18 May 2026

Trading conduct report 10-16 May 2026

Market monitoring weekly report

Trading conduct report 10-16 May 2026

1. Overview

1.1. This week the average spot price has increased by $6/MWh to $56/MWh. Prices have remained similar to last week due to lower levels of wind generation but increased hydro storage. National controlled storage has increased to 84% nominally full and 113% 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 10-16 May:

(a) The average spot price for the week was $56/MWh, an increase of around $6/MWh compared to the previous week.

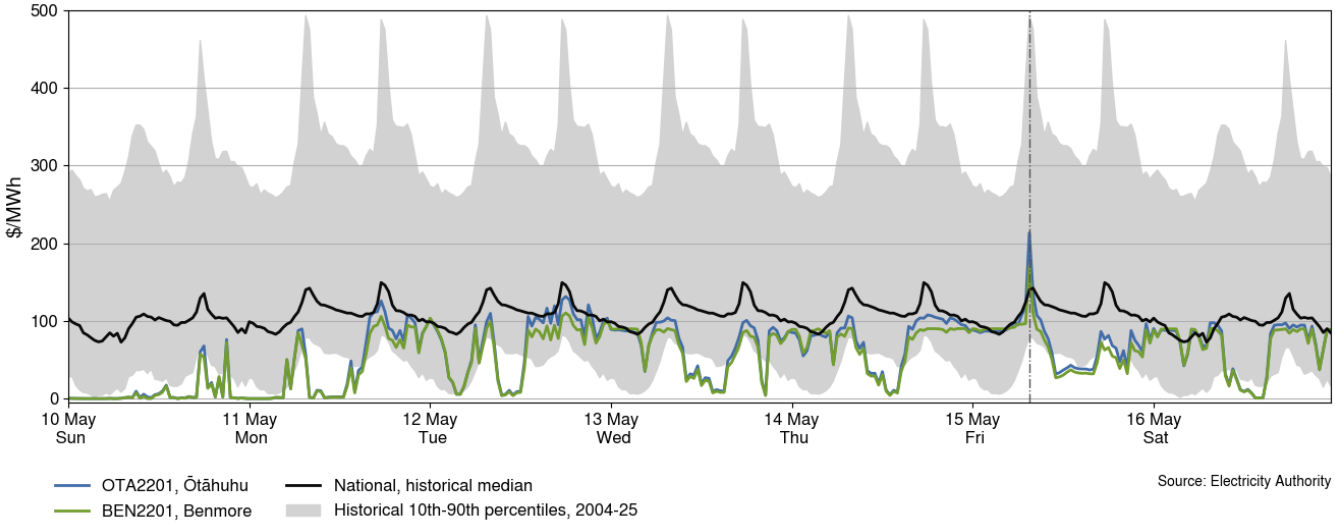
(b) 95% of prices fell between $0.02/MWh and $110/MWh.

2.3. Prices have been similar this week compared to last week. Wind generation has been slightly lower, but there has been more hydro storage available.

2.4. The highest price for the week occurred on Friday at 7.30am. At this time prices at Ōtāhuhu reached $213/MWh, and prices at Benmore reached $170/MWh. At this time, demand was 20MW above forecast, and at its weekly maximum of ~6,080MW. Wind generation was also low at ~100MW. The national residual was at its weekly minimum of ~750 MW.

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. Other notable prices are marked with black dashed lines.

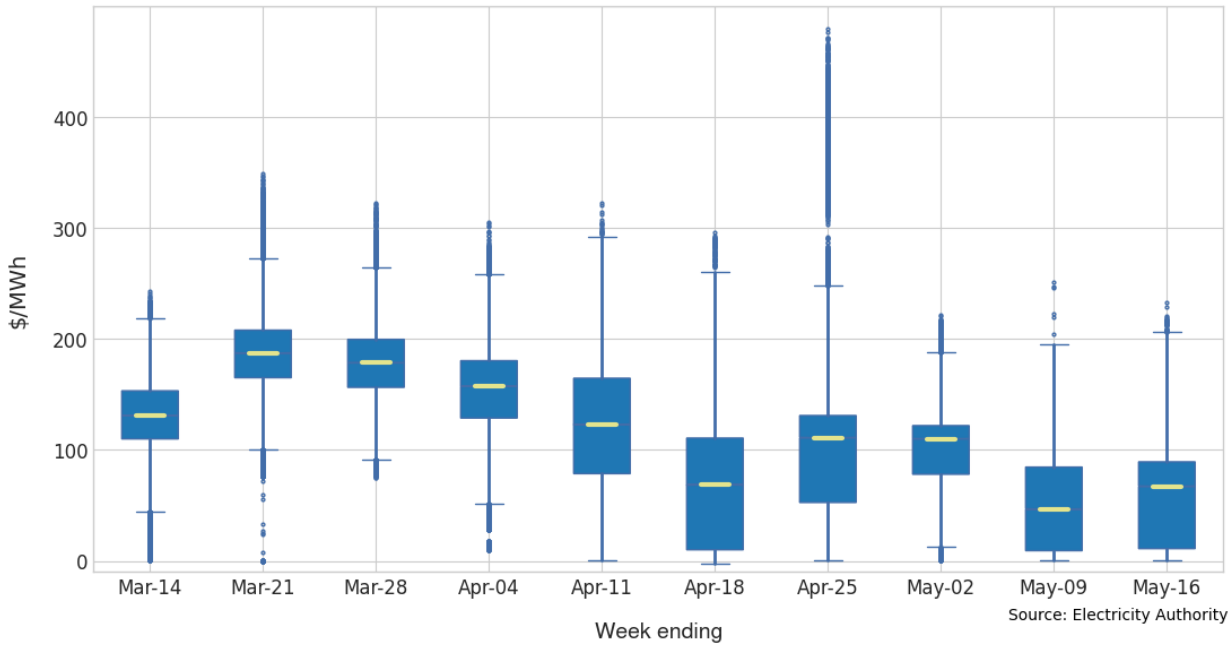
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 10-16 May



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 similar to last week. The median price was $67/MWh and most prices (middle 50%) fell between $11/MWh and $89/MWh.

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

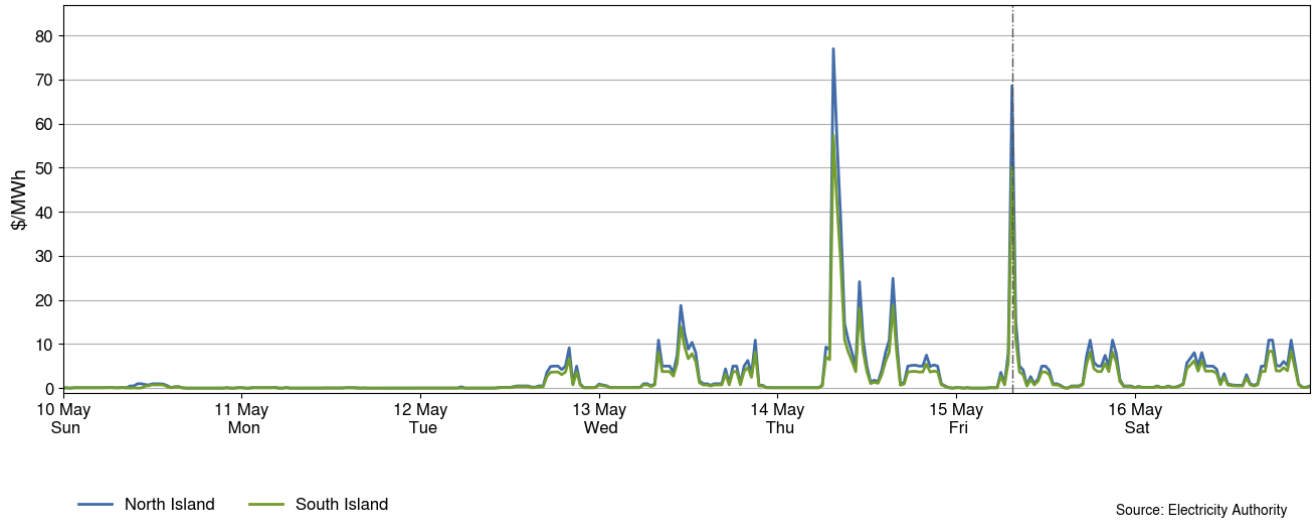


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices remained mostly below $3MWh, with FIR prices spiking above $50/MWh.

