhuhu and $143/MWh at Benmore), and demand was ~31MWh higher than forecast.

2.6. At 8.29am on Monday, the System Operator issued a potential low residual customer advice notice (CAN) for 7.30-8.30am, 6.00-7.30pm on Wednesday, and 7.30-8.30am on Thursday as the NRSL schedule (Long Non-Response Schedule) showed residual generation was less than 200MW.[1]

2.7. At 11.08pm on Tuesday the Thursday period was upgraded to a low residual situation.[2] At 8.24am on Wednesday another potential low residual situation CAN was issued for 7.30-8.30am on Friday,[3] this was upgraded to a low residual situation with another CAN at 12.50am on Friday.[4] These periods are highlighted with yellow bars throughout the report.

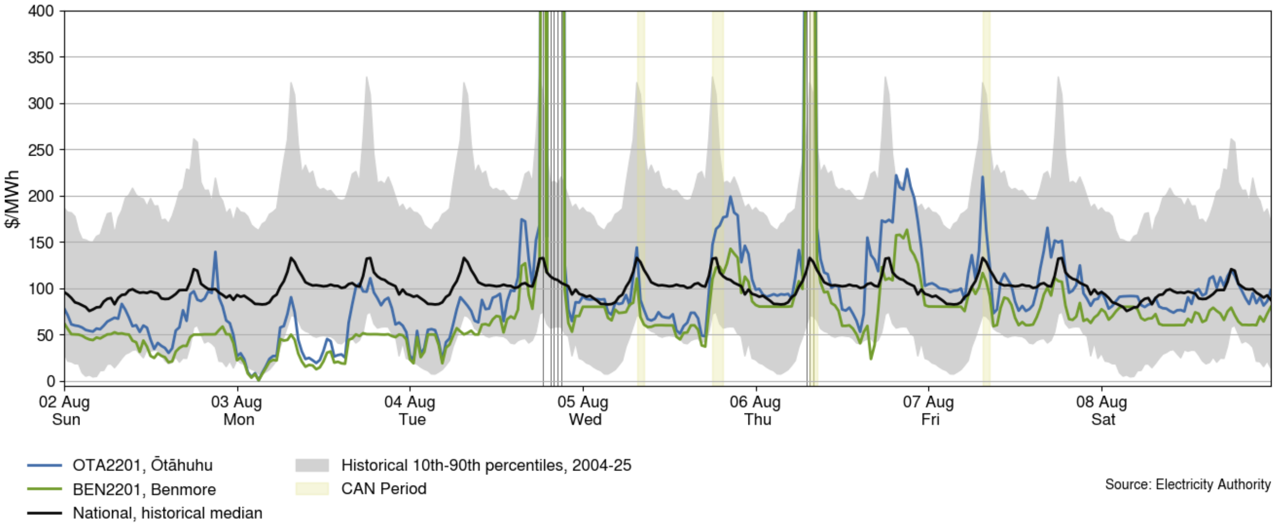
2.8. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 2-8 August



[1] CAN Potential Shortfall or Low Residual Situation 800000274.pdf
[2] CAN Low Residual Situation 800000279.pdf
[3] CAN Potential Short Fall or Low Residual Situation 800000281.pdf
[4] CAN Low Residual Situation 800000291.pdf

Figure 2: Wholesale spot prices at Benmore and Ōtāhuhu, 2-8 August (y-axis limited to $400/MWh)



2.9. Figure 3 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 but with a larger number of high price outliers. The median price was $123/MWh and most prices (middle 50%) fell between $55/MWh and $94/MWh.

Figure 3: Box plot showing the distribution of spot prices this week and the previous nine weeks

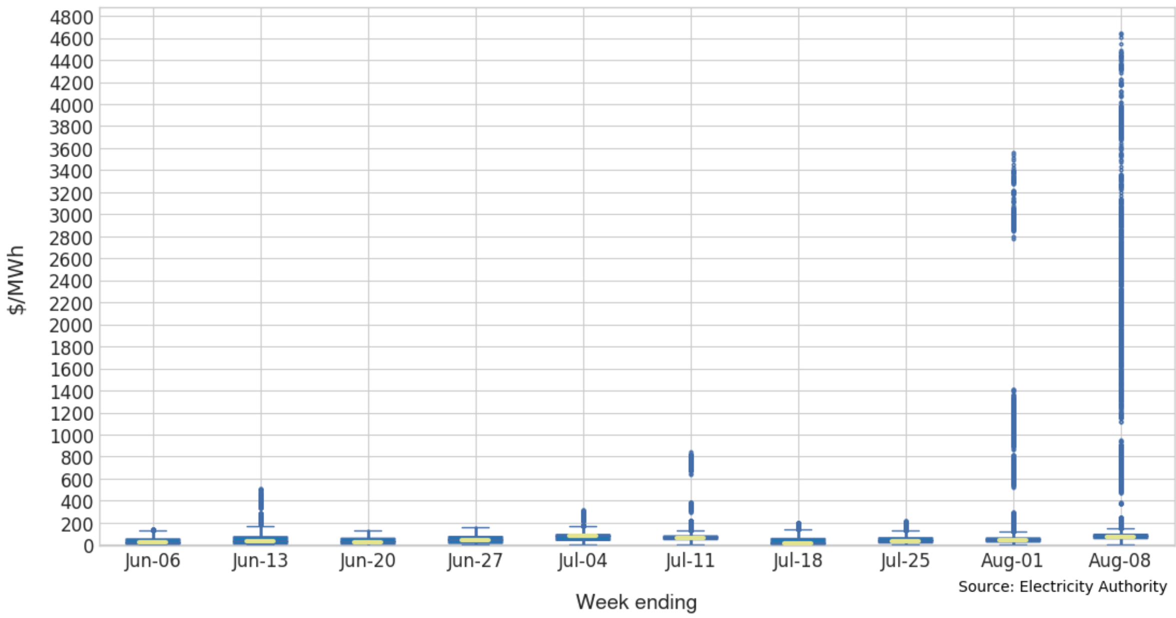
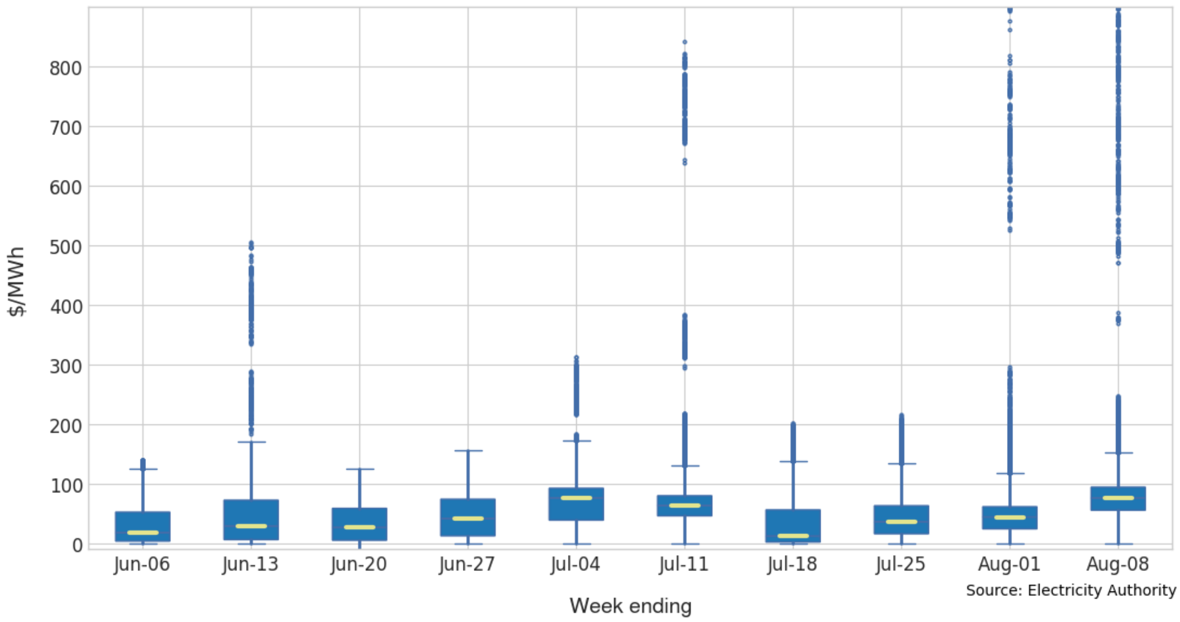


Figure 4: Box plot showing the distribution of spot prices this week and the previous nine weeks (y-axis limited to $900/MWh)



