

11 May 2026

Trading conduct report

3-9 May 2026

Market monitoring weekly report

Trading conduct report 3-9 May 2026

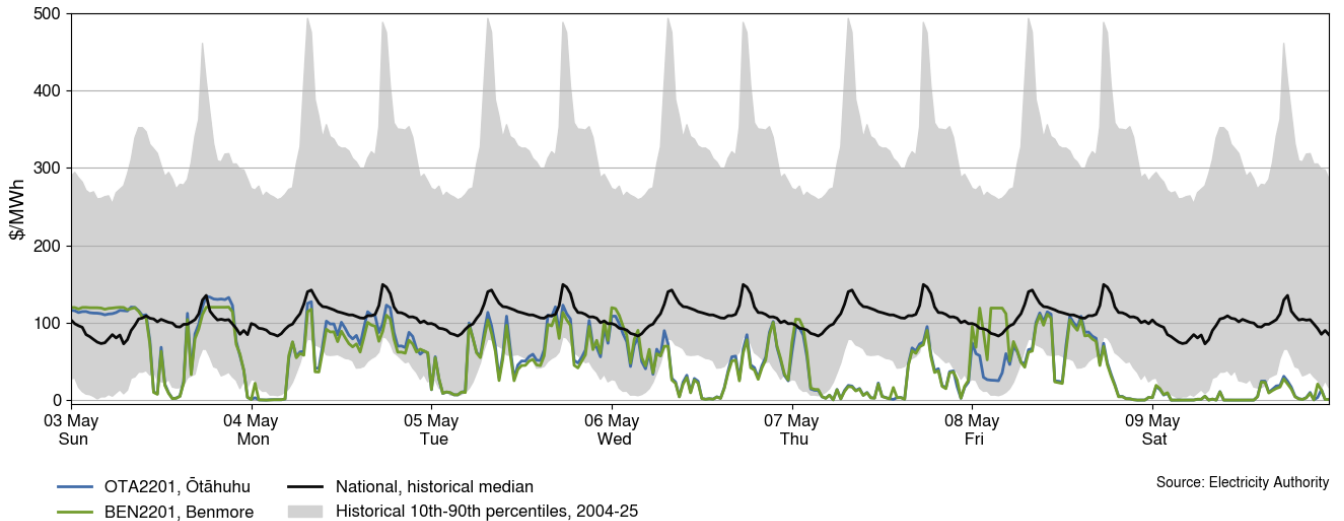
1. Overview

- 1.1. This week the average spot price decreased by \$45/MWh to \$50/MWh. Lower prices this week are associated with higher levels of wind generation and an increase in hydro storage. National controlled storage has increased to 83% nominally full and 111% of the historical average for this time of year.

2. Spot prices

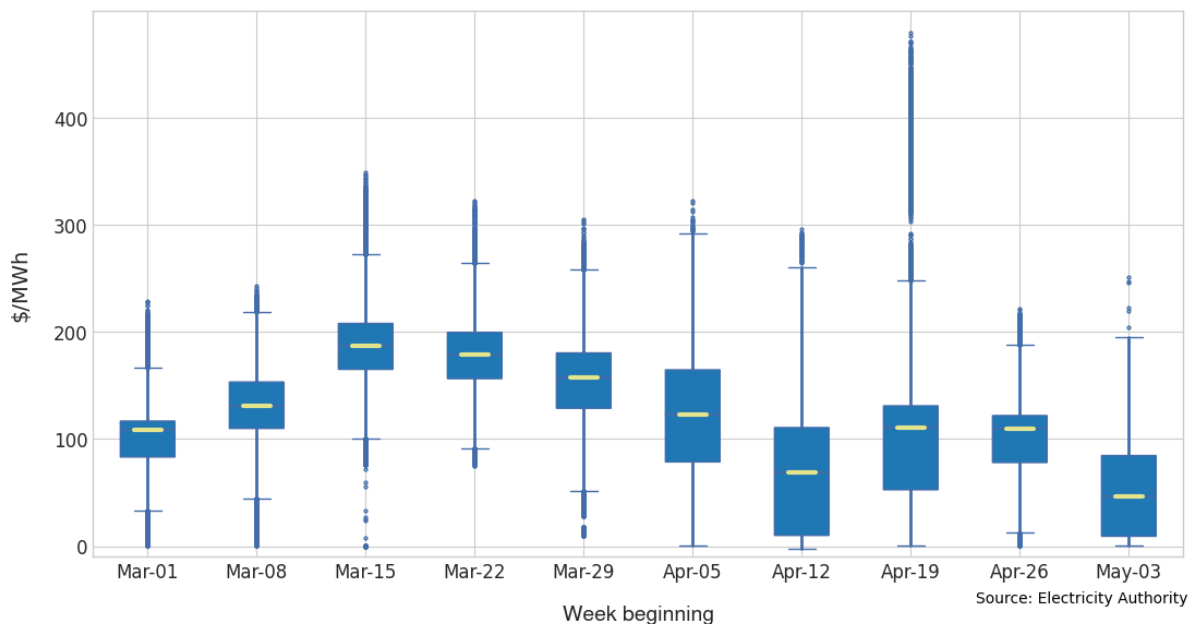
- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 3-9 May:
 - (a) The average spot price for the week was \$50/MWh, a decrease of around \$45/MWh compared to the previous week.
 - (b) 95% of prices fell between \$0.03/MWh and \$126/MWh.
- 2.3. Prices have been lower this week compared to last week due to higher levels of wind generation and an increase in hydro storage.
- 2.4. On Friday between 1.00am and 4.30am, the price difference between Benmore and Ōtāhuhu was above \$50/MWh. This difference reached \$93/MWh between 2.30am and 3.30am. At these times, flow was primarily southward and the HVDC was less than 50MW from capacity (Section 5.3). North Island wind generation was also high at these times, at above 500MW for this period. Total wind generation was also more than 100MW higher than forecast for this period.
- 2.5. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 3-9 May



- 2.6. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week’s median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The ‘whiskers’ extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.
- 2.7. The distribution of spot prices this week was lower than last week. The median price was \$47/MWh and most prices (middle 50%) fell between \$9/MWh and \$85/MWh.

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

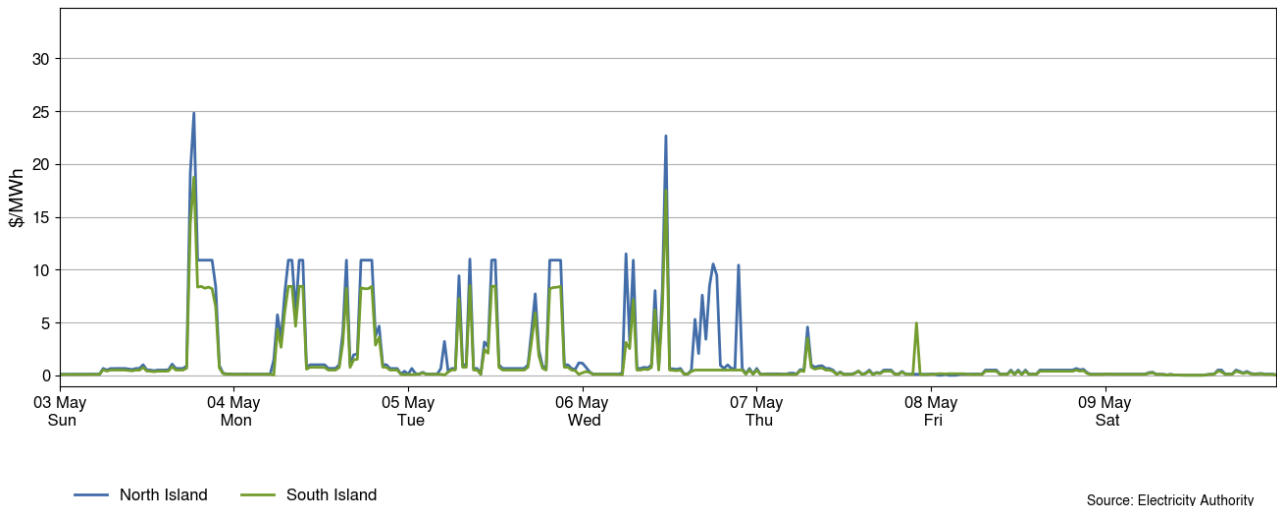


3. Reserve prices

- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices mostly remained below \$1/MWh, with FIR prices consistently spiking above \$10/MWh from Sunday to Wednesday.

