4 August 2026

Trading conduct report 26 July - 1 August 2026

Market monitoring weekly report

Trading conduct report 26 July - 1 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 Monday and Tuesday morning when there were low temperatures in parts of the country.

1.2. As a result, the average spot price for the week was $63/MWh, an increase of around $17/MWh compared to the previous week. National hydro storage has decreased to 83% nominally full and ~131% 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 26 July - 1 August:

(a) The average wholesale spot price across all nodes was $63/MWh, an increase of around $17/MWh.

(b) 95% of prices fell between $0.32/MWh and $164/MWh.

2.3. The highest price at Ōtāhuhu was $3,296/MWh at 5.30pm on Monday. At this time prices at Benmore were $571/MWh. This is due to the capacity available at the time being unable to ramp up fast enough to meet rising demand. Because of this SPD identified energy scarcity at Hepburn Road node (HEP0331) in Northland. Energy scarcity sets the price at the node to $21,000/MWh. This state lasted until the next SPD run 84 seconds later which resolved without energy scarcity.

2.4. Ōtāhuhu prices also spiked up to $1,228/MWh at 7.30am on Monday. At this time prices at Benmore were $145/MWh. The highest demand ever recorded occurred during this time. North Island reserve price spikes, low wind generation and demand forecasting errors also contributed to this price.

2.5. At 9:38am on Sunday, the System Operator issued a low residual customer advice notice (CAN) for 7.30-8.30am and 6.00-7.00pm on Monday as the NRSL schedule (Long Non-Response Schedule) showed residual generation was less than 200MW.[1] Later at 9.12am on Monday, another CAN was issued advising low residual generation for 7.30-8.30am on Tuesday.[2] These periods are highlighted with yellow

[1] CAN Low Residual Situation 800000260.pdf
[2] CAN Low Residual Situation 800000261.pdf

bars throughout the report. In real time, the lowest national residuals during these periods were:

(a) 198MW at 7.30am Monday,

(b) 58MW at 5.30pm Monday,

(c) and 191MW at 7.30am Tuesday.

2.6. 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, 26 July - 1 August

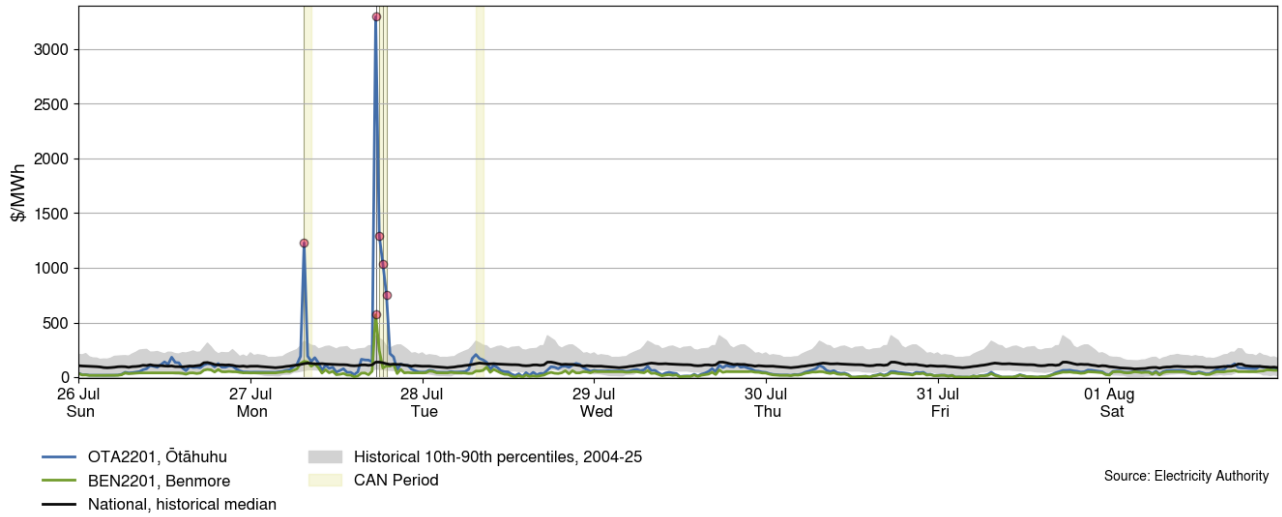
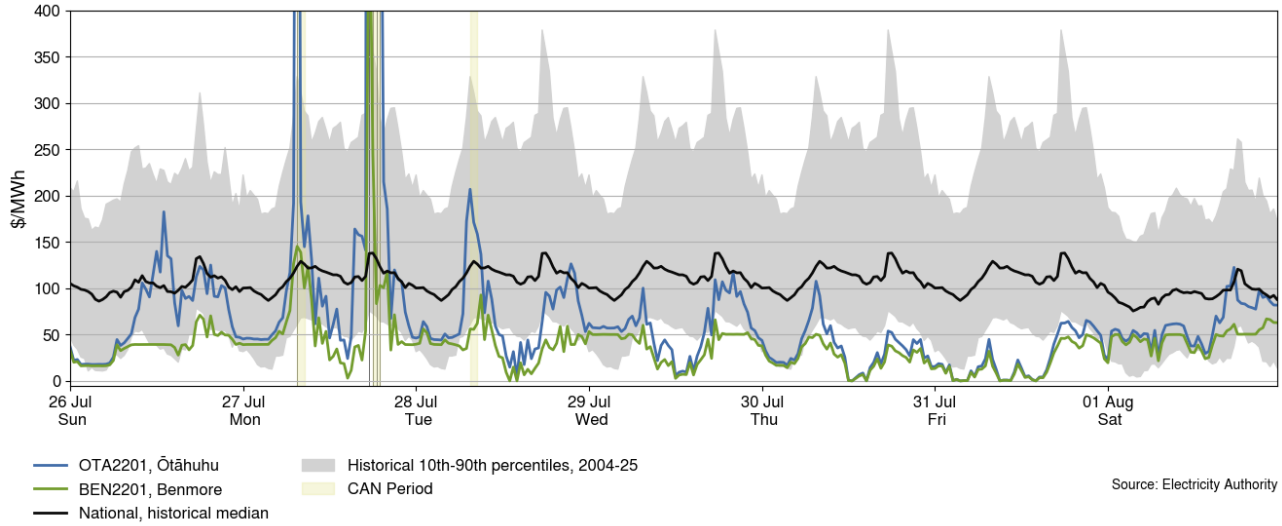


Figure 2: Wholesale spot prices at Benmore and Ōtāhuhu, 26 July - 1 August (y-axis limited to $400/MWh)



2.7. 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.

2.8. The distribution of spot prices this week was slightly narrower than last week but with a large number of high price outliers. The median price was $63/MWh and most prices (middle 50%) fell between $24/MWh and $61/MWh.