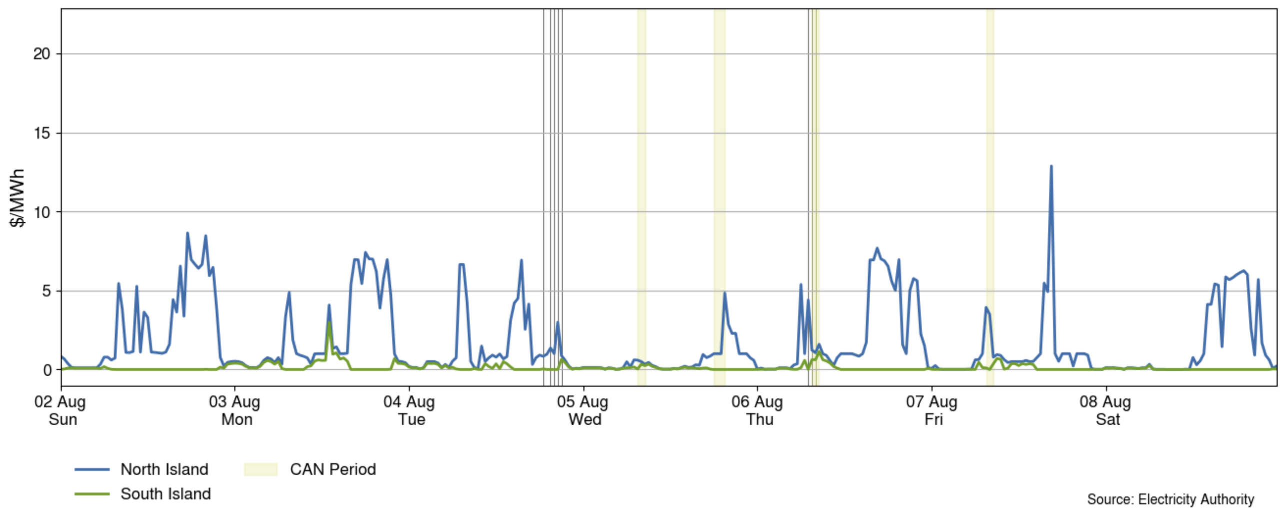
3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 5. FIR prices were mostly below $10/MWh this week.

3.2. The highest North Island FIR price was $12.87/MWh at 4.30pm on Friday.

3.3. There was frequent separation between North and South Island FIR prices as the HVDC was frequently at or near its northward flow capacity.

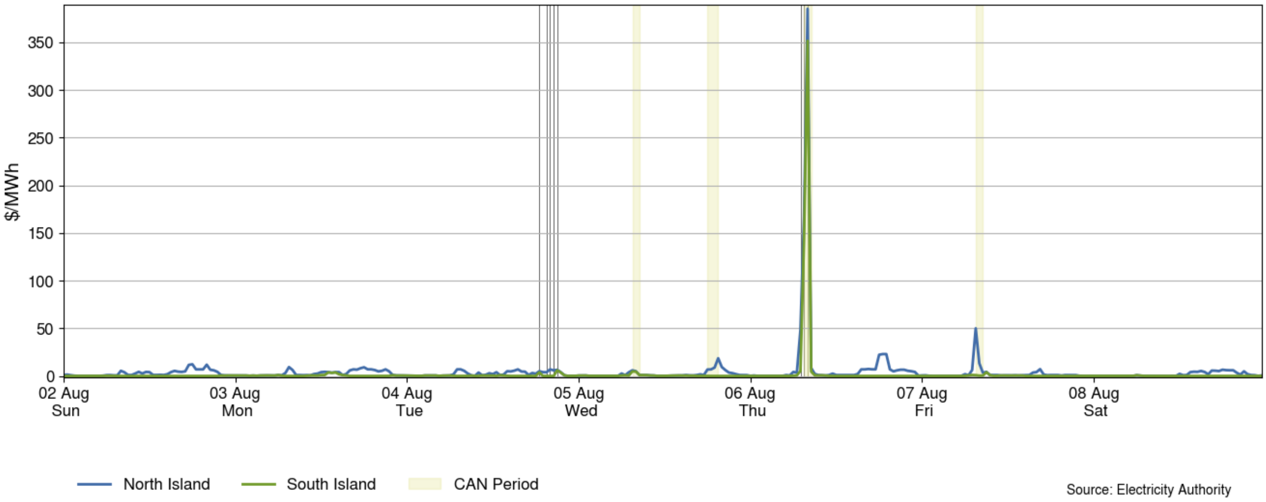
Figure 5: Fast instantaneous reserve price by trading period and island, 2-8 August



3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 6. SIR prices were mostly below $25/MWh this week.

North Island SIR prices spiked to $385/MWh on Thursday at 8.00am. At this time South Island SIR prices were $351/MWh. These higher prices resulted from additional reserve being available only after generators had increased energy output at some stations, which increased the price of reserve.

Figure 6: Sustained instantaneous reserve by trading period and island, 2-8 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 7 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.

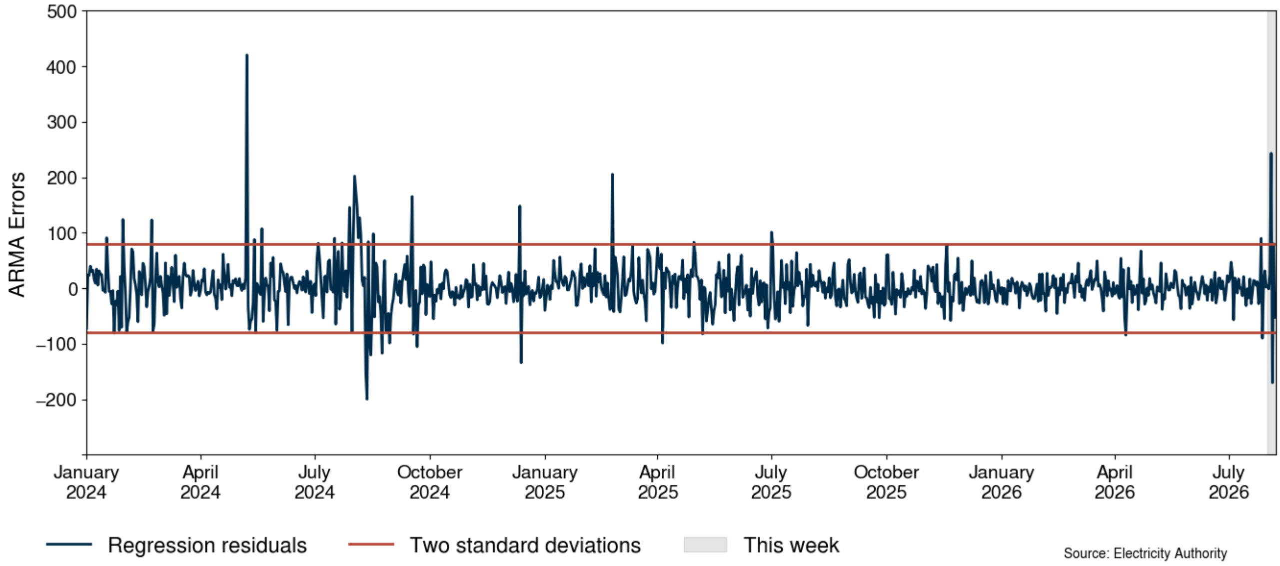
4.3. This week there were three residuals greater than two standard deviations, indicating that these prices differ significantly from those predicted by the model.

4.4. The first residual of 243 occurred on Tuesday likely due to the high prices caused by, at-the-time, record demand.

4.5. The second residual of -170 occurred on Wednesday and was likely due to the model overcompensating based on Tuesday's prices.

4.6. The final residual of 80 occurred on Thursday, and was likely due to higher prices on that day not being well predicted by the model.

Figure 7: Residual plot of estimated daily average spot prices, 1 January 2024 - 1 August 2026



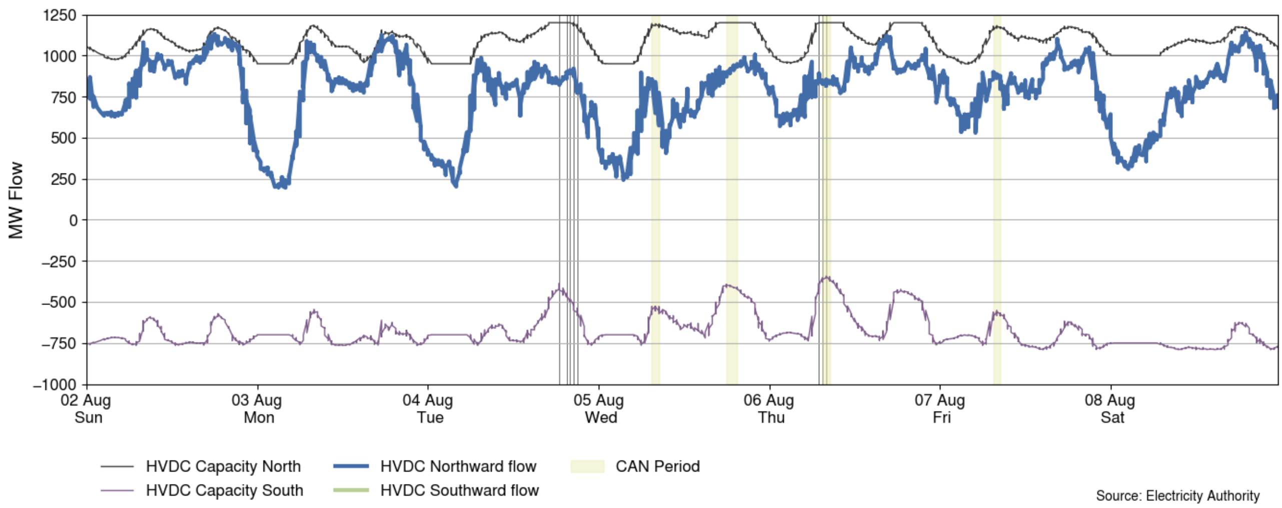
5. HVDC

5.1. Figure 8 shows the HVDC flow between 2-8 August. Due to high hydro generation and high demand, HVDC[5] flows have been entirely northward this week.

