9 February 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 1-7 February 2026

Market monitoring weekly report

Trading conduct report 1-7 February 2026

1. Overview

1.1. This week the average spot price increased by $14/MWh to $15/MWh, with prices mostly remaining below $50/MWh. Some price separation between the islands did occur during the week, with North Island prices reaching up to $250/MWh at times.

1.2. The proportion of hydro generation decreased slightly this week, while geothermal and wind generation increased slightly. Thermal generation remained low. National hydro storage decreased but remains high at 94% nominally full and ~115% of the historical average for this time of the 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 1-7 February:

(a) The average spot price for the week was $15/MWh, an increase of around $14/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $138/MWh.

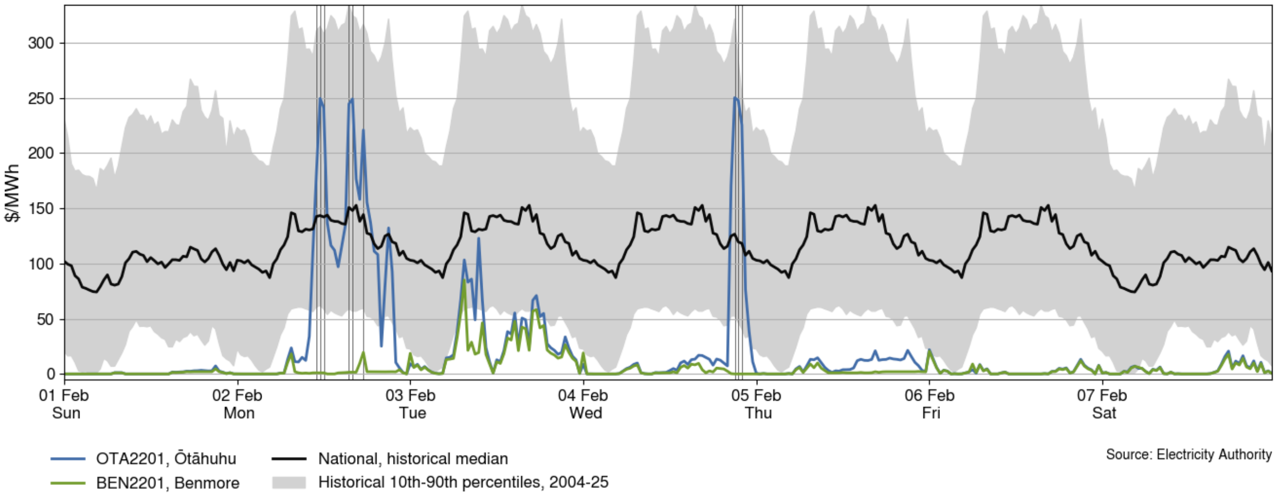
2.3. Price separation occurred between the two islands on Monday between 10.00am and 10.00pm, with Ōtāhuhu prices reaching up to $249/MWh. Meanwhile, Benmore prices mostly remained around $2/MWh. During this time, the HVDC was running close to its northward capacity and demand was higher than forecast throughout the day, up to 184MW.

2.4. On Tuesday, Ōtāhuhu prices reached up to $123/MWh and Benmore prices reached up to $85/MWh during the day. Demand and intermittent generation forecasting errors as well as a North Island reserve price spike contributed to higher prices during this time.

2.5. The highest price at Ōtāhuhu of the week was $250/MWh at 9:00pm on Wednesday, which occurred following the unplanned outage of HVDC Pole 3 at 8.30pm. During this time, Benmore prices remained at $0.01/MWh.

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.