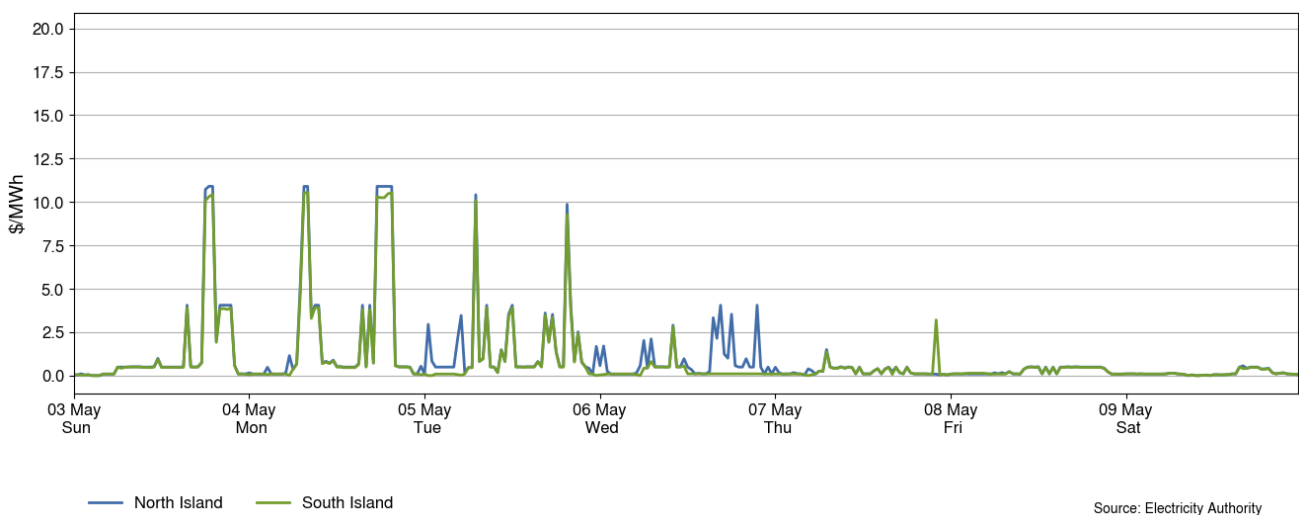
- 3.2. On Sunday at 6:30pm, North Island FIR prices reached \$25/MWh and South Island FIR prices reached \$19/MWh. During this time, the risk setter was Huntly 5, and the amount of FIR available decreased from the previous trading period. At this time, Ruakākā started an outage and stopped offering reserve.
- 3.3. On Wednesday at 11:00am, North Island FIR prices reached \$23/MWh, and South Island FIR prices reached \$18/MWh. During this time, Huntly 5 was the risk setter, and Rangipō was the secondary risk setter. Generation at Huntly 5 increased, increasing the amount of reserve needed to cover this risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 3-9 May



- 3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices remained mostly below \$1/MWh with SIR prices consistently spiking to around \$10/MWh from Sunday to Wednesday. During this time Ruakākā was on outage.

Figure 4: Sustained instantaneous reserve by trading period and island, 3-9 May

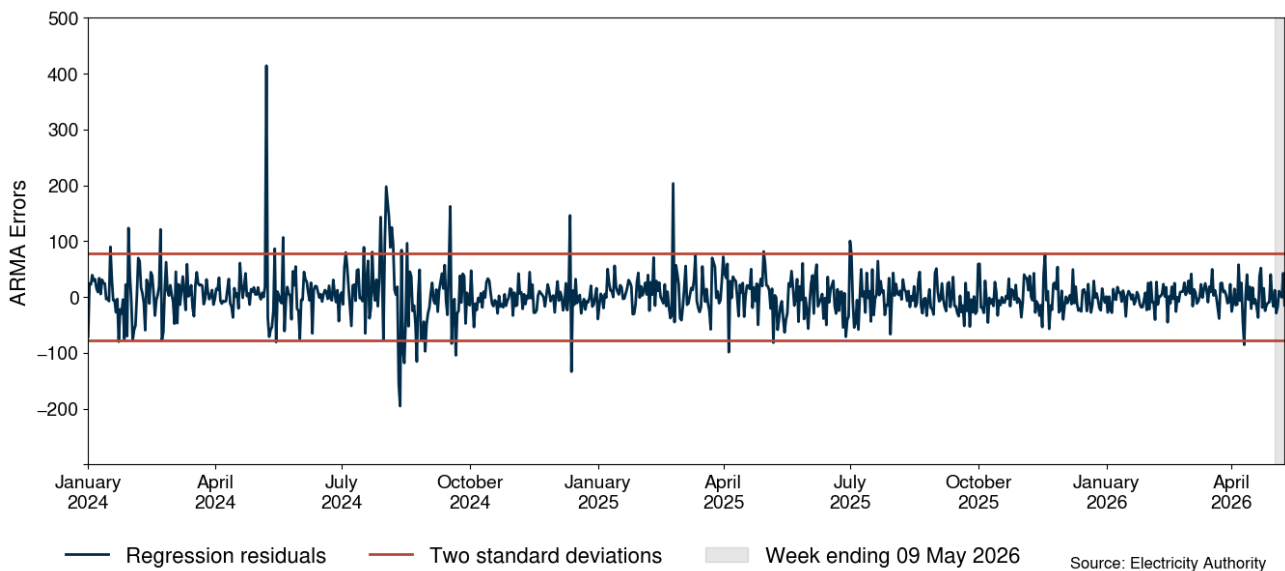


4. Regression residuals

- 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.

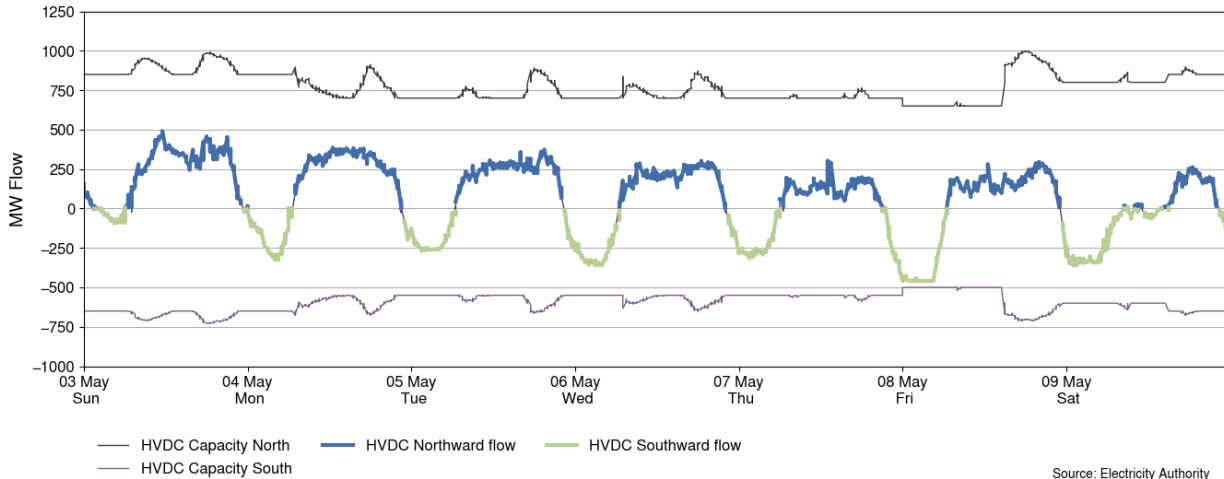
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 9 May 2026



5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 3-9 May. HVDC flows were mainly northward during the day and southward overnight.
- 5.2. The highest northward flow occurred on Sunday at 11.30am, with flow of around 491 MW.
- 5.3. The highest southward flow occurred on Friday between 12.00am and 4.30am, with around 460 MW. At these times southward capacity transitioned from 550 MW down to 500 MW.