5.2. Throughout the week, the HVDC was often near or at its northward flow capacity.

5.3. The highest northward flow this week was 1,172MW on Saturday at 7.00pm.

Figure 8: HVDC flow and capacity, 2-8 August



6. Demand

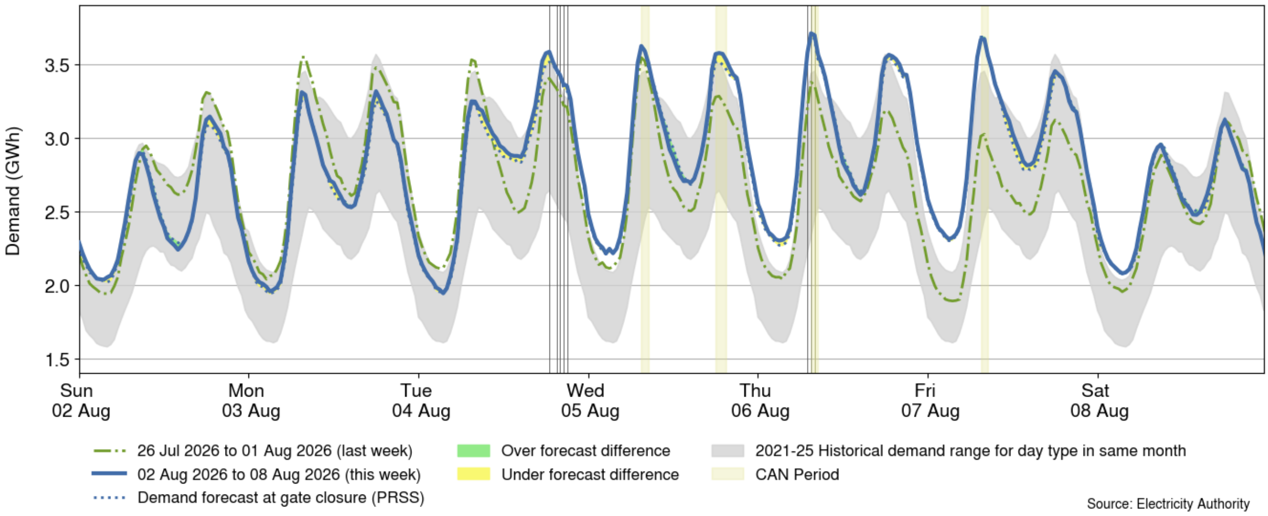
[5] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. 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.

6.1. Figure 9 shows national demand between 2-8 August, compared to the historic range and the demand of the previous week.

6.2. During the peak period on from Sunday to Tuesday morning demand was lower than last week. From Tuesday evening onward demand was higher than or similar to last week.

6.3. The Wednesday 7.30am trading period saw the highest half hourly demand ever recorded in New Zealand at 3.624GWh (7.25GW), surpassing Monday last week's record of 3.55GWh (3.71GW). However, this was quickly replaced by a new record of 3.71GWh (7.42GW) at 7.30am on Thursday.

Figure 9: National demand, 2-8 August compared to the previous week

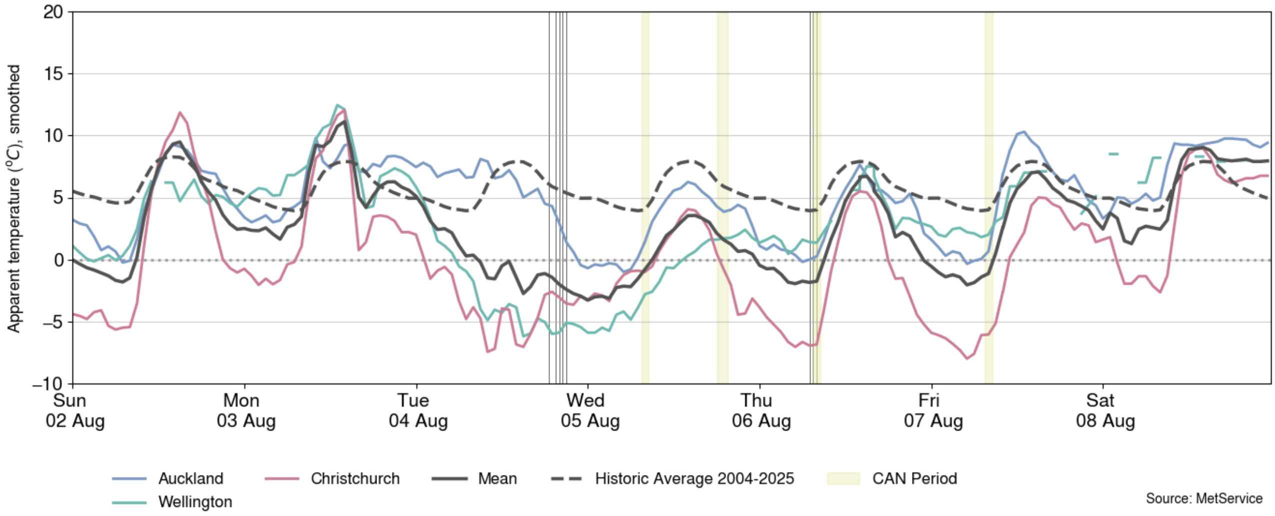


6.4. Figure 10 shows the hourly apparent temperature at main population centres from 2-8 August. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.5. Apparent temperatures ranged from -1°C to 11°C in Auckland, -7°C to 13°C in Wellington, and -9°C to 12°C in Christchurch.

6.6. Note that some temperature data is missing for Wellington this week.

Figure 10: Temperatures across main centres, 2-8 August



7. Generation

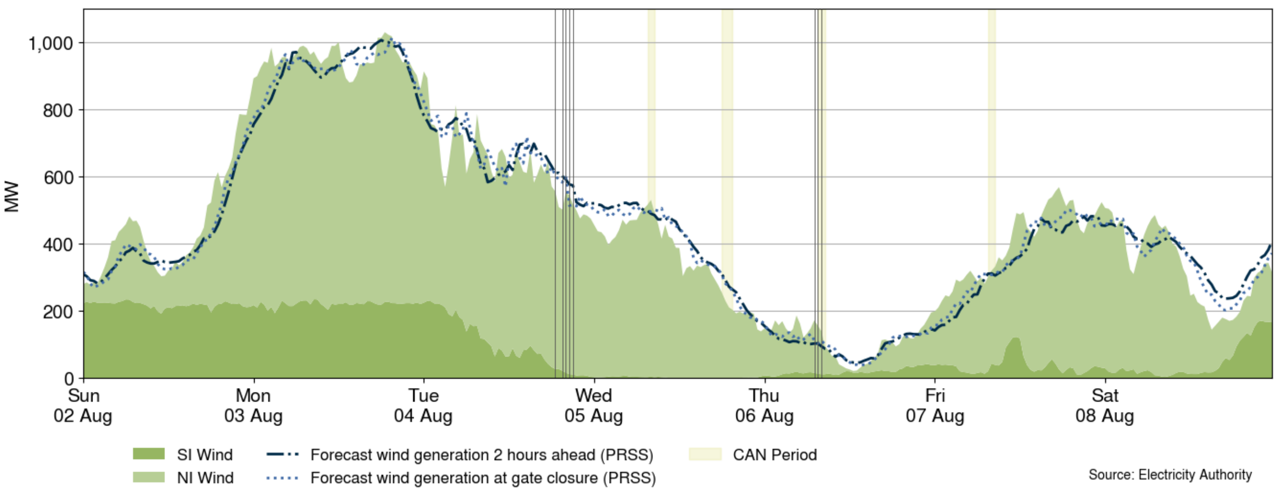
7.1. Figure 11 shows wind generation and forecast from 2-8 August. This week wind generation varied between 21MW and 1,030MW, with a weekly average of 461MW.

7.2. Wind generation was slightly higher overall than last week, with the highest generation occurring between Sunday evening and Wednesday morning. However, there was low wind generation between Wednesday evening and Friday morning, contributing to higher prices at times.