3.2. On Thursday at 7.30am, FIR prices spiked to $77/MWh in the North Island and $57/MWh in the South Island. On Friday at 7.30am, FIR prices spiked to $69/MWh in the North Island and $50/MWh in the South Island. At these times, Huntly 5 was the risk setter, and its generation increased, increasing the amount of reserve needed to cover this risk.

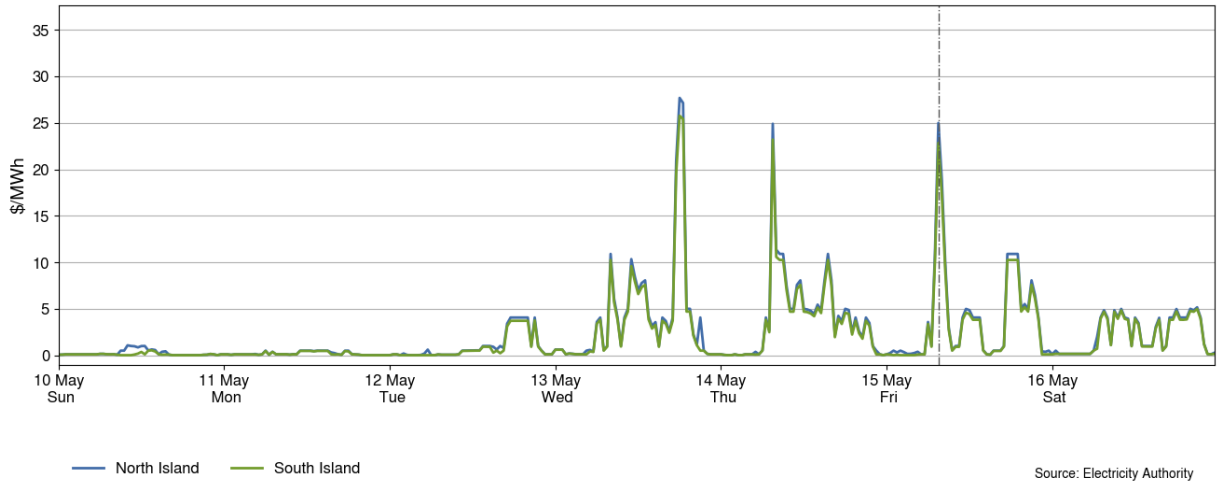
Figure 3: Fast instantaneous reserve price by trading period and island, 10-16 May



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices remained mostly below $4/MWh this week, with SIR prices reaching above $20/MWh.

3.4. On Wednesday at 6.00pm, SIR prices spiked to $28/MWh in the North Island and $26/MWh in the South Island. On Thursday at 7.30am, SIR prices spiked to $25/MWh in the North Island and $23/MWh in the South Island. On Friday at 7.30am, SIR prices spiked to $25/MWh in the North Island and $23/MWh in the South Island. At these times, Huntly 5 was the risk setter, and its generation increased, increasing the amount of reserve needed to cover this risk. Also over Thursday reserve prices were higher on average due to the outage of Ruakākā.

Figure 4: Sustained instantaneous reserve by trading period and island, 10-16 May



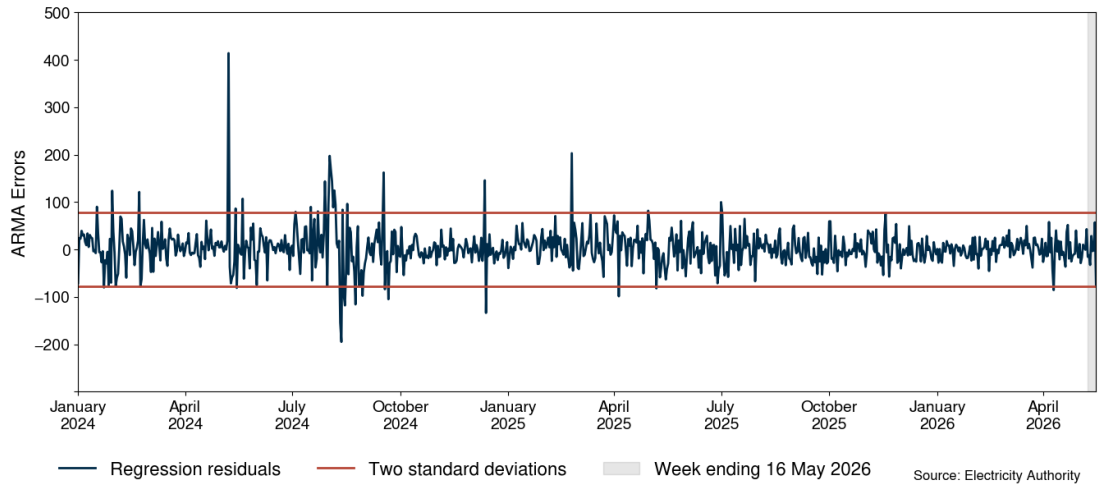
4. Regression residuals

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 - 16 May 2026



5. HVDC

5.1. Figure 6 shows the HVDC flow between 10-16 May. HVDC flows were mainly northward throughout the week.

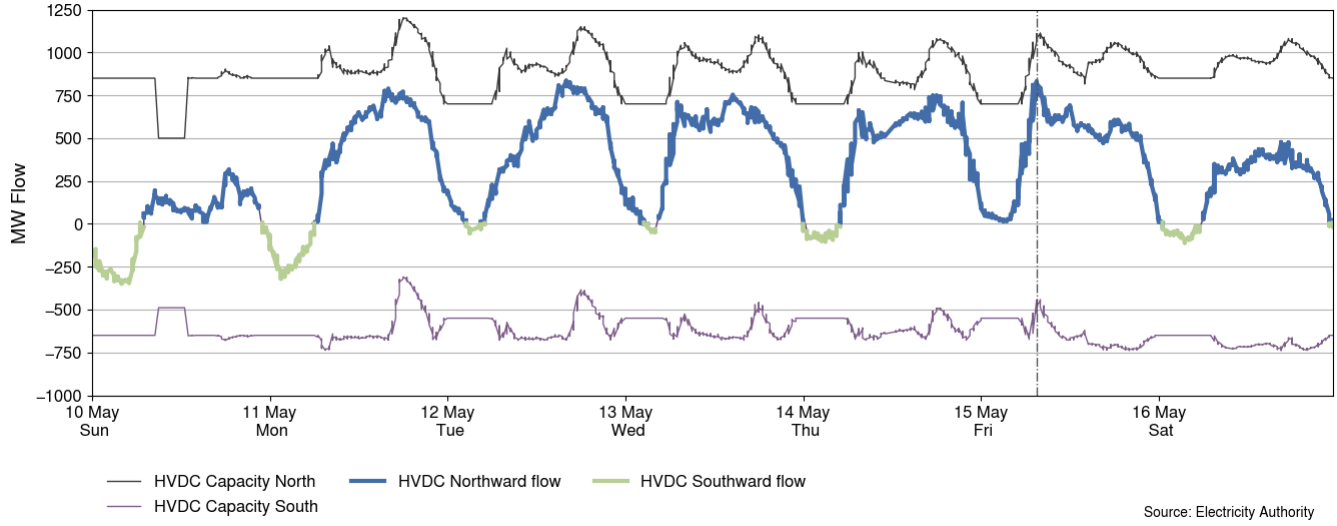
5.2. On Sunday from 9.00am to 1.00pm, HVDC Pole 3 was on a planned outage.[1]

5.3. The highest northward flow occurred on Tuesday at 4.00pm, with a flow of around 836 MW.

5.4. The highest southward flow occurred on Sunday at 4.00am, with a flow of around 349 MW.

[1] CAN - Planned Outage - 800000116.pdf.