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

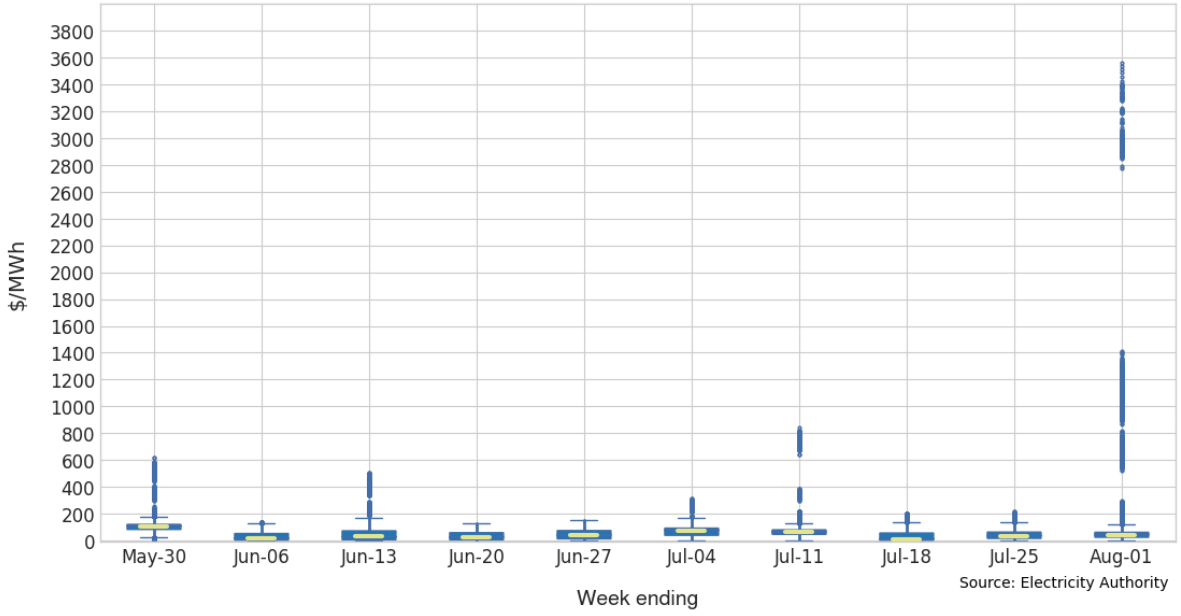
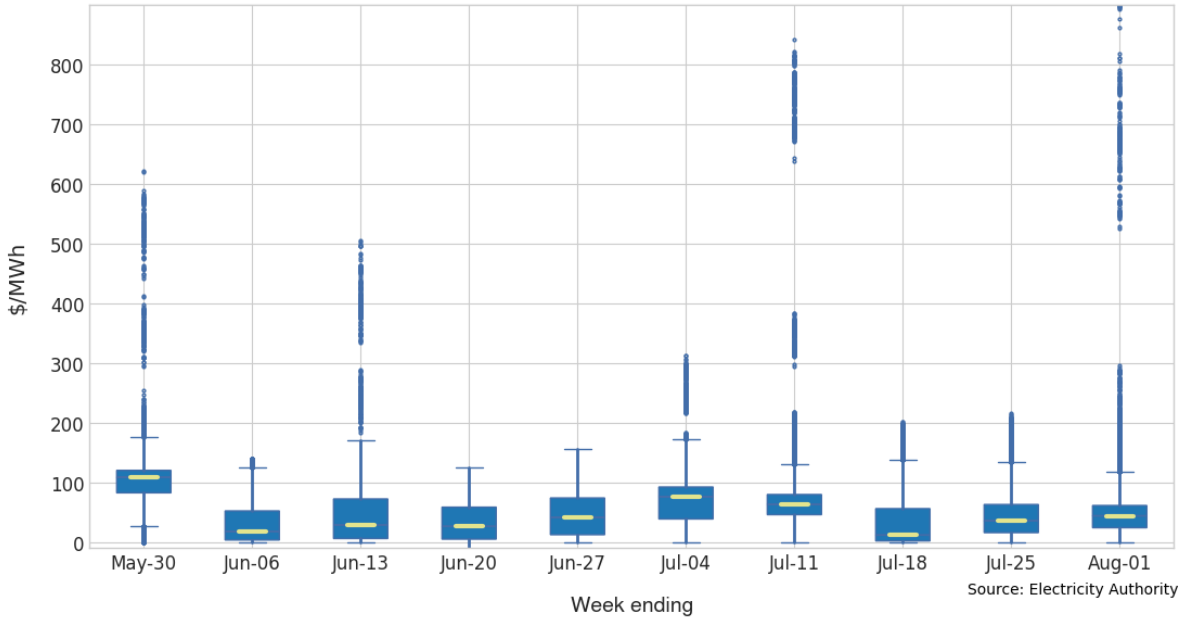


Figure 4: Box plot showing the distribution of spot prices this week and the previous nine weeks (y-axis limited to $900/MWh



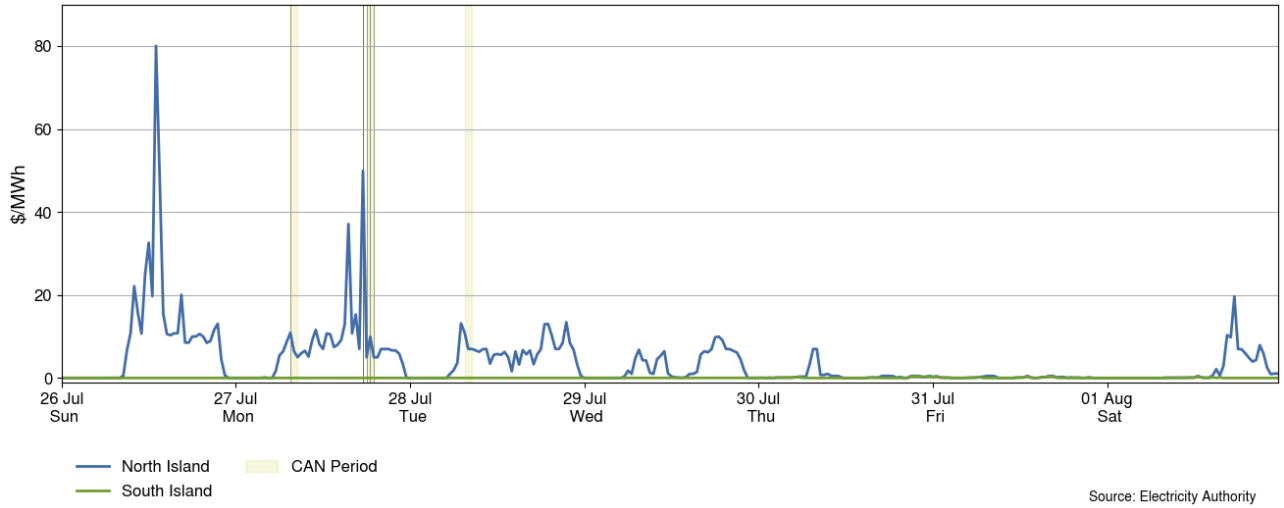
3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 5. FIR prices were mostly below $20/MWh this week.

3.2. North Island FIR prices spiked up to $80/MWh on Sunday at 1.00pm, at this time South Island FIR prices were $0/MWh.

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.

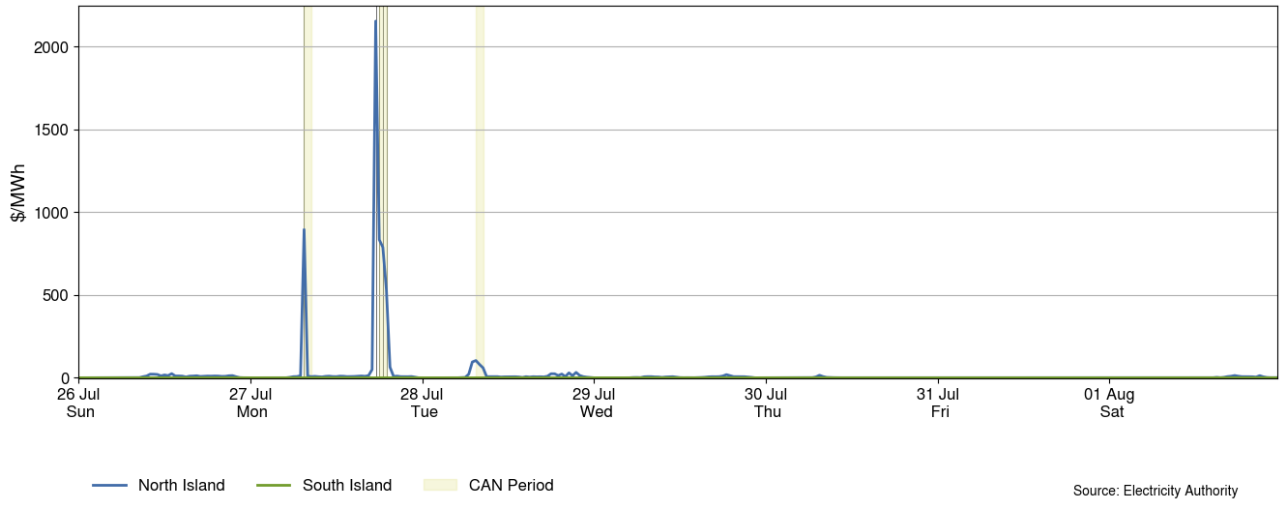
Figure 5: Fast instantaneous reserve price by trading period and island, 26 July - 1 August



3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 6. SIR prices were mostly below $20/MWh this week.

3.5. North Island SIR prices spiked to $895/MWh on Monday at 7.30am, followed by another spike to $2,154/MWh at 5.30pm the same day. During this trading period, a SIR scarcity price of $6,500 occurred for one 5-minute period. At these times South Island SIR prices were $0/MWh.

