25 May 2026

Trading conduct report 17-23 May 2026

Market monitoring weekly report

Trading conduct report 17-23 May 2026

1. Overview

1.1. This week the average spot price has increased by $49/MWh to $105/MWh. Prices have increased since last week due to higher demand plus lower wind and geothermal generation. National controlled storage has decreased to 80% nominally full and 109% 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 17-23 May:

(a) The average spot price for the week was $105/MWh, an increase of around $49/MWh compared to the previous week.

(b) 95% of prices fell between $19/MWh and $182/MWh.

2.3. Prices have been higher this week compared to last week. Demand has been higher, and wind generation has been lower. Additionally, around 100MW of geothermal generation has begun being on outage.

2.4. The highest prices for the week occurred on Wednesday from 7.30am to 8.00am, where the spot price reached $334/MWh at Benmore and $389/MWh at Ōtāhuhu. At these times, wind generation was between 31 and 36MW below forecast and generally below 200MW. Demand was also between 43 and 68MW above forecast and also at its weekly maximum of 6.25GW, and the national residual was at its weekly minimum of 322MW.

2.5. On Sunday from 5.30pm to 6.00pm, the spot price reached $177/MWh at Benmore, and $196/MWh at Ōtāhuhu. At these times, wind generation was between 50 and 72MW below forecast, and demand was between 5 and 46MW above forecast.

2.6. High prices near $200/MWh also occurred during the morning and evening peaks on Monday, Tuesday, and Wednesday. During these times, the national residual was low due to high demand, ranging from 321MW to 767MW. The South Island residual was particularly low, at below 200MW for almost all these times.

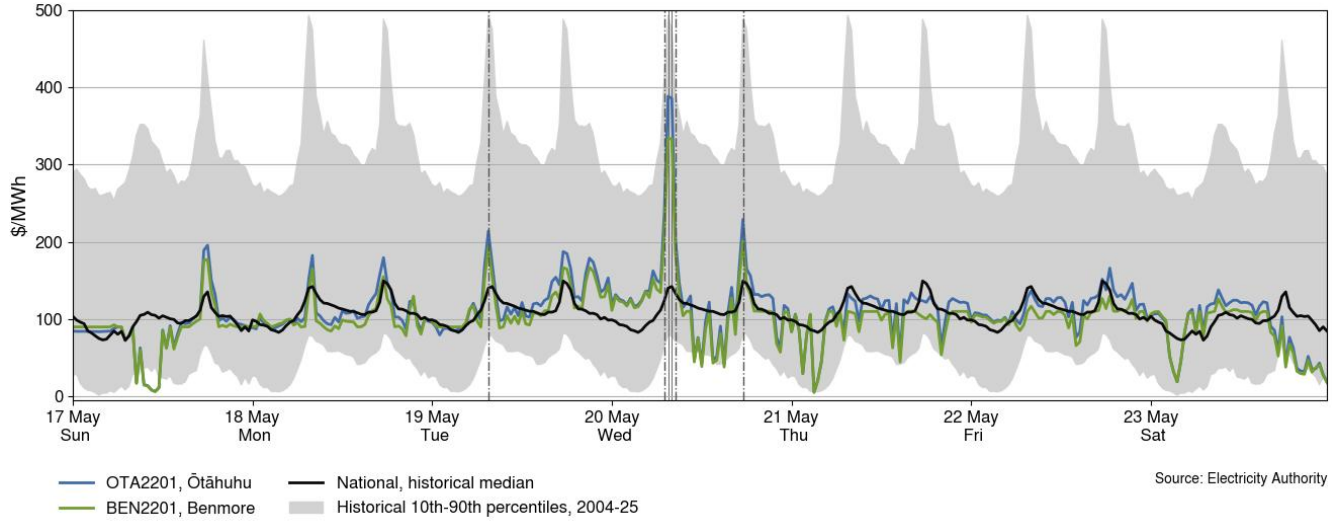
2.7. On Tuesday from 9.00pm to 9.30pm, the spot price reached $167/MWh at Benmore and $187/MWh at Ōtāhuhu. At these times, demand was between 63 and 65MW above forecast.

2.8. On Wednesday at 5.30am, the spot price reached $151/MWh at Benmore and $162/MWh at Ōtāhuhu. At this time, demand was 118MW above forecast, and wind generation was 33MW below forecast.

2.9. 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.

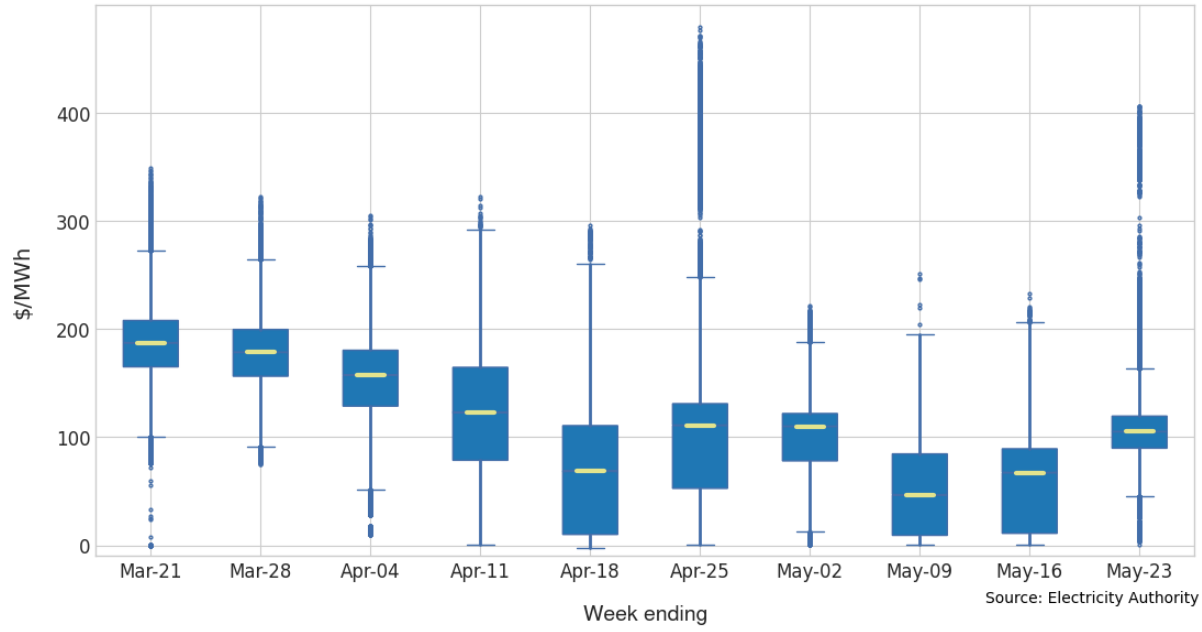
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 17-23 May



2.10. 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.

2.11. The distribution of spot prices this week was higher than last week. The median price was $105/MWh, and most prices (middle 50%) fell between $89/MWh and $120/MWh.

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



3. Reserve prices

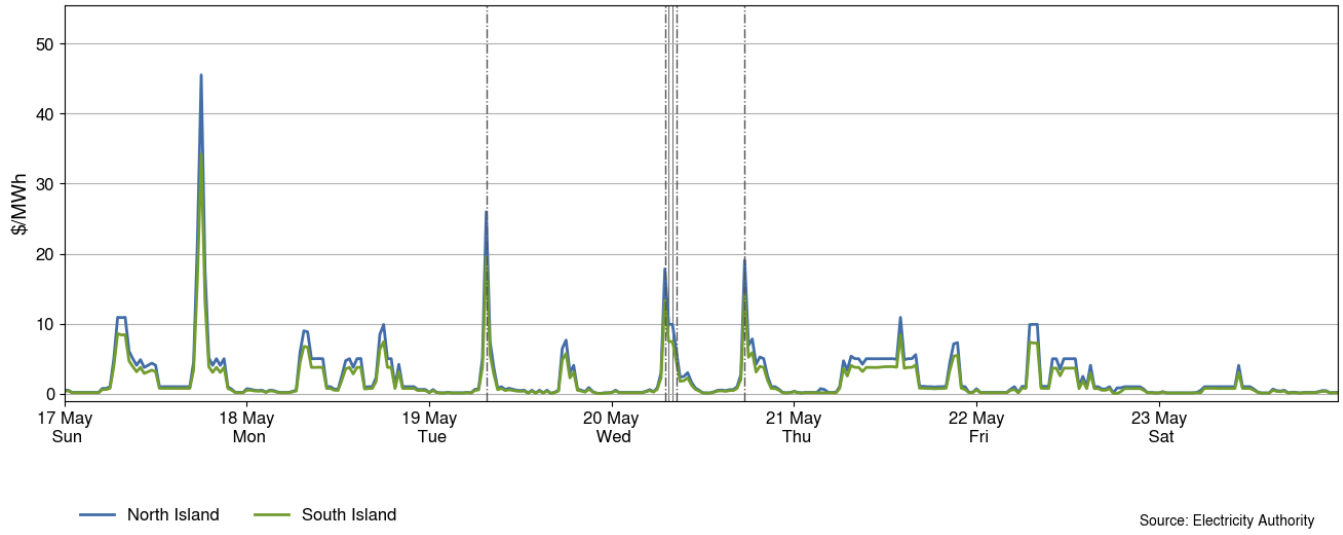
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices remained mostly below $3/MWh, with FIR price spiking above or around $20/MWh on Sunday, Tuesday and Wednesday.