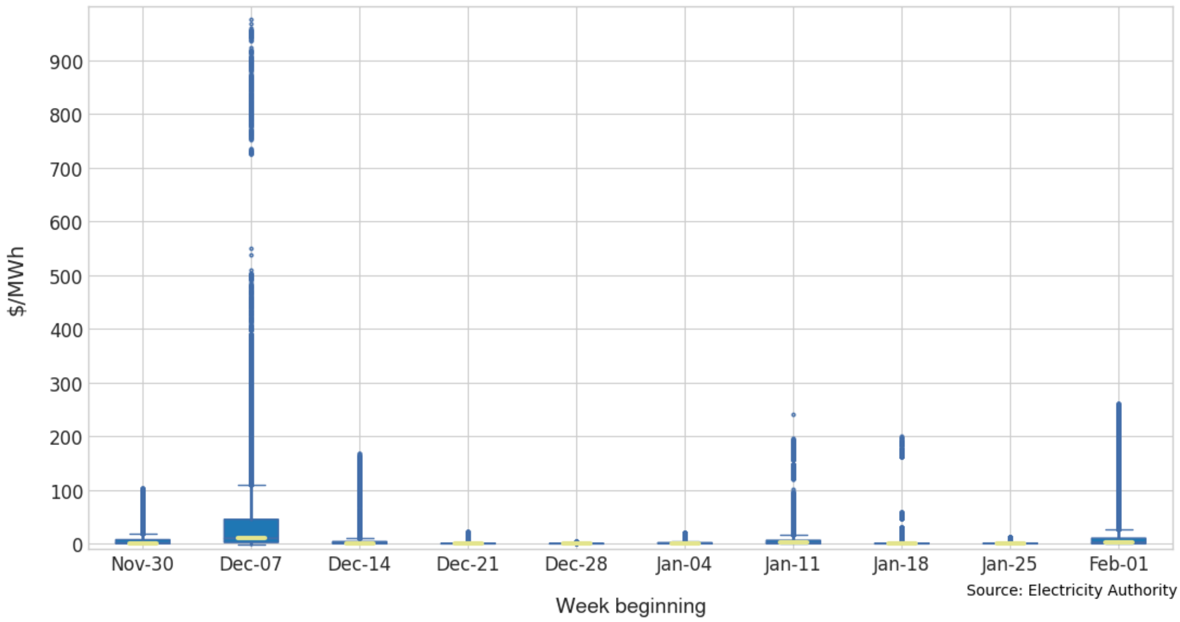
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 1-7 February



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 up.30per 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 $2/MWh and most prices (middle 50%) fell between $0.03/MWh and $11/MWh.

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

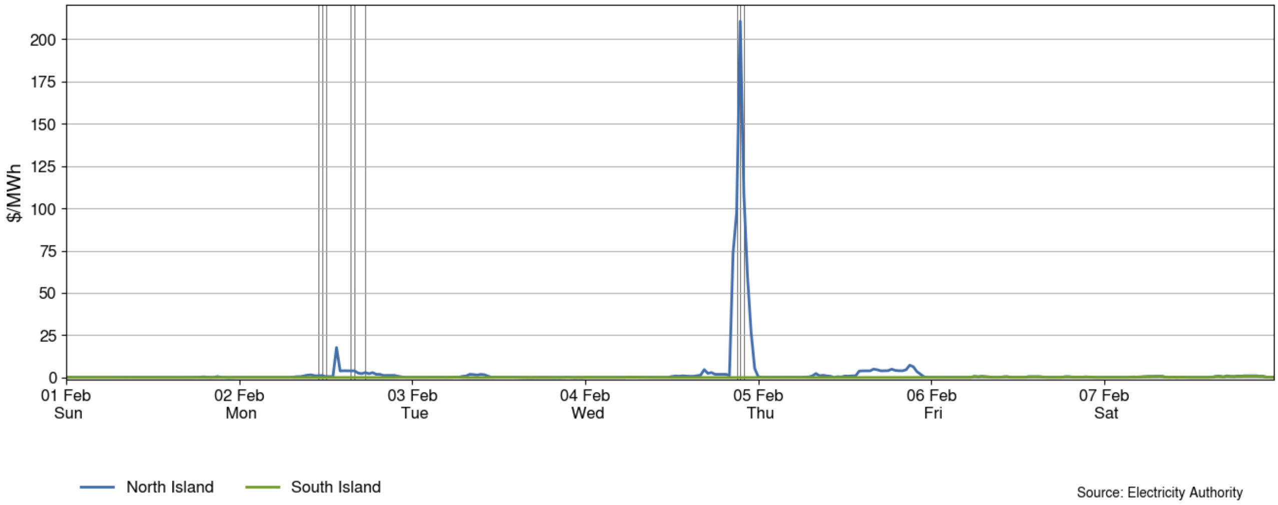


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices remained mostly below $7/MWh, aside from several high price spikes on Wednesday.