Figure 6: Sustained instantaneous reserve by trading period and island, 26 July - 1 August



4. Regression residuals

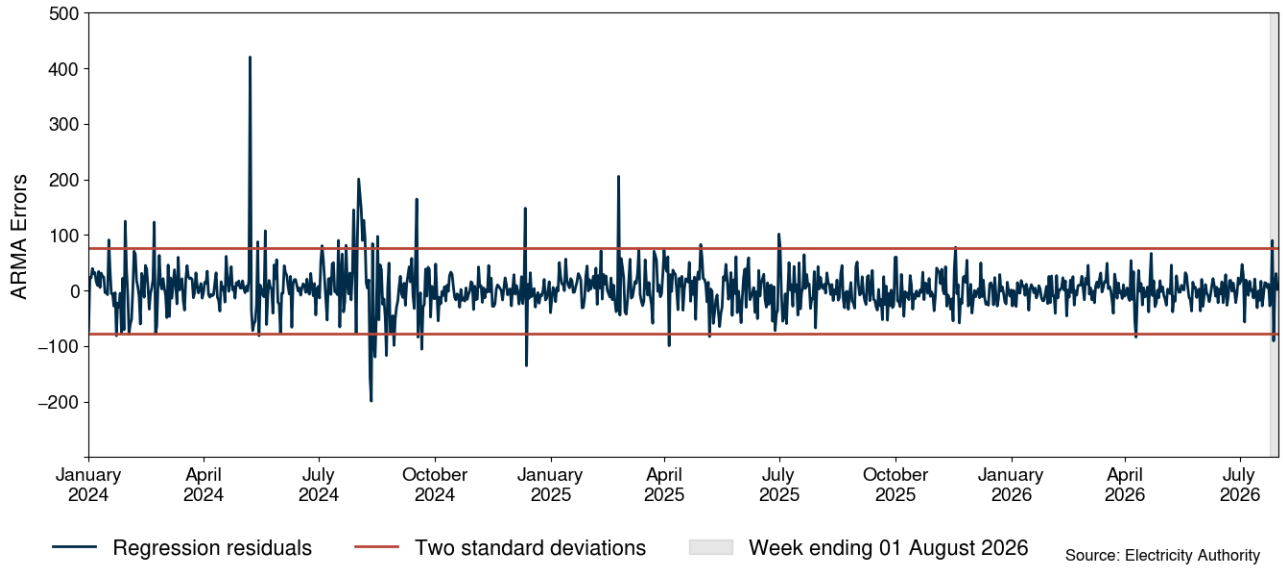
4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and

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 two residuals greater than two standard deviations, indicating that these prices differ significantly from those predicted by the model. A positive residual occurred on Monday, when energy and reserve scarcity not captured by the model set some prices. A negative residual then occurred on Tuesday as prices were lower compared to Monday.

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



5. HVDC

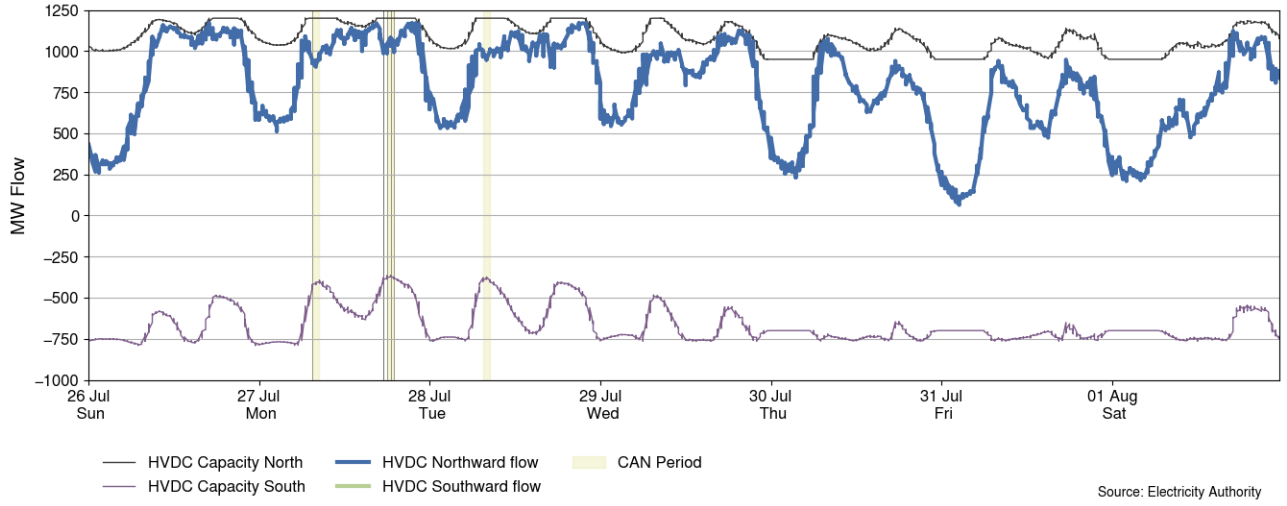
5.1. Figure 8 shows the HVDC flow between 26 July - 1 August. Due to high hydro generation and high demand, HVDC[3] flows have been entirely northward this week.

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 1,170MW on Monday at 4.30pm. This is the highest northward HVDC flow recorded since 2013.

[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 8: HVDC flow and capacity, 26 July - 1 August



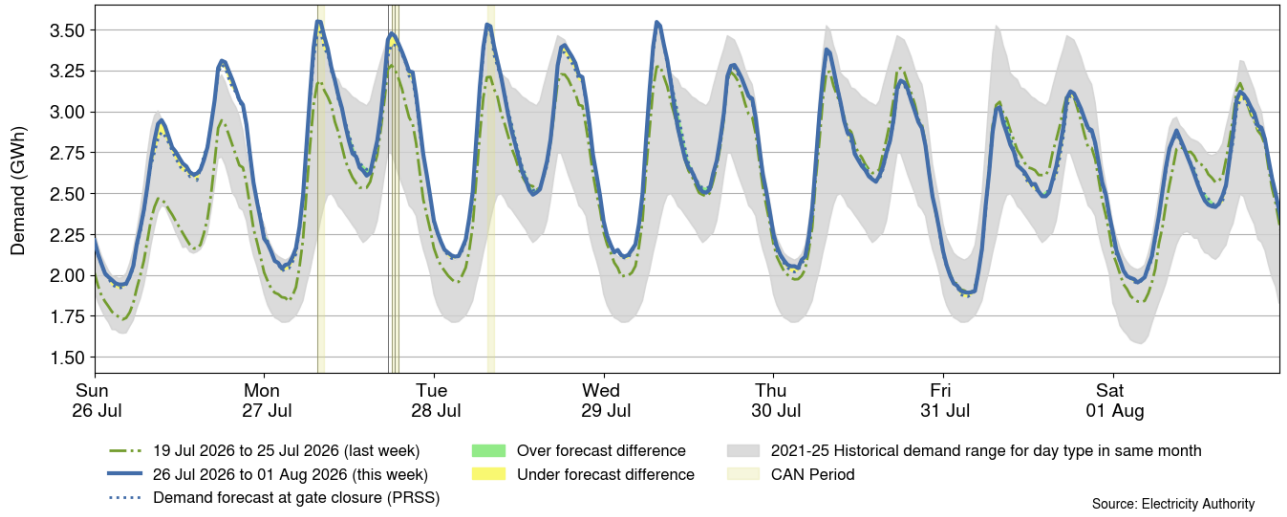
6. Demand

6.1. Figure 9 shows national demand between 26 July - 1 August, compared to the historic range and the demand of the previous week.

6.2. Demand was higher than last week during peak periods from Sunday to Wednesday Morning, likely due to particularly cold apparent temperatures in parts of the country on those days. Demand was up to 168MW and 212MW higher than forecast on Monday morning and evening respectively, contributing to higher prices during Monday's CAN periods. Otherwise, demand was mostly similar to last week, while being greater overall.

6.3. Monday saw the highest half hourly demand ever recorded in New Zealand at around 3.55GWh (7.1GW) at 7.30am on Monday.

Figure 9: National demand, 26 July - 1 August compared to the previous week

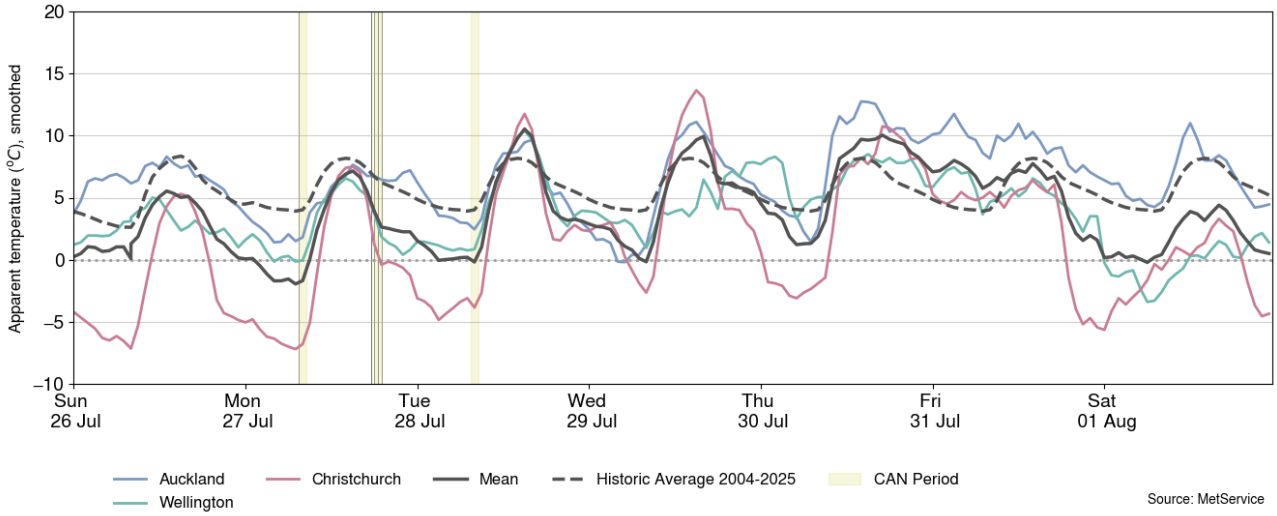


6.4. Figure 10 shows the hourly apparent temperature at main population centres from 26 July - 1 August. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean 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 13°C in Auckland, -4°C to 10°C in Wellington, and -8°C to 14°C in Christchurch.