7.3. Over-forecasting errors during the high priced periods on Tuesday evening were caused by Waipipi (60MW), Kaiwera Downs (15MW), and Harapaki (10MW) wind farms

7.4. Under-forecasting errors on Friday evening were caused by Harapaki (27MW, Waipipi (16MW), and White Hill (19MW)

Figure 11: Wind generation and forecast, 2-8 August



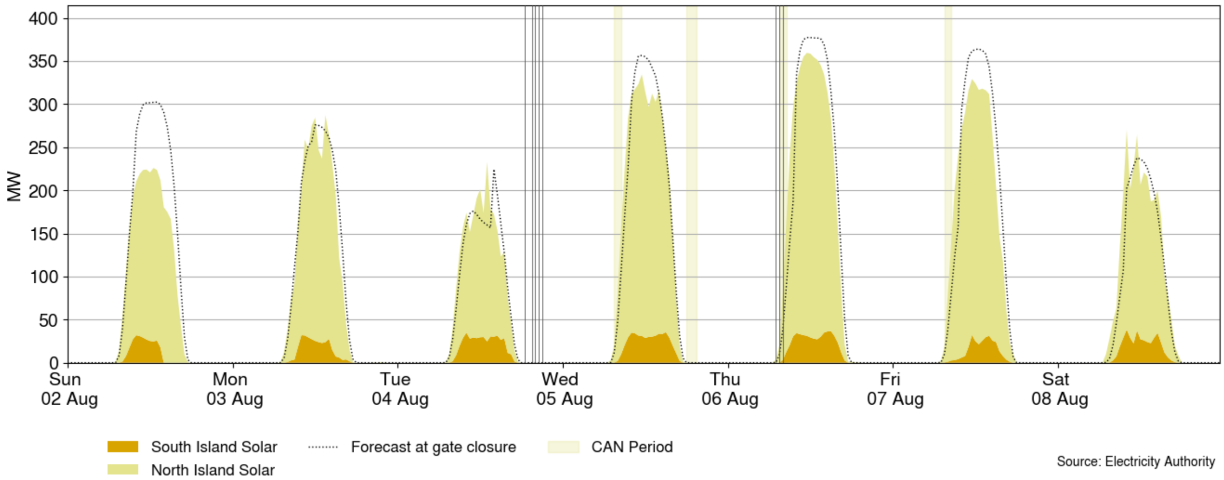
7.5. Figure 12 shows grid connected solar generation from 2-8 August.

7.6. Solar generation reached over 150MW each day this week, peaking at 359MW on Thursday at 11.30am.

7.7. Tauhei solar farm is nearing completion of its commissioning process. Its generation has been added to Figure 12.

7.8. Forecasting errors on Monday, Wednesday, Thursday, and Friday were caused by Tauhei solar farm.

Figure 12: Grid connected solar generation, 2-8 August

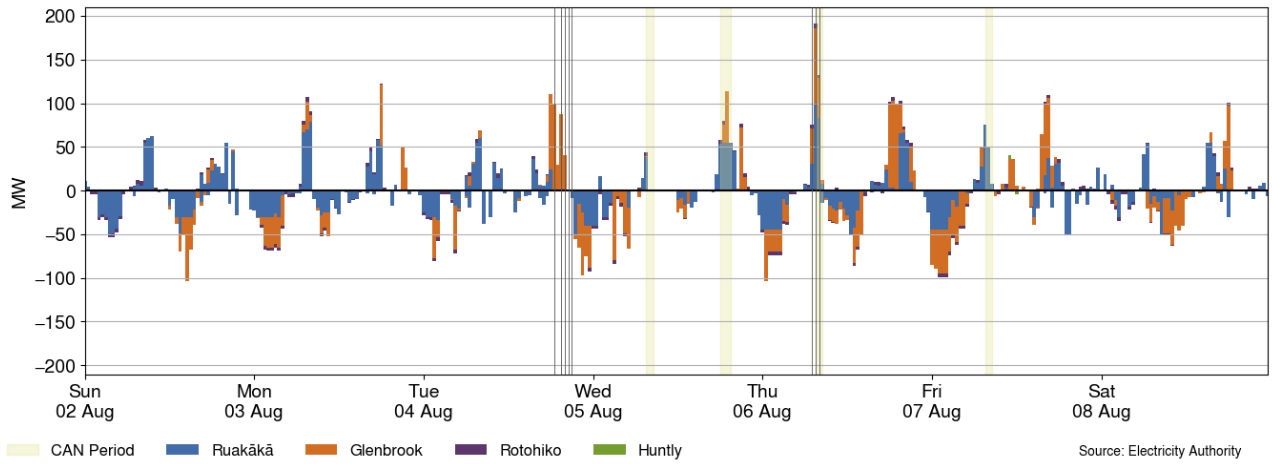


7.9. Figure 13 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.10. This week the batteries mostly charged overnight or during the day during lower prices and discharged during peak demand. The highest battery discharge to the grid occurred this week during the 7.30am trading period on Thursday morning.

7.11. Ruakākā did not discharge during the high-priced periods on Tuesday evening as it was fully depleted at the time.

Figure 13: Grid scale battery charge and discharge, 2-8 August

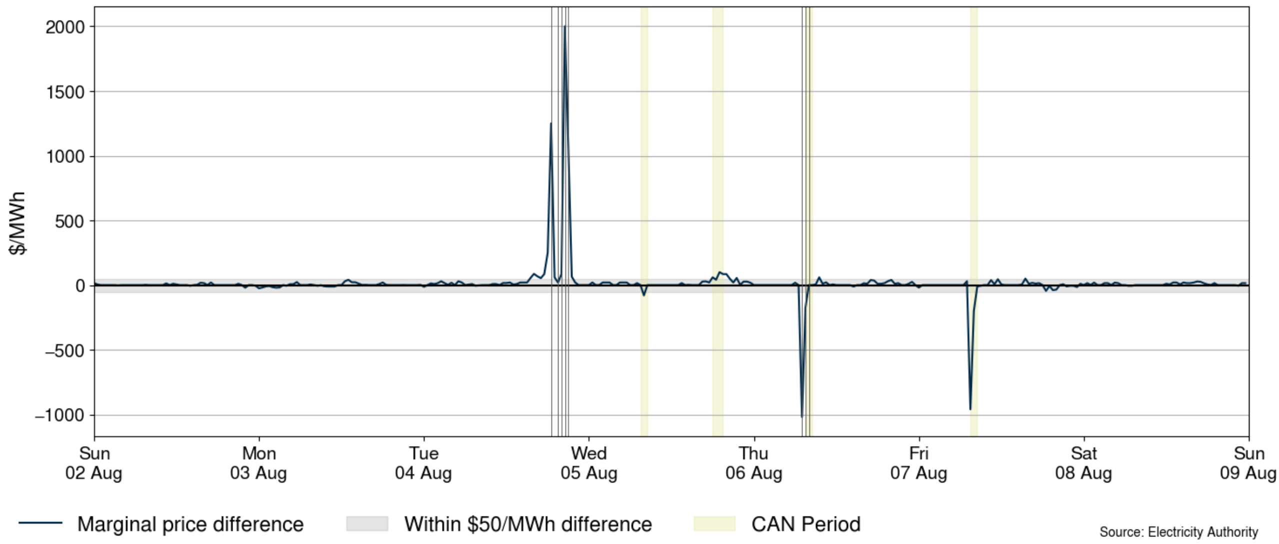


7.12. Figure 14 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[6]) projections. The figure highlights when forecasting inaccuracies are causing 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.

7.13. This week the large positive difference on Tuesday can be attributed to the multiple generation trips that occurred between gate closure and real time, including the Huntly 4 trip and the inability for the second Stratford peaker to start.

7.14. The greatest negative forecast difference was $1,020/MWh under-forecast at 7.00am on Thursday. Intermittent generation was 71MW higher than forecast at this time. Similar circumstances occurred on Friday morning.

Figure 14: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 2-8 August



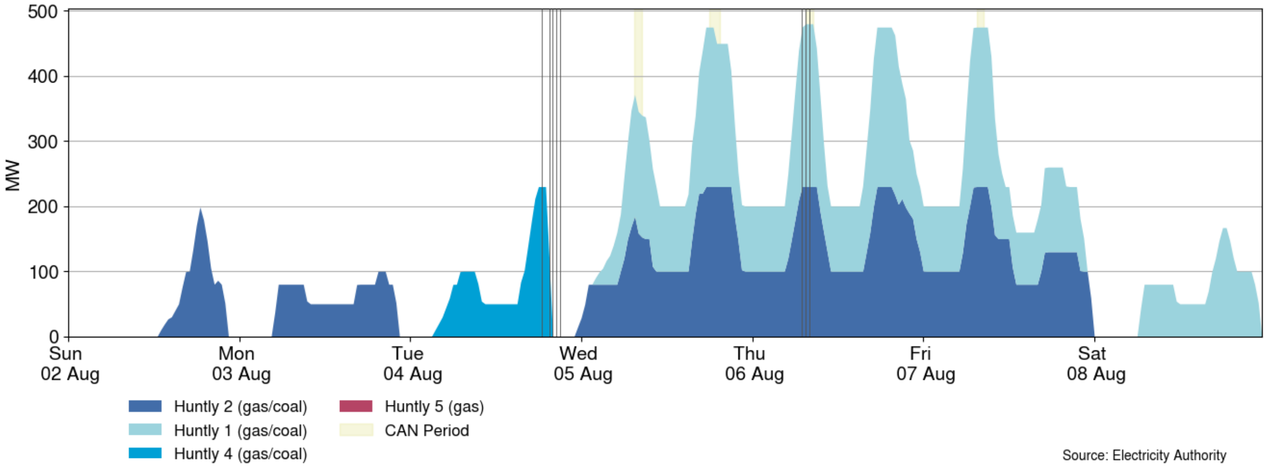
7.15. Figure 15 shows the generation of thermal baseload between 2-8 August.