3.2. On Wednesday, North Island FIR prices spiked between 8.30pm and 11.00pm following the unplanned outage of HVDC Pole 3. The highest FIR price spike during this period was $211/MWh, which occurred at 9.30pm.

Figure 3: Fast instantaneous reserve price by trading period and island, 1-7 February

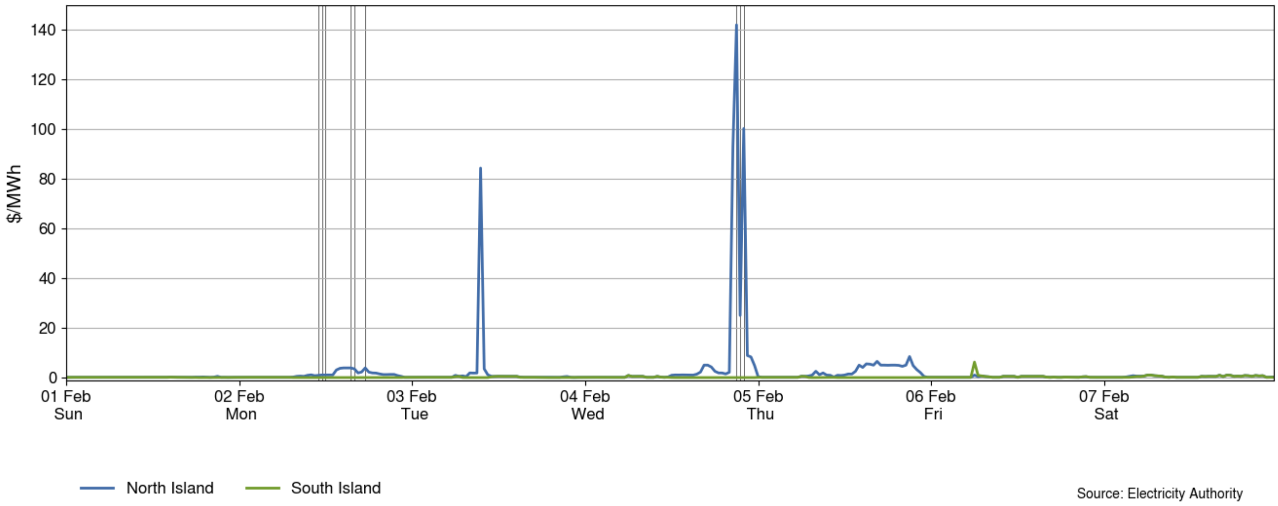


3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $8/MWh, aside from one price spike on Tuesday and several price spikes on Wednesday.

3.4. On Tuesday, North Island SIR prices spiked up to $84/MWh at 9.30am. The HVDC was setting the risk at this time.

3.5. North Island SIR prices also spiked between 8.30pm and 10.00pm following the unplanned outage of HVDC Pole 3. The highest SIR price spike during this period was $142/MWh, which occurred at 9.00pm.

Figure 4: Sustained instantaneous reserve by trading period and island, 1-7 February