3.2. On Sunday at 6.00pm, North Island FIR prices peaked at $46/MWh while South Island FIR prices peaked at $34/MWh.

3.3. On Tuesday at 7.30am, North Island FIR prices reached $26/MWh while South Island FIR prices reached $20/MWh.

3.4. At these times, Huntly 5 was the risk setter. Generation increased at Huntly 5, increasing the amount of reserve needed to cover this risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 17-23 May



3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in At these times, Huntly 5 was the risk setter. Generation increased at Huntly 5, increasing the amount of reserve needed to cover this risk.

3.6. Figure 4. SIR prices remained mostly below $3/MWh, with SIR prices spiking above or around $20/MWh on Wednesday and Friday.

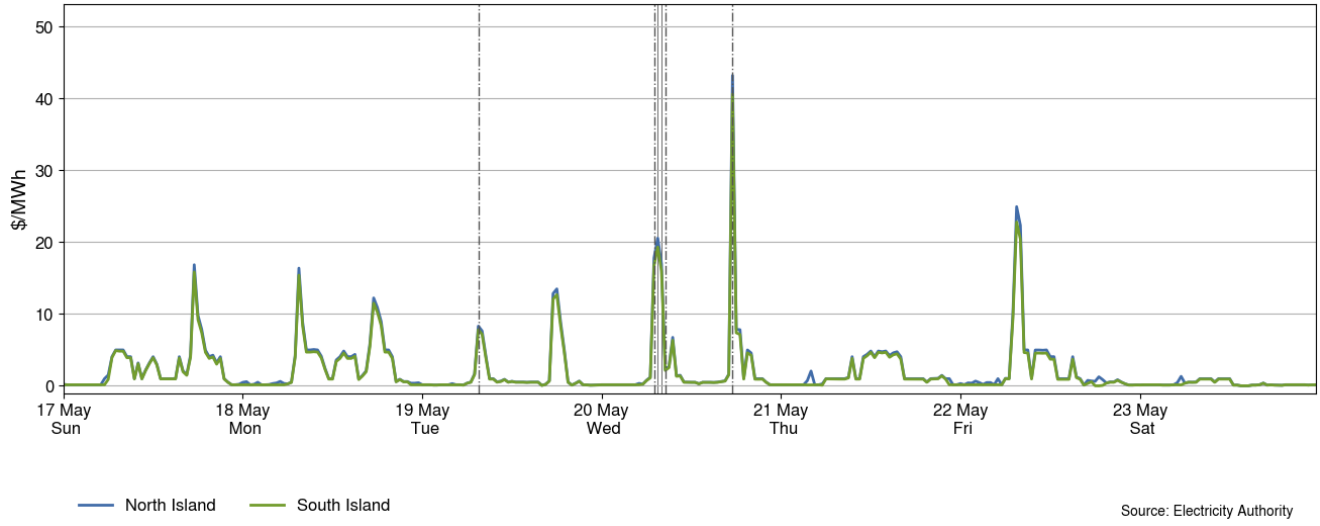
3.7. On Wednesday at 7.30am, North Island SIR prices reached $21/MWh and South Island SIR prices reached $20/MWh.

3.8. On Wednesday at 5.30pm, North Island SIR prices peaked at $43/MWh while South Island SIR prices peaked at $41/MWh.

3.9. On Friday at 7.30am, North Island SIR prices reached $25/MWh and South Island SIR prices reached $23/MWh.

3.10. At these times, Huntly 5 was the risk setter. Generation increased at Huntly 5, increasing the amount of reserve needed to cover this risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 17-23 May



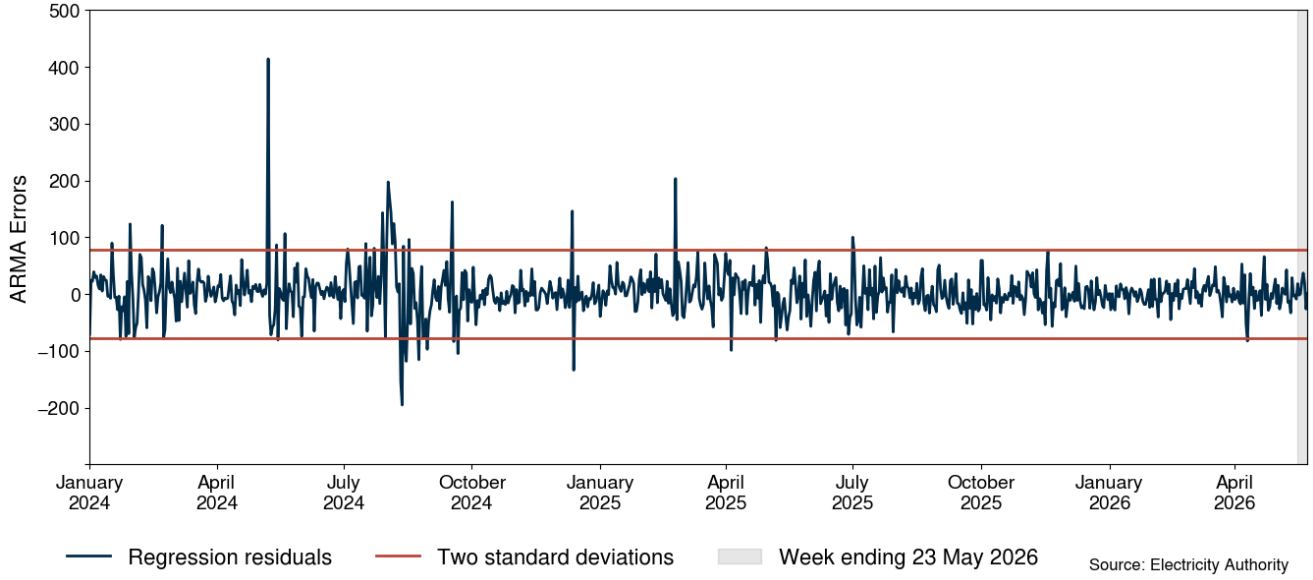
4. Regression residuals

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 - 23 May 2026

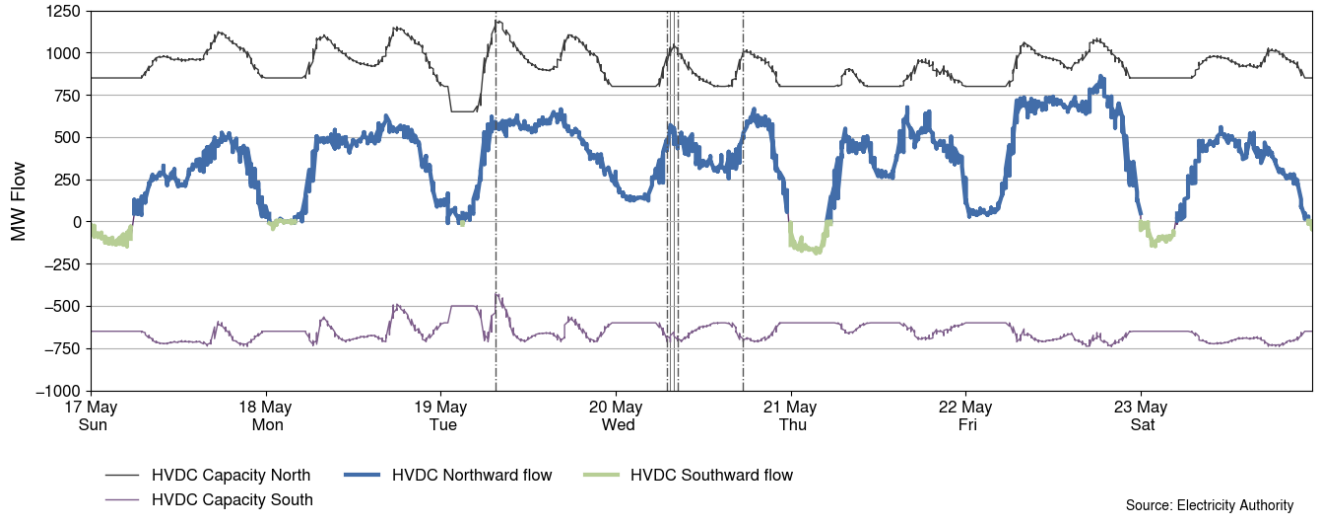


5. HVDC

5.1. Figure 6 shows the HVDC flow between 17-23 May. As wind generation has remained low this week, HVDC flows were mostly northward, with some southward flow occurring overnight.

