16 March 2026

Trading conduct report 8-14 March 2026

Market monitoring weekly report

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1. Overview

1.1. This week the average spot price increased by $30/MWh to $126/MWh. Higher demand, lower wind generation, higher thermal generation, decreasing hydro storage and increased geothermal outages have all contributed to higher prices this week. National hydro storage decreased this week to 84% nominally full and ~105% 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 8-14 March:

(a) The average spot price for the week was $126/MWh, an increase of around $30/MWh compared to the previous week.

(b) 95% of prices fell between $11/MWh and $189/MWh.

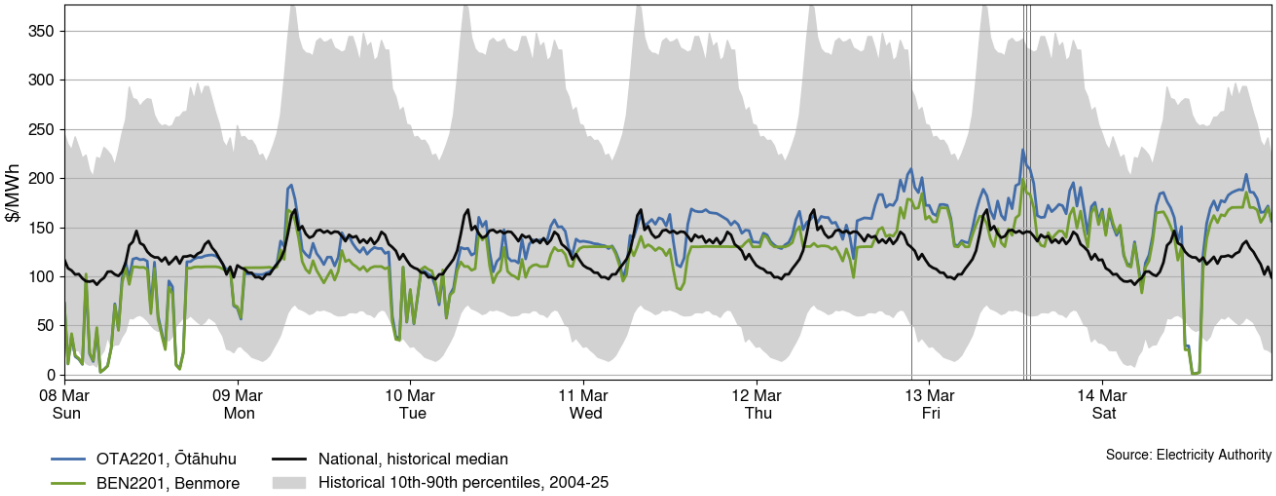
2.3. Prices are higher this week due to slightly higher demand, lower wind generation, higher thermal generation, declining hydro storage, and increased geothermal outages.

2.4. Prices spiked above $200/MWh at Ōtāhuhu between 1.00pm and 2.00pm on Friday, with the highest Ōtāhuhu price of the week of $229/MWh occurring at 1.00pm. These prices occurred during higher demand and relatively lower wind. Demand was also up to 165MW higher than forecast at this time.

2.5. Ōtāhuhu prices also climbed up to $209/MWh on Thursday at 9.30pm. At this time, intermittent generation was 65M lower than forecast and demand 77MW higher than forecast.

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. Other notable prices are marked with black dashed lines.

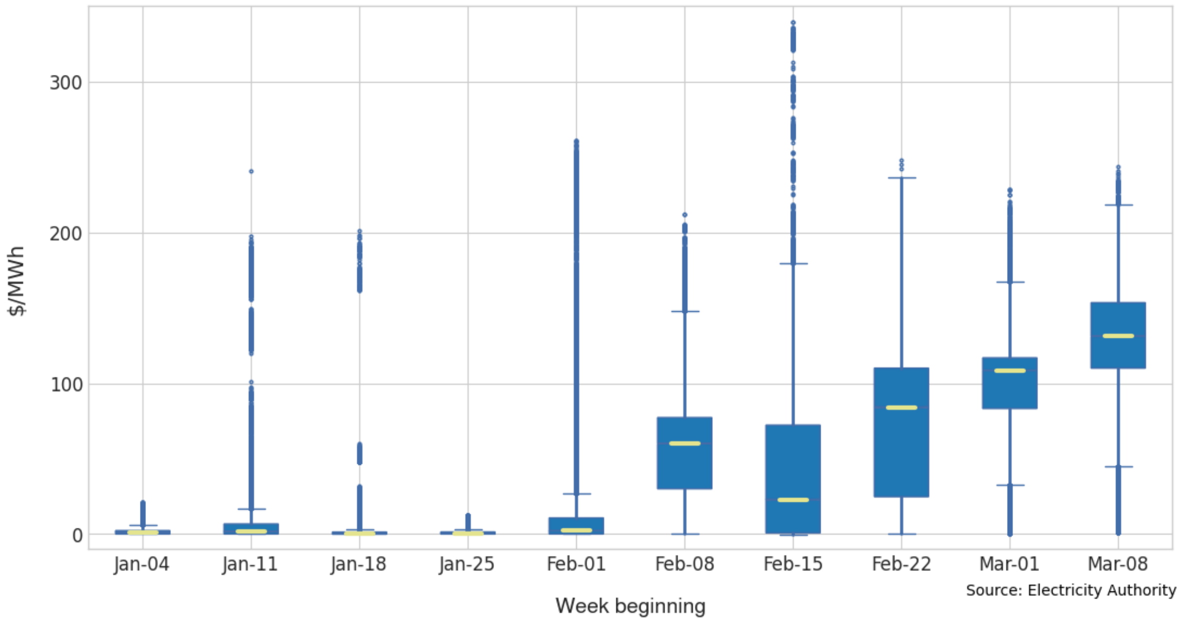
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 8-14 March



2.7. 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.

2.8. The distribution of spot prices this week was slightly wider compared to last week. The median price was $131/MWh and most prices (middle 50%) fell between $110/MWh and $153/MWh.

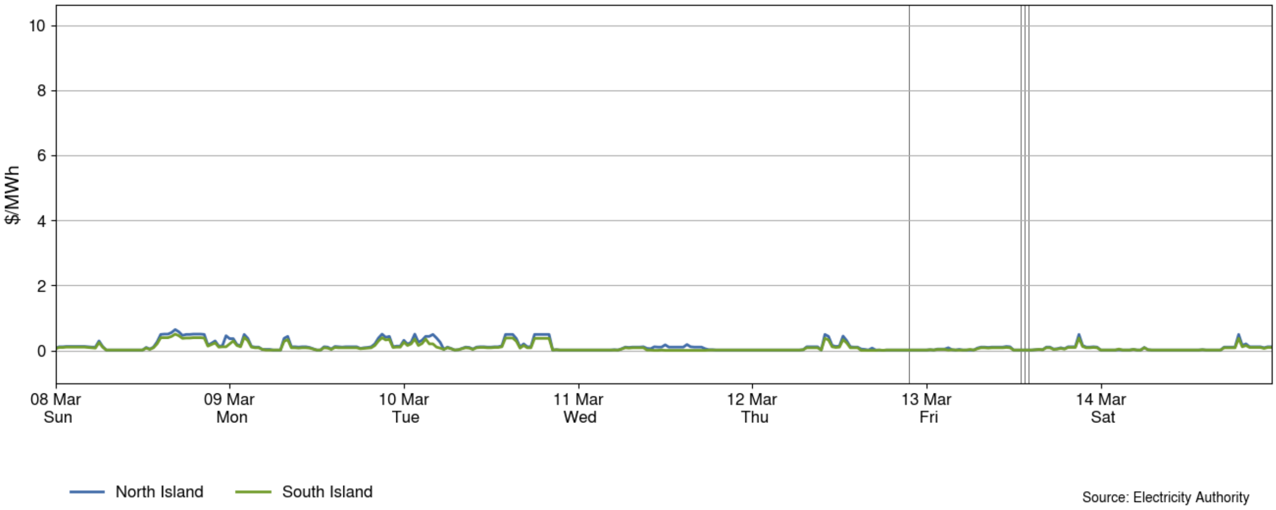
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