7.16. Baseload thermal generation this week was provided by Huntly units 1, 2, and 4, with Huntly 1 and 2 generating during the high-priced periods on Thursday.

7.17. Huntly 4 unexpectedly tripped off during the 7.00pm trading period on Tuesday while generating above 200MW.

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

Figure 15: Thermal baseload generation, 2-8 August



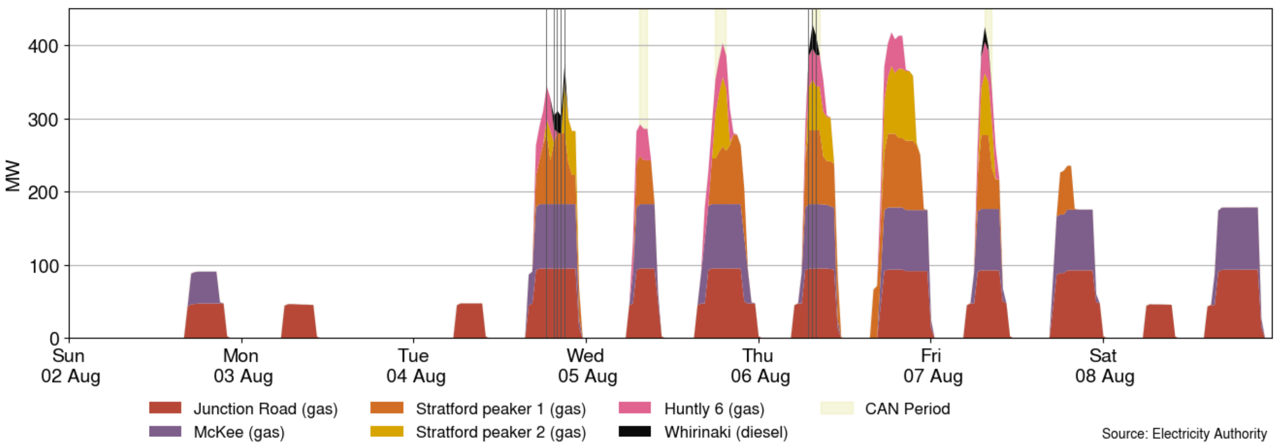
7.18. Figure 16 shows the generation of thermal peaker plants between 2-8 August.

7.19. Peaker generation this week was greatest during Thursday morning peak demand, with all peakers providing generation. The least peaker generation ran on Sunday and Monday.

7.20. Stratford Peaker 2 turned off during the 6.30pm trading period on Tuesday and was unable to restart from 7.30-8.30pm.

7.21. Whirinaki ran during Tuesday evening, Thursday morning, and Friday morning peak periods. Whirinaki generation was cleared on Tuesday between 7.30-8.30pm. During the Thursday and Friday morning peaks it was constrained on for reserves.

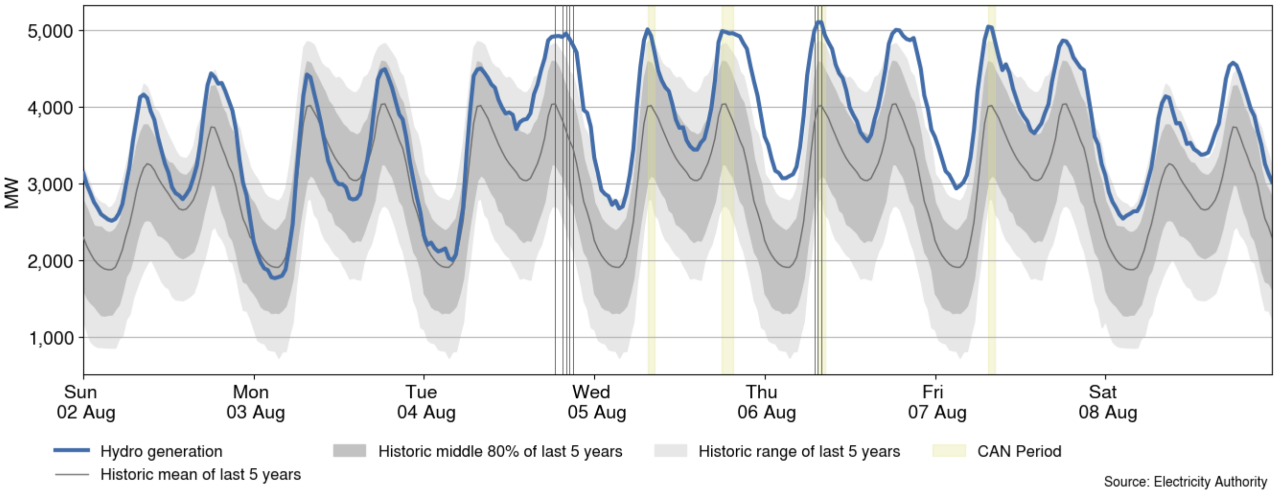
Figure 16: Thermal peaker generation, 2-8 August



7.22. Figure 17 shows hydro generation between 2-8 August.

7.23. Hydro generation was above the historic range for the last 5 years during peak periods from Tuesday evening to Friday morning. Hydro generation remained high throughout the rest of the week, only dropping below the mean at times on Monday.

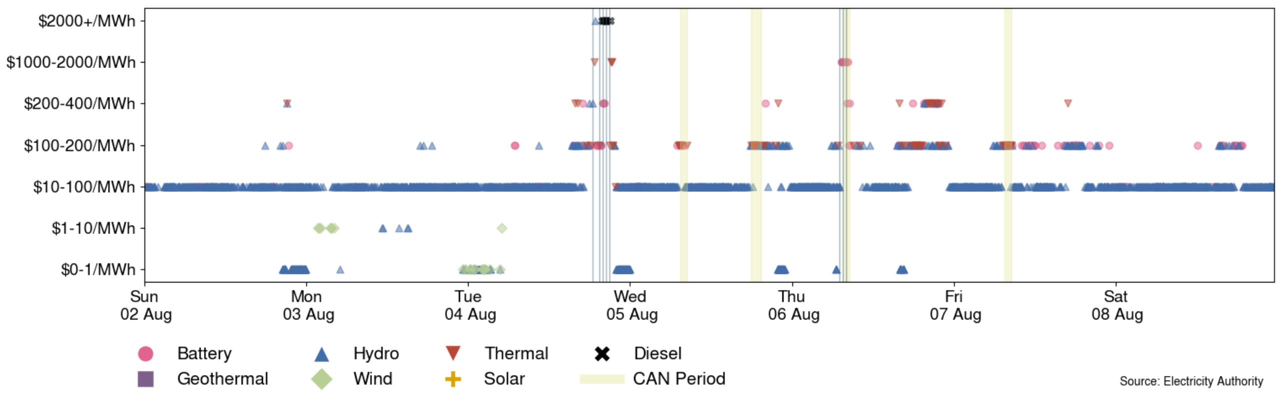
Figure 17: Hydro generation, 2-8 August



7.24. Figure 18 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.

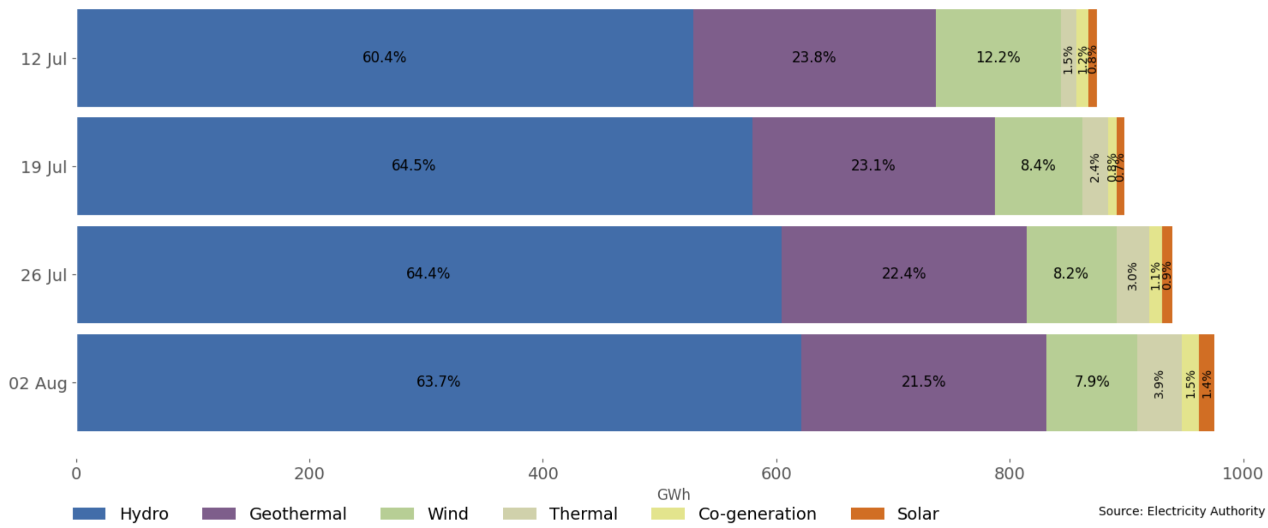
7.25. The highest marginal price of $6,125/MWh was set by Whirinaki on Tuesday at 8.00pm. The most common technology setting prices this week was hydro, with batteries the second most common. Most marginal prices were between $10-100/MWh.