Figure 6: HVDC flow and capacity, 10-16 May

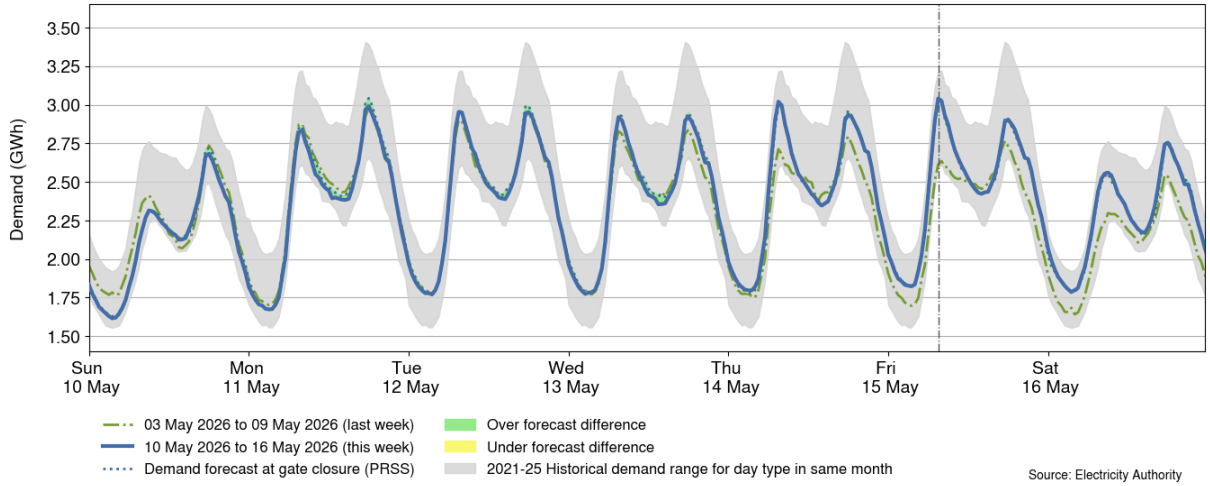


6. Demand

6.1. Figure 7 shows national demand between 10-16 May, compared to the historic range and the demand of the previous week. Demand was mostly the same this week, until Thursday where demand became higher than last week. On Thursday, Friday and Saturday, demand was higher due to colder temperatures.

6.2. The maximum demand for the week occurred at 7.30am on Friday, at around 3.04GWh.

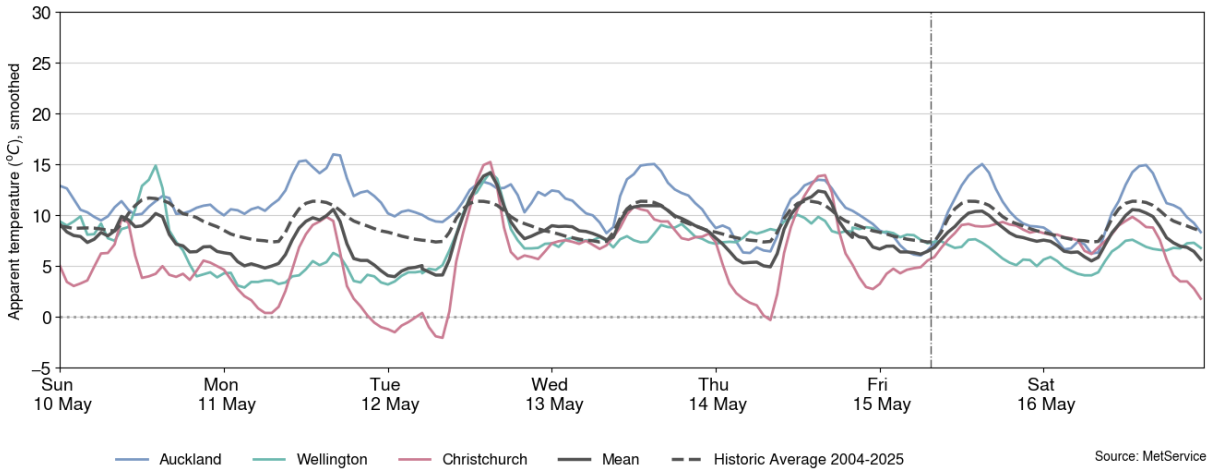
Figure 7: National demand, 10-16 May compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 10-16 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.

6.4. Apparent temperatures ranged from 6°C to 17°C in Auckland, 2°C to 16°C in Wellington, and -2°C to 16°C in Christchurch.

Figure 8: Temperatures across main centres, 10-16 May



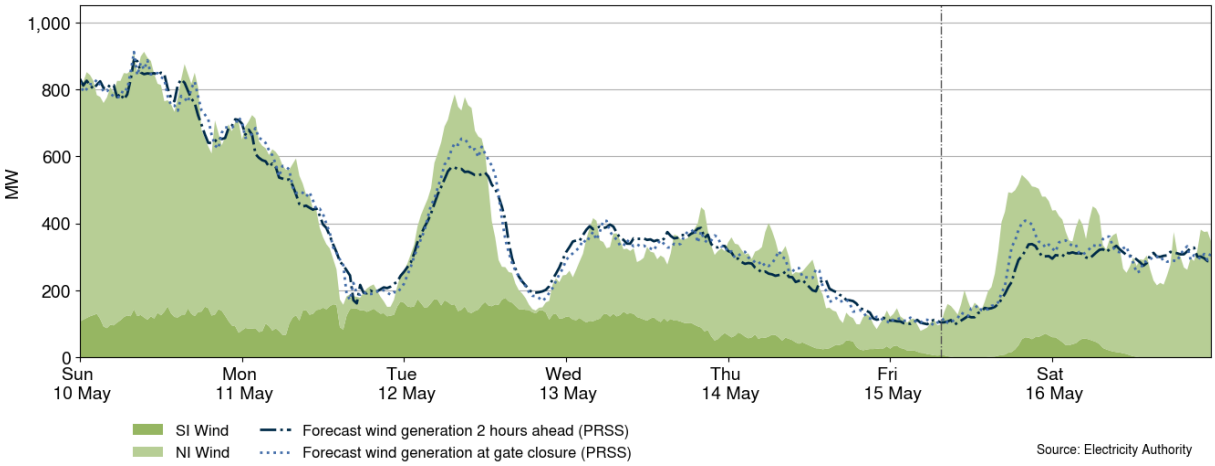
7. Generation

7.1. Figure 9 shows wind generation and forecast from 10-16 May. This week wind generation varied between 79MW and 912MW, with a weekly average of 393MW. Wind generation was high on Sunday, with periods of low wind generation on Monday and Tuesday, and low wind generation for the rest of the week.

7.2. Under-forecasting errors on Tuesday were mainly due to forecasting errors at Harapaki and Te Āpiti.

7.3. The over-forecasting error on Tuesday afternoon was due to an amalgamation of forecasting errors at different wind farms.

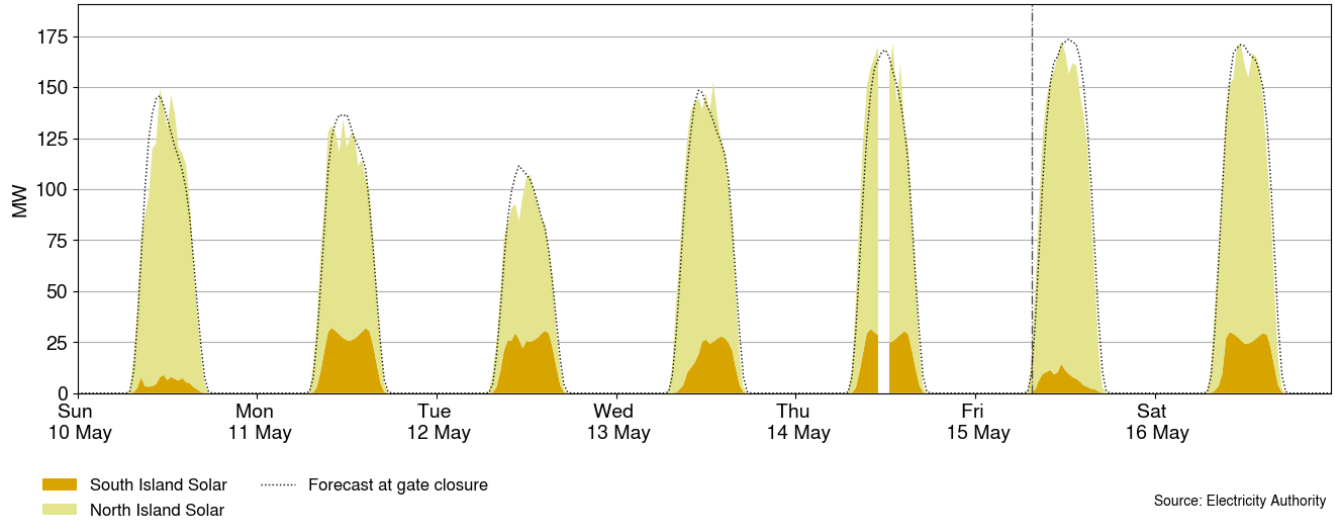
Figure 9: Wind generation and forecast, 10-16 May