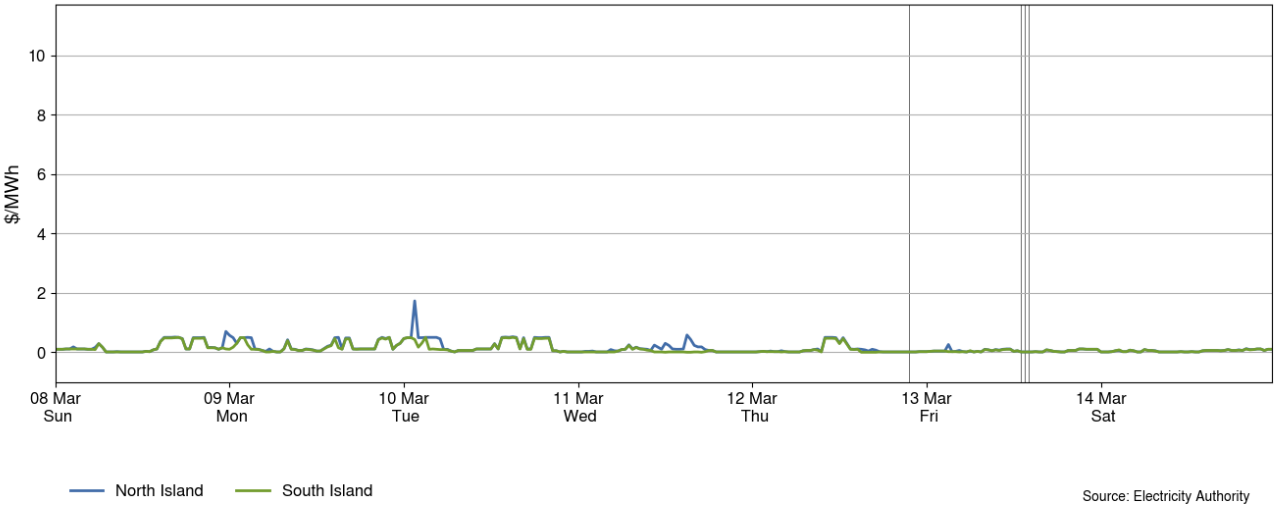
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices across both the North and South Islands remained below $1/MWh this week.

Figure 3: Fast instantaneous reserve price by trading period and island, 8-14 March



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices across both the North and South Islands remained below $2/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 8-14 March



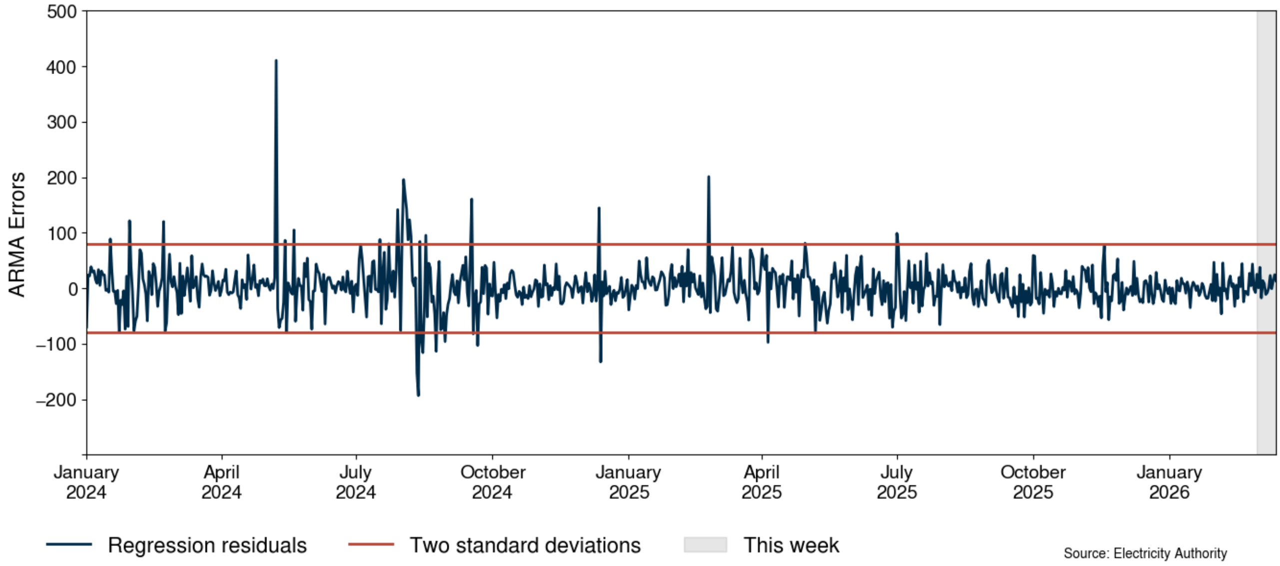
4. Regression residuals

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 - 14 March 2026

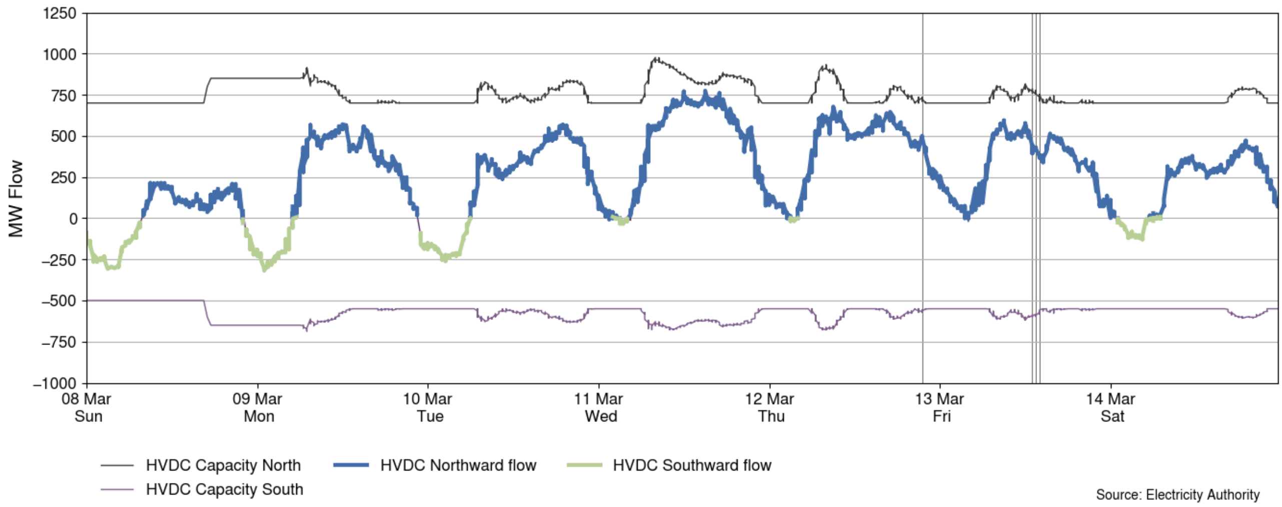


5. HVDC

5.1. Figure 6 shows the HVDC flow between 8-14 March. This week, HVDC flows were mostly northward, with periods of southward flow overnight most days. Higher wind generation between Sunday and Tuesday saw increased levels of southward flow overnight.