Figure 10: Temperatures across main centres, 26 July - 1 August



7. Generation

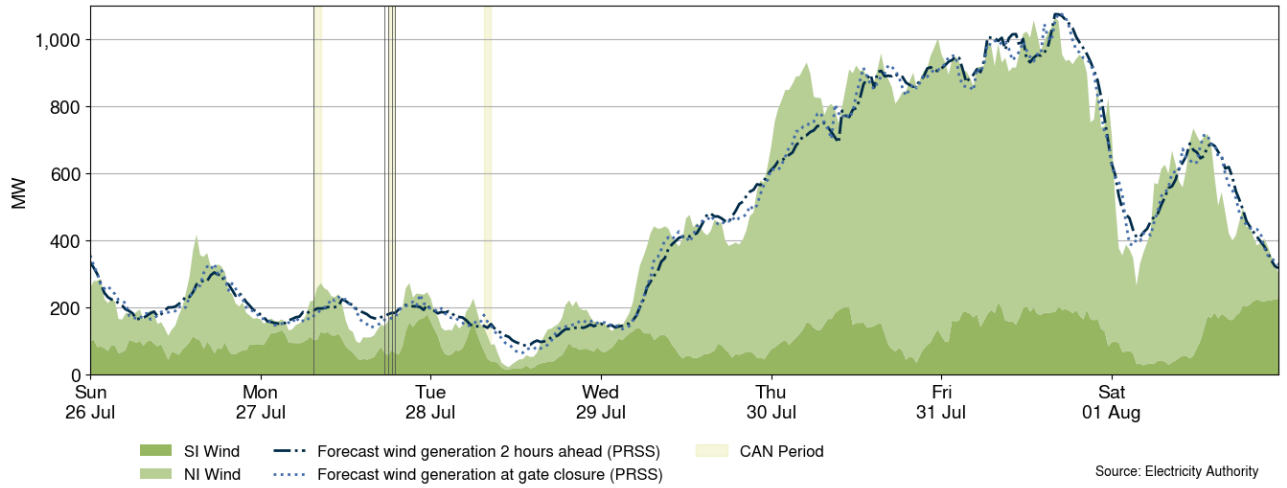
7.1. Figure 11 shows wind generation and forecast from 26 July - 1 August. This week wind generation varied between 22MW and 1,066MW, with a weekly average of 460MW.

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

7.3. Over-forecasting errors on Saturday were caused by Harapaki, Kaiwera Downs, and Te Āpiti wind farms.

7.4. Under-forecasting errors on Thursday morning are due to Waipipi and West Wind 1 wind farms.

Figure 11: Wind generation and forecast, 26 July - 1 August

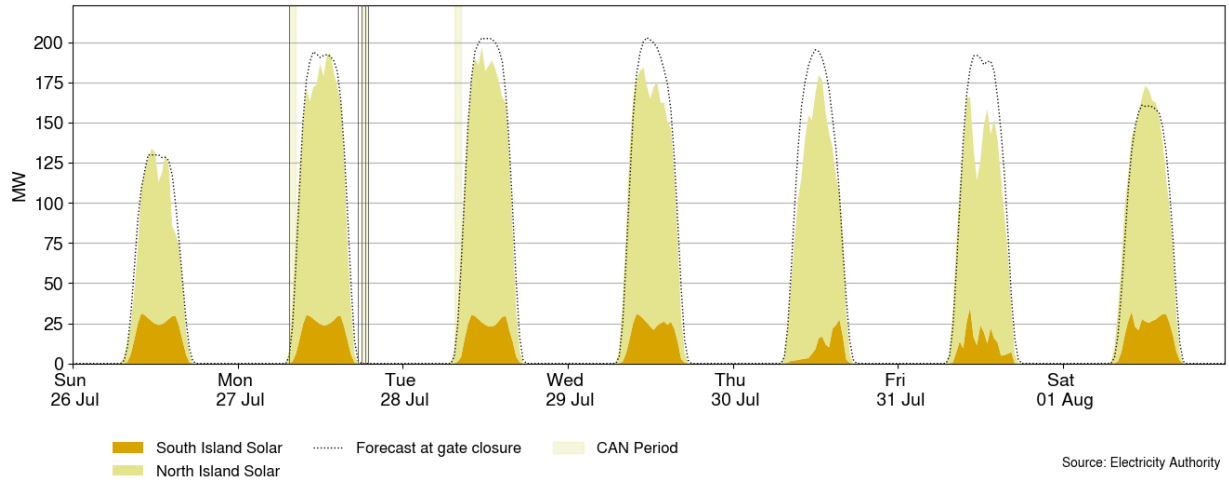


7.5. Figure 12 shows grid connected solar generation from 26 July - 1 August.

7.6. Solar generation reached over 125MW each day this week, peaking at 197MW on Tuesday at 11.30am.

7.7. Forecasting errors on Friday were due to an accumulation of errors at various solar farms.

Figure 12: Grid connected solar generation, 26 July - 1 August



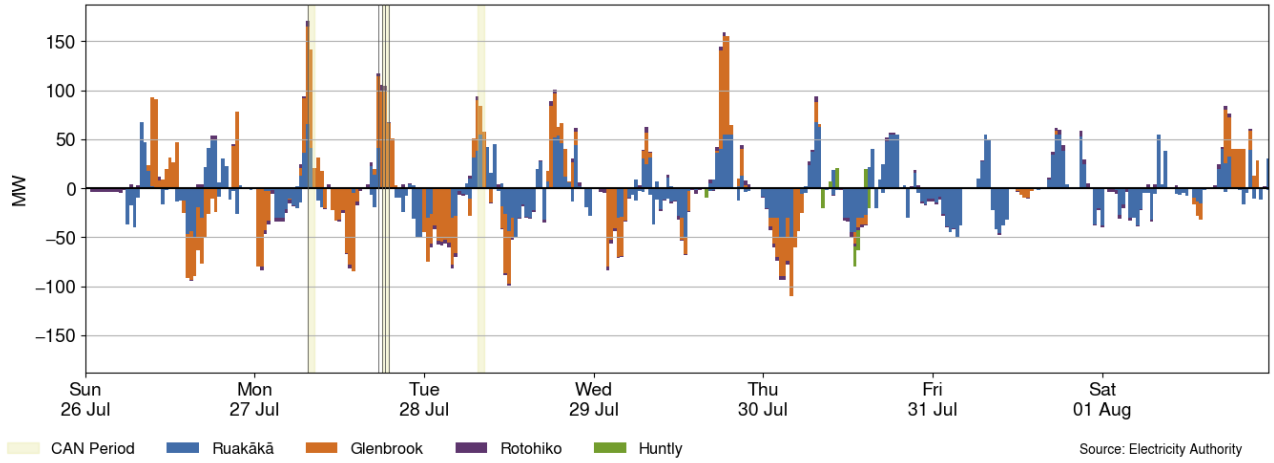
7.8. Figure 13 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into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

7.9. Genesis' 100MW/200MWh Huntly BESS has been generating this week, peaking on Thursday. The output of the battery will vary as it commissions.

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 Monday morning.

7.11. Ruakākā was on a planned outage between 10.00am to 4.00pmon Monday so had limited ability to recharge before the evening peak.

Figure 13: Grid scale battery charge and discharge, 26 July - 1 August



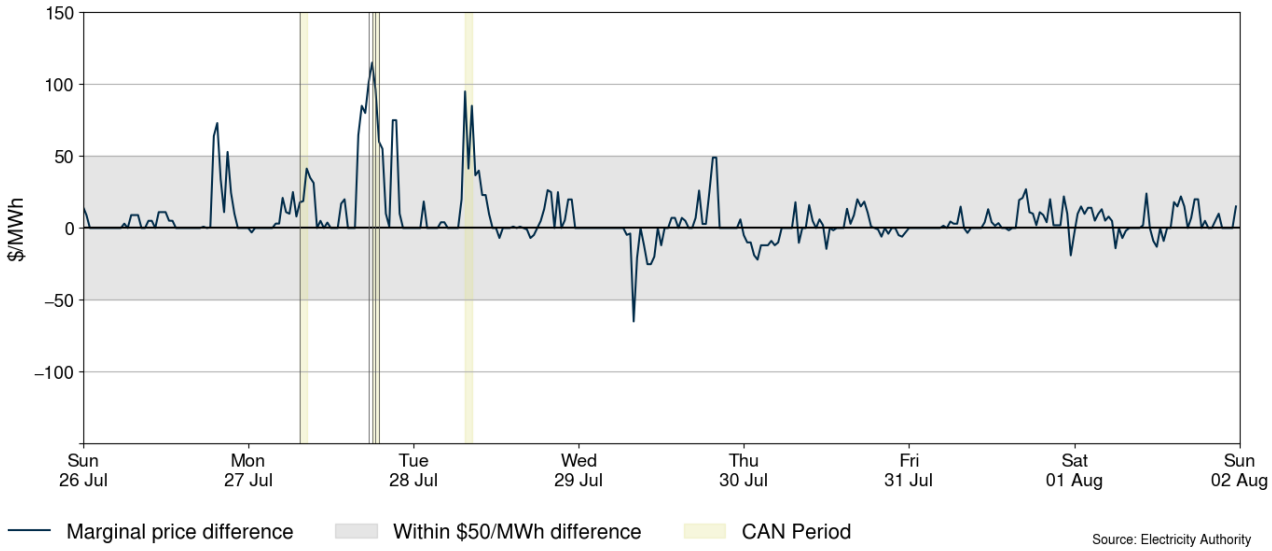
7.12. Figure 14 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[4]) projections. The figure highlights when forecasting inaccuracies are causing 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. The greatest positive forecast difference was $115/MWh over-forecast at 6.00pm on Monday. Demand was 139MW higher than forecast at this time.