5.2. The highest northward flow of 863MW occurred on Friday at 6.30pm. The highest southward flow of 190MW occurred on Thursday at 3.30am.

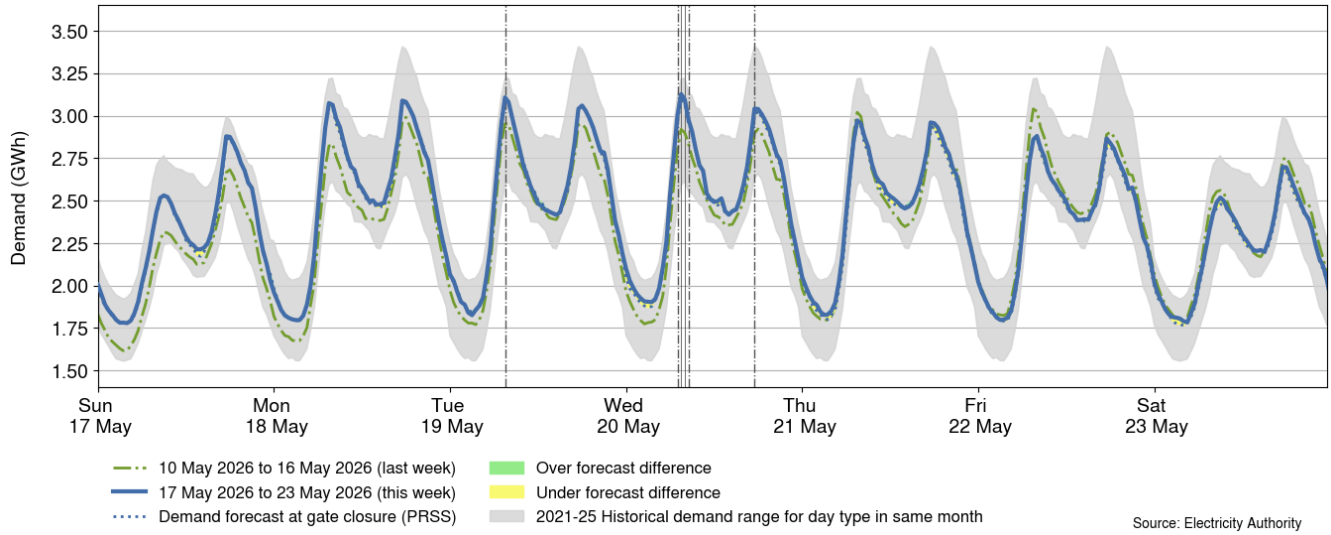
Figure 6: HVDC flow and capacity, 17-23 May



6. Demand

6.1. Figure 7 shows national demand between 17-23 May, compared to the historic range and the demand of the previous week. Demand was higher than last week from Sunday to Wednesday, when temperatures were lower, and similar to last week from Thursday to Saturday, when temperatures were similar.

Figure 7: National demand, 17-23 May compared to the previous week

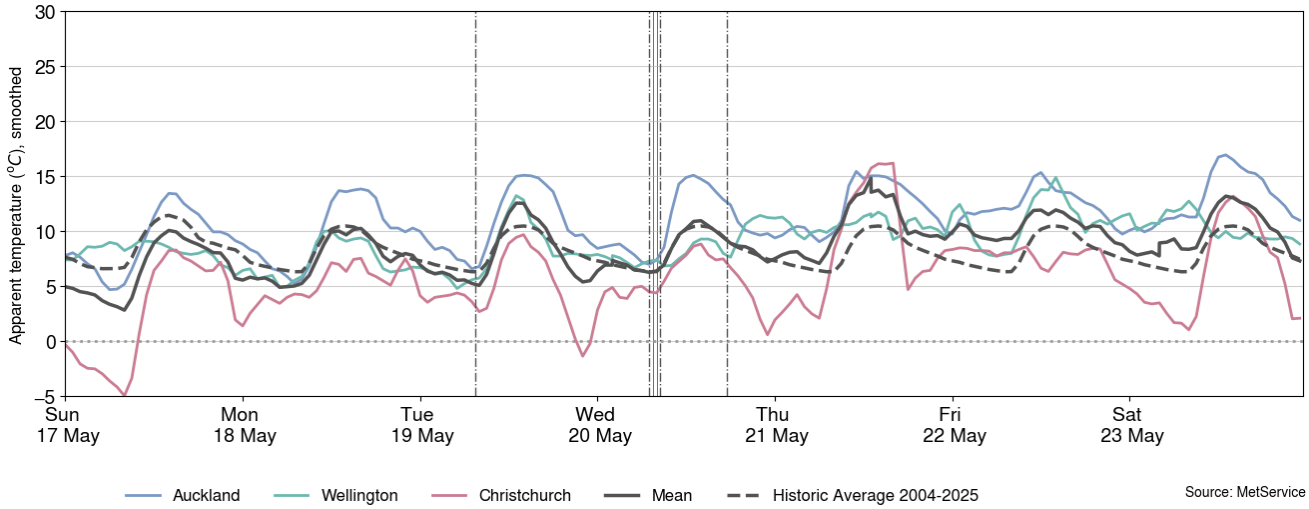


6.2. Figure 8 shows the hourly apparent temperature at main population centres from 17-23 May. The apparent temperature is an adjustment of the recorded temperature that accounts

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.

6.3. Apparent temperatures ranged from 5°C to 17°C in Auckland, 4°C to 16°C in Wellington, and -5°C to 16°C in Christchurch.

Figure 8: Temperatures across main centres, 17-23 May



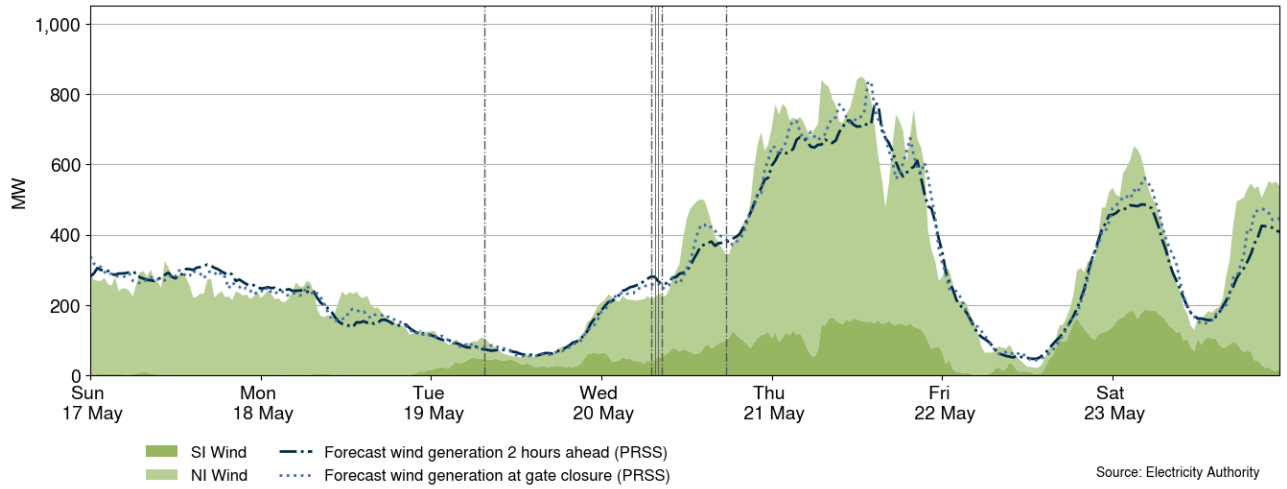
7. Generation

7.1. Figure 9 shows wind generation and forecast from 17-23 May. This week wind generation varied between 22MW and 849MW, with a weekly average of 311MW. Wind generation was low for most of the week, generally only reaching high levels on Thursday, and overnight on Friday and Saturday.