5.2. The highest northward flow occurred at 3.00pm on Wednesday with a flow of 775MW.

Figure 6: HVDC flow and capacity, 8-14 March



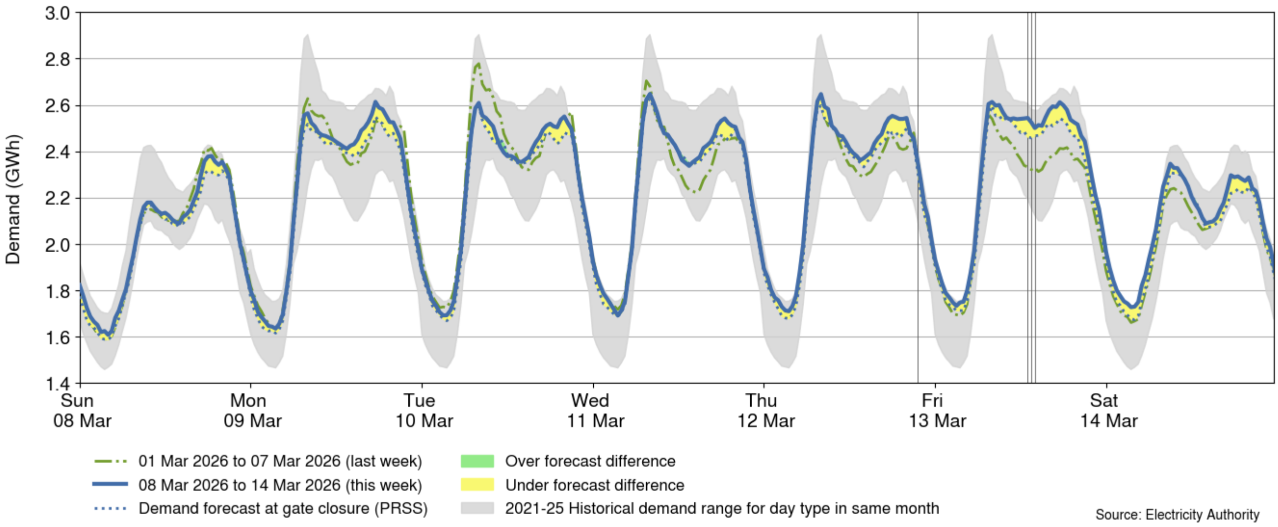
6. Demand

6.1. Figure 7 shows national demand between 8-14 March, compared to the historic range and the demand of the previous week.

6.2. For much of the week, demand was similar to the previous week. Demand was higher compared to the previous week on Friday, with warm temperatures likely contributing to this.

6.3. The highest demand of the week was around 2.65GWh at 8.00am on Wednesday.

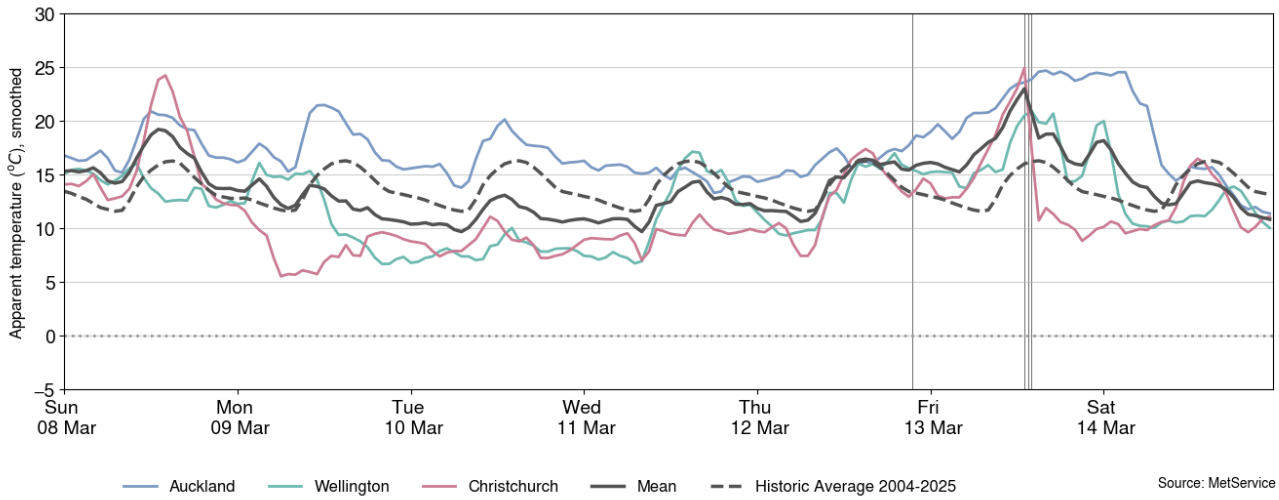
Figure 7: National demand, 8-14 March compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 8-14 March. 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 11°C to 25°C in Auckland, 6°C to 21°C in Wellington, and 5°C to 26°C in Christchurch.

Figure 8: Temperatures across main centres, 8-14 March



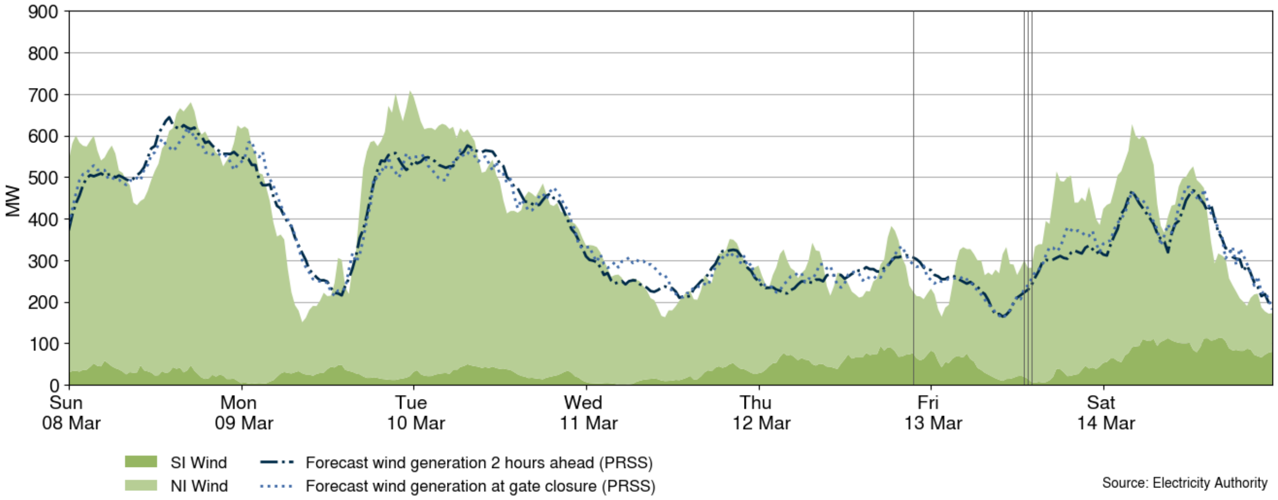
7. Generation

7.1. Figure 9 shows wind generation and forecast from 8-14 March. This week wind generation varied between 151MW and 709MW, with a weekly average of 394MW.

7.2. Wind generation was mostly high between Sunday and Tuesday, aside from a drop on Monday. From Wednesday, wind declined and remained below 400MW until Friday.