7.4. Figure 10 shows grid connected solar generation from 10-16 May. Solar generation was relatively high this week, reaching above 100MW every day and 173MW on Friday at 11.30am.

7.5. Note that data is missing for trading periods 24 and 25 on Thursday.

Figure 10: Grid connected solar generation, 10-16 May

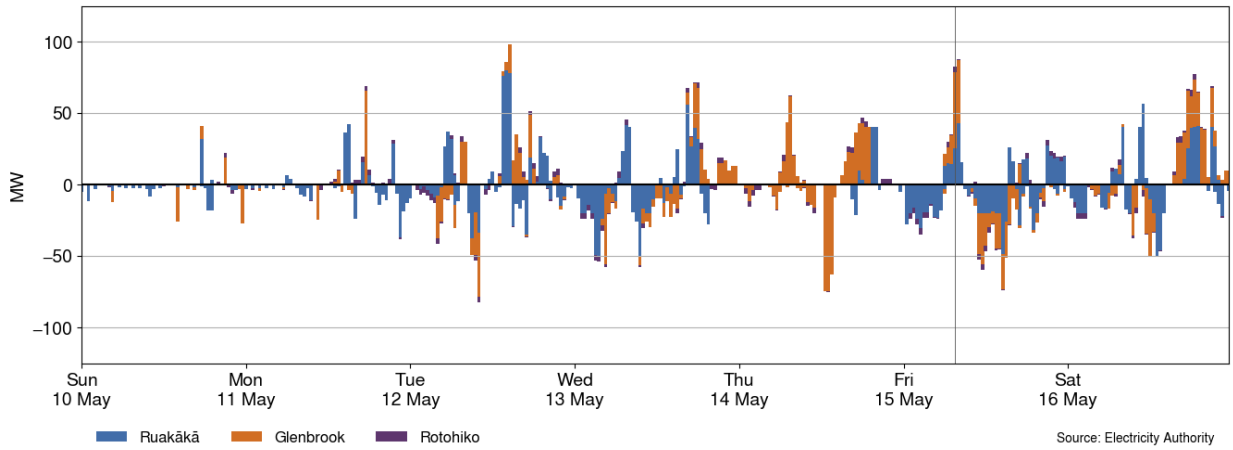


7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are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

7.7. This week, the batteries generally discharged when prices were higher, at above ~$100/MWh, and charged when prices were lower, at below ~$50/MWh.

7.8. The batteries did not discharge much on Sunday and Monday when prices were low and discharged on Friday at 7.30am when prices spiked. Ruakākā was on outage on Thursday.

Figure 11: Grid scale battery charge and discharge, 10-16 May



7.9. 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[2]) 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

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

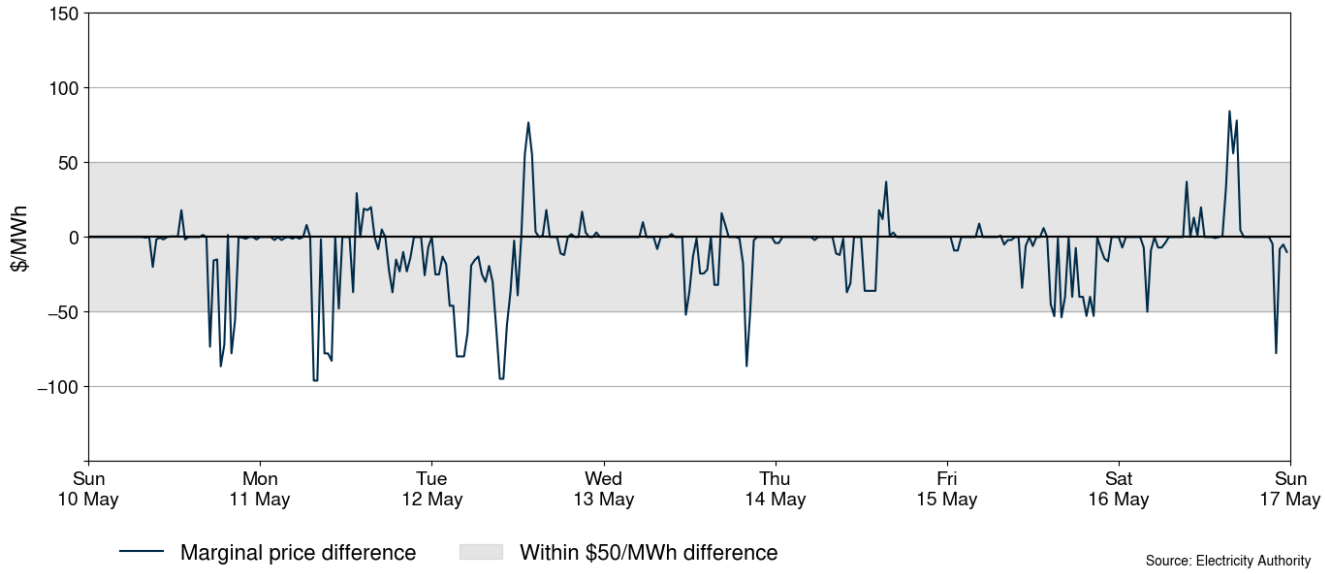
ahead and the RTD intermittent generation and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.10. Some trading periods this week had a marginal price difference over $50/MWh.

7.11. The maximum positive difference of $84/MWh occurred on Saturday at 3.30pm. At this time, demand was 85MW higher than forecast, and intermittent generation was 101MW lower than forecast.

7.12. The maximum negative difference of $96/MWh occurred on Monday at 7.30am. At this time, demand was 53MW lower than forecast, and intermittent generation was 75MW higher than forecast.

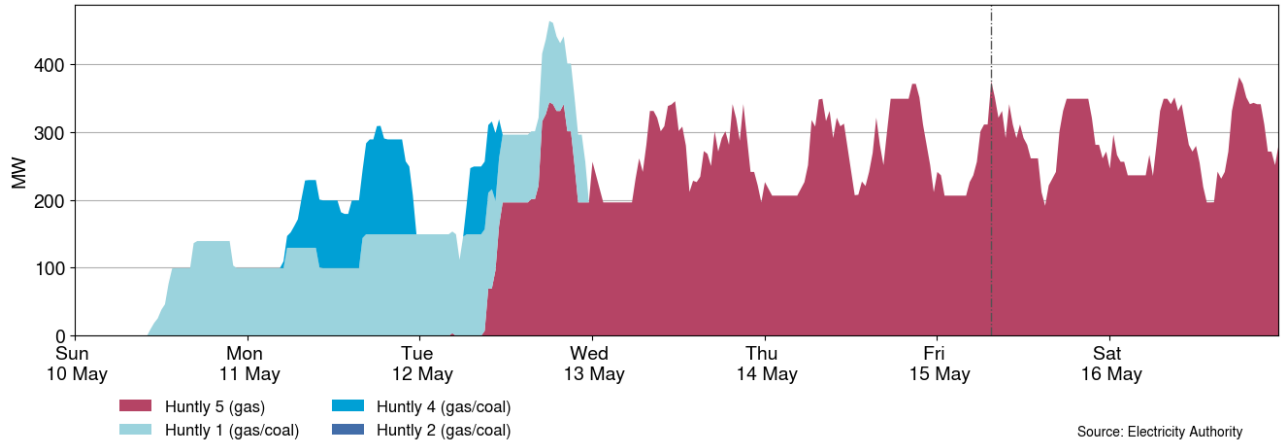
Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 10-16 May



7.13. Figure 13 shows the generation of thermal baseload between 10-16 May. Huntly 1 ran continuously from Sunday afternoon to Tuesday evening, and Huntly 4 ran at times on Monday and Tuesday. Huntly 5 ran continuously from Tuesday afternoon to Saturday.