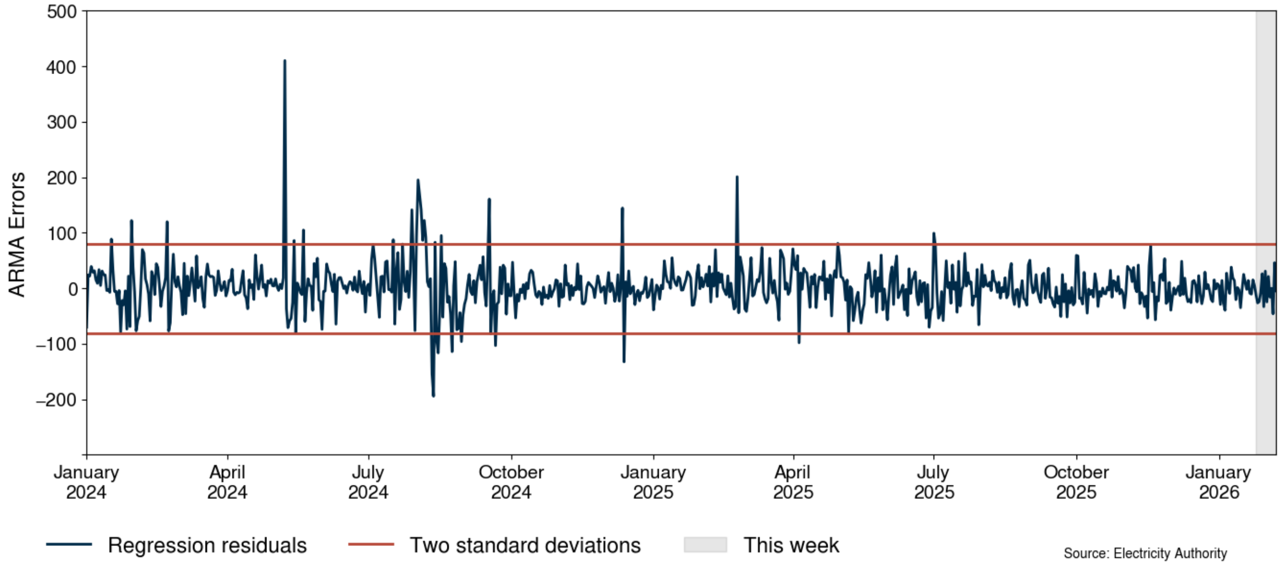
4. Regression residuals

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 - 7 February 2026



5. HVDC

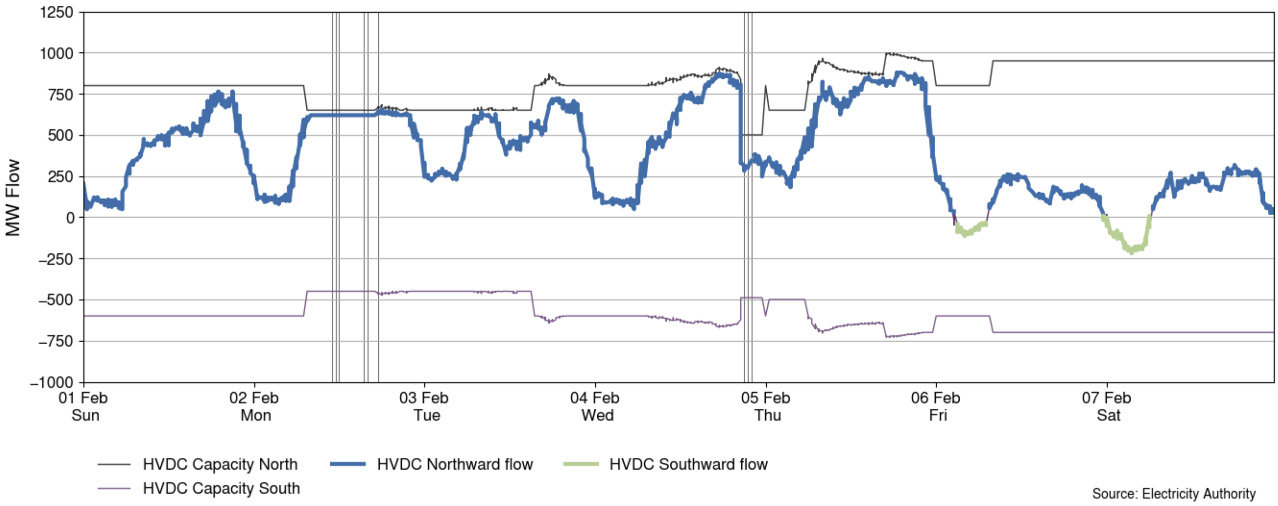
5.1. Figure 6 shows the HVDC flow between 1-7 February. HVDC flows were mostly northward this week.