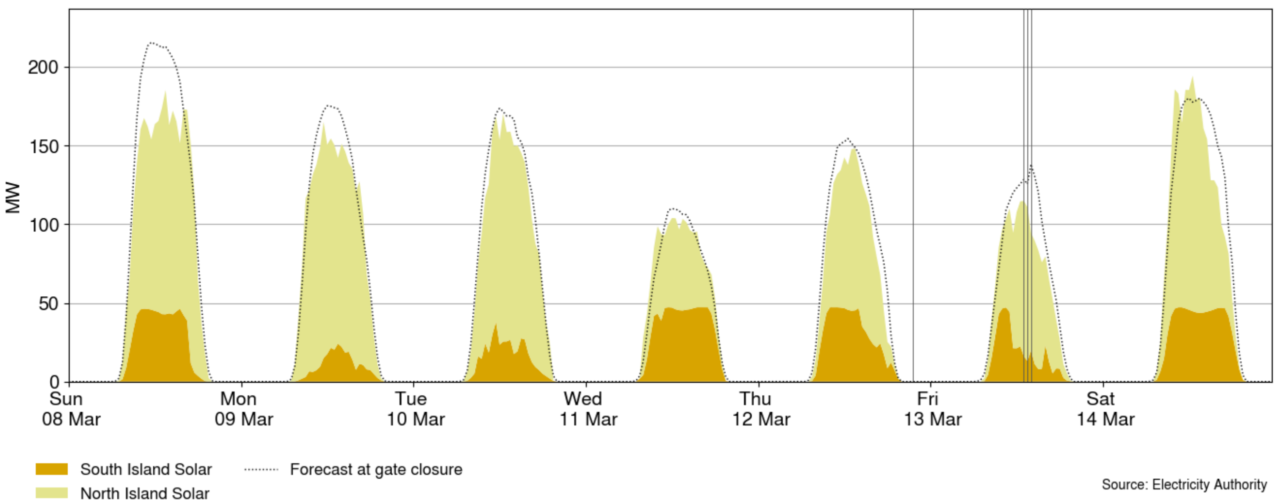
7.3. Wind forecasting errors on Monday, Thursday and Friday were the result of an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 8-14 March



7.4. Figure 10 shows grid connected solar generation from 8-14 March. Solar generation reached above 110MW each day this week, aside from on Wednesday, where solar generation reached a maximum of only 104MW. Solar generation peaked on Saturday at 12.30pm at 194MW.

Figure 10: Grid connected solar generation, 8-14 March

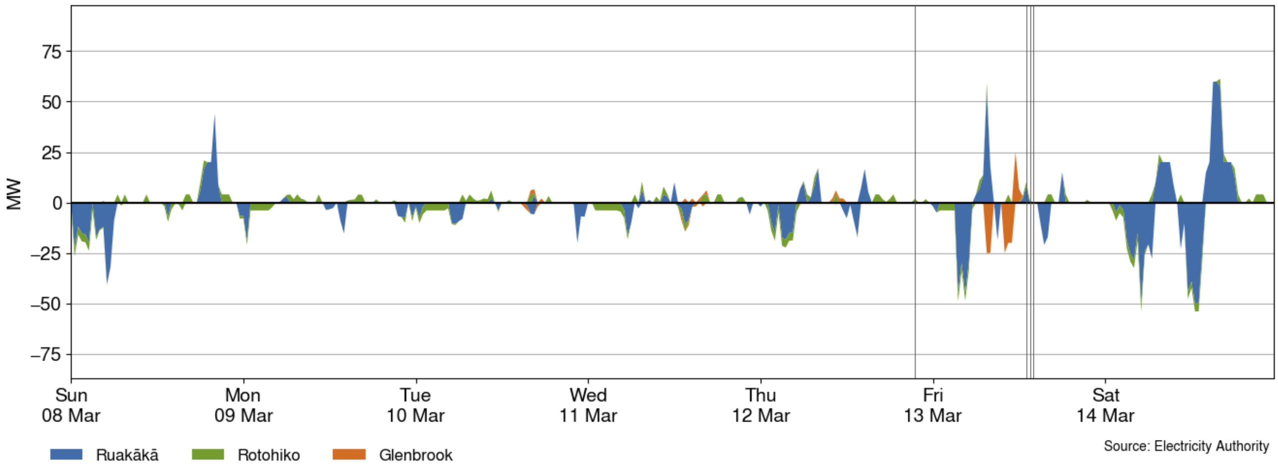


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.6. Contact’s Glenbrook battery began commissioning this week, with bids and offers for the battery occurring between Tuesday and Friday.

7.7. This week, the batteries mostly discharged during the day during relatively higher prices. The batteries mostly charged during relatively lower prices during the day or overnight.

Figure 11: Grid scale battery charge and discharge, 8-14 March



7.8. 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.

7.9. Several trading periods this week had marginal price differences greater than $50/MWh.

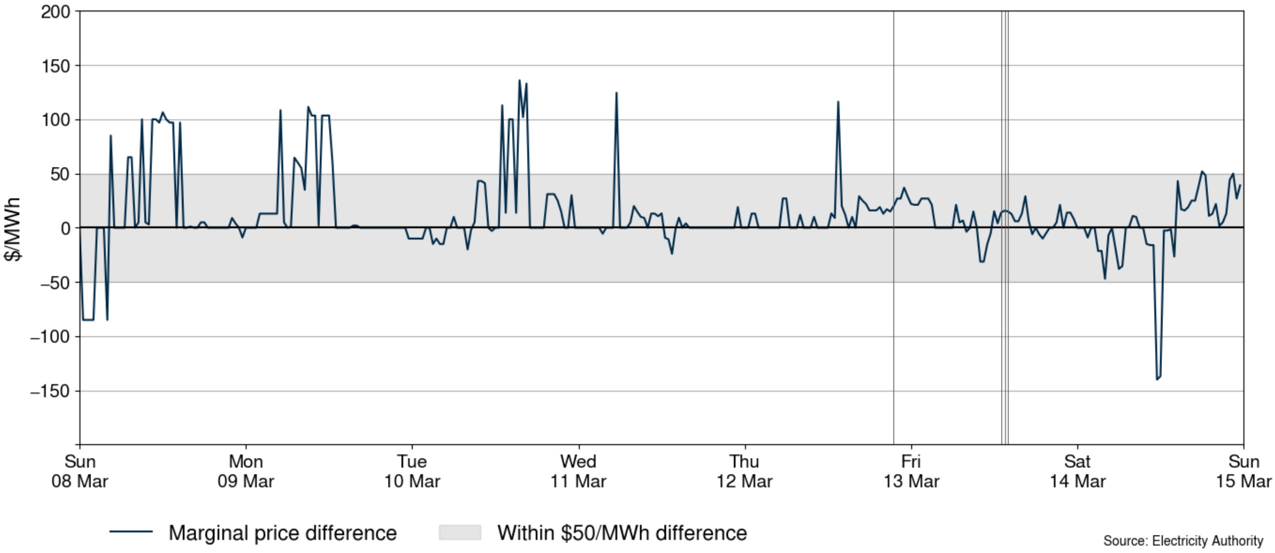
7.10. The maximum positive difference of $136/MWh occurred on Tuesday at 3.30pm. At this time, demand was 43MW higher than forecast. Intermittent generation was 13MW higher than forecast, however.

7.11. Several positive differences also occurred on Sunday and Monday during extended periods of higher-than-forecast demand.

7.12. The maximum negative difference of $140/MWh occurred on Saturday at 11.30am. At this time, demand was 7MW lower than forecast and intermittent generation 32MW higher than forecast.

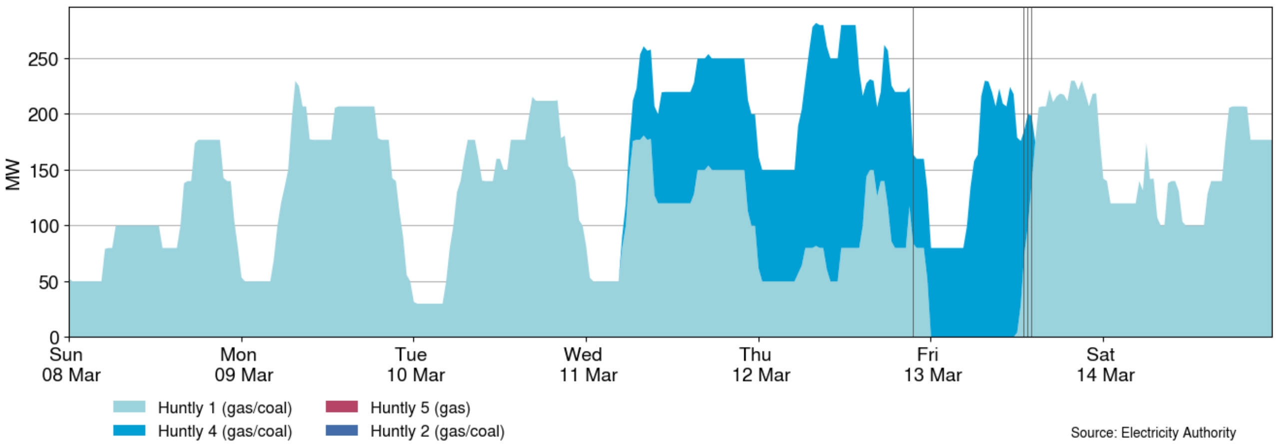
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 8-14 March