Figure 18: Prices of marginal generation, 2-8 August



7.26. As a percentage of total generation, between 2-8 August, total weekly hydro generation was 63.7%, geothermal 21.5%, wind 7.9%, thermal 3.9%, co-generation 1.5%, and solar (grid connected) 1.4%, as shown in Figure 19.

Figure 19: Total generation by type as a percentage each week, between 12 July and 2 August



8. Outages

8.1. Figure 20 shows generation capacity on outage. Total capacity on outage between 2-8 August ranged between ~847MW and ~1,451MW. Figure 21 shows the thermal generation capacity outages.

Figure 20: Total MW loss from generation outages, 2-8 August

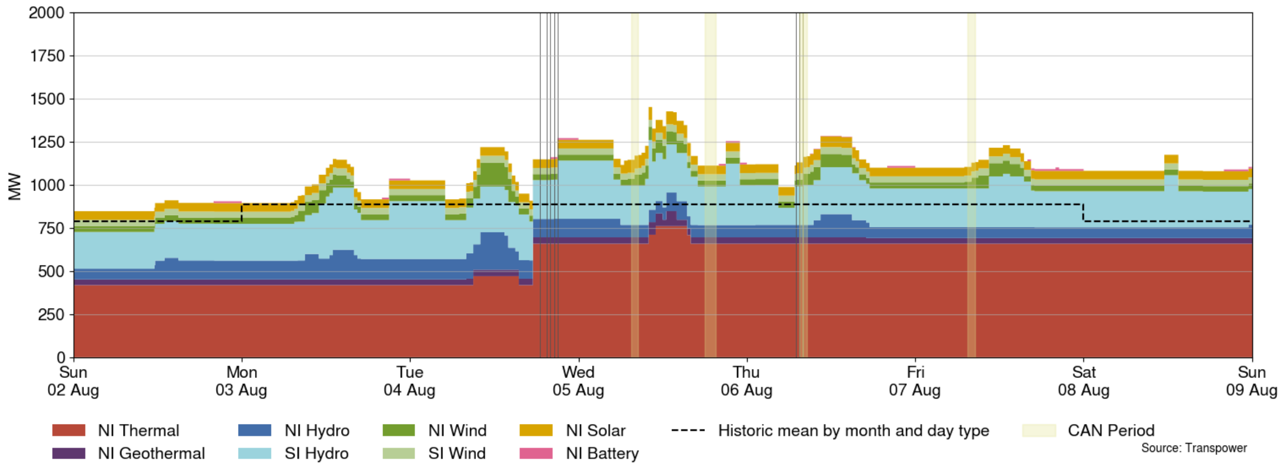
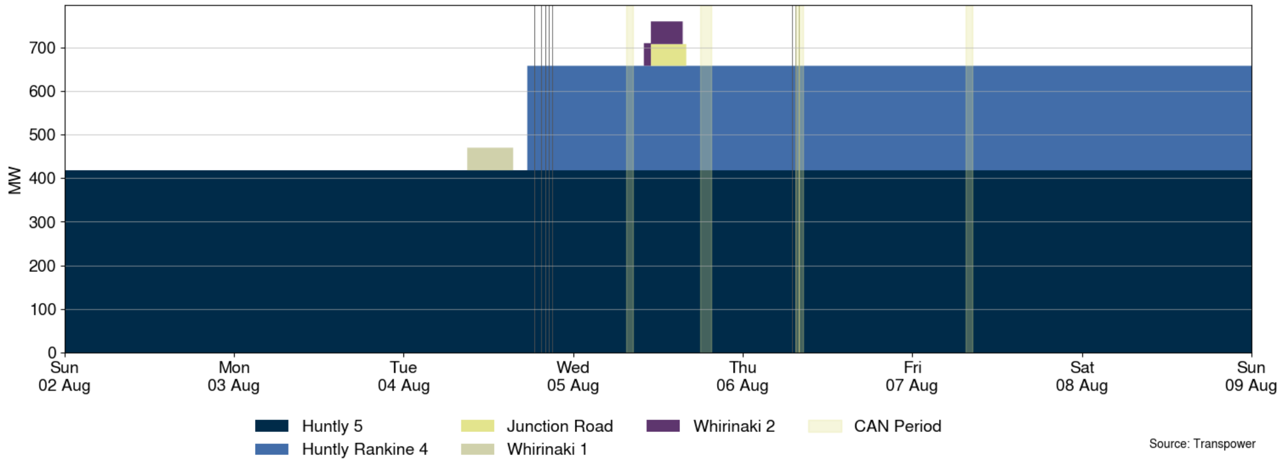


Figure 21: Total MW loss from thermal outages, 2-8 August



8.2. Notable outages include:

Plant	Partial or Full	End Date
Benmore unit 0	Full	3 August 2026
Te Āpiti Station	Full	4 August 2026
Manapōuri unit 1, 2	Full	5 August 2026
Kaiwaikawe Wind Farm	Full	5 August 2026
Tauhei Solar Farm	Partial	7 August 2026
Takapō B Station	Partial	8 August 2026
Huntly 4	Partial	10 August 2026
Huntly 5	Full	14 August 2026
Manapōuri unit 7	Full	18 August 2026
Kaiwaikawe Wind Farm	Partial	30 November 2026
Roxburgh unit 8	Full	24 September 2026

9. Generation balance residuals

9.1. Figure 22 shows the national generation balance residuals between 2-8 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. Figure 23 shows the national residuals compared to the minimum residual across all forecasts up to gate closure.

9.2. At 8.29am on Monday, the System Operator issued a potential low residual CAN for 7.30-8.30am, 6.00-7.30pm on Wednesday, and 7.30-8.30am on Thursday as the NRSL schedule (Long Non-Response Schedule) showed residual generation was less than 200MW. At 11.08pm on Tuesday, the Thursday period was upgraded to a low residual situation. At 8.24am on Wednesday another potential low residual situation CAN was issued for 7.30-8.30am Friday, this was upgraded to a low residual situation with another CAN at 12.50am on Friday. These periods are highlighted with yellow bars throughout the report. In real time the lowest residuals were:

(a) 142MW at 8.00pm on Tuesday

(b) 276MW at 6.30pm on Wednesday

(c) 81MW at 7.30am on Thursday

(d) 226MW at 7.00am on Friday

Figure 22: National generation balance residuals, 2-8 August

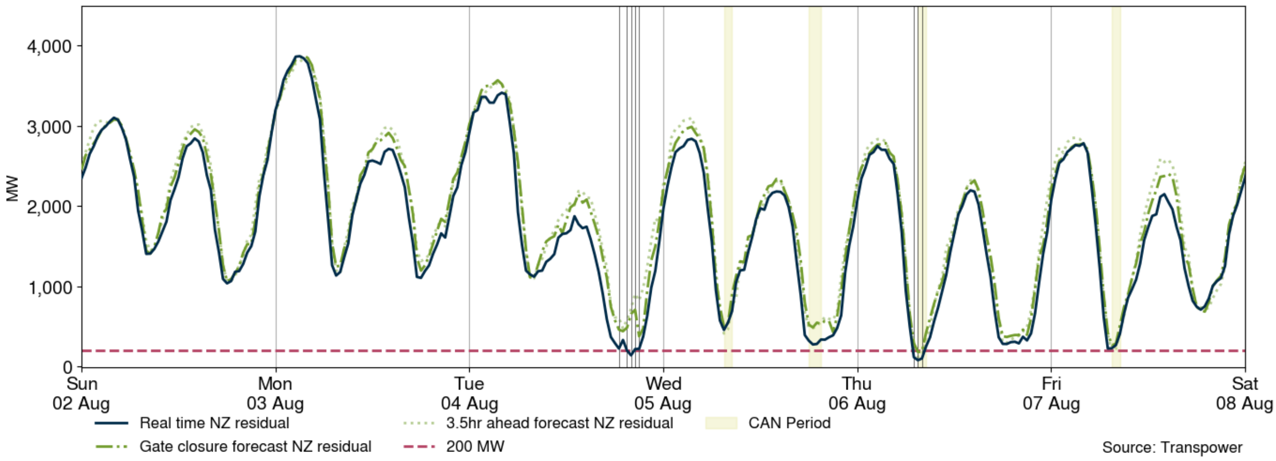
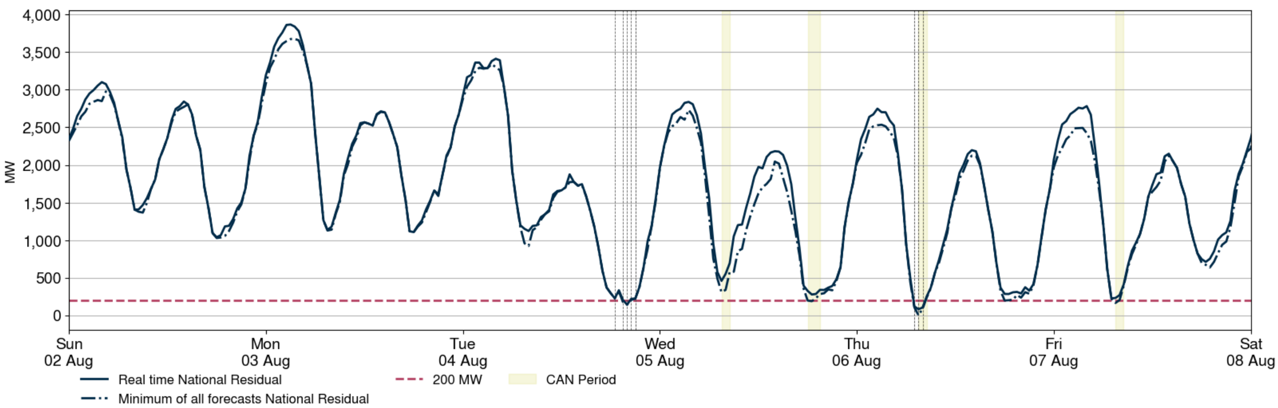


Figure 23: Minimum of all forecast national residuals



10. Storage/fuel supply

10.1. Figure 24 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 8 August, national controlled storage was 77% nominally full and ~124% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (82% full[7]) is significantly higher than the historic 90th percentile for this time of year.

10.4. Storage at Lake Tekapō (68% full) is slightly below the historic 90th percentile for this time of year.

[7] Percentage full values sourced from NZX Hydro.

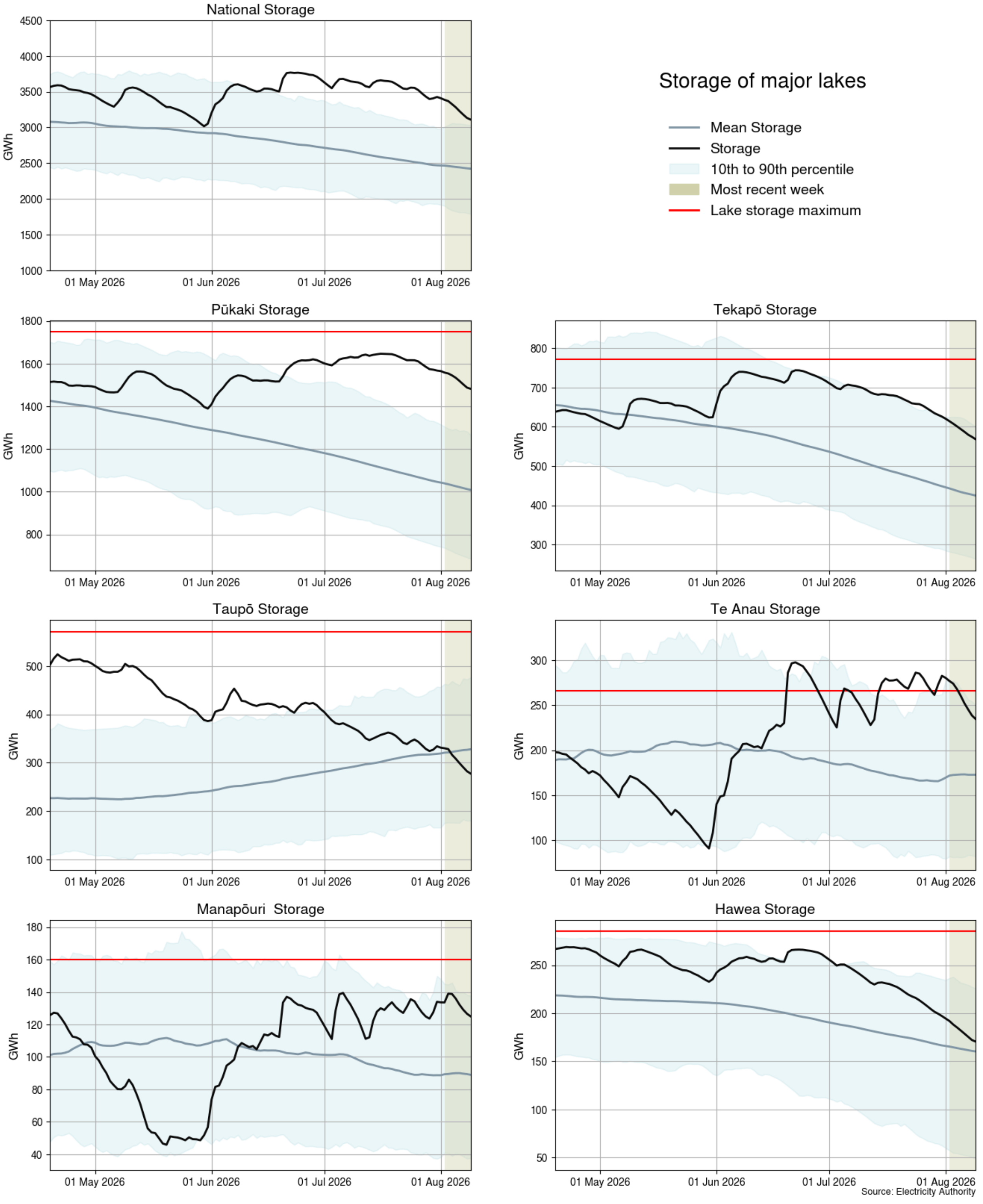
10.5. Storage at Lake Taupō is (48% full) is below average for this time of year.

10.6. Storage at Lake Te Anau (88% full) is slightly below the historic 90th percentile for this time of year.

10.7. Storage at Lake Manapōuri (79% full) is slightly below the historic 90th percentile for this time of year.

10.8. Storage at Lake Hawea (60% full) is slightly above average for this time of year.

Figure 24: 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.

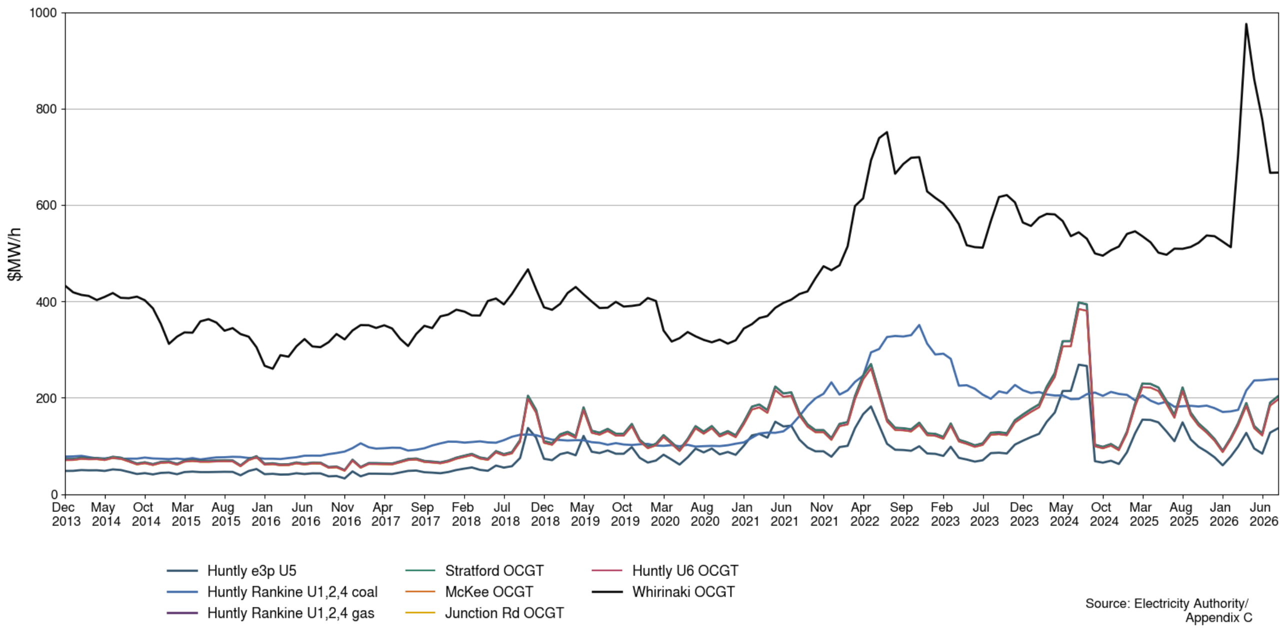
11.5. The SRMC of gas fuelled thermal plants is currently between $136/MWh and $203/MWh.