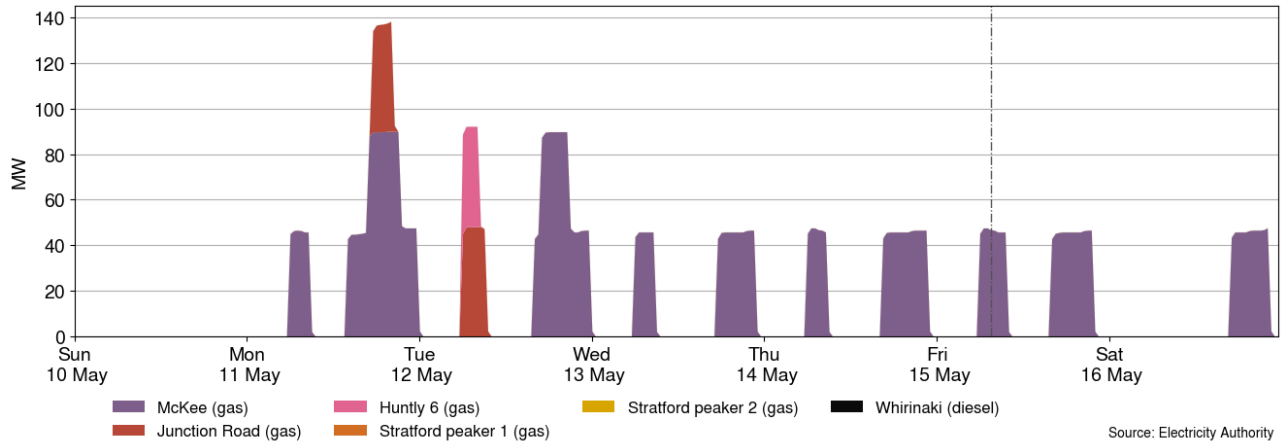
7.14. Huntly 5 began running on Tuesday after gas from the Kupe gas field became available.

Figure 13: Thermal baseload generation, 10-16 May



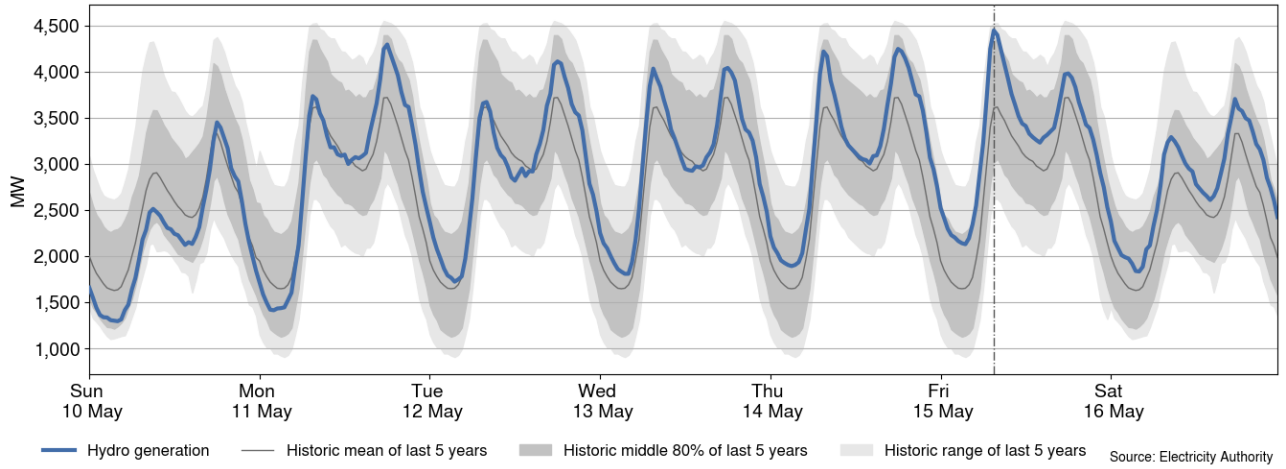
7.15. Figure 14 shows the generation of thermal peaker plants between 10-16 May. McKee ran at times each day from Monday to Saturday, Junction Road ran at times on Monday and Tuesday, and Huntly 6 ran briefly on Tuesday.

Figure 14: Thermal peaker generation, 10-16 May



7.16. Figure 15 shows hydro generation between 10-16 May. Hydro generation was mostly above the historic mean, apart from Sunday morning where it was below the historic mean.

Figure 15: Hydro generation, 10-16 May

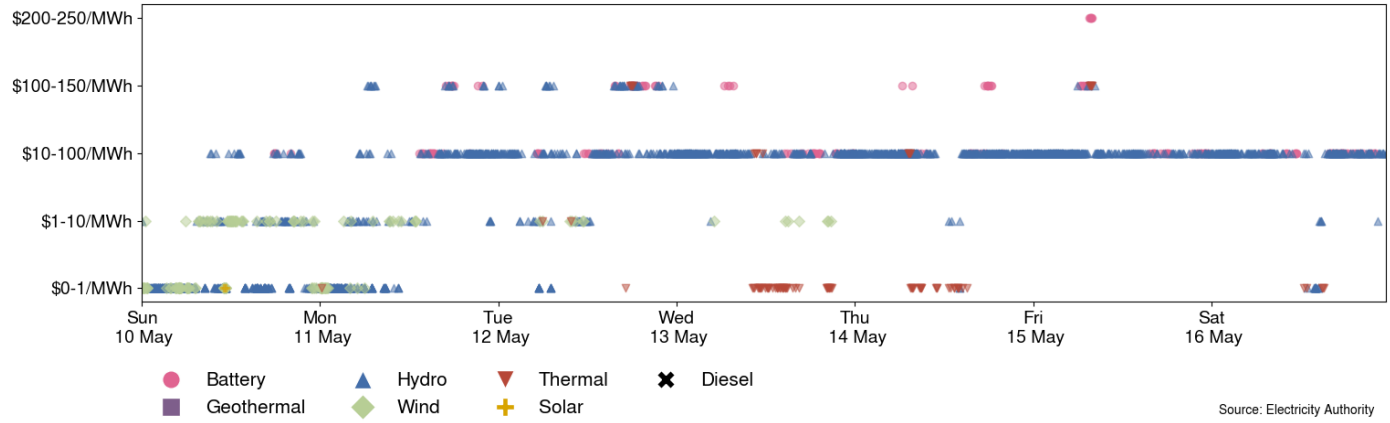


7.17. The highest prices were set by Contact's Glenbrook battery on Friday. The most common technology setting prices was hydro generation, with wind the second most common. Most marginal prices were between $10-100/MWh.

7.18. 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.