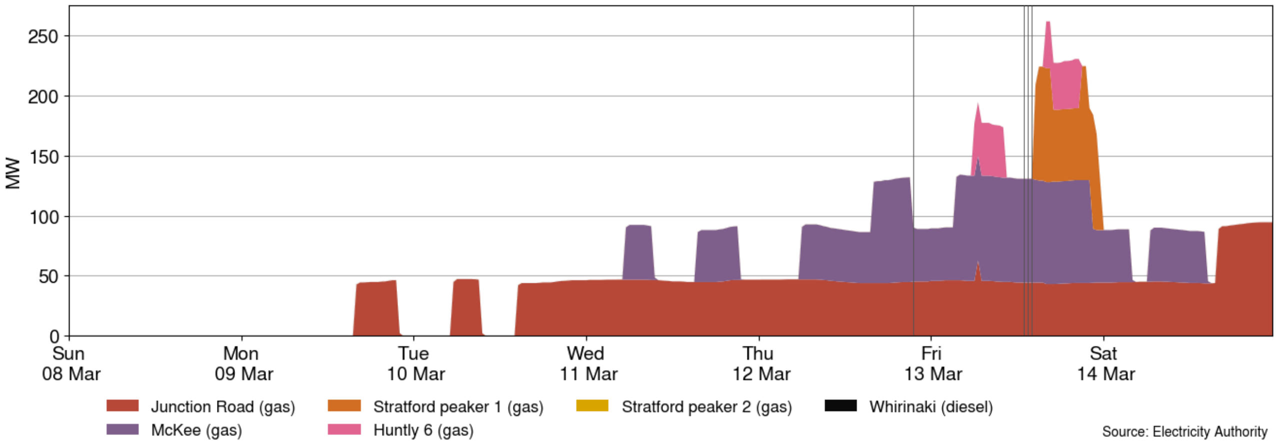
7.13. Figure 13 shows the generation of thermal baseload between 8-14 March. Huntly 1 ran for most of the week. Following the end of a partial outage on Wednesday, Huntly 4 came online. However, the unit then went on full outage on Friday at 3.00pm.

Figure 13: Thermal baseload generation, 8-14 March



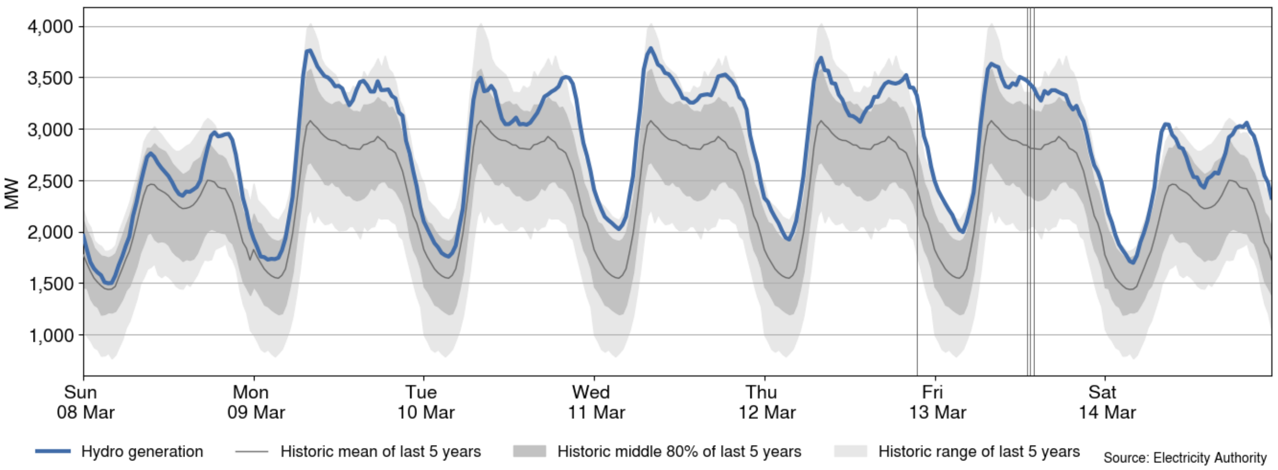
7.14. Figure 14 shows the generation of thermal peaker plants between 8-14 March. From Monday, Junction Road ran for most of the week with McKee running between Wednesday and Saturday. Additionally, Huntly 6 and Stratford peaker 1 both ran on Friday.

Figure 14: Thermal peaker generation, 8-14 March



7.15. Figure 15 shows hydro generation between 8-14 March. Hydro generation was above the historic mean for the entire week, reaching above the historic range at times between Thursday and Saturday and on Tuesday.

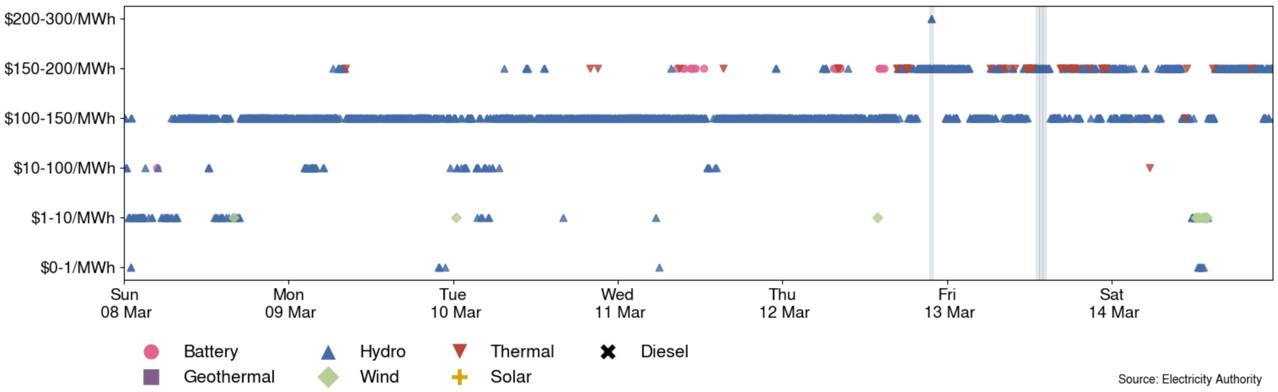
Figure 15: Hydro generation, 8-14 March



7.16. 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.