7.14. The greatest negative forecast difference was $65/MWh under-forecast at 8.00am on Wednesday. Intermittent generation was 98MW higher than forecast.

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

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, 26 July - 1 August

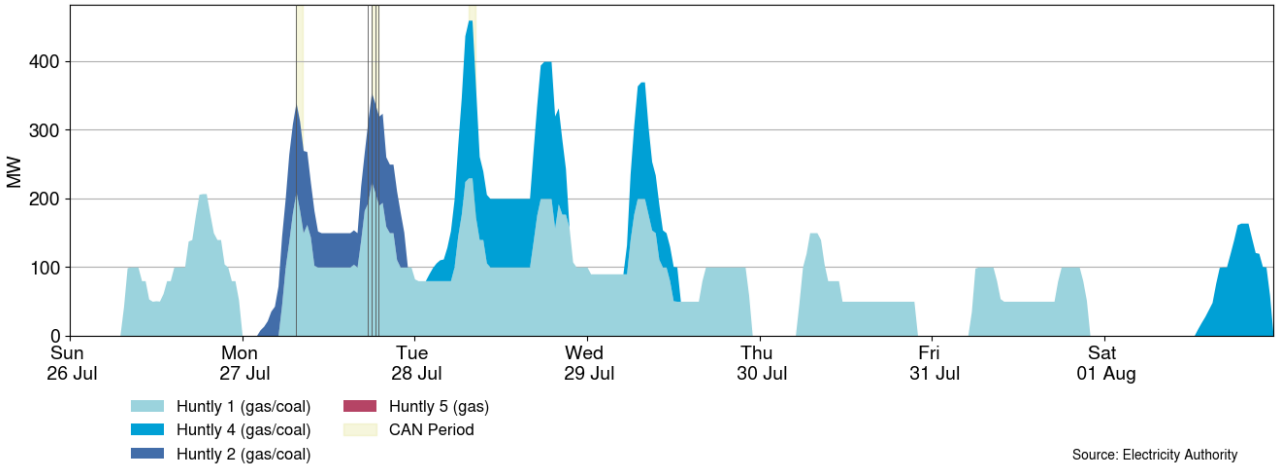


7.15. Figure 15 shows the generation of thermal baseload between 26 July - 1 August.

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 Monday.

7.17. There was an unexpected fault at Huntly 2 which meant it was only able to offer 140MW of its capacity during the high-priced periods on Monday.

Figure 15: Thermal baseload generation, 26 July - 1 August

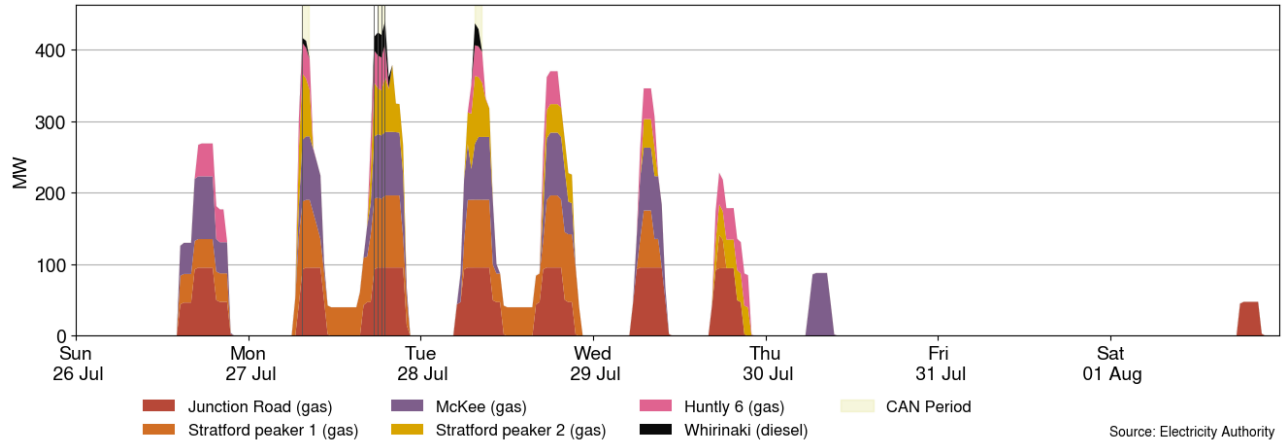


7.18. Figure 16 shows the generation of thermal peaker plants between 26 July - 1 August.

7.19. Peaker generation this week was greatest during Tuesday morning peak demand, with all peakers providing generation. No peaker generation ran on Friday.

7.20. Whirinaki ran during Monday peak periods and the Tuesday morning peak. Whirinaki did not clear in the energy market but was instead constrained on to provide reserve.

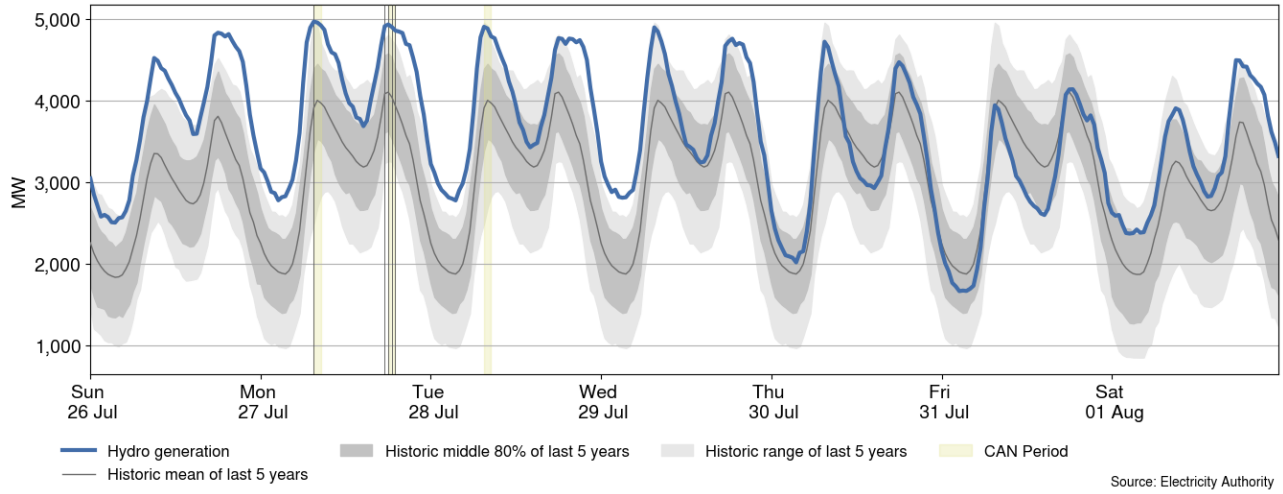
Figure 16: Thermal peaker generation, 26 July - 1 August



7.21. Figure 17 shows hydro generation between 26 July - 1 August.

7.22. Hydro generation was above the historic range for the last 5 years during peak periods from Sunday to Wednesday morning. Hydro generation fluctuated throughout the rest of the week, dropping below the lower 80th percentile during the day on Friday, and exceeding the historic range on Saturday evening

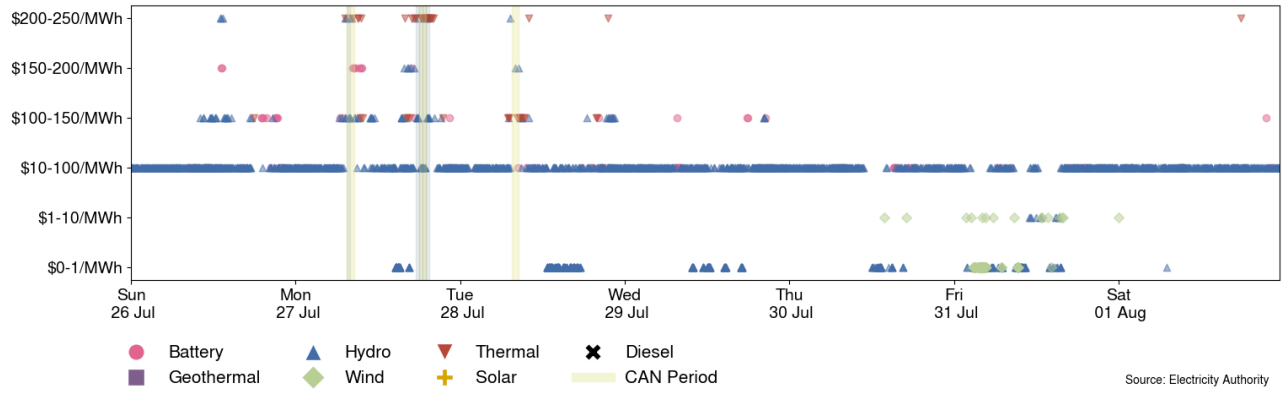
Figure 17: Hydro generation, 26 July - 1 August



7.23. 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.