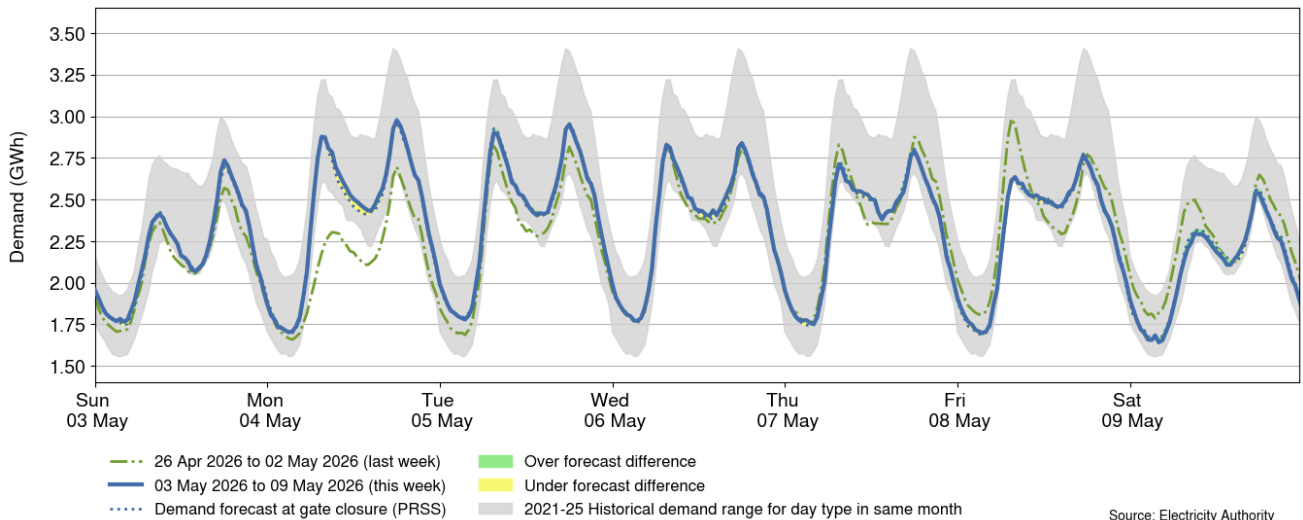
Figure 6: HVDC flow and capacity, 3-9 May



6. Demand

6.1. Figure 7 shows national demand between 3-9 May, compared to the historic range and the demand of the previous week. Demand was mostly similar to last week until Thursday, though it was higher on Monday as it was ANZAC Day last week. On Friday and Saturday, demand was slightly lower than last week due to warmer temperatures.

Figure 7: National demand, 3-9 May compared to the previous week



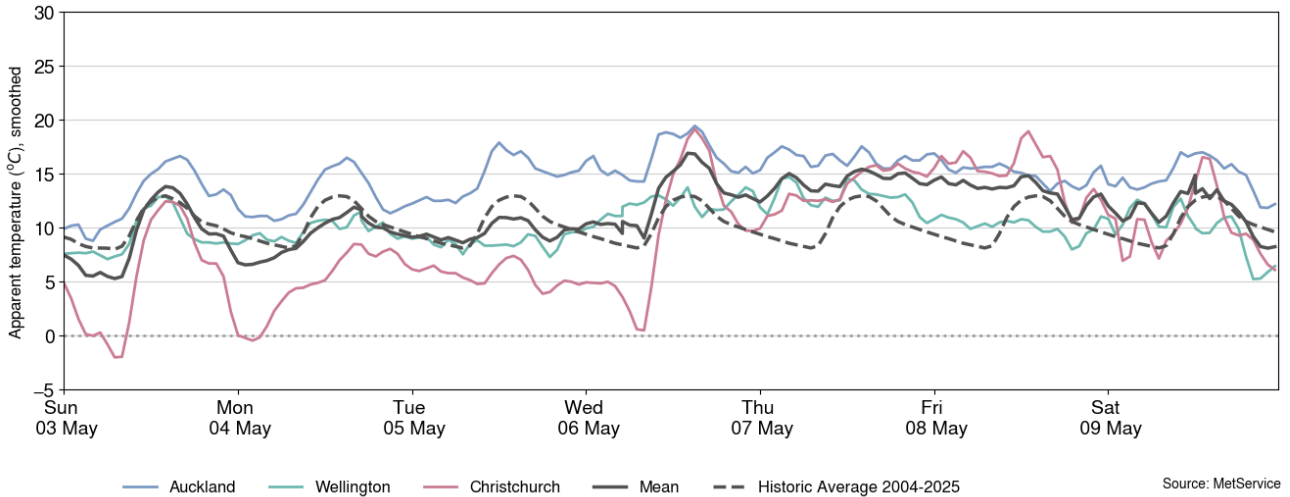
6.2. Apparent temperatures ranged from 8°C to 20°C in Auckland, 4°C to 15°C in Wellington, and -3°C to 20°C in Christchurch.

6.3. Apparent temperatures have been mostly near the historic mean this week, though Christchurch was below the historic mean from Sunday to Wednesday.

6.4. Figure 8 shows the hourly apparent temperature at main population centres from 3-9 May. 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 8°C to 20°C in Auckland, 4°C to 15°C in Wellington, and -3°C to 20°C in Christchurch.
- 6.6. Apparent temperatures have been mostly near the historic mean this week, though Christchurch was below the historic mean from Sunday to Wednesday.

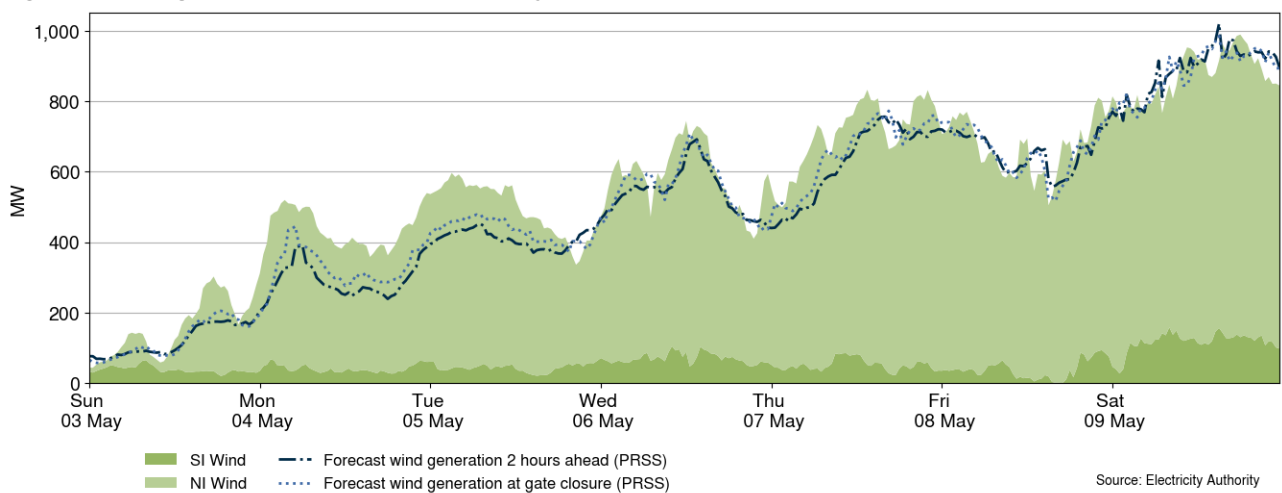
Figure 8: Temperatures across main centres, 3-9 May



7. Generation

- 7.1. Figure 9 shows wind generation and forecast from 3-9 May. This week wind generation varied between 44MW and 989MW, with a weekly average of 559MW. Wind generation was low on Sunday but remained high for the rest of the week.
- 7.2. Sustained forecasting errors on Monday and Tuesday were a result of an amalgamation of forecasting errors from West Wind 1 and from in the Manawatū-Whanganui region at Tararua, Te Āpiti, and Turitea wind farms.

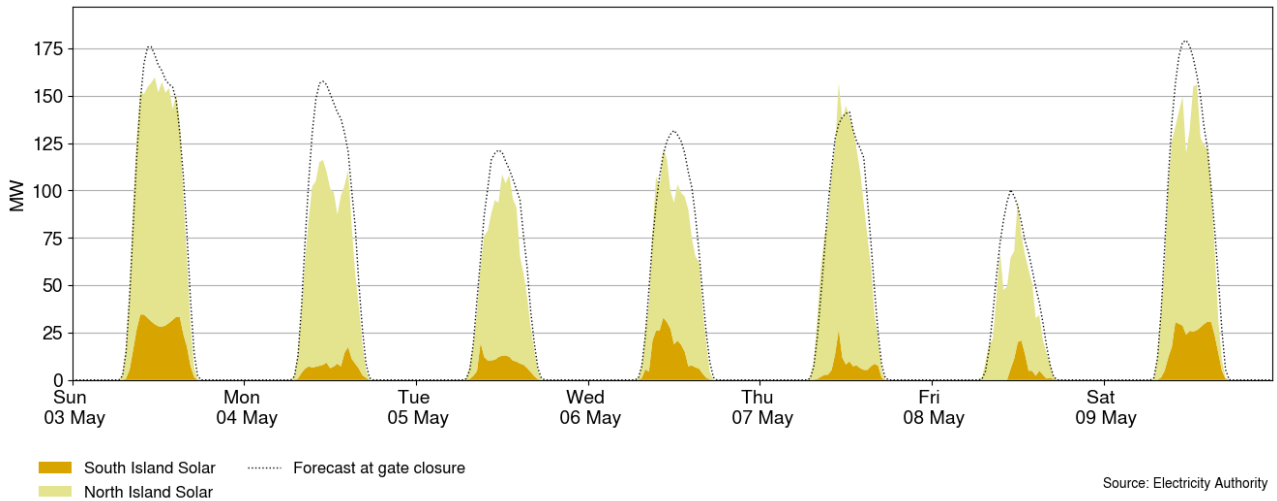
Figure 9: Wind generation and forecast, 3-9 May



- 7.3. Figure 10 shows grid connected solar generation from 3-9 May. Solar generation has been lower this week, peaking below 100MW on Friday, and peaking overall at 160MW on Sunday at 11.30am.