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 25: Estimated monthly SRMC for thermal fuels

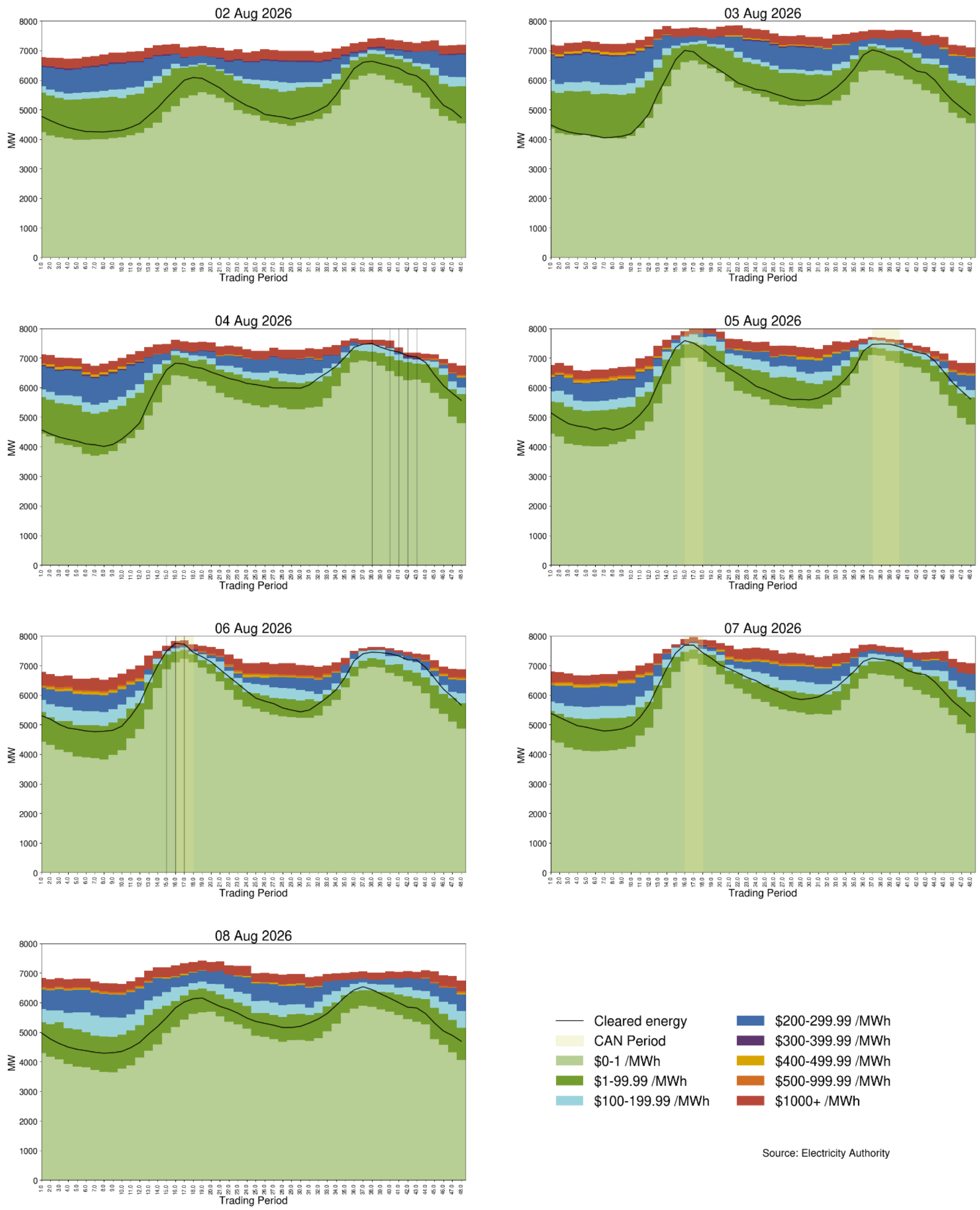


12. Offer behaviour

12.1. Figure 26 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 $200/MWh, although some offers cleared above $1000+/MWh on Tuesday during the peak periods.

Figure 26: National daily offer stacks



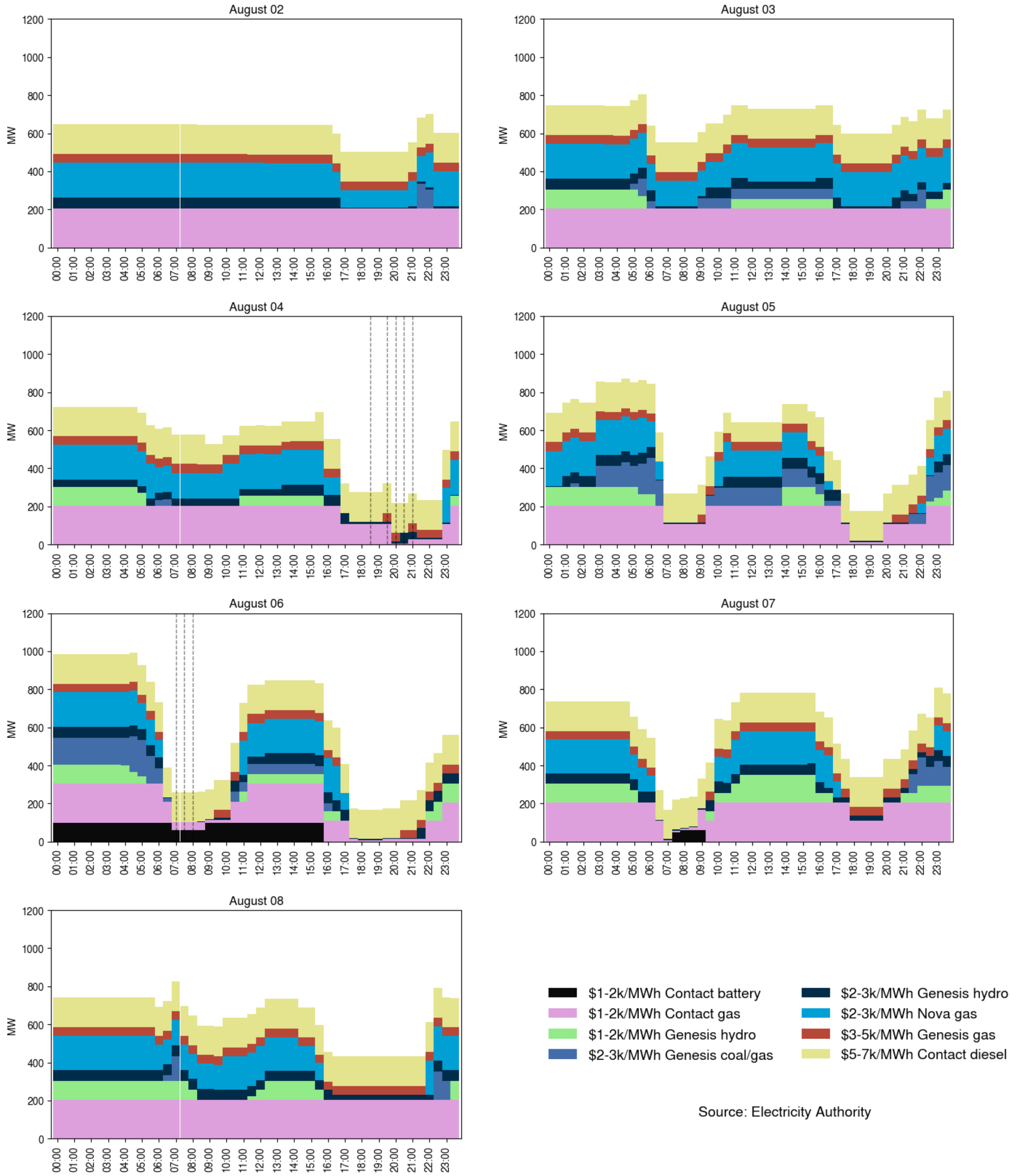
Source: Electricity Authority

12.3. Figure 27 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 607MW per trading period was priced above $1,000/MWh this week, which is roughly 10% of the total energy available.

Figure 27: 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 will be looking into Glenbrook battery and Tekapō offers further.

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
02/05/2026	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
22/07/2026	16-18	Further analysis	Contact	Stratford peakers	Offers
06/08/2026	Several	Further analysis	Contact	Glenbrook battery	Offers
02-08/08/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers
13/08/2026	29-33	Further analysis	Genesis	Tekapō	Offers