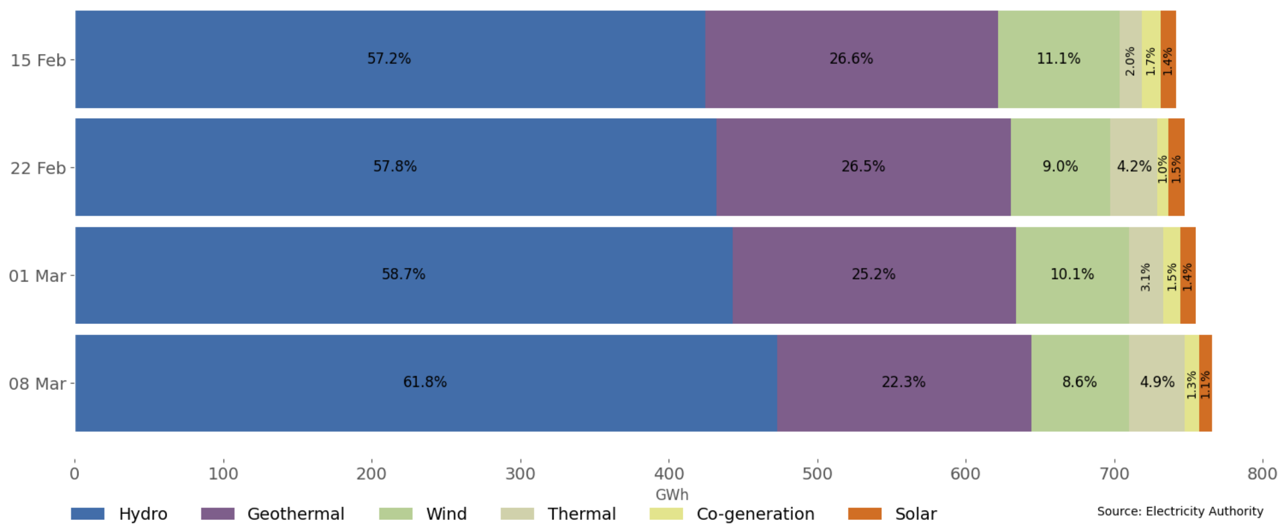
7.17. The highest prices this week were set by Mercury hydro on Thursday. The most common technology setting prices this week was hydro generation, with thermal generation the second most common. Most marginal prices were between $100-150/MWh.

Figure 16: Prices of marginal generation, 8-14 March



7.18. As a percentage of total generation, between 8-14 March, total weekly hydro generation was 61.8%, geothermal 22.3%, wind 8.6%, thermal 4.9%, co-generation 1.3%, and solar (grid connected) 1.1%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 15 February and 14 March



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 8-14 March ranged between ~1,492MW and ~2,256MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 8-14 March

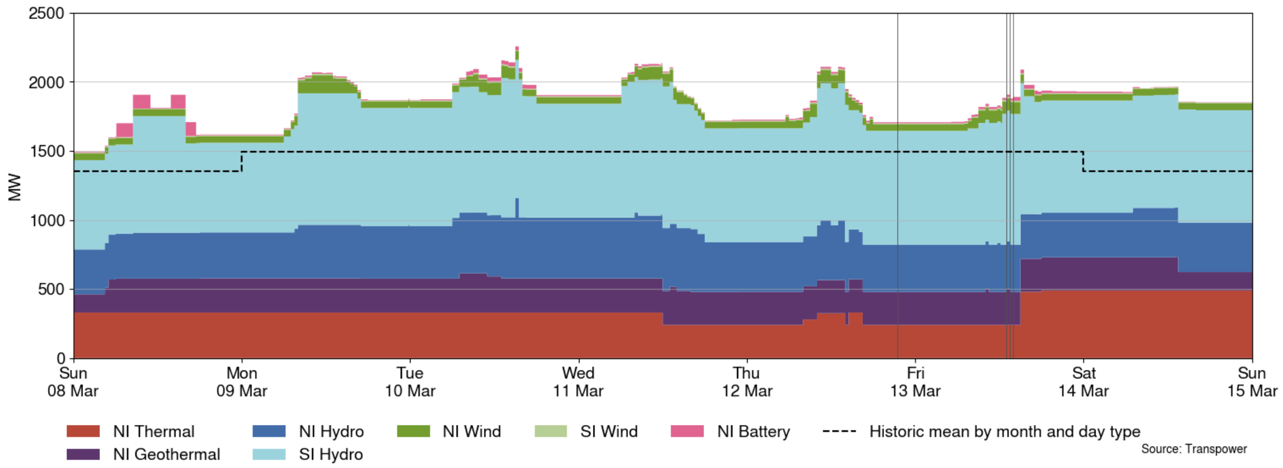
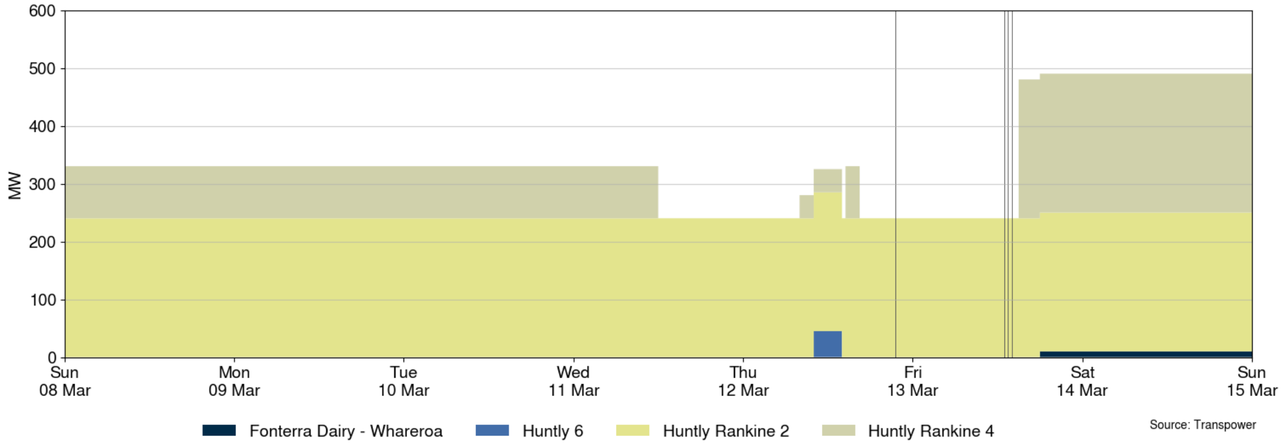


Figure 19: Total MW loss from thermal outages, 8-14 March



8.2. Notable outages include:

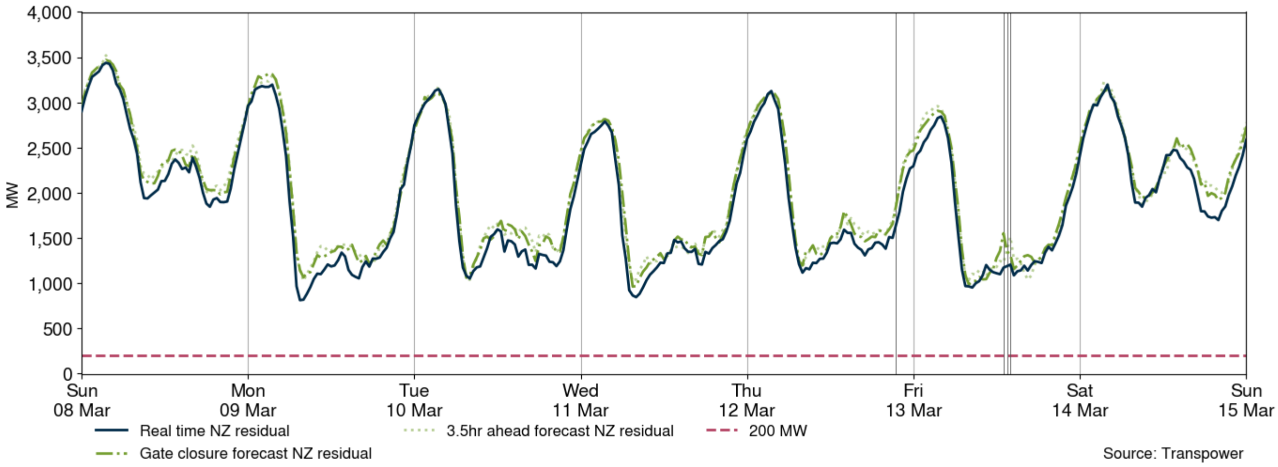
Plant	Partial or Full	End Date
Huntly 4	Partial	11 March 2026
Roxburgh unit 5	Full	13 March 2026
Benmore unit 6	Full	13 March 2026
Kawerau Station	Full	14 March 2026
Huntly 4	Full	18 March 2026
Rangipō unit 6	Full	29 March 2026
Benmore unit 5	Full	2 April 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 8-14 March. 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. Overall, residuals were healthy this week. The lowest national residual was 812MW on Monday at 7.30am.