7.4. The large forecasting error on Monday was primarily caused by forecasting errors at Lauriston solar farm.

Figure 10: Grid connected solar generation, 3-9 May

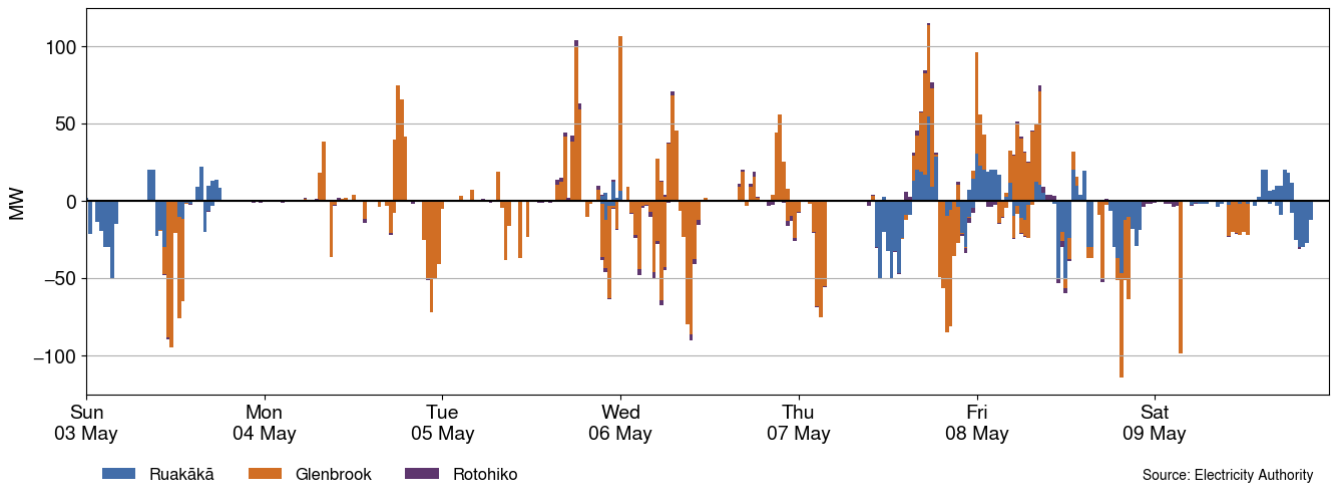


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.6. This week, the batteries have charged when the prices were lower and discharged when the prices are higher.

7.7. Ruakākā was on outage from Sunday evening to Thursday afternoon.

Figure 11: Grid scale battery charge and discharge, 3-9 May



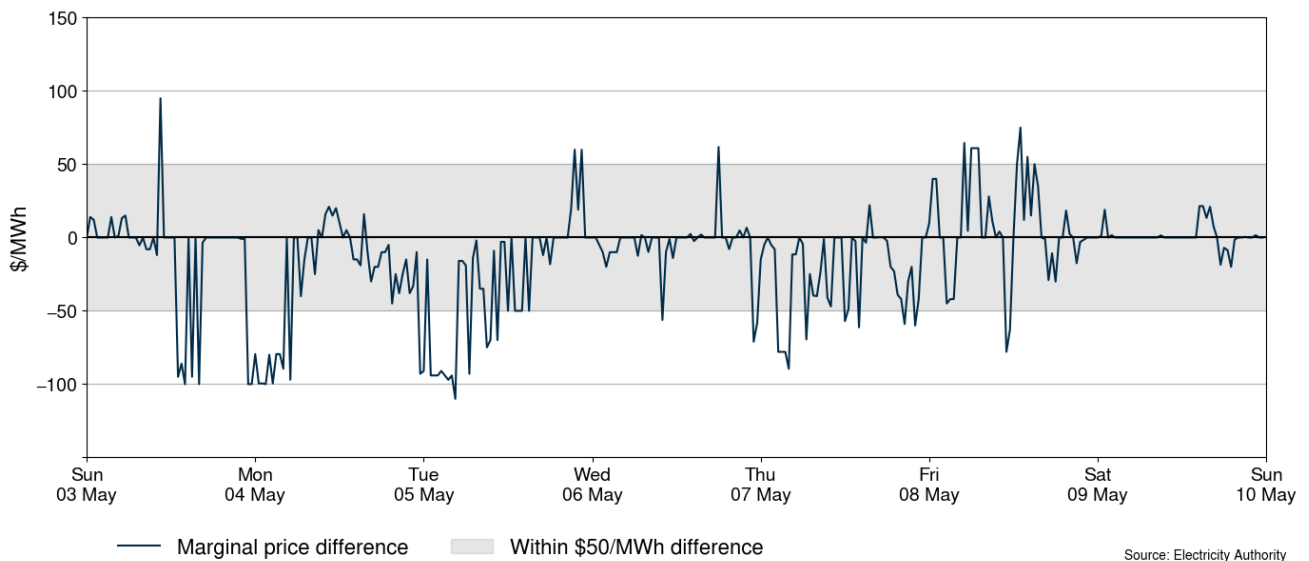
7.8. Some trading periods this week had a marginal price difference of more than \$50/MWh.

7.9. The maximum positive difference of \$95/MWh occurred on Sunday at 10.30am. At this time, demand was 10MW lower than forecast, and wind generation was 14MW lower than forecast.

7.10. The maximum negative difference of \$110/MWh occurred on Tuesday at 4.30am. At this time, demand was 24MW lower than forecast, and wind generation was 112MW higher than forecast.

- 7.11. 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 (PRSS¹) 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.
- 7.12. Some trading periods this week had a marginal price difference of more than \$50/MWh.
- 7.13. The maximum positive difference of \$95/MWh occurred on Sunday at 10.30am. At this time, demand was 10MW lower than forecast, and wind generation was 14MW lower than forecast.
- 7.14. The maximum negative difference of \$110/MWh occurred on Tuesday at 4.30am. At this time, demand was 24MW lower than forecast, and wind generation was 112MW higher than forecast.

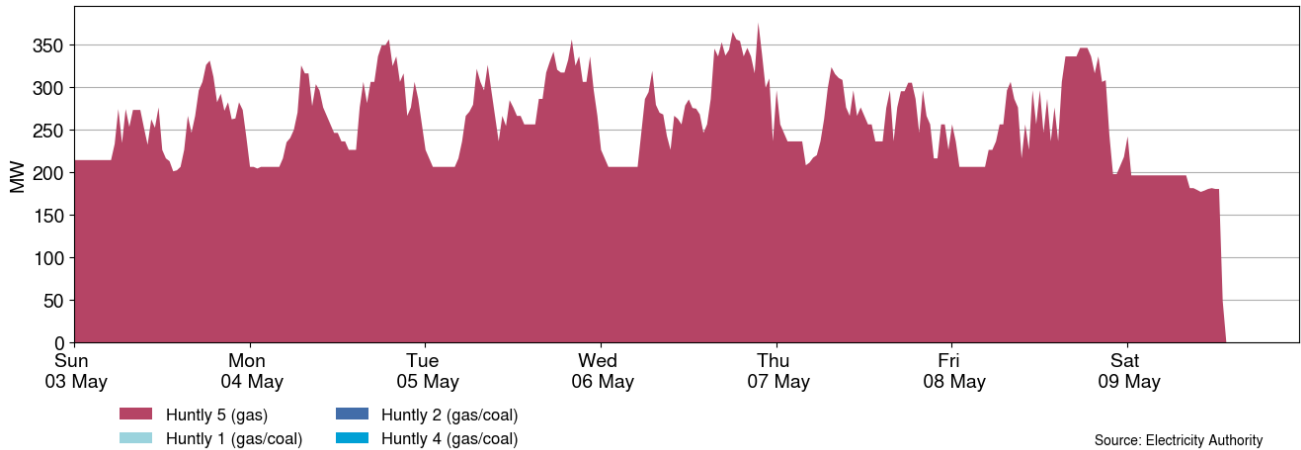
Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 3-9 May



- 7.15. Figure 13 shows the generation of thermal baseload between 3-9 May. Huntly 5 ran the whole week until Saturday afternoon when it turned off following an unplanned production outage at Kupe gas field.