5.2. Friday and Saturday saw lower northward HVDC transfer than other days alongside periods of southward flow overnight, due to lower demand and high wind generation. Northward HVDC flow reduced steeply following the unplanned outage of HVDC Pole 3 at 8.30pm on Wednesday.[1]

5.3. The highest northward flow occurred at 7.00pm on Thursday with a flow of around 880MW.

[1] CAN Unplanned Outage HVDC Pole 3 7099580146.pdf

Figure 6: HVDC flow and capacity, 1-7 February



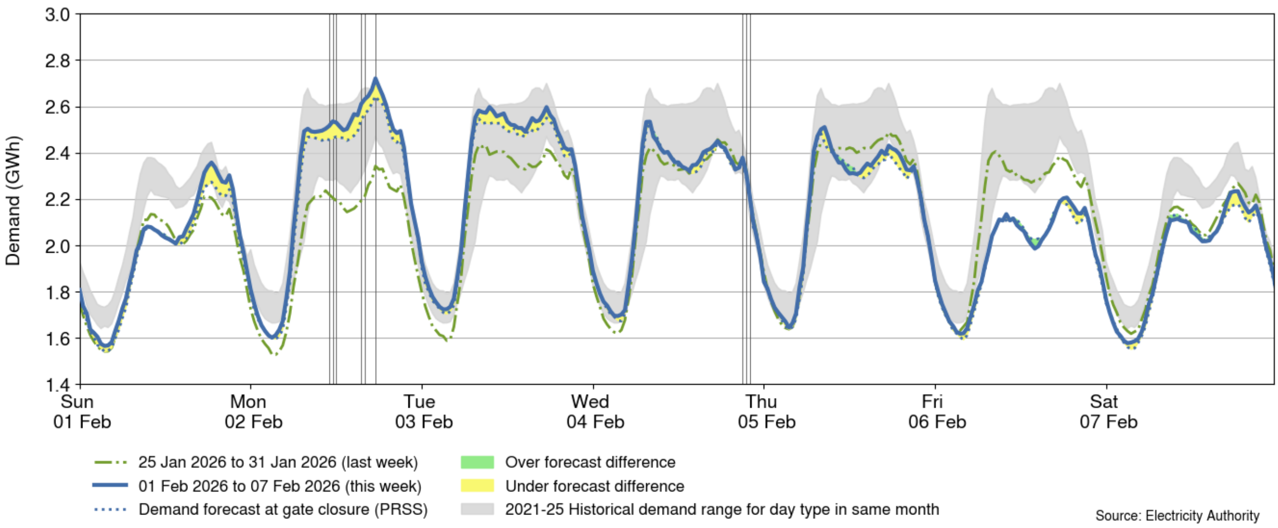
6. Demand

6.1. Figure 7 shows national demand between 1-7 February, compared to the historic range and the demand of the previous week.

6.2. Demand between Sunday evening and Tuesday was higher compared to the previous week. Higher temperatures on Monday likely partially contributed to this. Friday saw demand much lower than the previous week due to Waitangi Day.

6.3. The highest demand of the week was around 2.72GWh at 5.30pm on Monday.

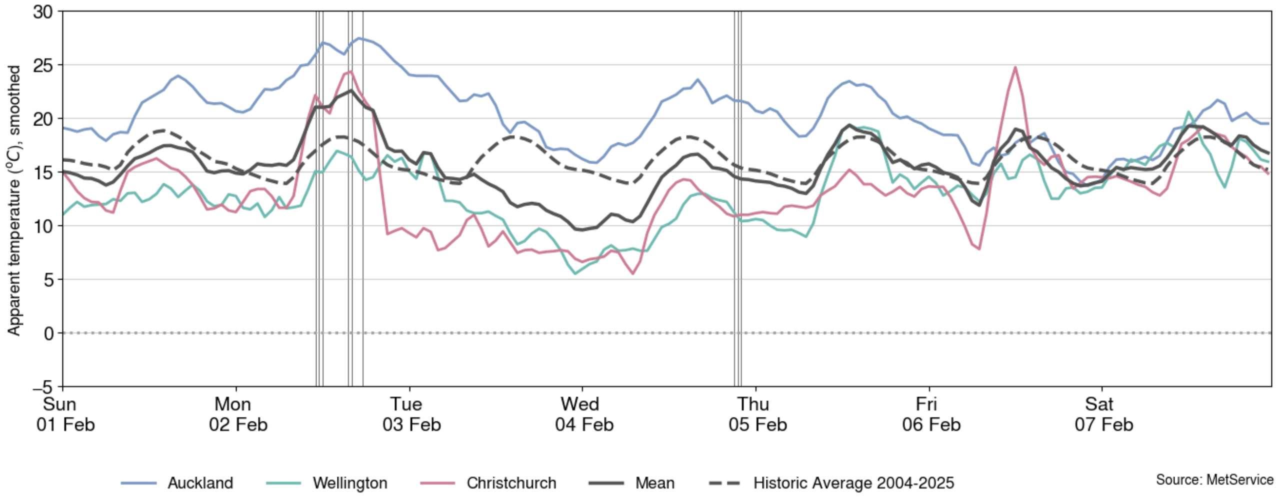
Figure 7: National demand, 1-7 February compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 1-7 February. 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 13°C to 28°C in Auckland, 5°C to 21°C in Wellington, and 5°C to 26°C in Christchurch. High temperatures in Auckland and Christchurch on Monday likely contributed to higher demand due to extra cooling.