7.2. On Thursday 21st May between 3.00pm-4.30pm, the largest over wind generation over forecast occurred at around 199 MW. This forecasting error was the result of an amalgamation of errors at farms, with large contributors including Harapaki, Tararua wind farms, Te Āpiti and Turitea.

7.3. General over and under forecasting of wind generation throughout the week, were the results of an amalgamation of errors across multiple wind farms.

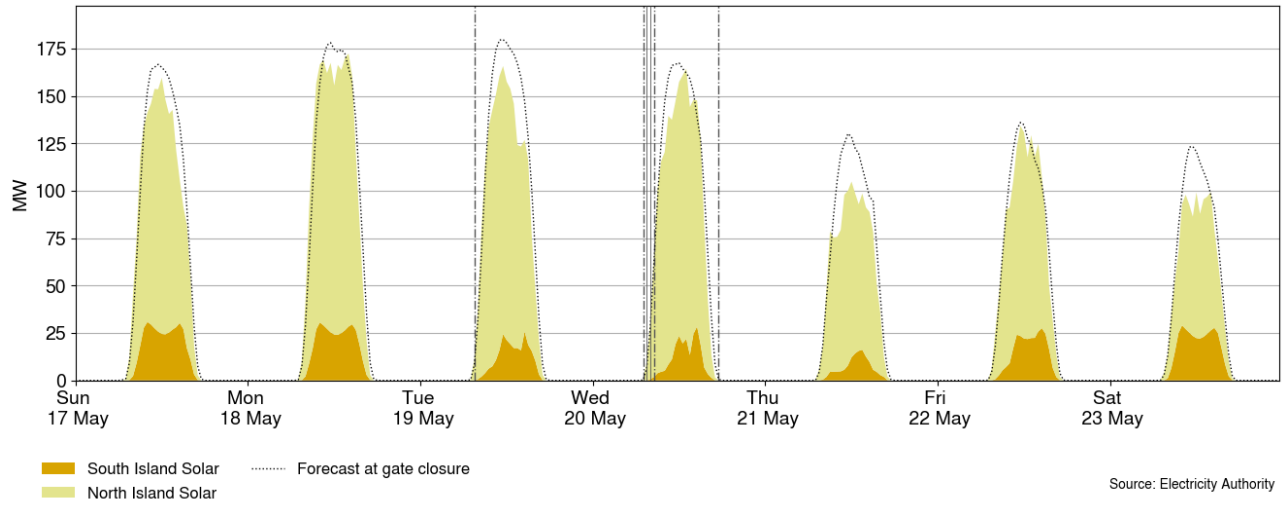
Figure 9: Wind generation and forecast, 17-23 May



7.4. Figure 10 shows grid connected solar generation from 17-23 May. Solar generation was relatively high from Sunday to Wednesday, and lower from Thursday onwards.

7.5. Solar generation peaked at 165MW on Monday at 2.00pm.

Figure 10: Grid connected solar generation, 17-23 May

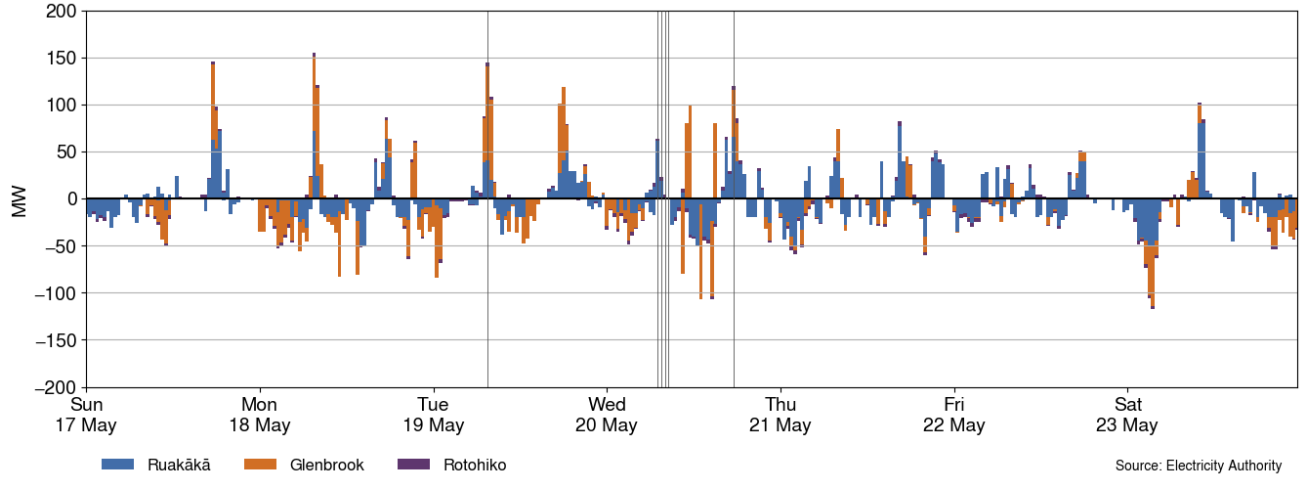


7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are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

7.7. This week, the batteries generally charged while prices were lower, at below $125/MWh, and discharged when prices were higher, at above $125/MWh.

7.8. Glenbrook did not make offers during the price spike on Wednesday morning. This is being looked into further by the monitoring team.

Figure 11: Grid scale battery charge and discharge, 17-23 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[1]) 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.

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

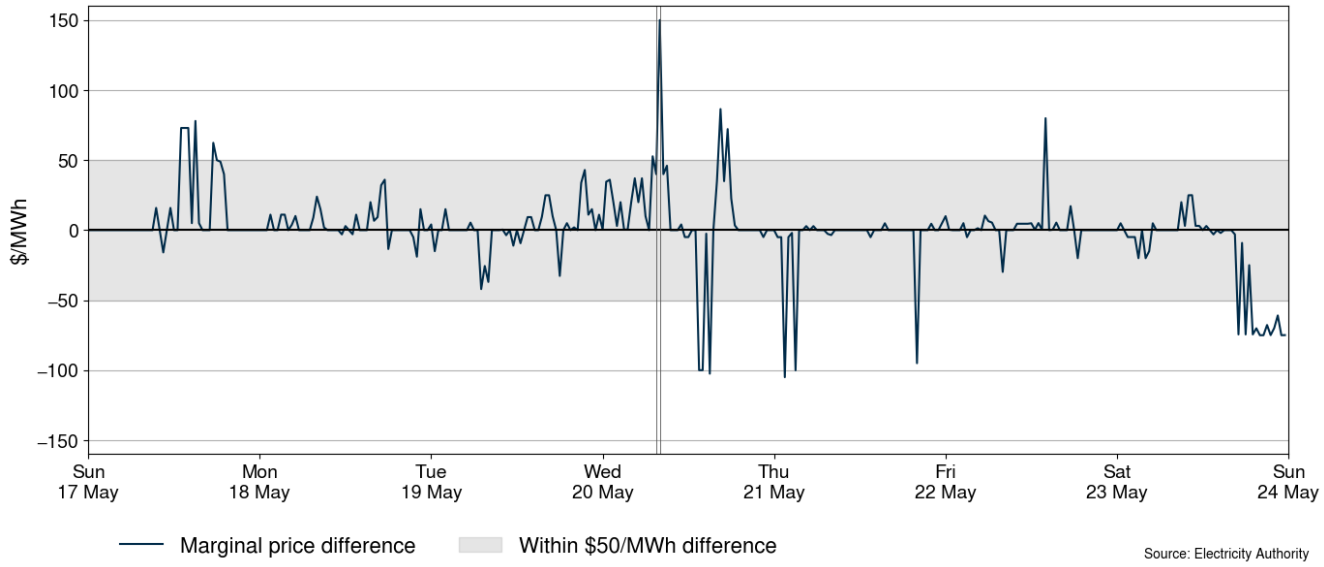
7.11. The maximum positive difference of $150/MWh occurred on Wednesday at 8.00am. At this time, wind generation was 31MW below forecast, and demand was 43MW above forecast.

7.12. The maximum negative difference of $105/MWh occurred on Thursday at 1.30am. At this time, wind generation was 125MW above forecast, and demand was 64MW above forecast.