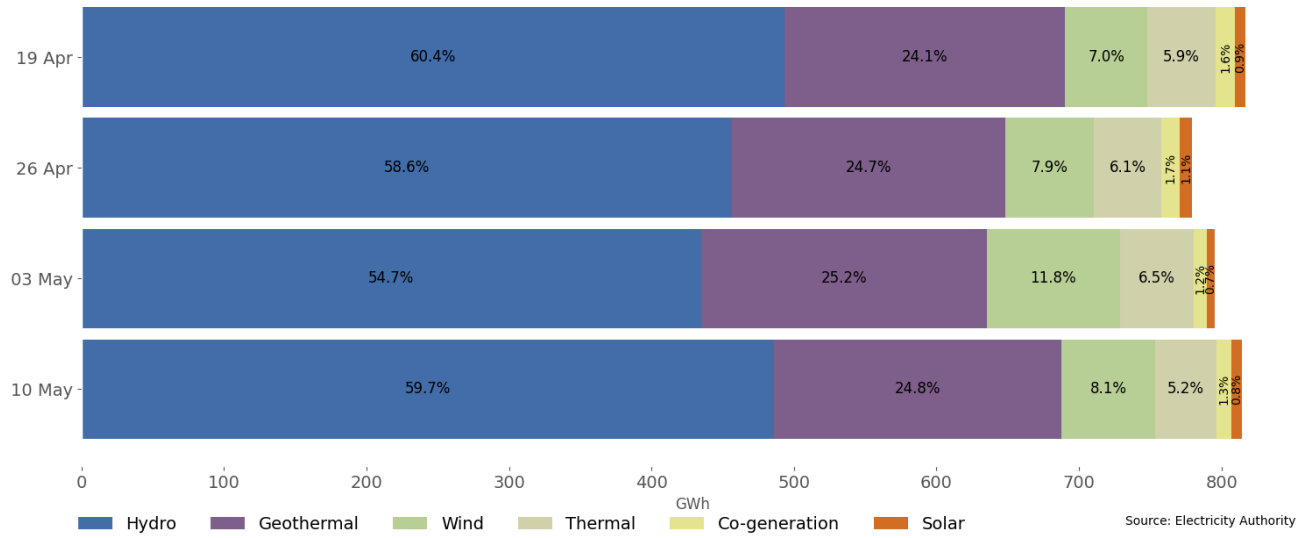
7.19. The highest prices were set by Contact's Glenbrook battery on Friday. The most common technology setting prices was hydro generation, with wind the second most common. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 10-16 May



7.20. As a percentage of total generation, between 10-16 May, total weekly hydro generation was 59.7%, geothermal 24.8%, wind 8.1%, thermal 5.2%, co-generation 1.3%, and solar (grid connected) 0.8%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 19 April and 16 May



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 10-16 May ranged between ~836MW and ~1,658MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 10-16 May

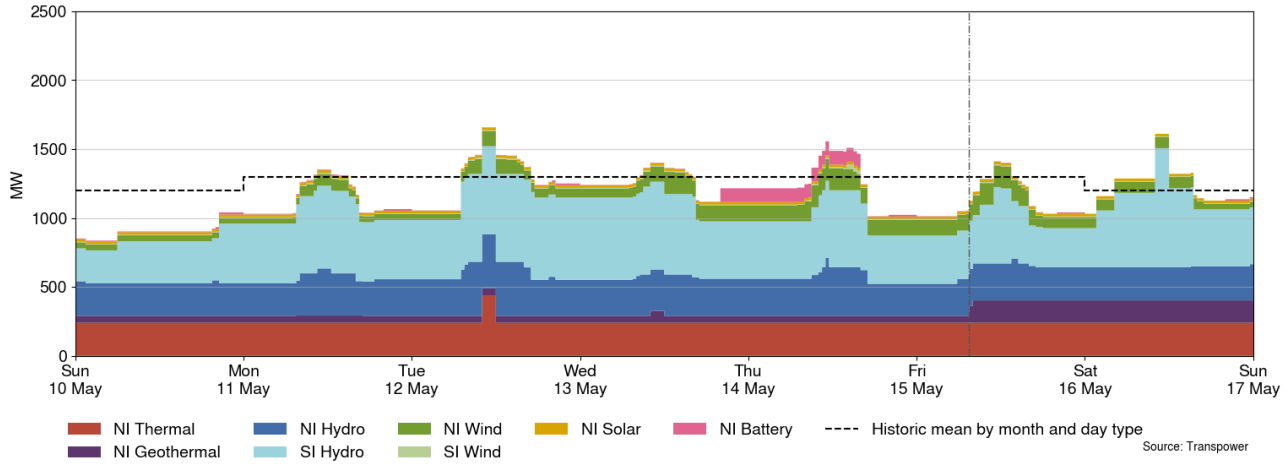
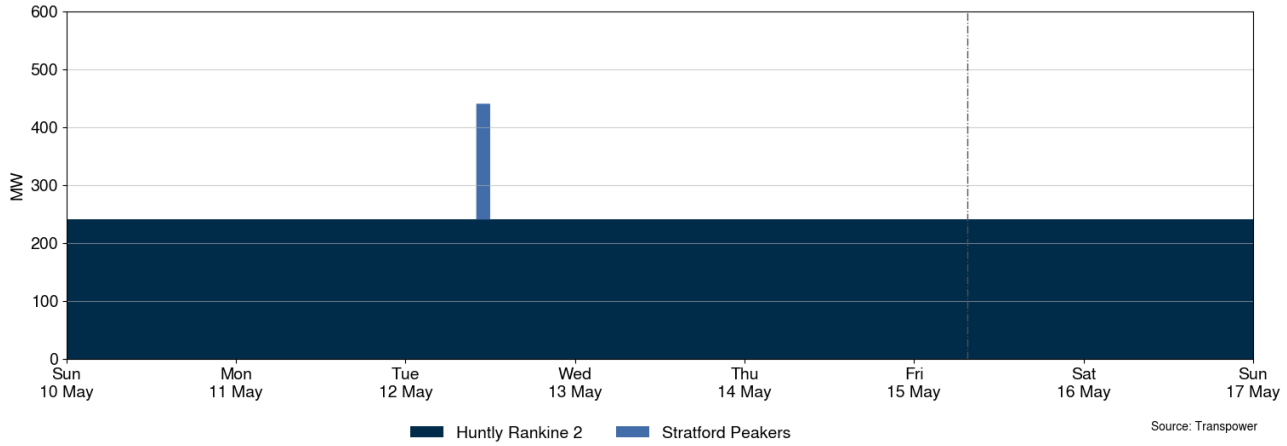


Figure 19: Total MW loss from thermal outages, 10-16 May



8.2. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 1	Full	13 May 2026
Ruakākā Battery	Full	14 May 2026
Manapōuri unit 5	Full	19 May 2026
Huntly 2	Full	20 May 2026
Ōhau unit 5	Full	29 May 2026
Manapōuri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

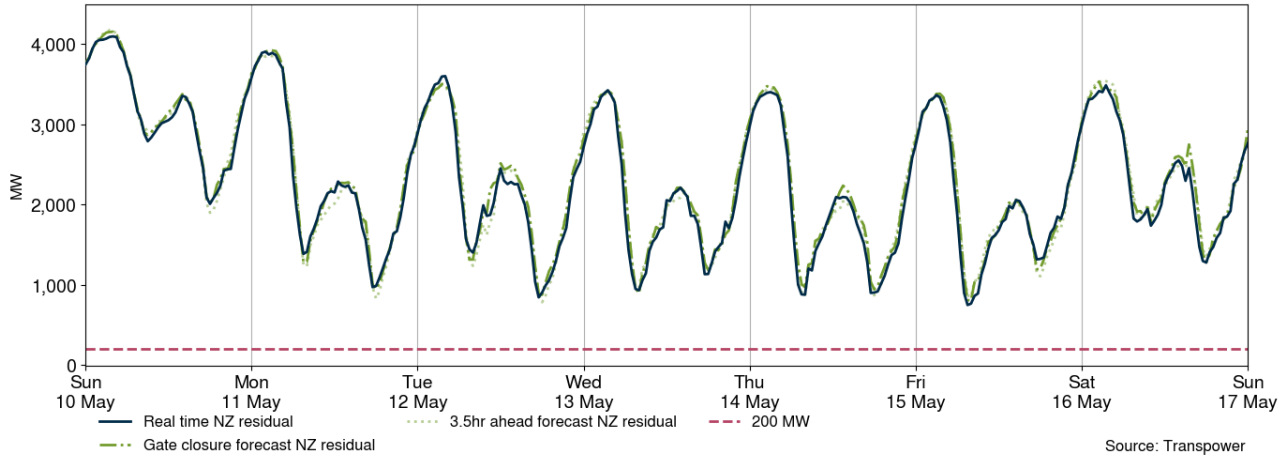
9.1. Overall, national residuals have been healthy this week. The lowest national residual was 750MW on Friday at 7.30am.