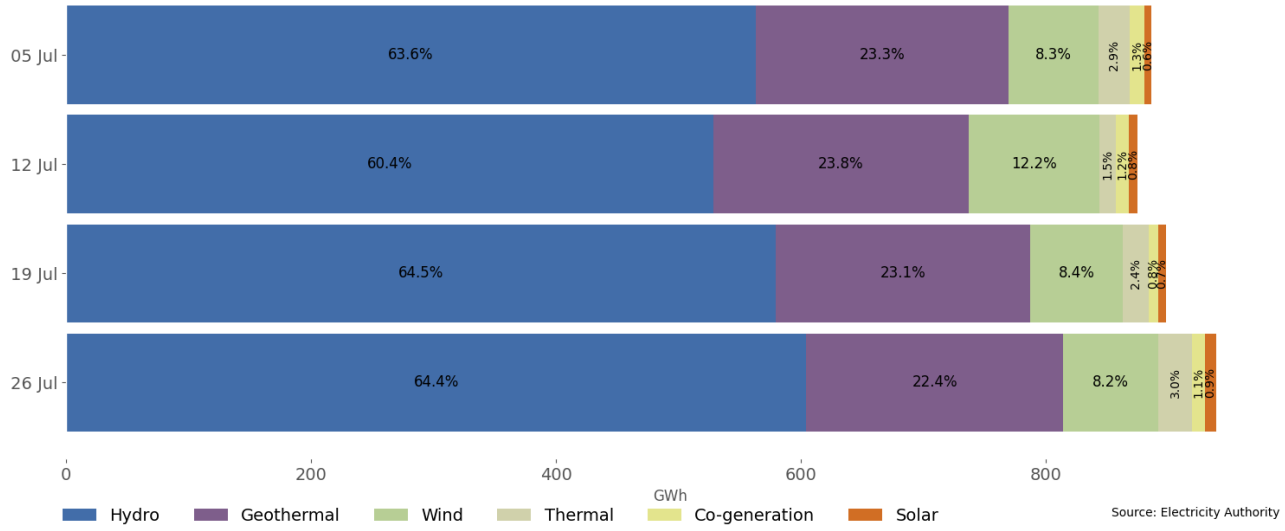
7.24. The highest marginal price of $210/MWh was set by Karāpiro hydro station on Sunday at 1.00pm. The most common technology setting prices this week was hydro, with batteries the second most common. Most marginal prices were between $10-100/MWh. High prices this week were a result of either energy scarcity or high reserve prices, not high-priced energy clearing.

Figure 18: Prices of marginal generation, 26 July - 1 August



7.25. As a percentage of total generation, between 26 July - 1 August, total weekly hydro generation was 64.4%, geothermal 22.4%, wind 8.2%, thermal 3.0%, co-generation 1.1%, and solar (grid connected) 0.9%, as shown in Figure 19.

Figure 19: Total generation by type as a percentage each week, between 5 July and 26 July



8. Outages

8.1. Figure 20 shows generation capacity on outage. Total capacity on outage between 26 July - 1 August ranged between ~718MW and ~1,394MW. Figure 21 shows the thermal generation capacity outages.

Figure 20: Total MW loss from generation outages, 26 July - 1 August

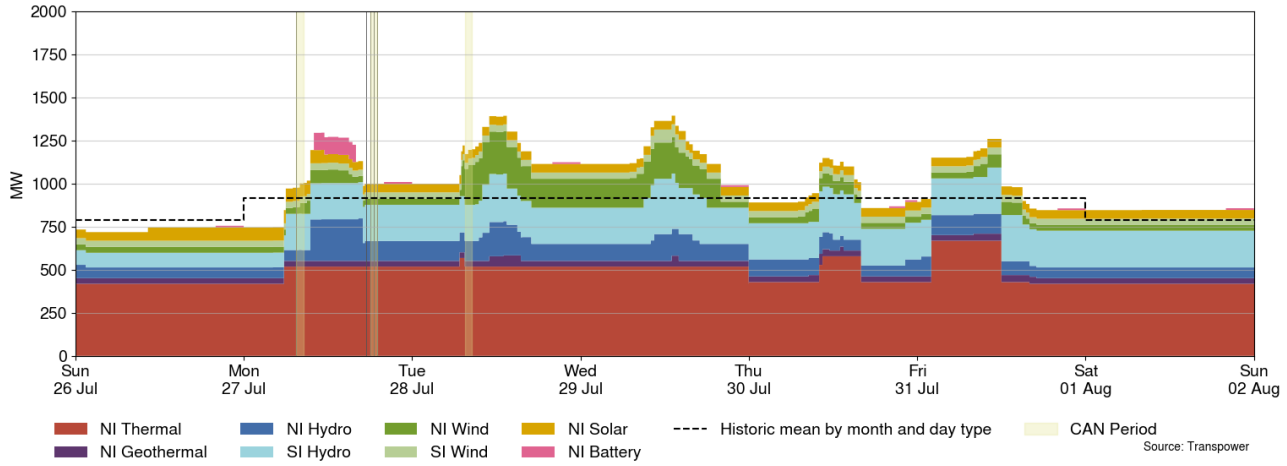
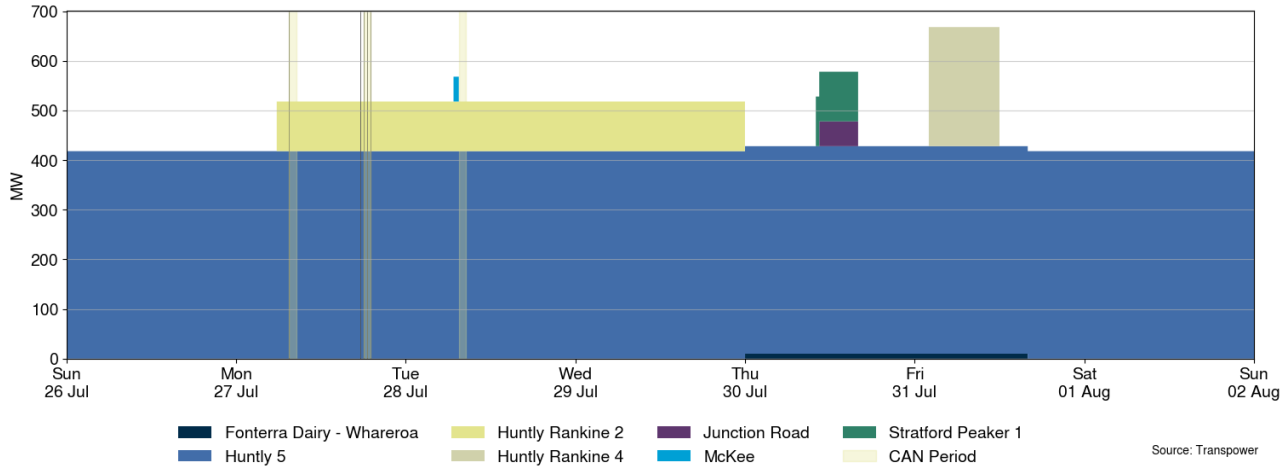


Figure 21: Total MW loss from thermal outages, 26 July - 1 August



8.2. Notable outages include:

Plant	Partial or Full	End Date
Ruakākā Station	Full	27 July 2026
Huntly 2	Partial	29 July 2026
Waipipi Station	Full	29 July 2026
Stratford peaker 1	Full	30 July 2026
Huntly 4	Full	31 July 2026
Kaiwaikawe	Full	05 August 2026
Huntly 5	Full	10 August 2026
Tauhei Solar Farm	Partial	31 August 2026
Roxburgh unit 8	Full	24 September 2026

9. Generation balance residuals

9.1. Figure 22 shows the national generation balance residuals between 26 July - 1 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 9:38am on Sunday, the System Operator issued a CAN for 7.30-8.30am and 6.00-7.00pm on Monday as the NRSL schedule showed residual generation was less than 200MW. Later at 9.12am on Monday another CAN was issued advising low residual generation for 7.30-8.30am on Tuesday. In real time, the lowest national residuals were:

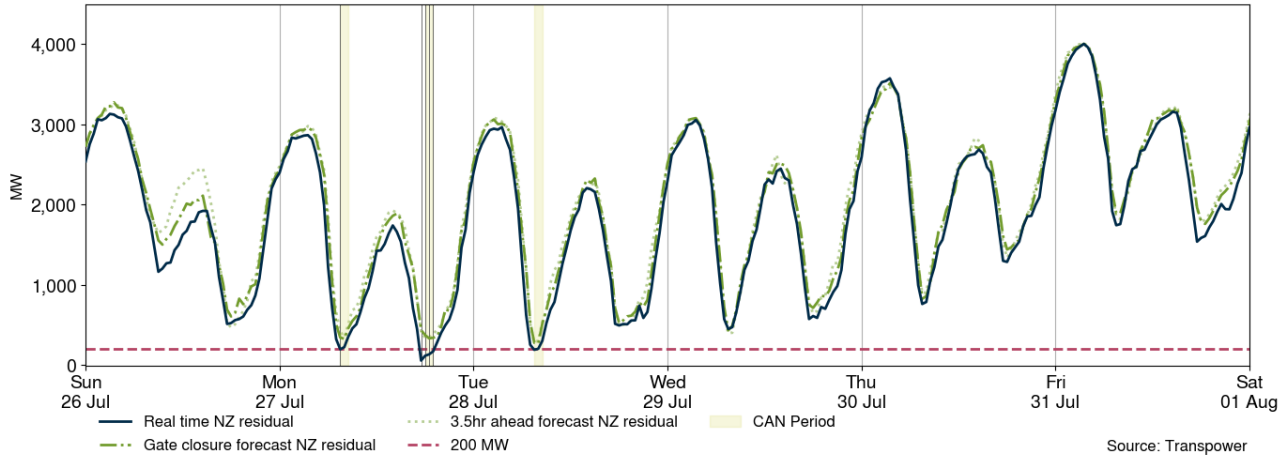
(a) 198MW at 7.30am Monday

(b) 58MW at 5.30pm Monday

(c) and 191MW at 7.30am Tuesday.

9.3. The lowest national residual of 58MW occurred at 5.30pm on Monday. At this time the North Island residual was 1MW and the South Island residual was 40MW.

Figure 22: National generation balance residuals, 26 July - 1 August



10. Storage/fuel supply

10.1. Figure 23 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 25 July, national controlled storage was 83% nominally full and ~131% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (86% full[5]) is significantly higher than the historic 90th percentile for this time of year.

10.4. Storage at Lake Tekapō (73% full) is at the historic 90th percentile for this time of year.

10.5. Storage at Lake Taupō is (57% full) is above average for this time of year.

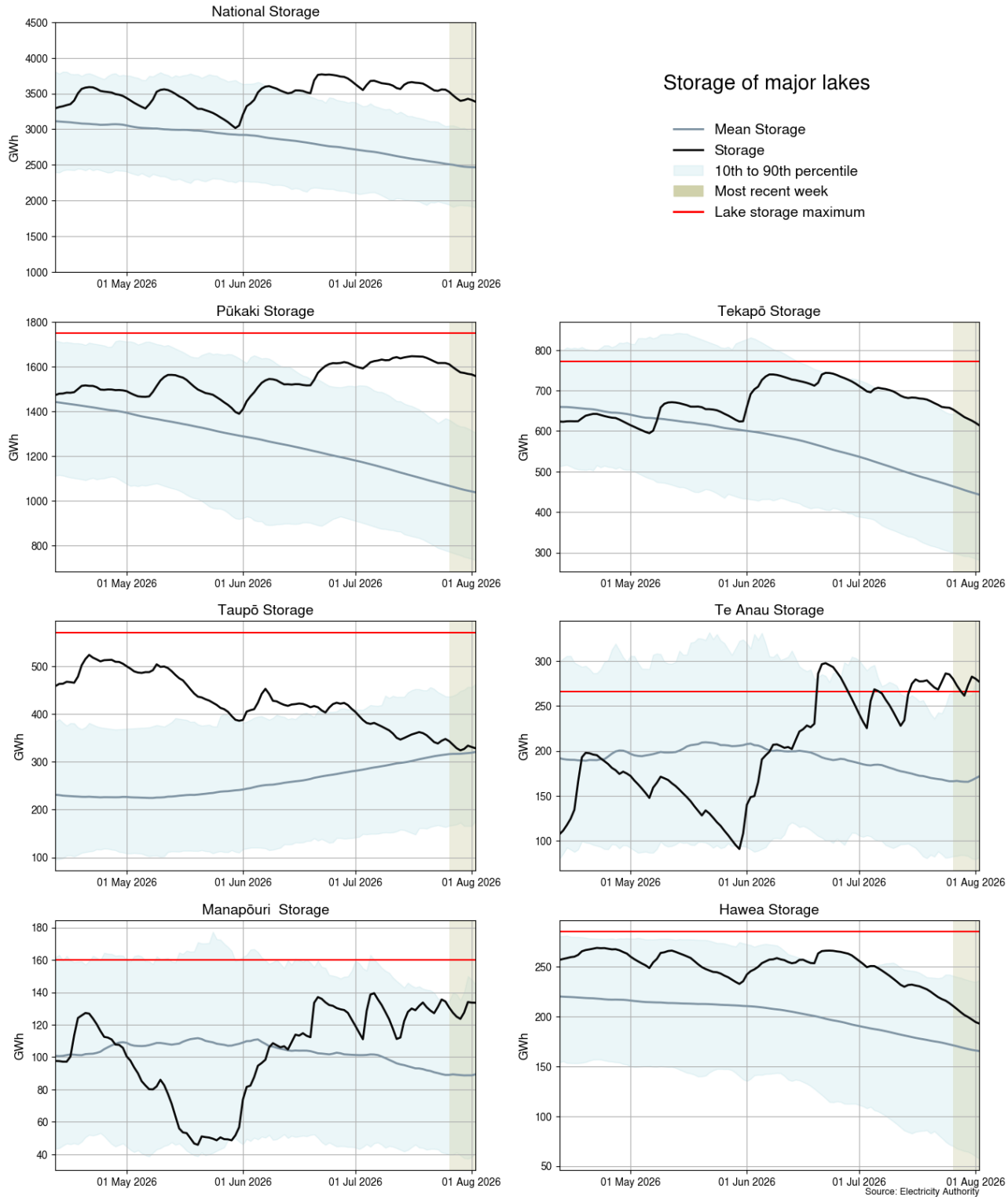
10.6. Storage at Lake Te Anau (104% full) is above its storage maximum and above the historic 90th percentile for this time of year.

[5] Percentage full values sourced from NZX Hydro.

10.7. Storage at Lake Manapōuri (85% full) is slightly below the historic 90th percentile for this time of year.

10.8. Storage at Lake Hawea (68% full) remains slightly below the historic 90th percentile for this time of year.

Figure 23: 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.

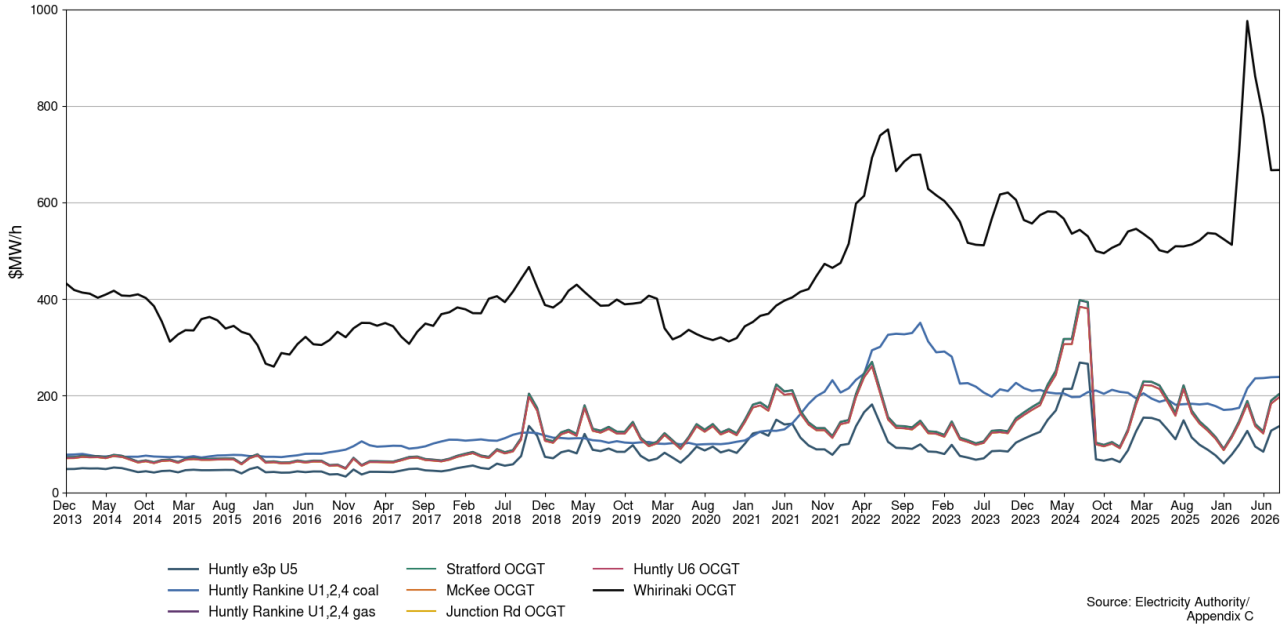
11.5. The SRMC of gas fuelled thermal plants is currently between $136/MWh and $203/MWh.