Figure 8: Temperatures across main centres, 1-7 February



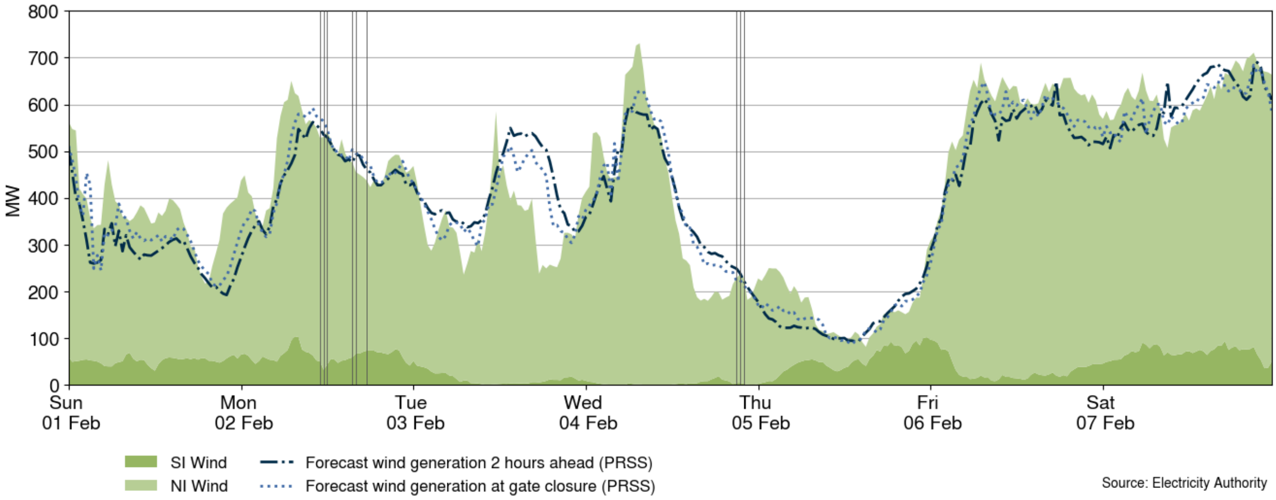
7. Generation

7.1. Figure 9 shows wind generation and forecast from 1-7 February. This week wind generation varied between 81MW and 731MW, with a weekly average of 422MW.

7.2. Wind generation was high at times between Monday and Wednesday, before declining on Thursday. Friday saw wind increase and remain high for the rest of the week.