9.2. Figure 20 shows the national generation balance residuals between 10-16 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 750MW on Friday at 7.30am.

Figure 20: National generation balance residuals, 10-16 May



10. Storage/fuel supply

10.1. As of 16 May, national controlled storage was 84% nominally full and ~113% of the historical average for this time of the year.

10.2. Storage at Lake Pūkaki (85% full) and Lake Tekapō (76% full) remain above their historic mean.

10.3. Storage at Lake Te Anau (54% full) and Lake Manapōuri (34% full) remain below their historic mean.

10.4. Storage at Lake Taupō (80% full) remains above its historic 90th percentile for this time of year.

10.5. Storage at Lake Hawea (91% 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 16 May, national controlled storage was 84% nominally full and ~113% of the historical average for this time of the year.

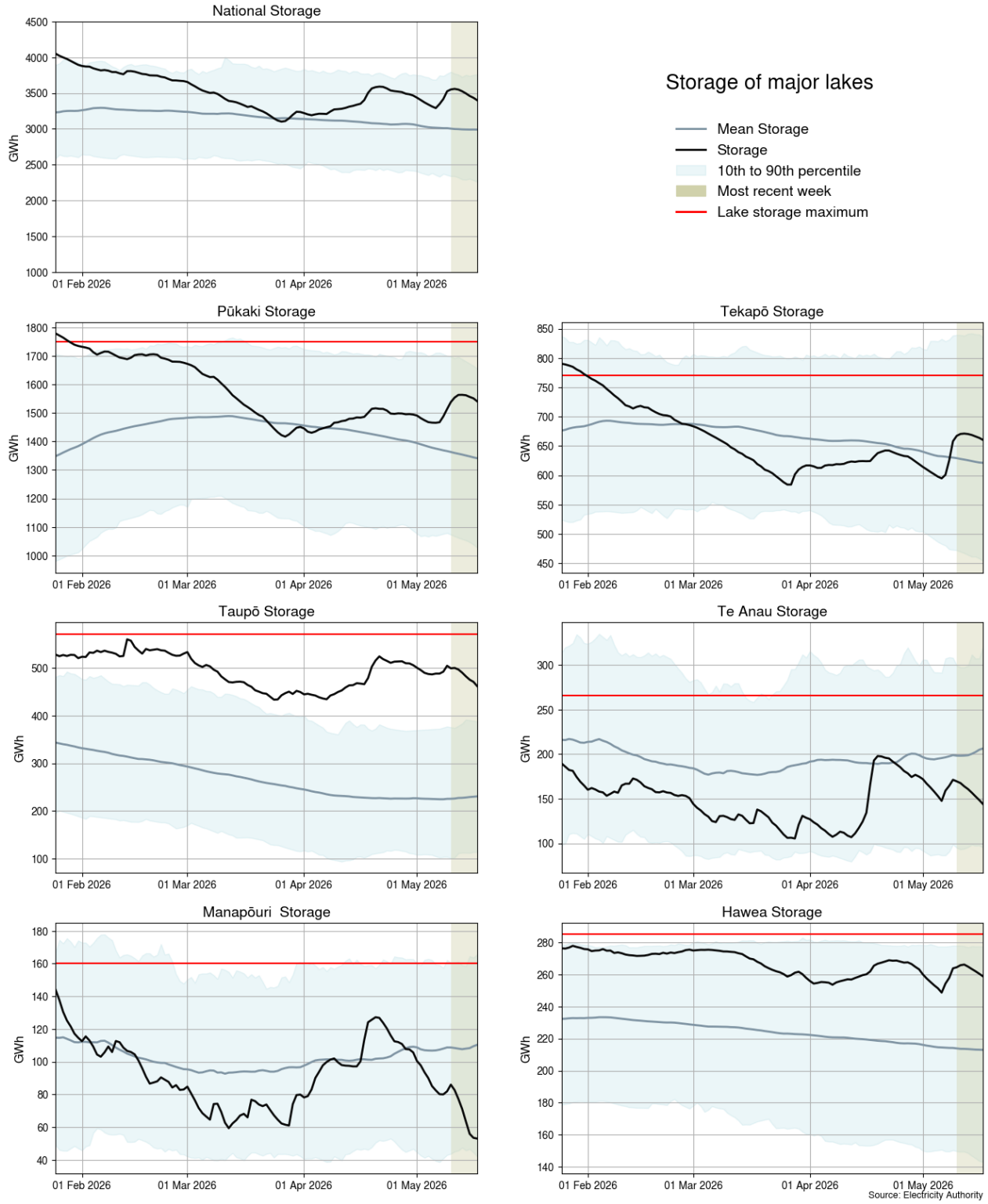
10.8. Storage at Lake Pūkaki (85% full) and Lake Tekapō (76% full) remain above their historic mean.

10.9. Storage at Lake Te Anau (54% full) and Lake Manapōuri (34% full) remain below their historic mean.

10.10. Storage at Lake Taupō (80% full) remains above its historic 90th percentile for this time of year.

10.11. Storage at Lake Hawea (91% full) is below its historic 90th percentile but remains above its historic mean.

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.

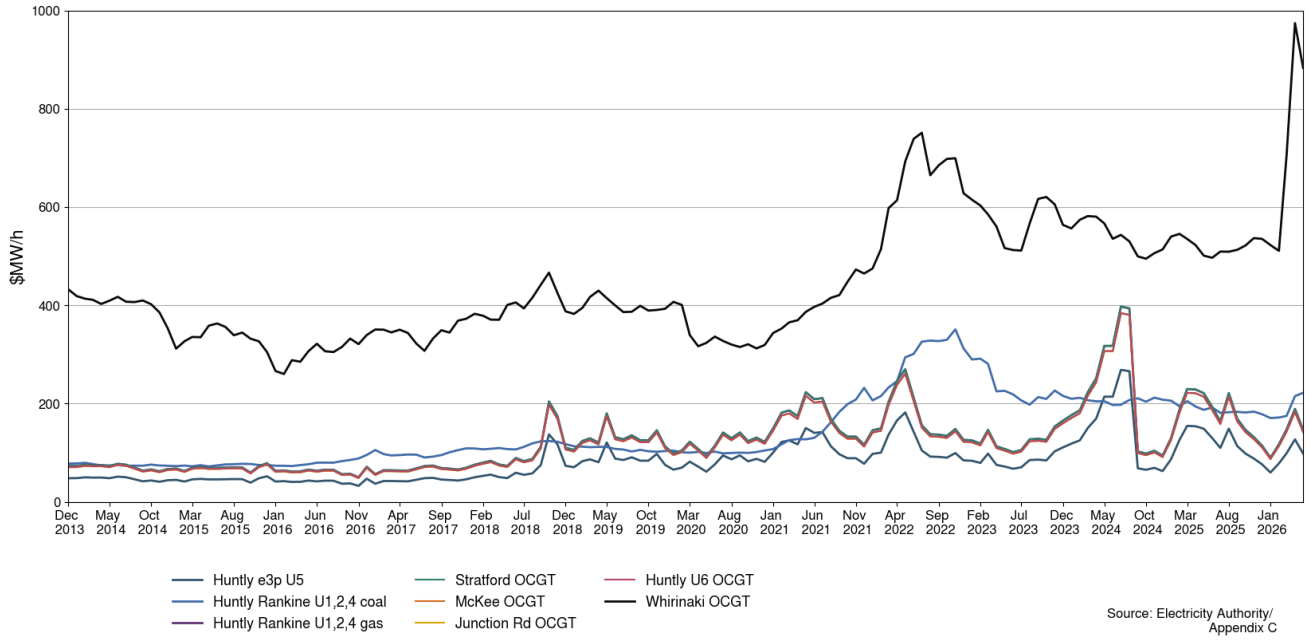
11.5. The SRMC of gas fuelled thermal plants is currently between $98/MWh and $142/MWh.