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

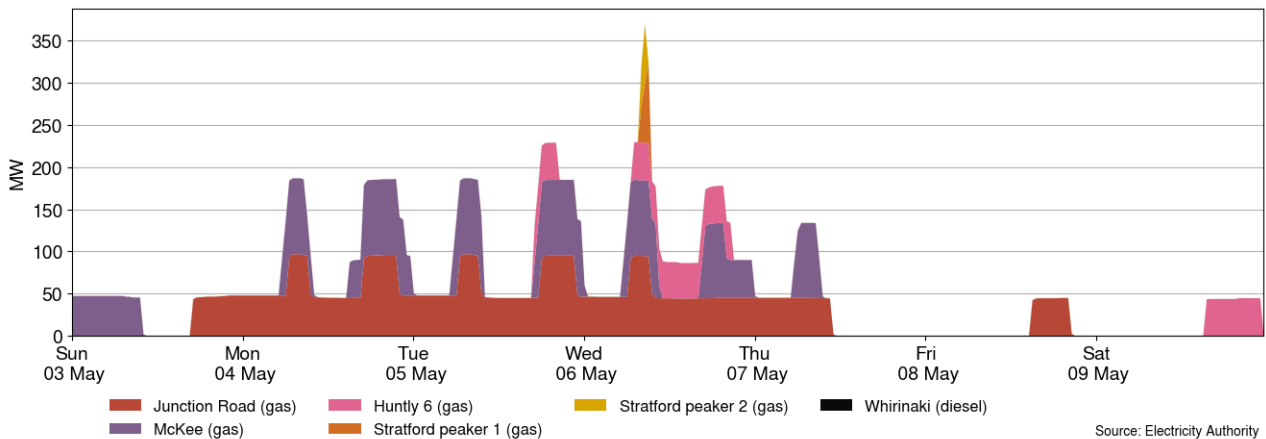
Figure 13: Thermal baseload generation, 3-9 May



7.16. Figure 14 shows the generation of thermal peaker plants between 3-9 May. Junction Road ran continuously from Sunday to Thursday, and at times on Friday. McKee ran continuously from Sunday to Thursday, and at times on Friday. McKee ran at times from Sunday to Thursday, Huntly 6 ran at times on Tuesday, Wednesday, and Saturday, and the Stratford peakers ran on Wednesday.

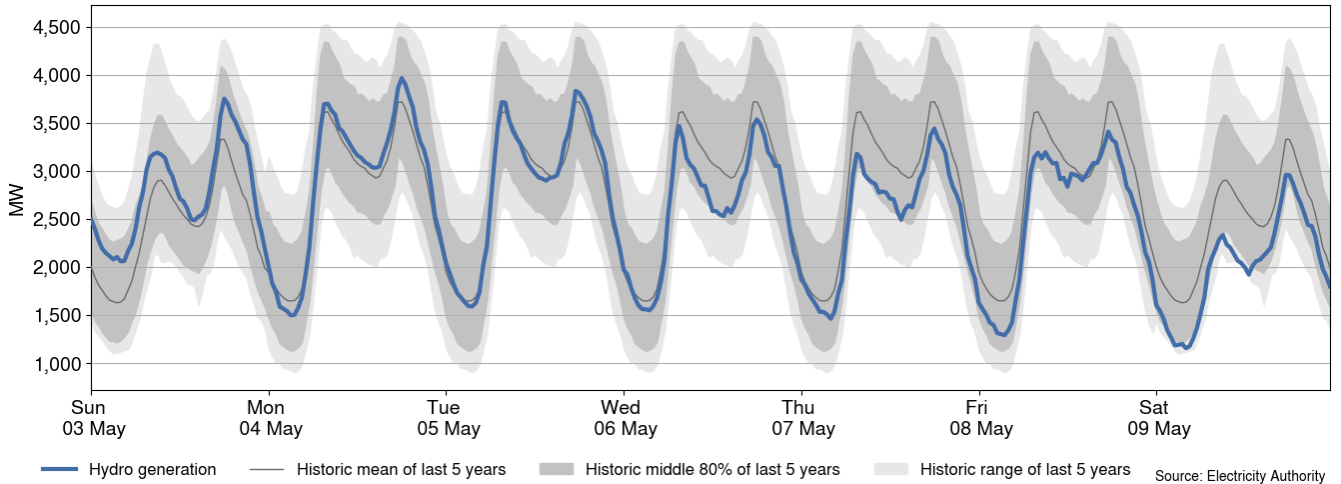
7.17. The Stratford peakers appear to have been testing after their outage on Tuesday.

Figure 14: Thermal peaker generation, 3-9 May



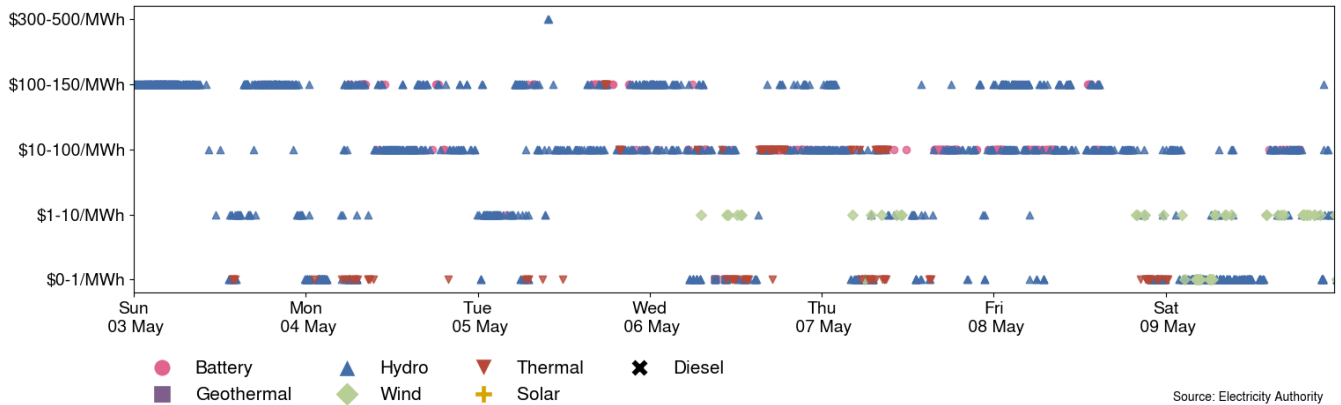
7.18. Figure 15 shows hydro generation between 3-9 May. Hydro generation was above the historic mean on Sunday, near the historic mean on Monday and Tuesday, and below the historic mean for the rest of the week.

Figure 15: Hydro generation, 3-9 May



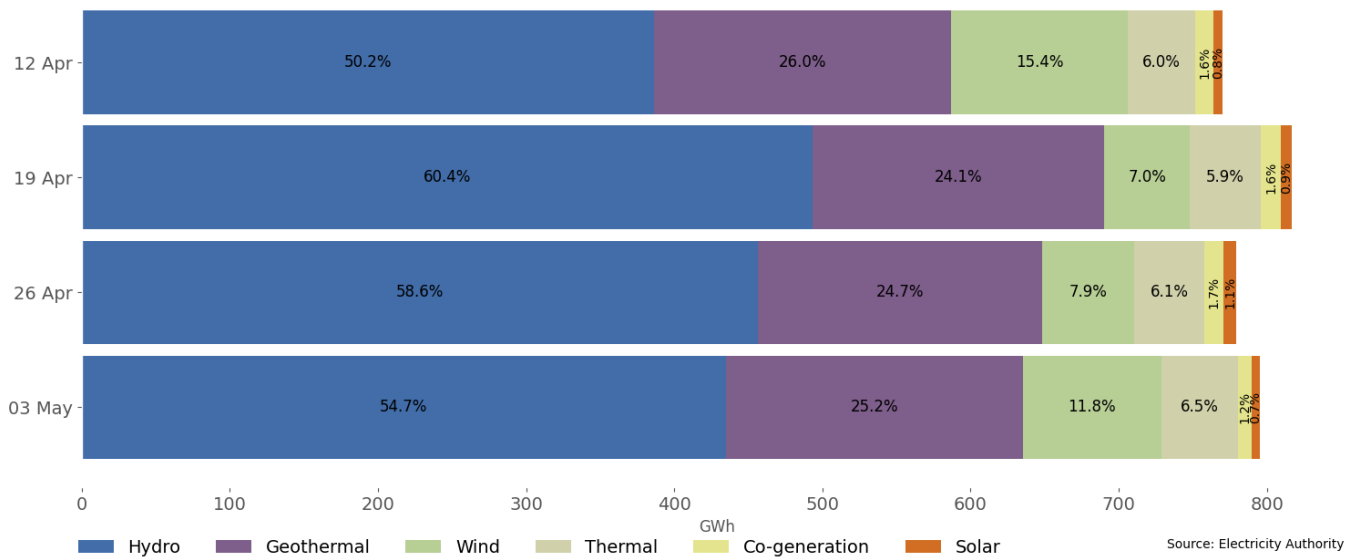
- 7.19. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.
- 7.20. The highest prices were set by Contact hydro on Tuesday. The most common technology setting prices was hydro generation, with batteries the second most common. Most marginal prices were between \$10-100/MWh.