7.13. On Saturday from 7.00pm to 11.30pm, the marginal price difference was consistently below -$60/MWh. At these times, wind generation was between 30 and 133MW above forecast.

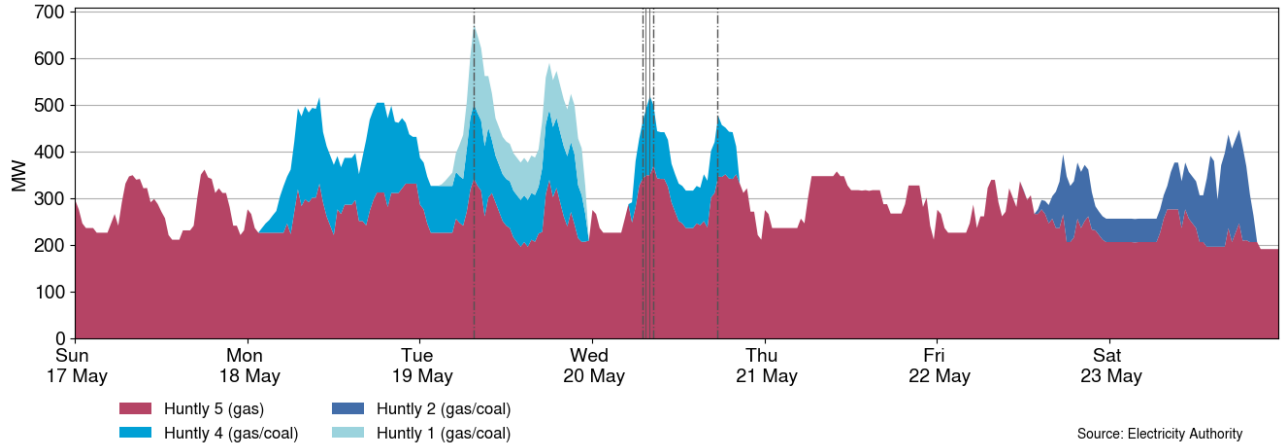
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 17-23 May



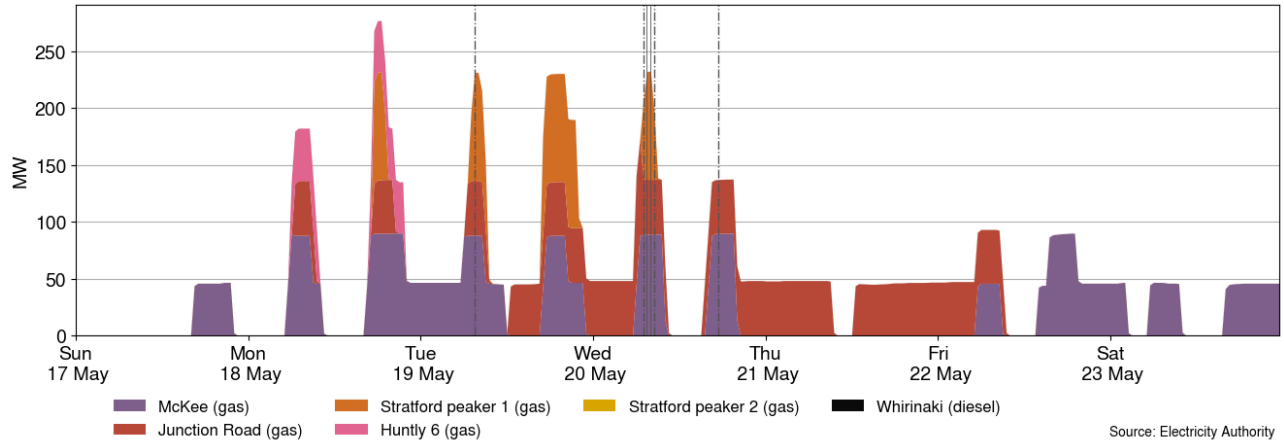
7.14. Figure 13 shows the generation of thermal baseload between 17-23 May. Huntly 5 ran continuously this week. Huntly 4 ran on Monday, Tuesday, and Wednesday, Huntly 1 ran on Tuesday, and Huntly 2 ran on Friday and Saturday.

Figure 13: Thermal baseload generation, 17-23 May



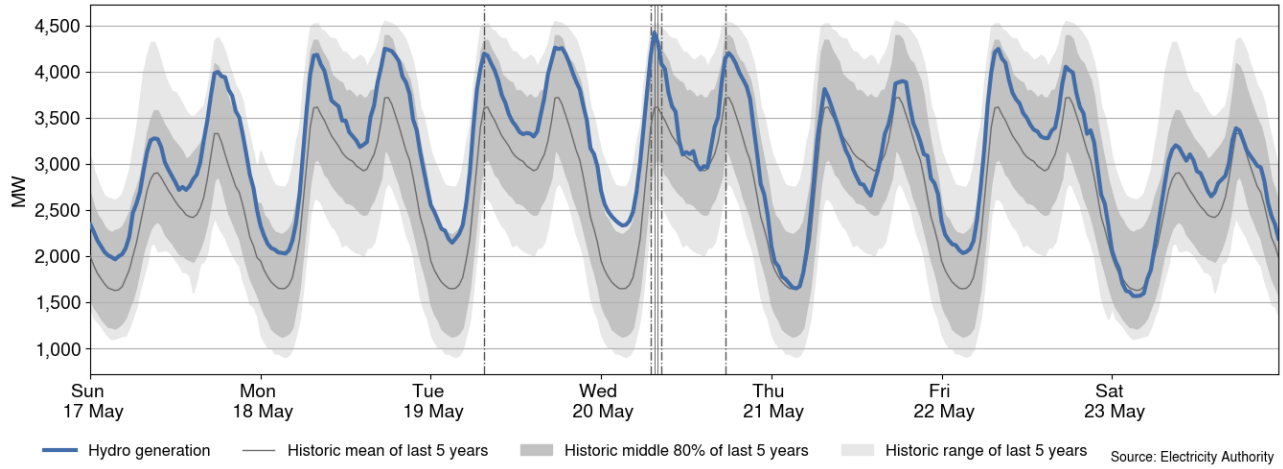
7.15. Figure 14 shows the generation of thermal peaker plants between 17-23 May. McKee ran at times every day this week except for Thursday, while Junction Road ran at times every weekday. Stratford peaker 1 ran at times from Monday to Wednesday, while Huntly 6 ran at times on Monday.

Figure 14: Thermal peaker generation, 17-23 May



7.16. Figure 15 shows hydro generation between 17-23 May. Hydro generation has mostly been above the historic mean this week, with relatively high demand and hydro storage higher than usual for this time of year.

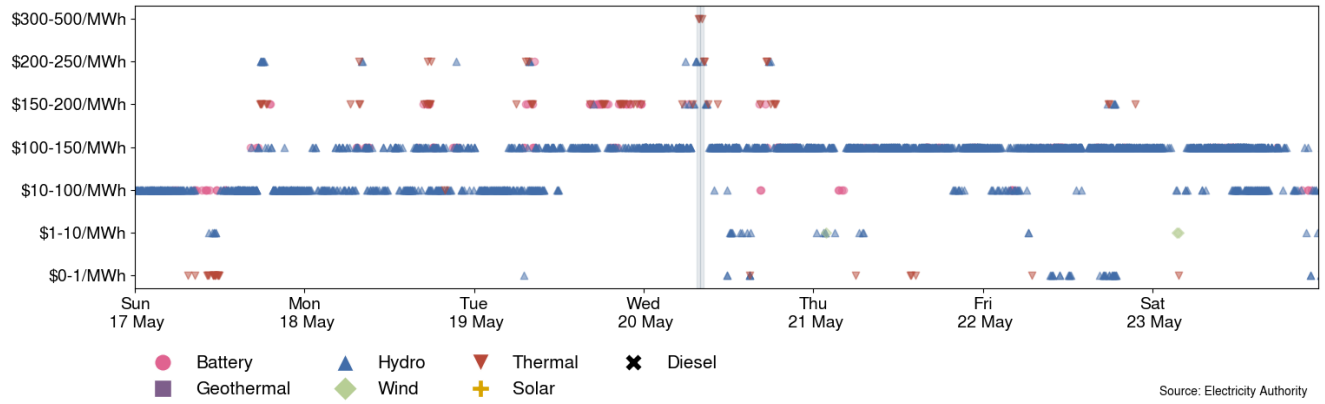
Figure 15: Hydro generation, 17-23 May



7.17. 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.