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

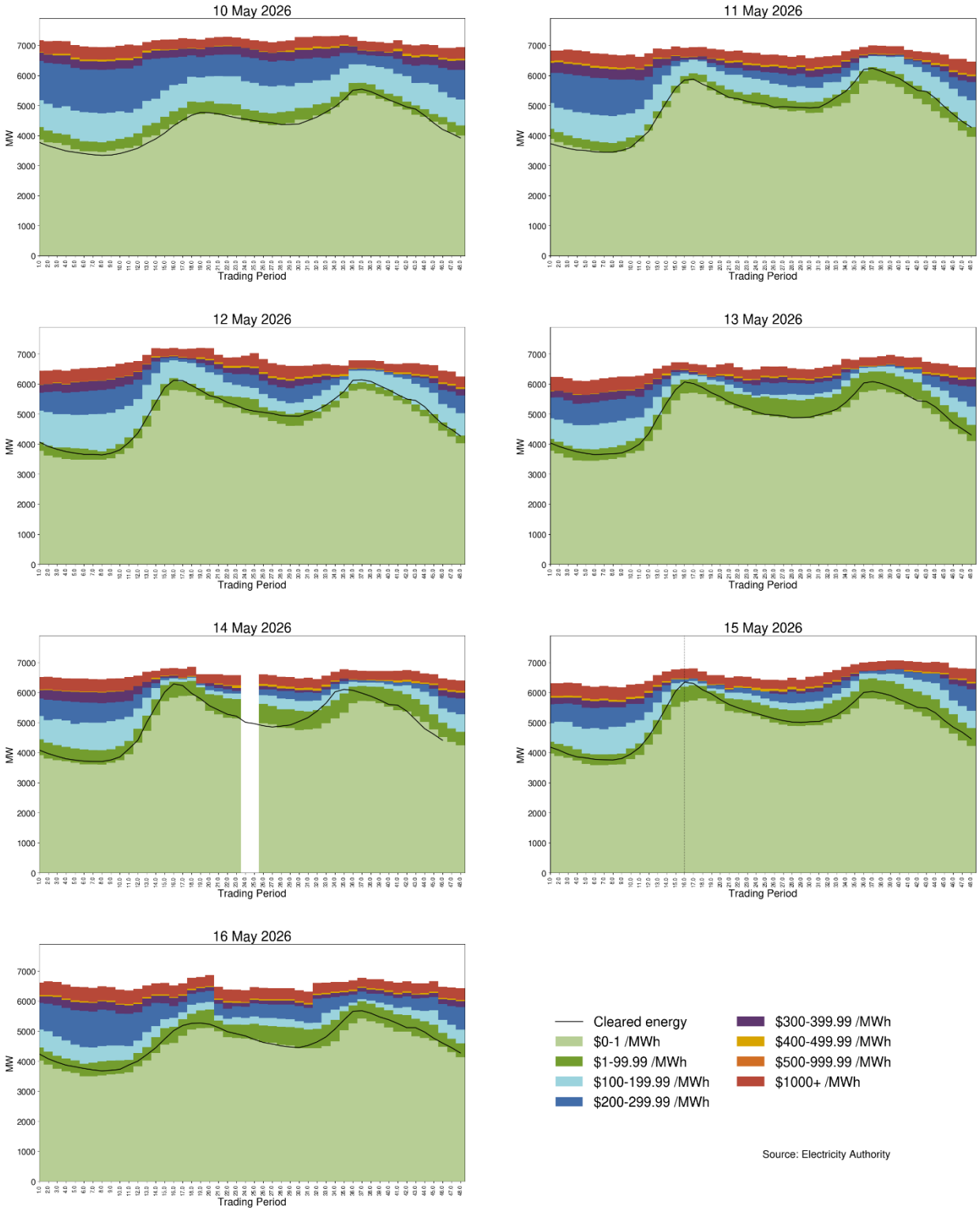
12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most energy cleared below $200/MWh this week.

12.3. From Monday onwards, Mercury hydro priced energy down from $200-299/MWh to $0.01-199/MWh.

12.4. Note that data is missing for trading periods 24 and 25 on Thursday.

Figure 23: Daily offer stacks



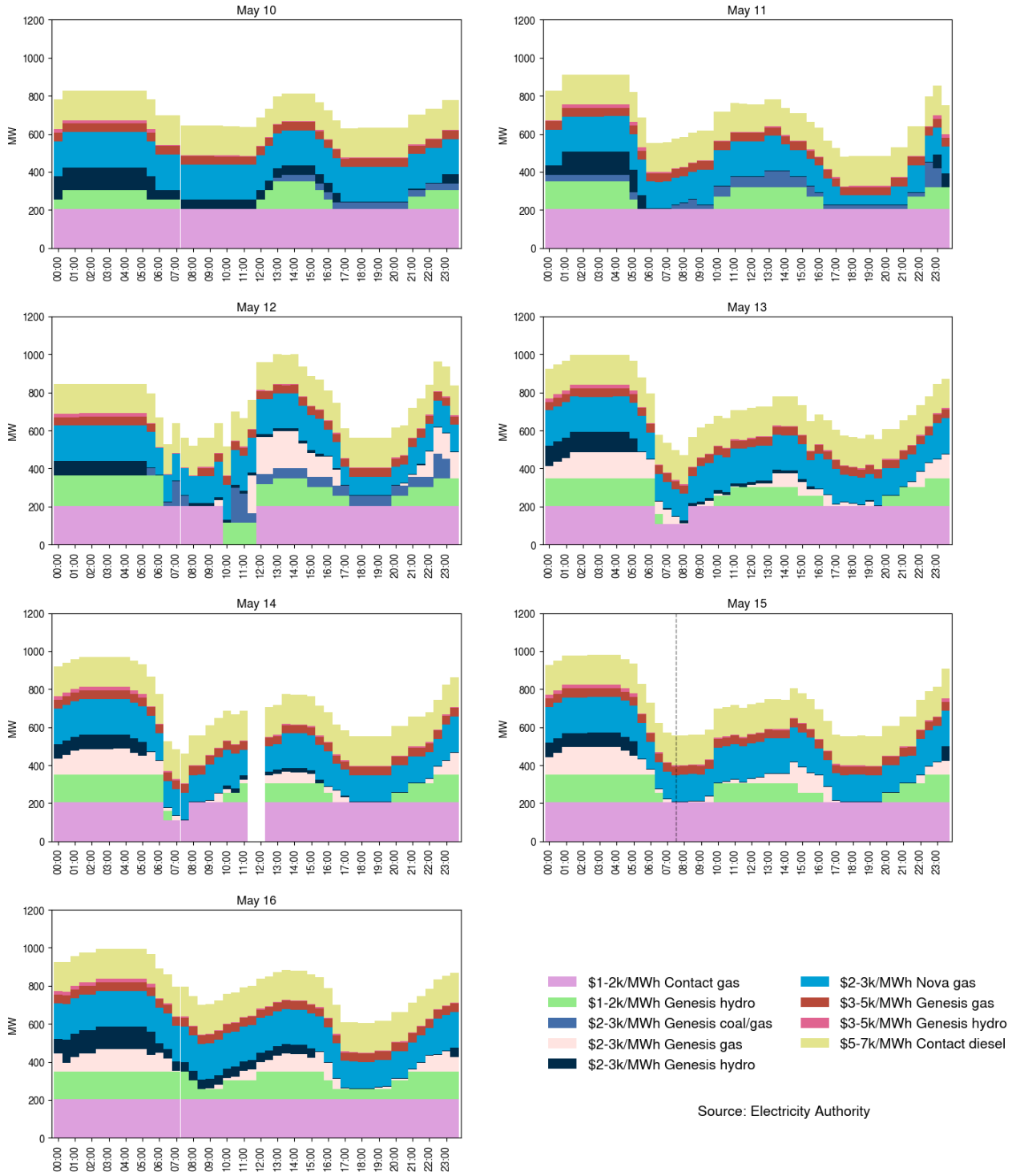
12.5. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.6. 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.

12.7. On average 743MW per trading period was priced above $1,000/MWh this week, which is roughly 13% 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.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

14. 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
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