Figure 16: Prices of marginal generation, 3-9 May



- 7.21. As a percentage of total generation, between 3-9 May, total weekly hydro generation was 54.7%, geothermal 25.2%, wind 11.8%, thermal 6.5%, co-generation 1.2%, and solar (grid connected) 0.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 12 April and 9 May



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 3-9 May ranged between ~836MW and ~1,694MW. Figure 19 shows the thermal generation capacity outages.

8.2. The Ruakākā battery was on outage from Sunday 6.00pm to Thursday 10.30am.

Figure 18: Total MW loss from generation outages, 3-9 May

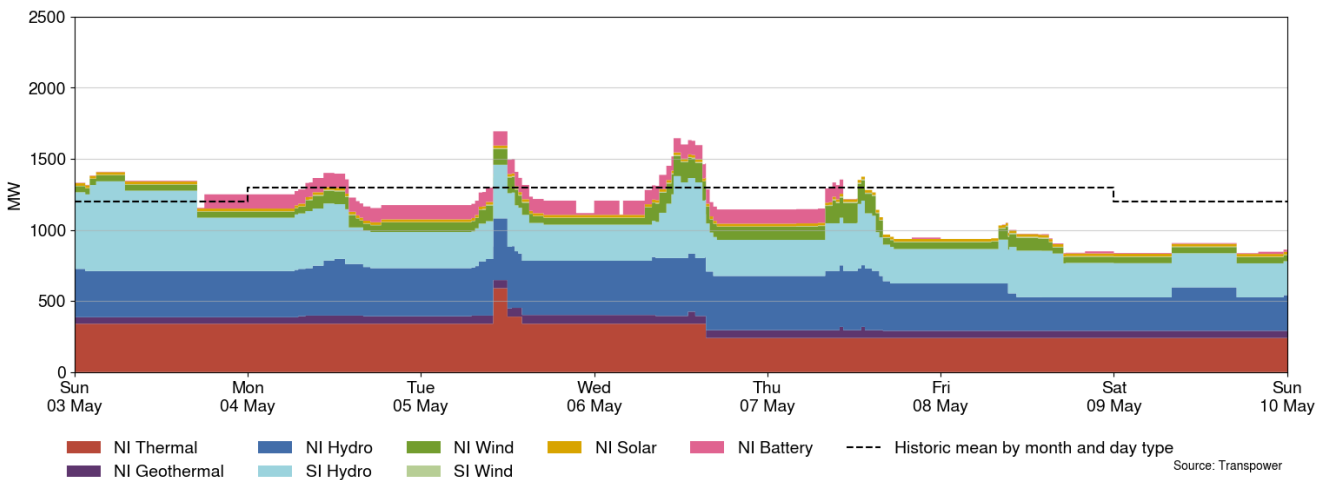
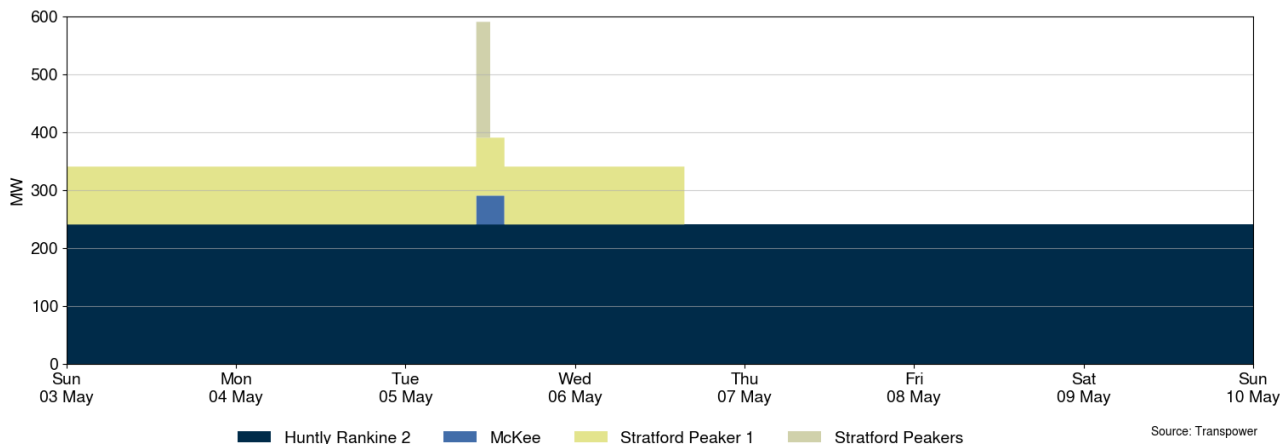


Figure 19: Total MW loss from thermal outages, 3-9 May



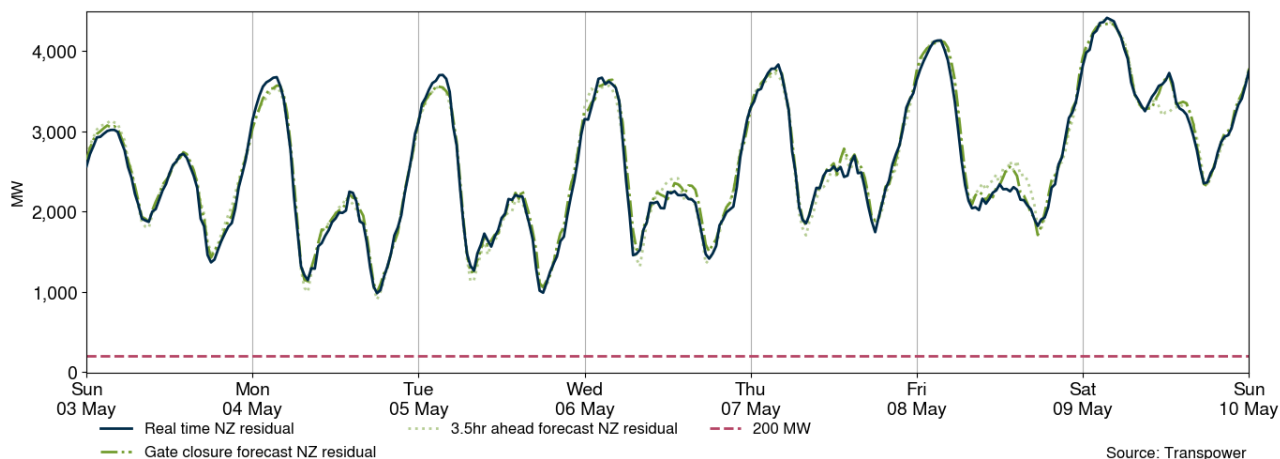
8.3. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 6	Full	4 May 2026
Stratford Peaker 1	Full	6 May 2026
Ruakākā Battery	Full	7 May 2026
Rangipō unit 6	Full	8 May 2026
Huntly 2	Full	20 May 2026
Manapōuri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

- 9.1. Overall, national residuals have been healthy this week. The lowest national residual was 906MW on Monday at 6.00pm.
- 9.2. Figure 20 shows the national generation balance residuals between 3-9 May. 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.
- 9.3. Overall, national residuals have been healthy this week. The lowest national residual was 906MW on Monday at 6.00pm.