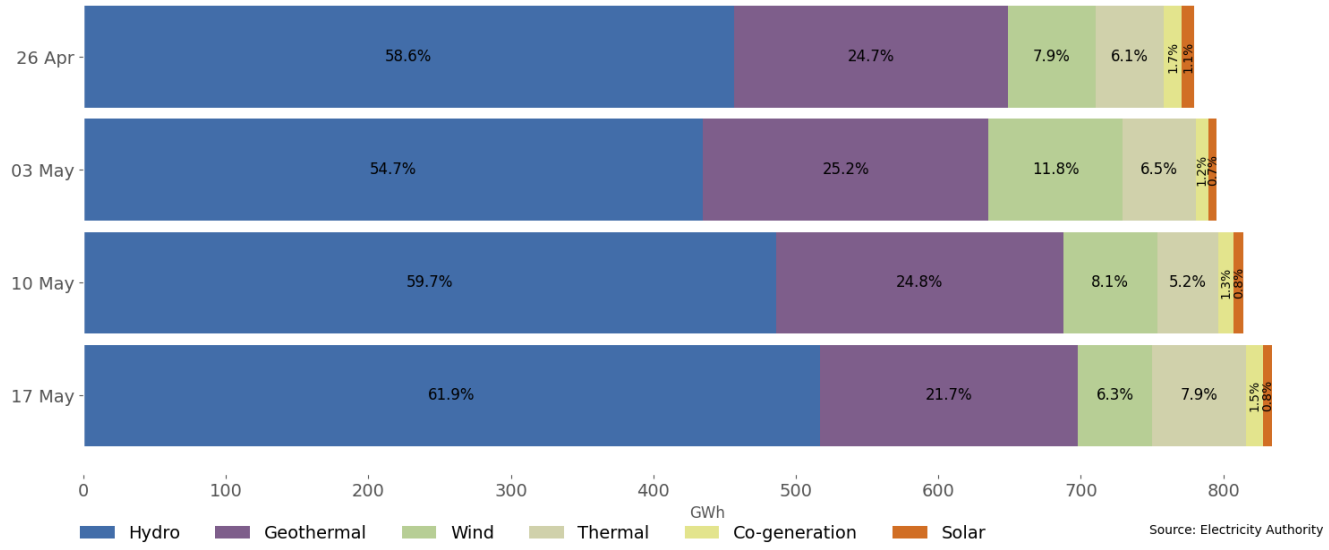
7.18. The highest prices were set by Genesis thermal (Huntly 4 at ~$400/MWh). The most common technology setting prices was hydro, with batteries the second most common. Most marginal prices were between $100-150/MWh.

Figure 16: Prices of marginal generation, 17-23 May



7.19. As a percentage of total generation, between 17-23 May, total weekly hydro generation was 61.9%, geothermal 21.7%, wind 6.3%, thermal 7.9%, co-generation 1.5%, and solar (grid connected) 0.8%, as shown in Figure 17. The proportion of geothermal generation has decreased, with ~100MW of Mercury geothermal on outage this week.

Figure 17: Total generation by type as a percentage each week, between 26 April and 23 May



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 17-23 May ranged between ~924MW and ~1800MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 17-23 May

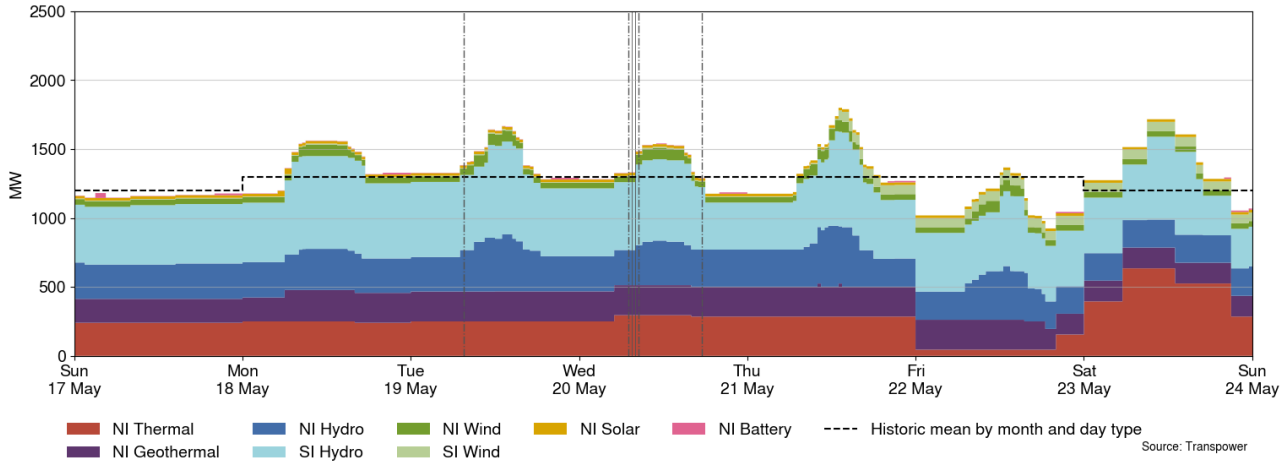
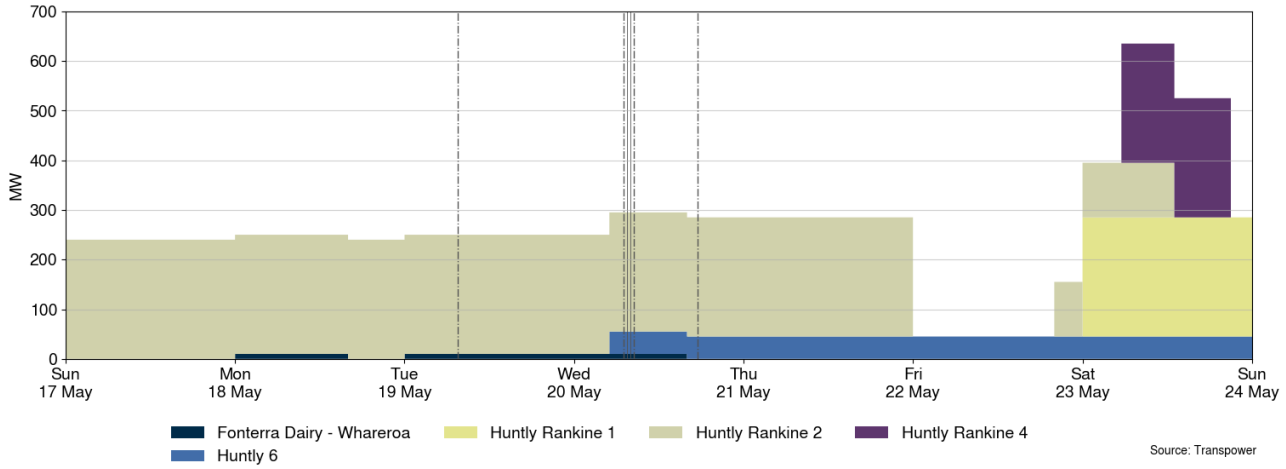


Figure 19: Total MW loss from thermal outages, 17-23 May



8.2. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 5	Full	18 May 2026
Huntly 2	Full	21 May 2026
Ōhau unit 5	Full	29 May 2026
Huntly 1	Full	4 June 2026
Kaiwera Downs	Partial	23 June 2026
Manapōuri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

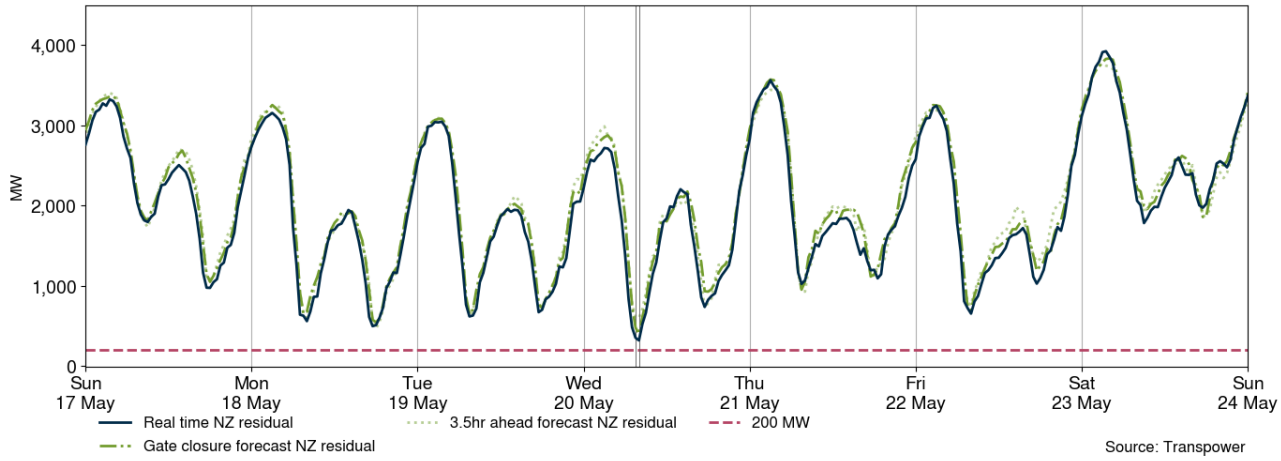
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 17-23 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.