Figure 20: National generation balance residuals, 8-14 March



10. Storage/fuel supply

10.1. 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.

10.2. As of 14 March, national controlled storage has decreased to 84% nominally full and ~105% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (88% full[2]) is below its historic 90th percentile but remains above mean, while Lake Takapō (78% full) is below its historic mean.

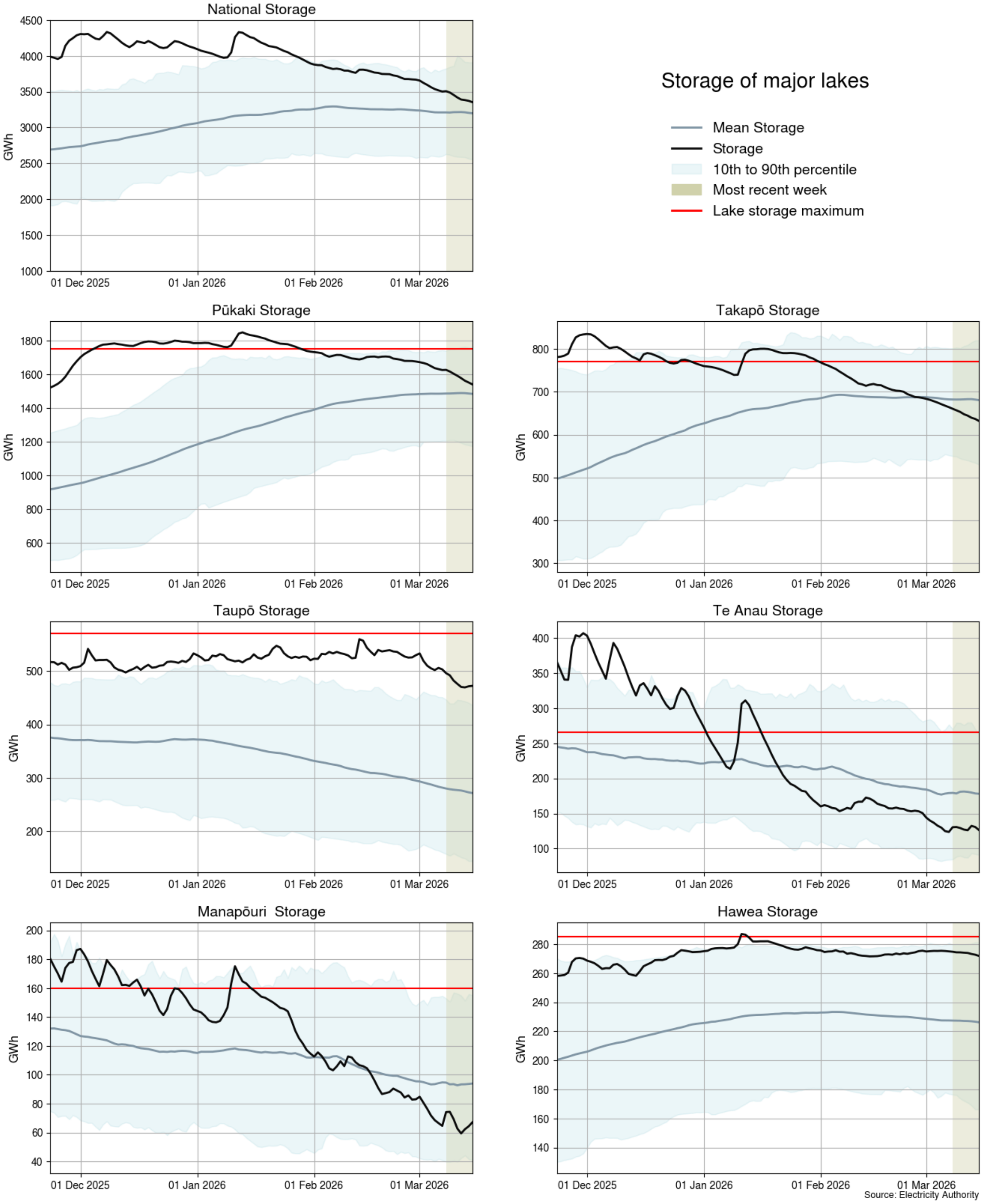
10.4. Storage at Lake Te Anau (48% full) is below its historic mean, with Lake Manapōuri (43% full) also below its historic mean.

10.5. Storage at Lake Taupō (82% full) remains above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (95% full) is close to its historic 90th percentile.

[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 March 2026. Coal prices were last updated on 1 February so previous prices have been carried forward. The SRMCs for all thermal-fuelled generation have increased.

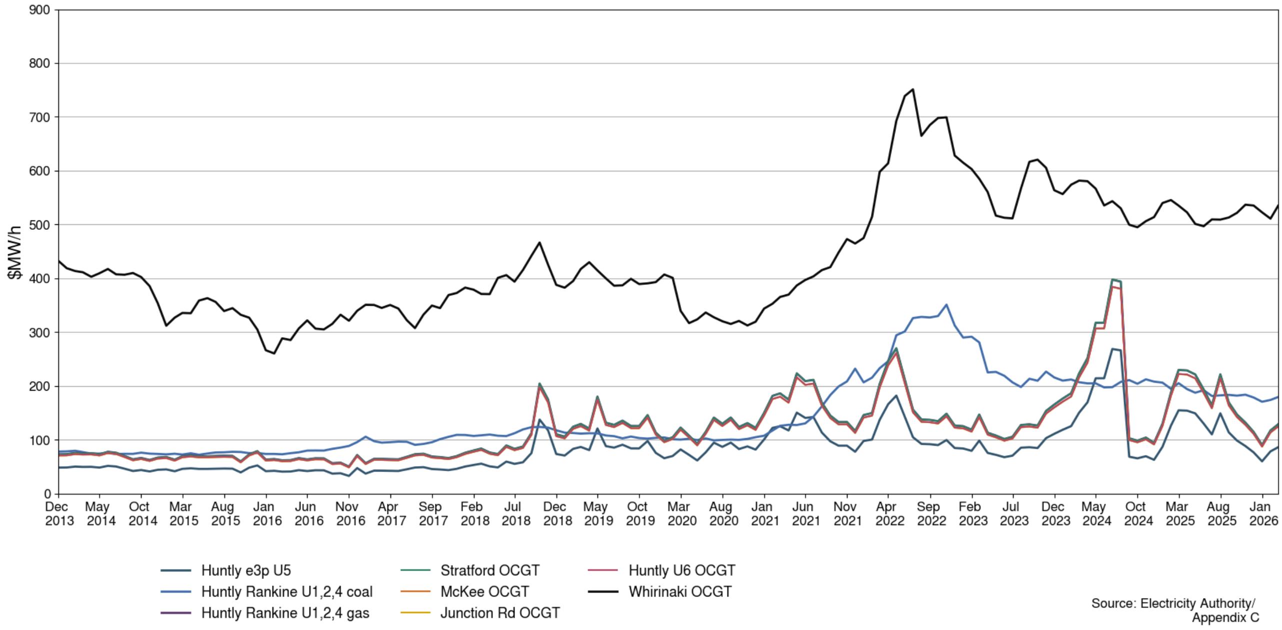
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$179/MWh. The cost of running the Rankines on gas is ~$128/MWh.