Figure 20: National generation balance residuals, 3-9 May

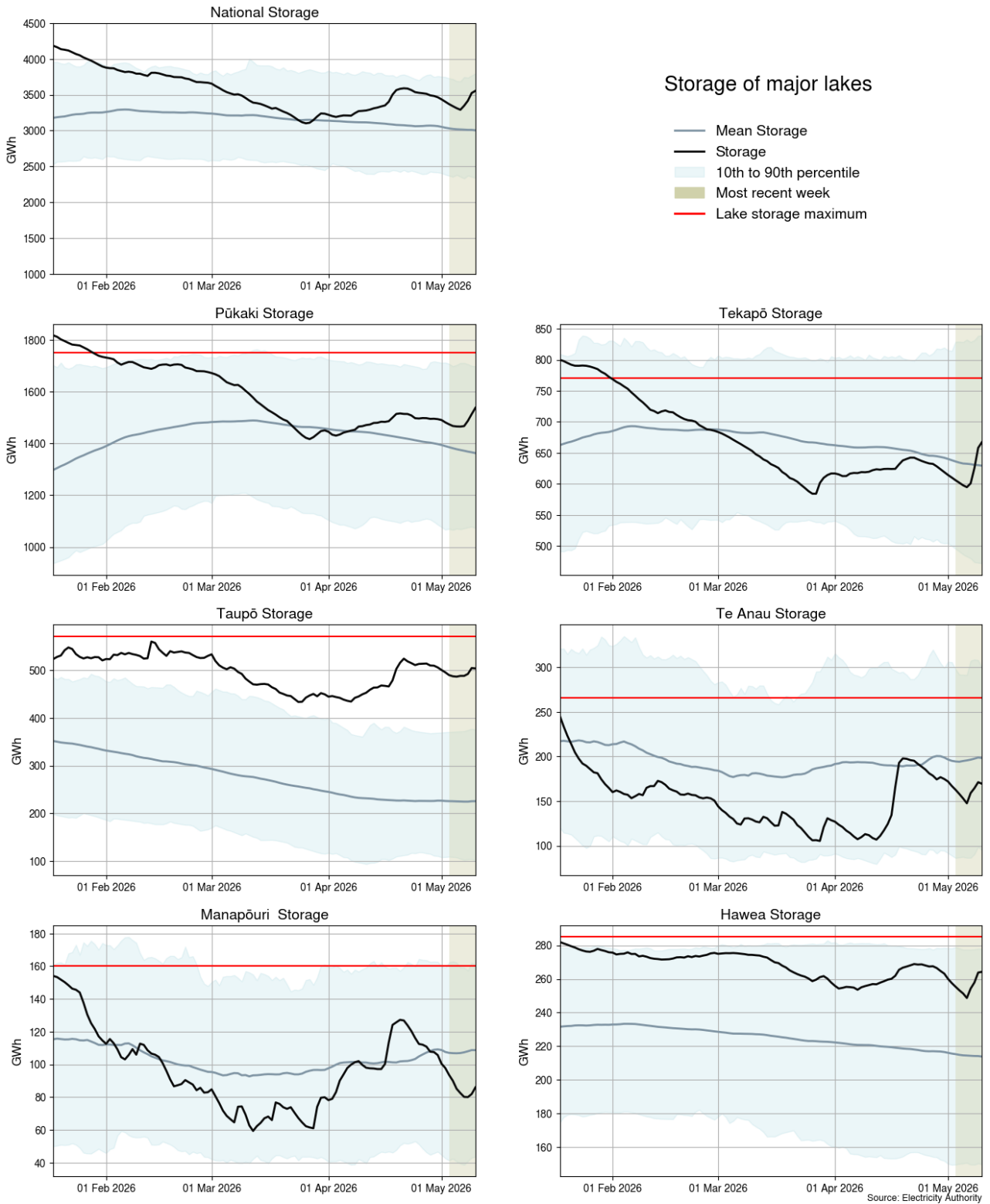


10. Storage/fuel supply

- 10.1. As of 9 May, national controlled storage was 83% nominally full and ~111% of the historical average for this time of the year.
- 10.2. Storage at Lake Pūkaki (85% full) is above its historic mean, and Lake Tekapō (77% full) has risen above its historic mean.
- 10.3. Storage at Lake Te Anau (64% full) is below its historic mean, with Lake Manapōuri (55% full) remaining below its historic mean.
- 10.4. Storage at Lake Taupō (88% full) is above its historic 90th percentile for this time of year.
- 10.5. Storage at Lake Hawea (93% full) is below its historic 90th percentile but remains above its historic mean.
- 10.6. Figure 21 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.
- 10.7. As of 9 May, national controlled storage was 83% nominally full and ~111% of the historical average for this time of the year.
- 10.8. Storage at Lake Pūkaki (85% full²) is above its historic mean, and Lake Tekapō (77% full) has risen above its historic mean.
- 10.9. Storage at Lake Te Anau (64% full) is below its historic mean, with Lake Manapōuri (55% full) remaining below its historic mean.
- 10.10. Storage at Lake Taupō (88% full) is above its historic 90th percentile for this time of year.
- 10.11. Storage at Lake Hawea (93% full) is below its historic 90th percentile but remains above its historic mean.

² Percentage full values sourced from NZX Hydro.

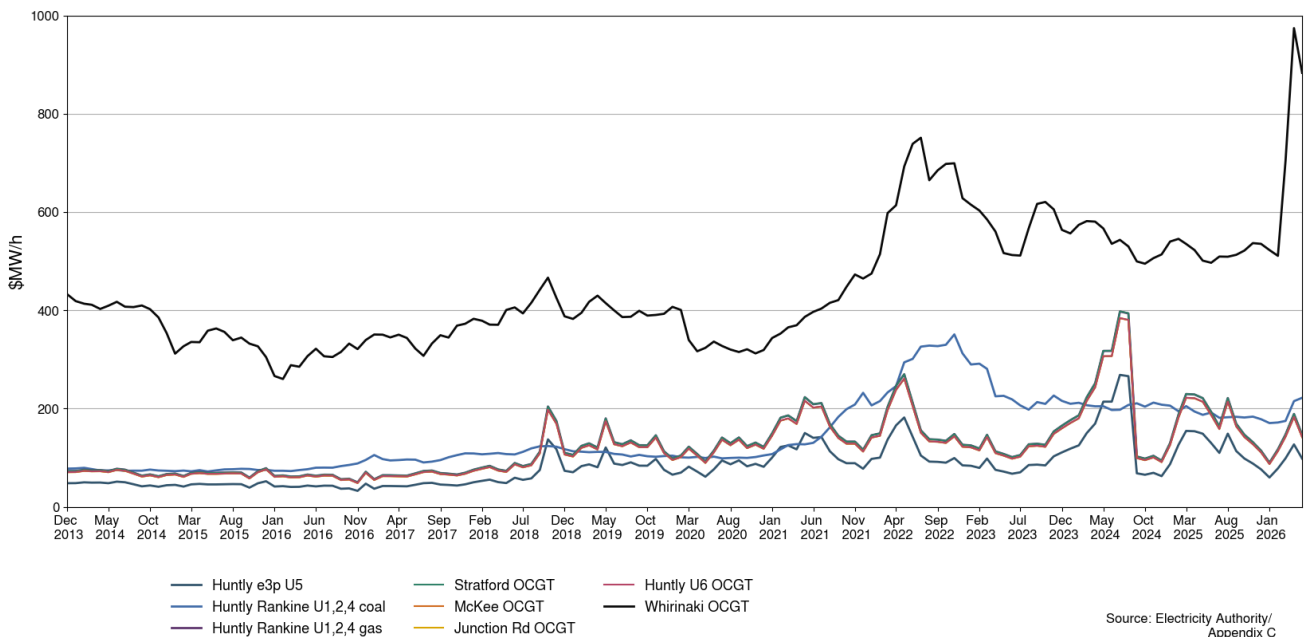
Figure 21: Hydro storage



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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 May 2026. The SRMCs for most thermal-fuelled generation have decreased.
- 11.4. The latest SRMC of coal-fuelled Rankine generation is ~\$221/MWh. The cost of running the Rankines on gas is ~\$147/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$98/MWh and \$142/MWh.
- 11.6. The SRMC of Whirinaki, using diesel, has decreased from ~\$970/MWh to ~\$883/MWh.
- 11.7. Note that the coal prices used in the calculation have been rolled forward from April.
- 11.8. More information on how the SRMC of thermal plants is calculated can be found in [Appendix C](#).