9.2. This week, the national residual has neared the 200MW residual mark. The lowest national residual this week was 322MW on Wednesday at 8.00am. At this time, the South Island residual was 1MW.

9.3. The national residual was below 500MW on Monday at 5.30pm, and on Wednesday from 7.00am to 8.00am.

Figure 20: National generation balance residuals, 17-23 May



10. Storage/fuel supply

10.1. 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 23 May, national controlled storage was 80% nominally full and ~109% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (81% full) and Lake Tekapō (75% full) remain above their historic mean.

10.4. Storage at Lake Te Anau (45% full) and Lake Manapōuri (32% full) remain below their historic mean.

10.5. Storage at Lake Taupō (74% full) remains above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (86% full) is below its historic 90th percentile but remains above its historic mean.

10.7. **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.

10.8. As of 23 May, national controlled storage was 80% nominally full and ~109% of the historical average for this time of the year.

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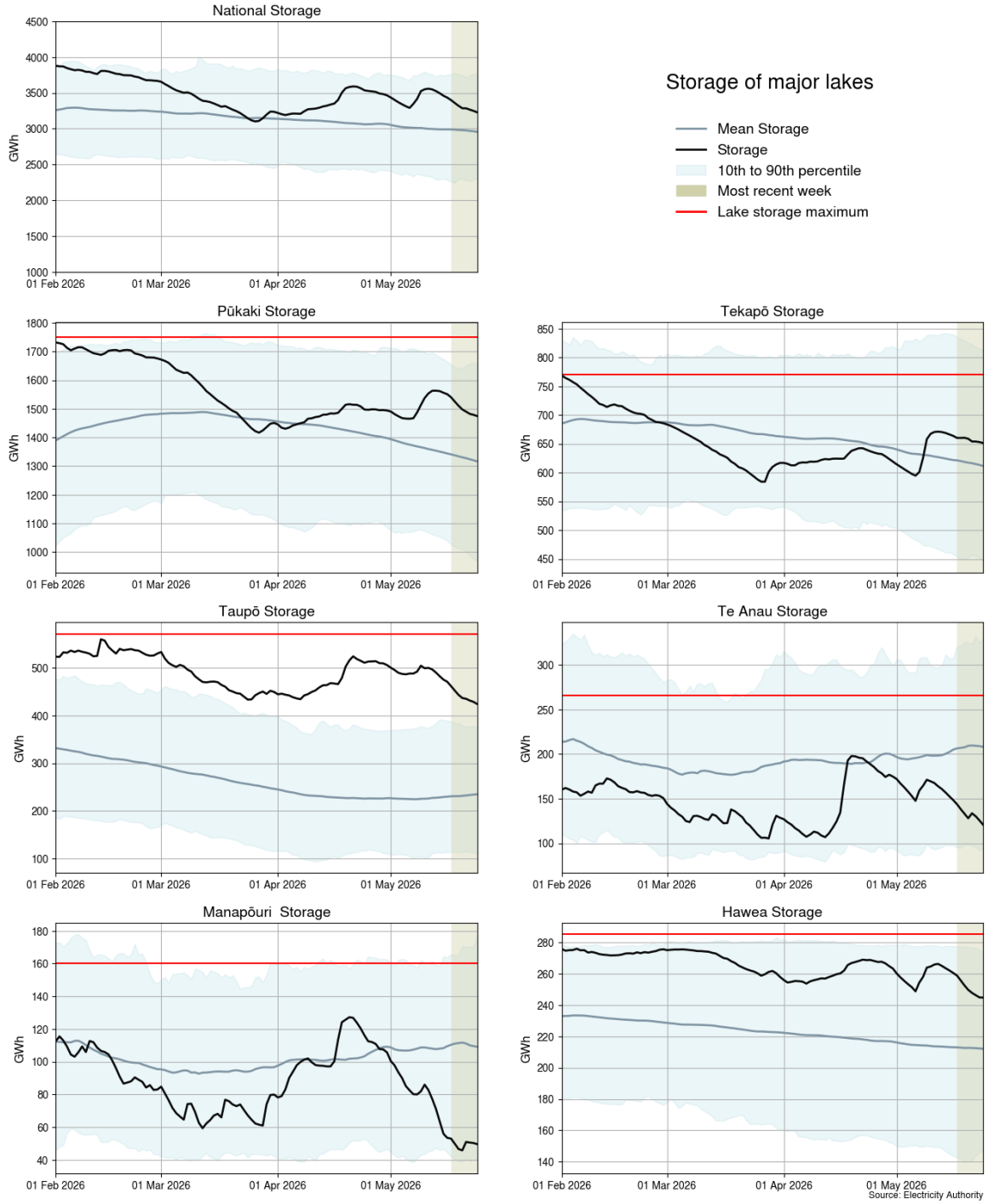
10.11. Storage at Lake Taupō (74% full) remains above its historic 90th percentile for this time of year.

10.12. Storage at Lake Hawea (86% 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 generation has decreased, aside from coal fuelled generation.

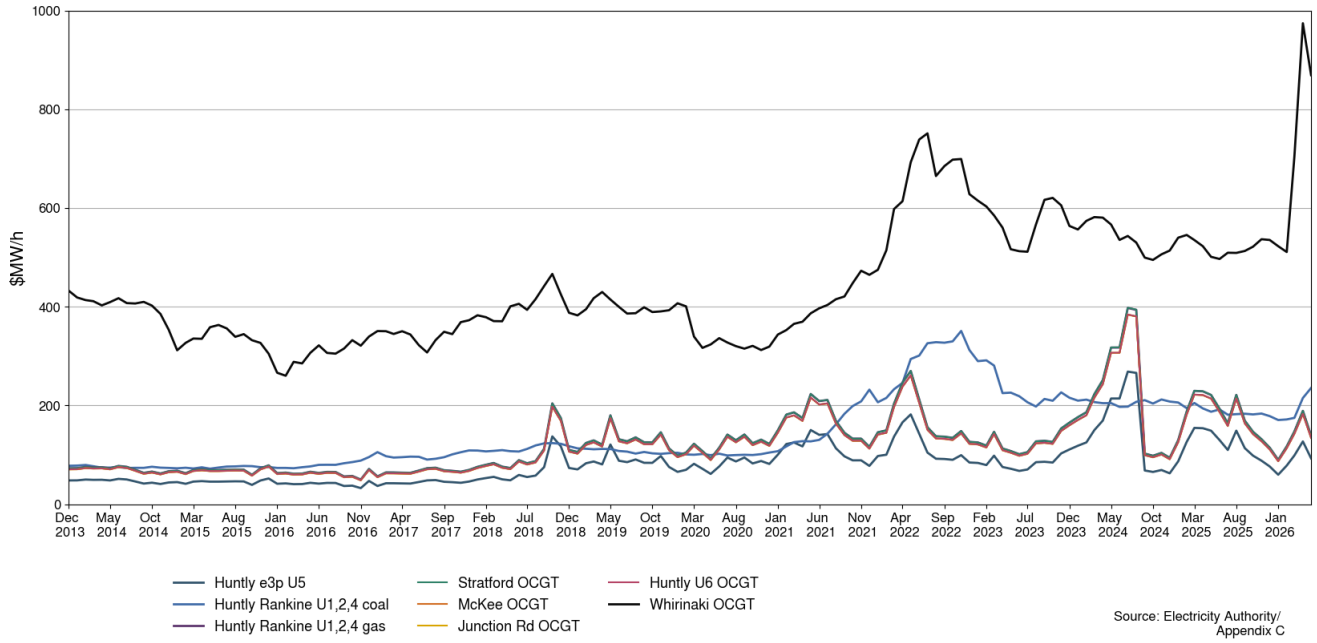
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$235/MWh, while the cost of running the Rankines on gas is ~$139/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $93/MWh and $139/MWh.