11.5. The SRMC of gas-fuelled thermal plants is currently between $86/MWh and $129/MWh.

11.6. The SRMC of Whirinaki is ~$535/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



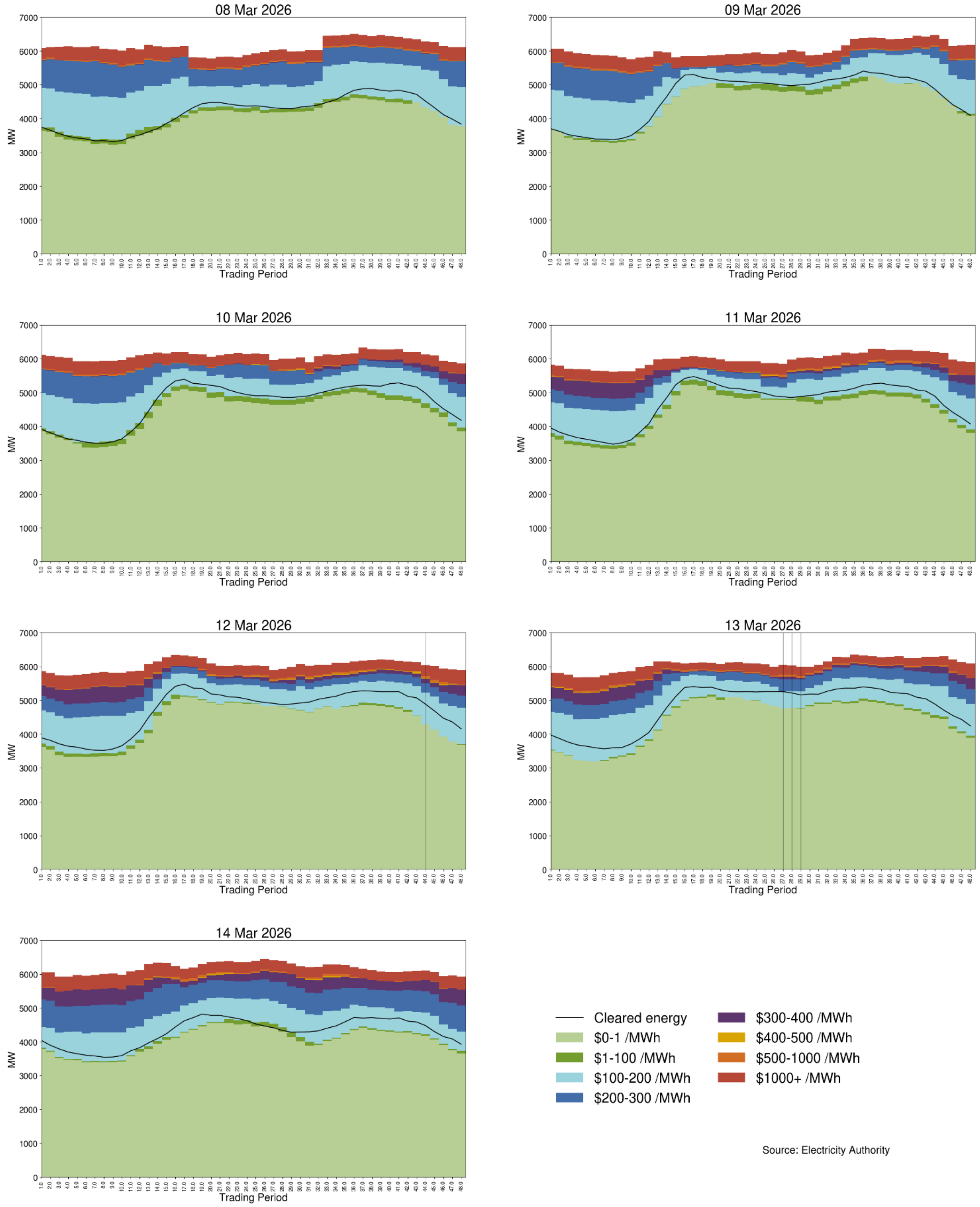
12. Offer behaviour

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 offers this week cleared below $200/MWh. Some energy cleared above $200/MWh on Friday during higher demand.

12.3. Offers decreased during the day on Sunday, in line with a full outage at Ōhau A. A portion of Mercury hydro offers were priced up into the $300-400/MWh range from Tuesday.

Figure 23: Daily offer stacks

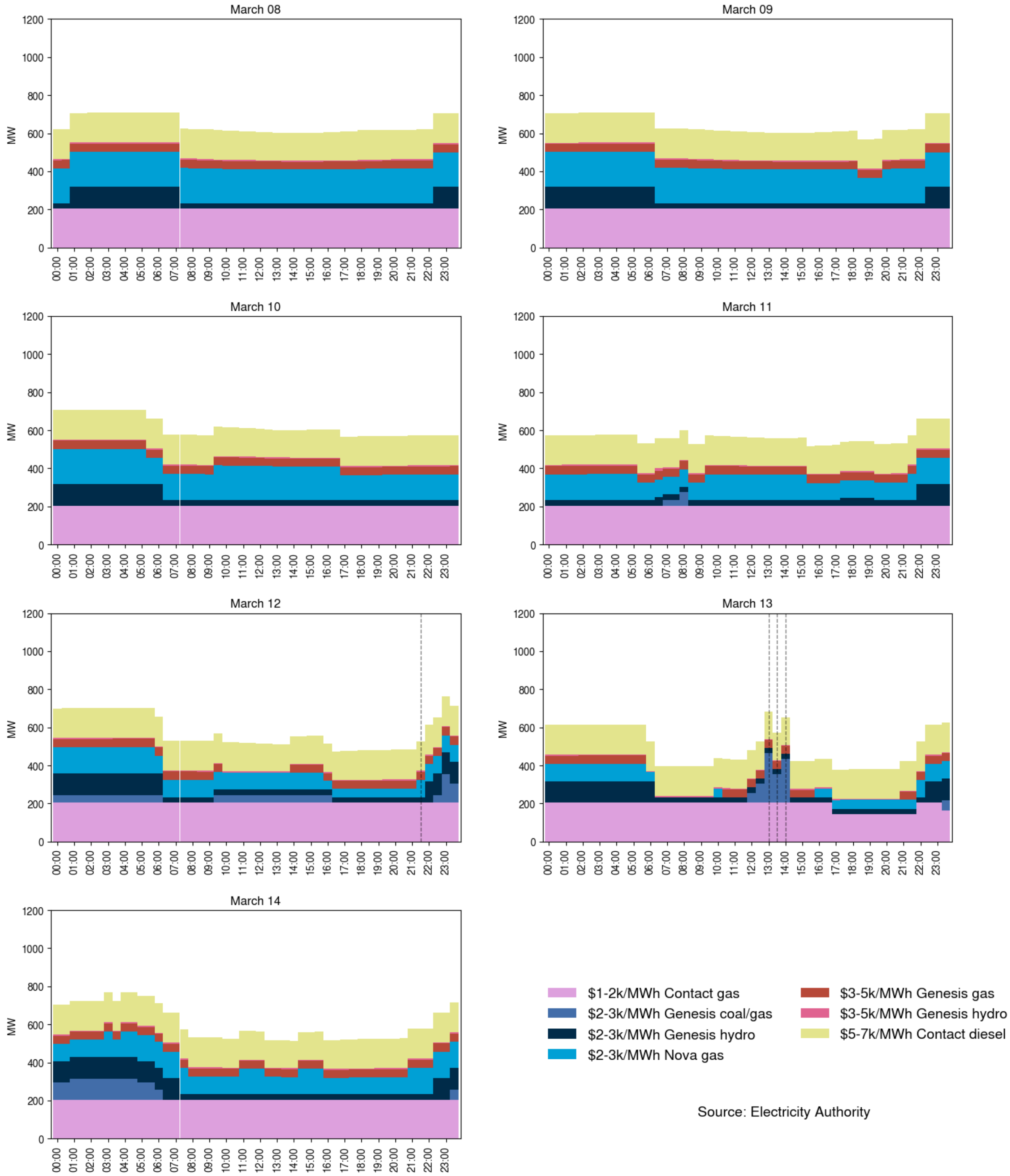


12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 592MW per trading period was priced above $1,000/MWh this week, which is roughly 11% of the total energy available.

Figure 24: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

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
04/02/2026-05/02/2026	Several	Further analysis	Contact/Manawa	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
13/03/2026	27-30	Further analysis	Contact	Clyde	Offers