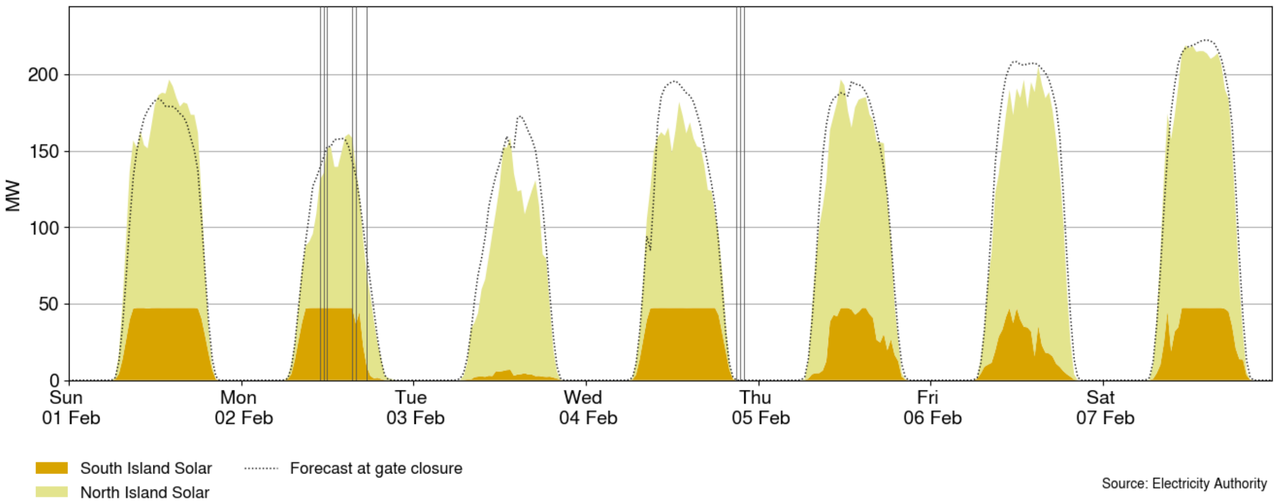
7.3. Wind forecasting errors on Tuesday and Wednesday were an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 1-7 February



7.4. Figure 10 shows grid connected solar generation from 1-7 February. Solar generation reached above 155MW daily, peaking on Saturday at 11.30am at around 219MW. This is a new maximum for solar generation across a single trading period.

Figure 10: Grid connected solar generation, 1-7 February

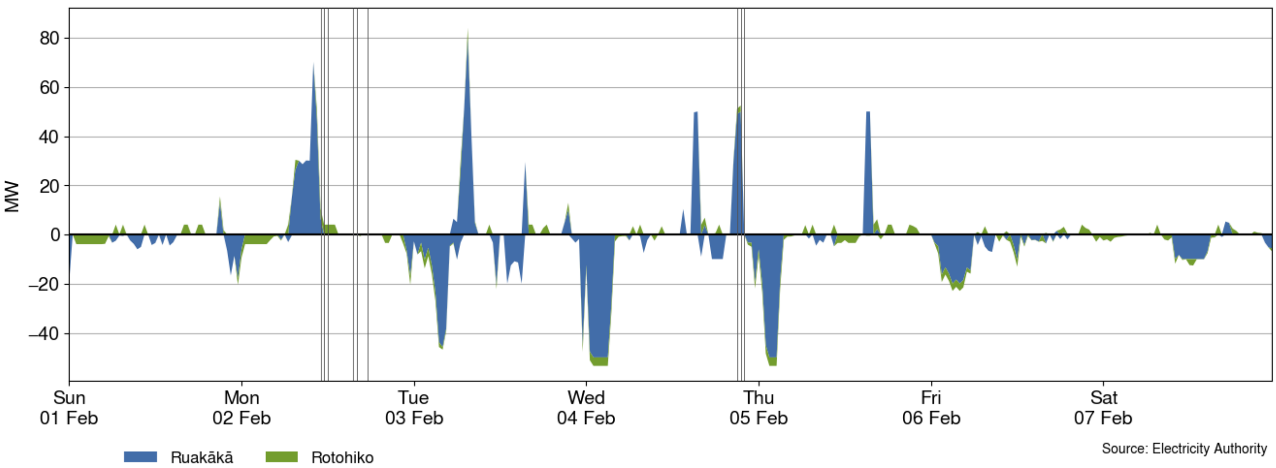


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.6. This week, the batteries mostly discharged during the day when prices were higher. On Monday, the Ruakākā battery had discharged throughout the morning so likely did not have energy available to discharge during high prices later that day. Both batteries were able to discharge during the HVDC trip period on Wednesday.

7.7. The batteries mostly charged overnight or during the day when prices were low. When daytime prices were lower on Sunday, Friday and Saturday, the batteries discharged less.

Figure 11: Grid scale battery charge and discharge, 1-7 February



7.8. Figure 12 shows the difference between the real-time dispatch (RTD) marginal price and a simulated marginal price for Ōtāhuhu and Benmore 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

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

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.