11.6. The SRMC of Whirinaki is ~$869/MWh.

11.7. 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



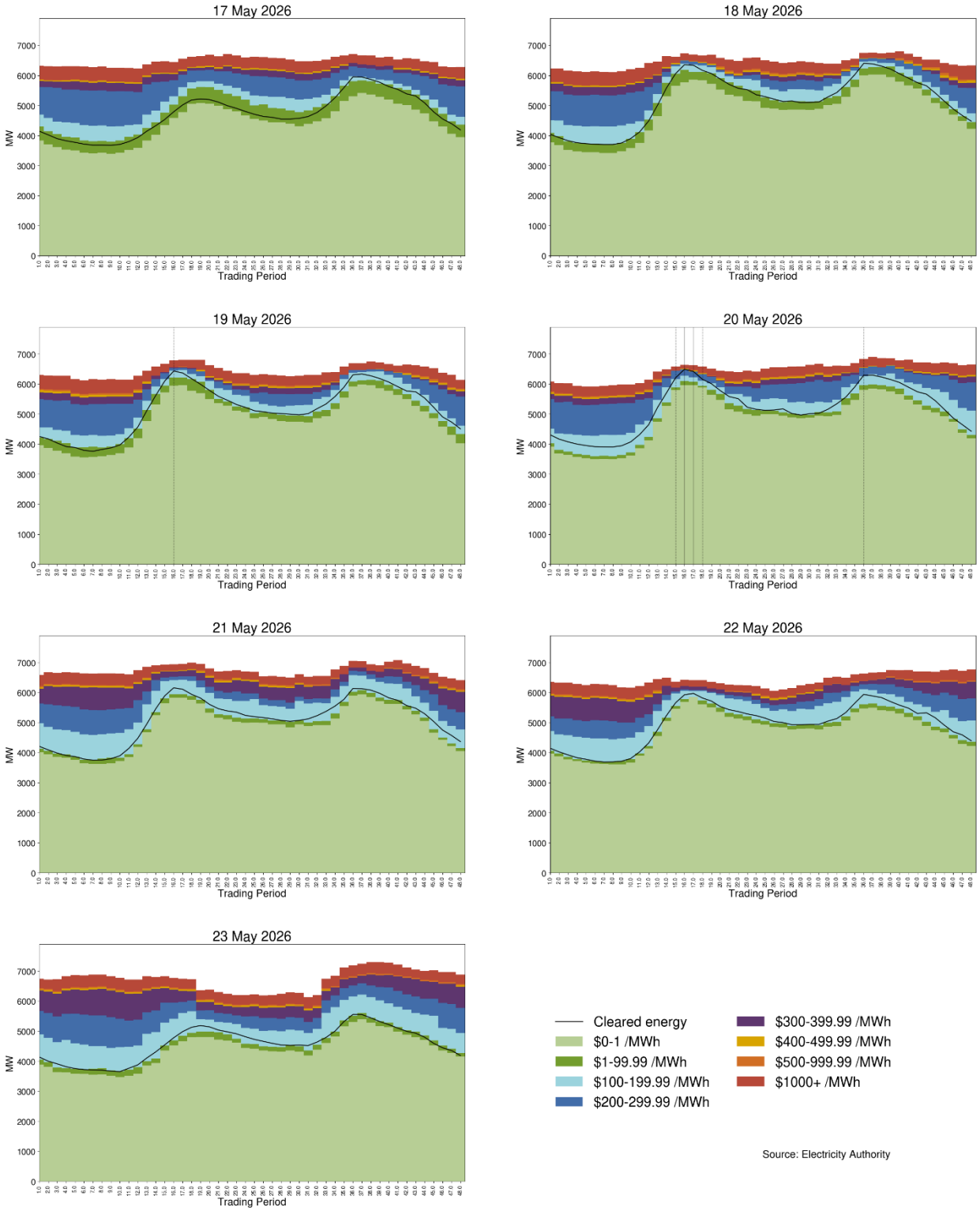
12. Offer behaviour

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 $300/MWh this week.

12.3. From Thursday onwards, Mercury hydro priced up energy from $200-299/MWh to $300-399/MWh.

Figure 23: Daily offer stacks



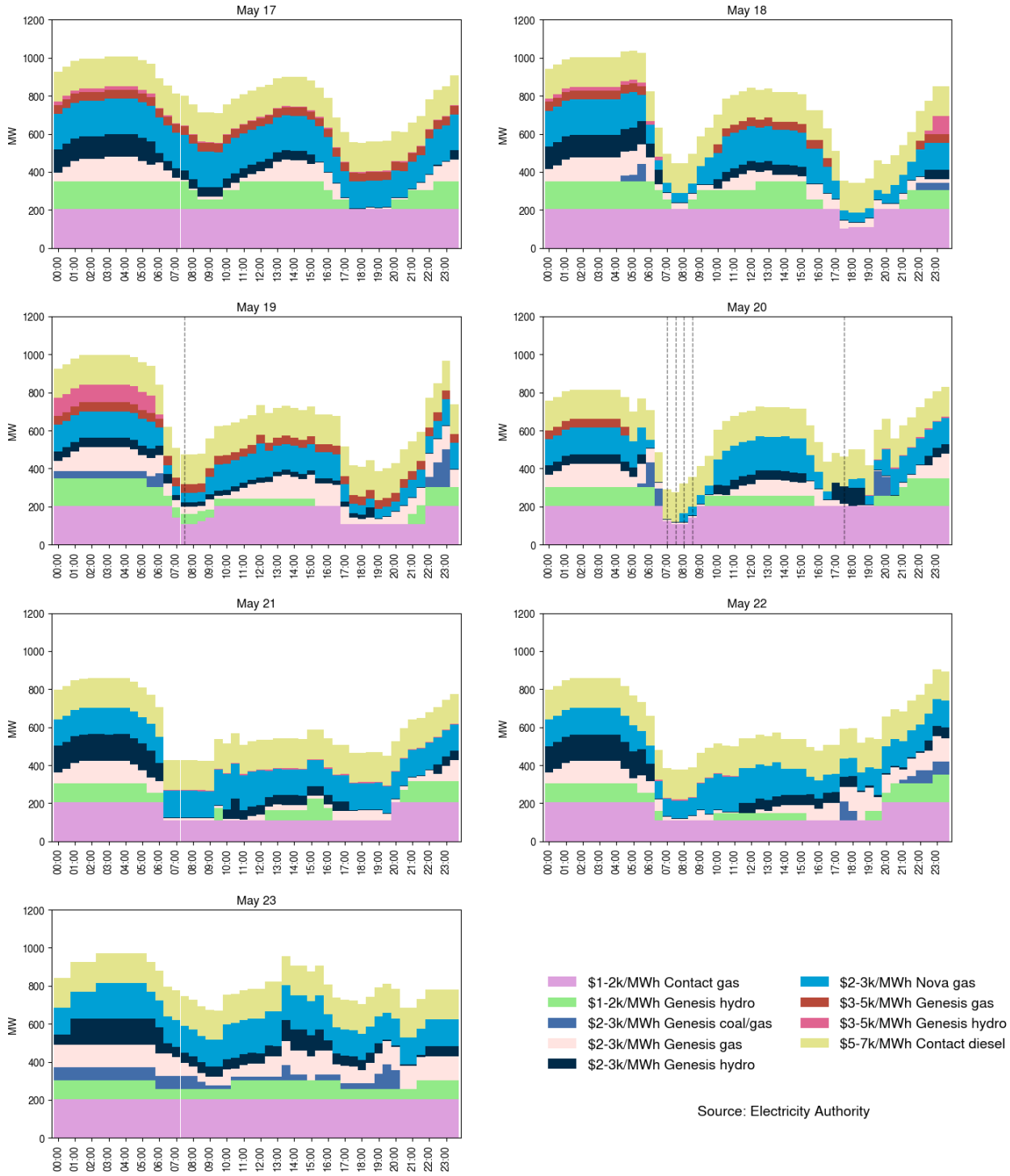
12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 709MW per trading period was priced above $1,000/MWh this week, which is roughly 12.6% 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.

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
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
20/05/2026	Several	Further analysis	Contact	Glenbrook	Offers
20/05/2026	35-38	Further analysis	Genesis	Tekapō	Offers