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 24: Estimated monthly SRMC for thermal fuels

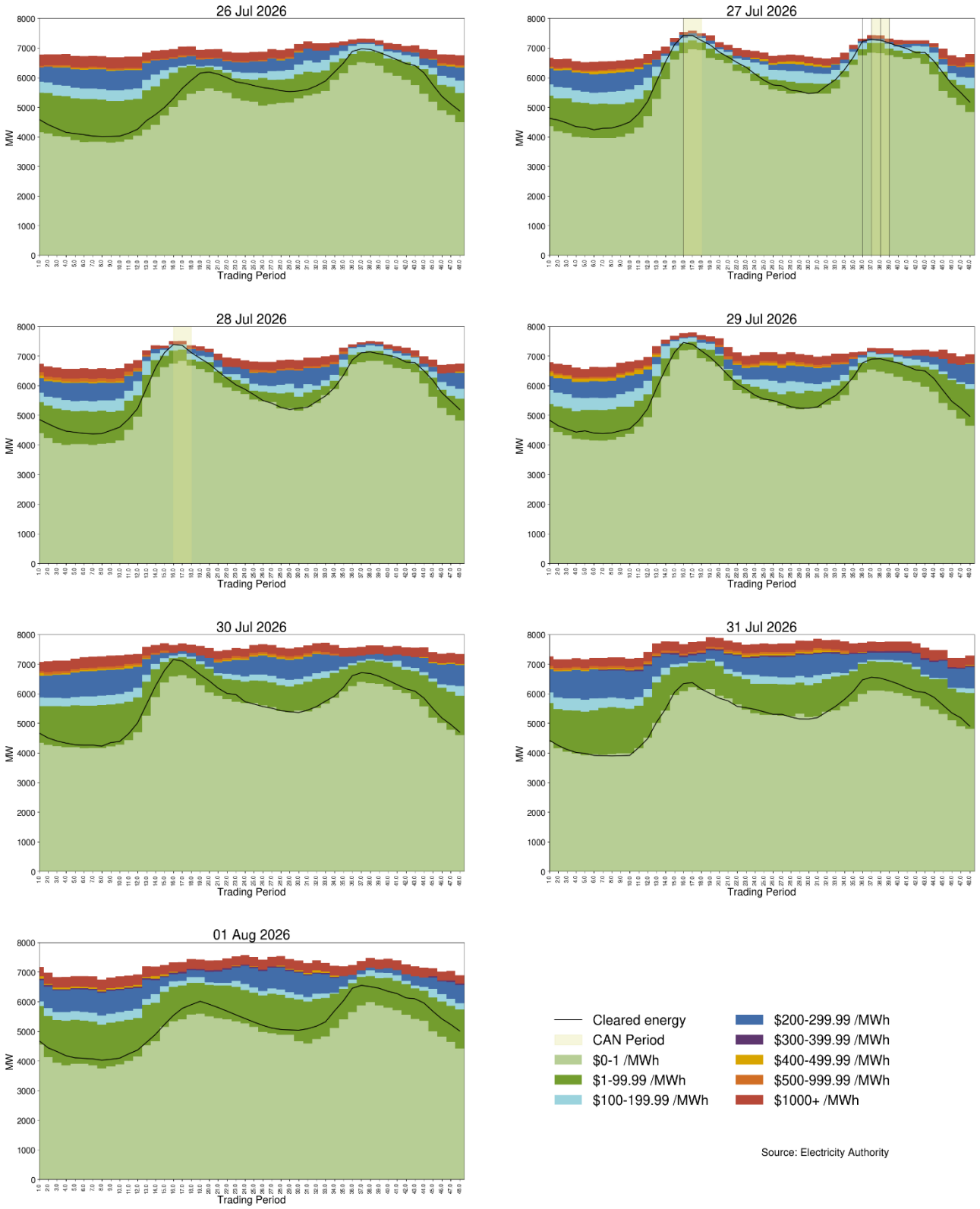


12. Offer behaviour

12.1. Figure 25 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 between $200-299/MWh on Monday during the peak periods.

Figure 25: National daily offer stacks



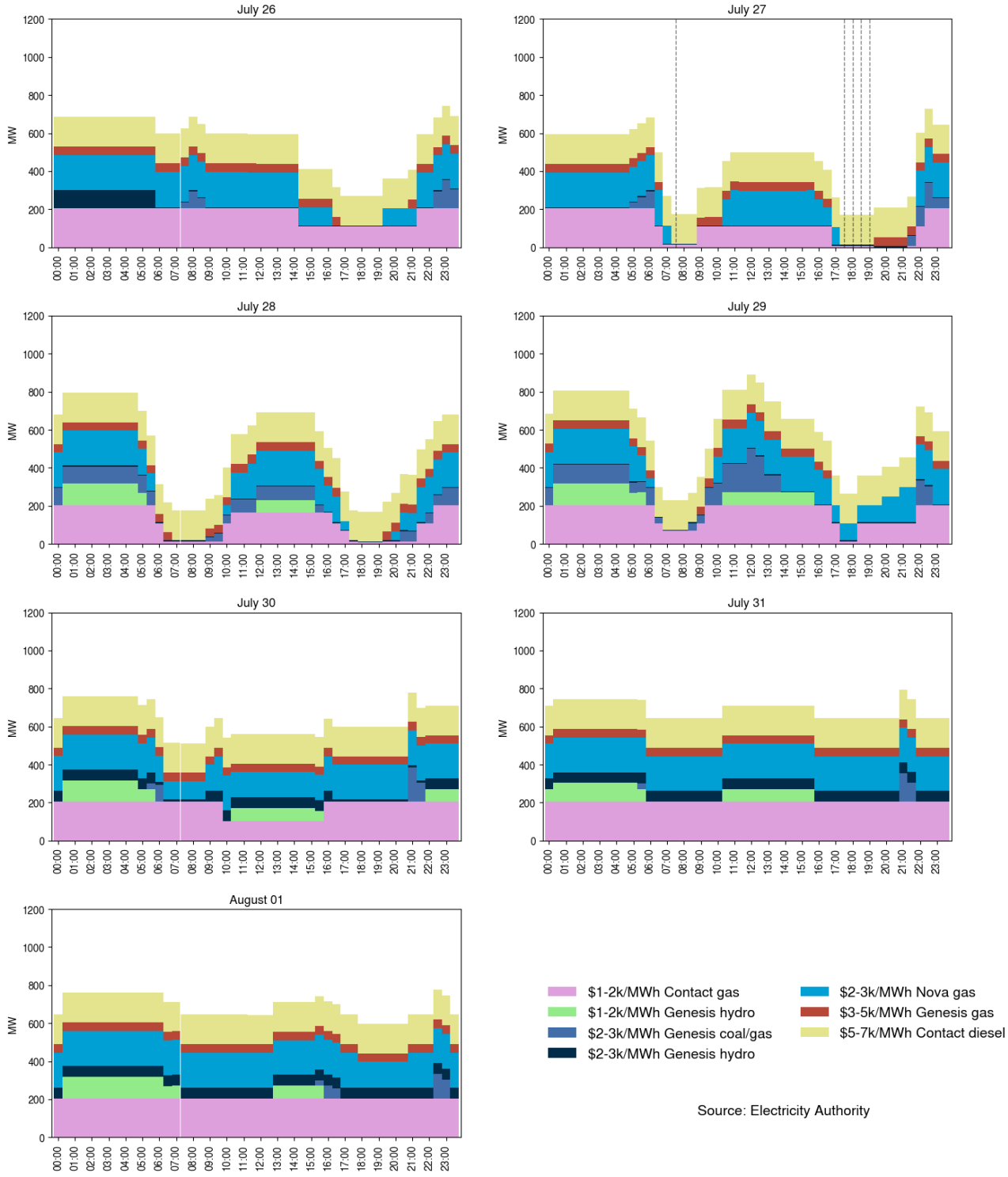
12.3. Figure 26 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 586MW per trading period was priced above $1,000/MWh this week, which is roughly 10% of the total energy available.

Figure 26: High priced offers



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
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
24/06/2026	Several	Further analysis	Contact	Stratford peakers	Offers
22/07/2026	16-18	Further analysis	Contact	Stratford peakers	Offers