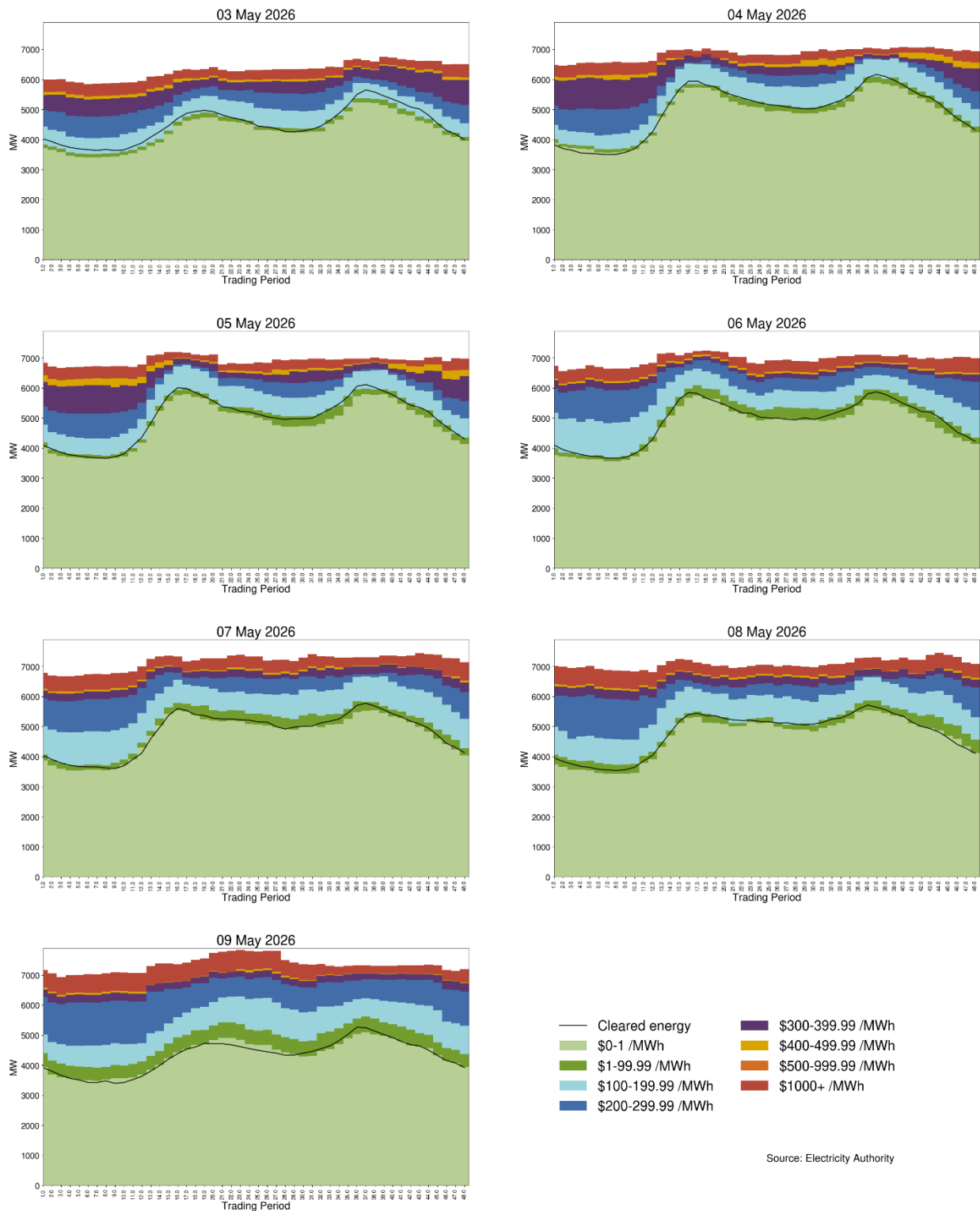
Figure 22: Estimated monthly SRMC for thermal fuels



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 energy cleared below \$200/MWh this week.
- 12.3. From Wednesday, Meridian hydro priced down energy from \$300-499/MWh to \$100-299/MWh.

Figure 23: Daily offer stacks



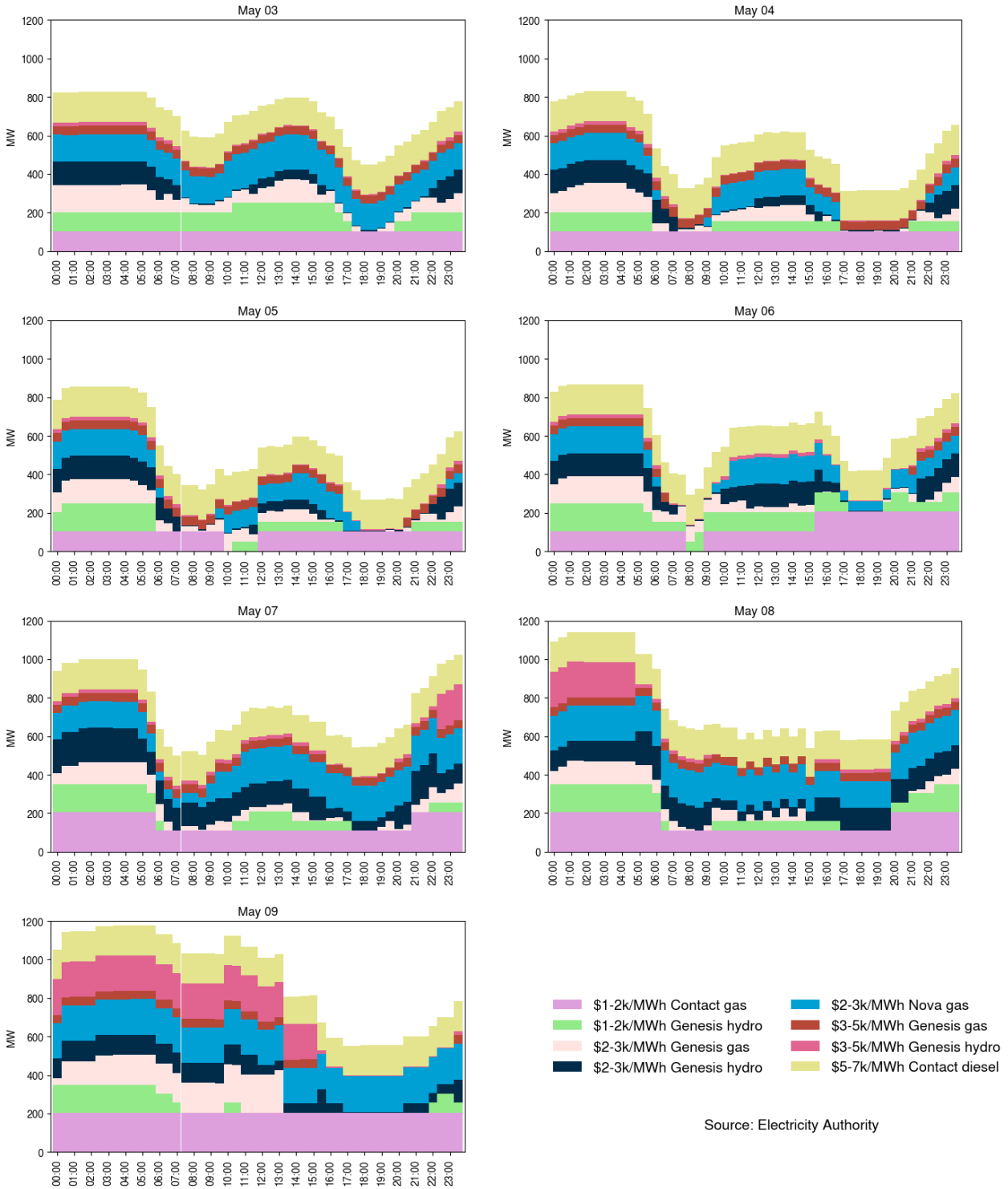
12.4. Figure 24 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.5. 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.

12.6. On average 697MW per trading period was priced above \$1,000/MWh this week, which is roughly 12% of the total energy available.

Figure 24: High priced offers



13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. The monitoring team is looking into Genesis hydro offers further this week.

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
03/03/2026-04/03/2026	Several	Further analysis	Genesis	Waikaremoana	Offers
13/03/2026	27-31	Further analysis	Genesis	Huntly 1 and 4	Offers
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers
26/04/2026-02/05/2026	Several	Further analysis	Contact	Roxburgh	Offers
02/05/2026	Several	Further analysis	Genesis	Tokaanu	Offers
07/05/2026-08/05/2026	Several	Further analysis	Genesis	Tekapō	Offers