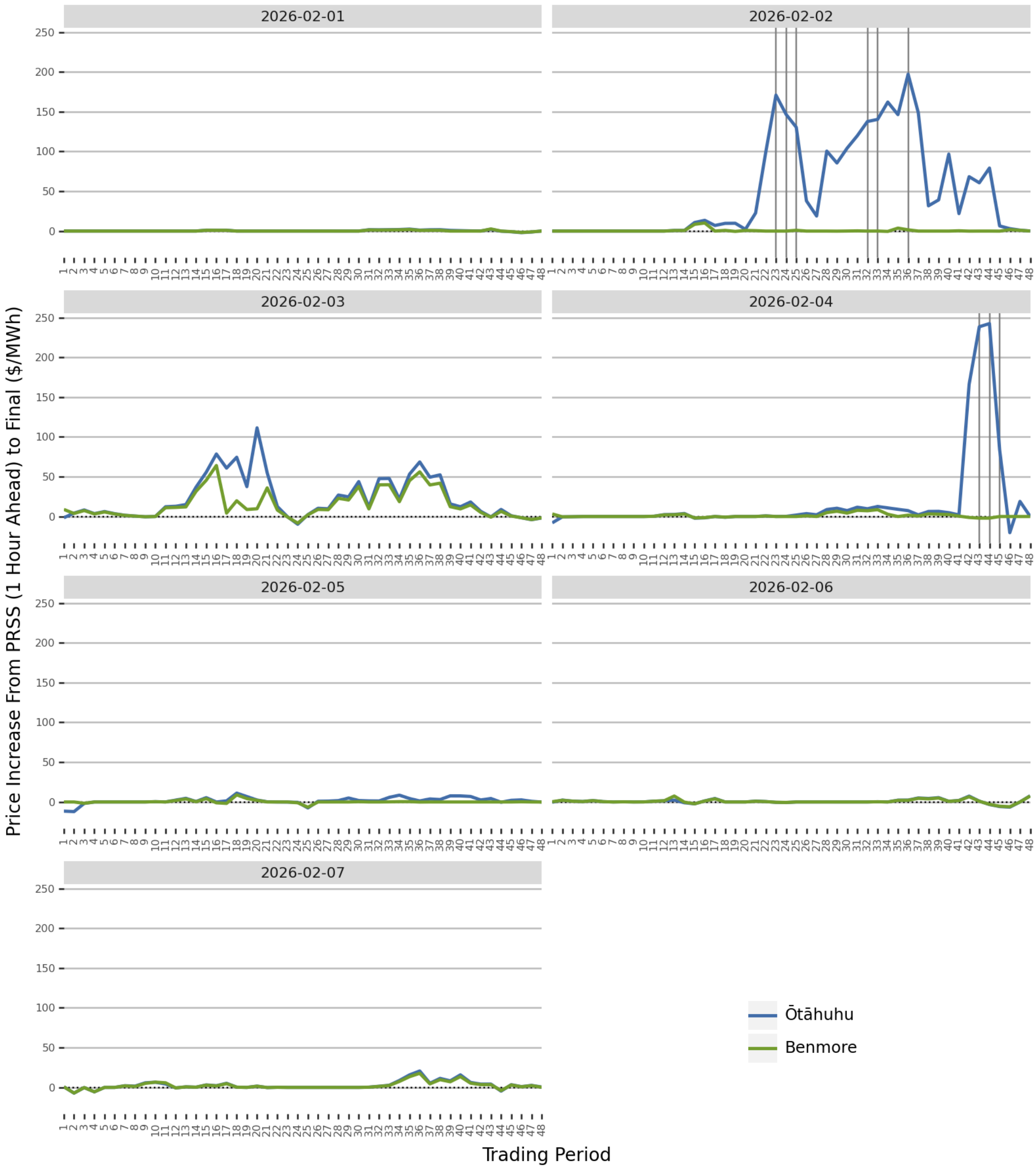
7.9. There were several trading periods with a positive marginal price difference above $50/MWh this week.

7.10. Monday saw positive differences up to $197/MWh for Ōtāhuhu, with demand forecasting errors up to 164MW and intermittent generation errors up to 48MW at times.

7.11. On Tuesday, positive differences above $50/MWh occurred for both Ōtāhuhu and Benmore at times. Demand was up to 70MW higher than forecast and intermittent generation up to 262MW lower than forecast during these times.

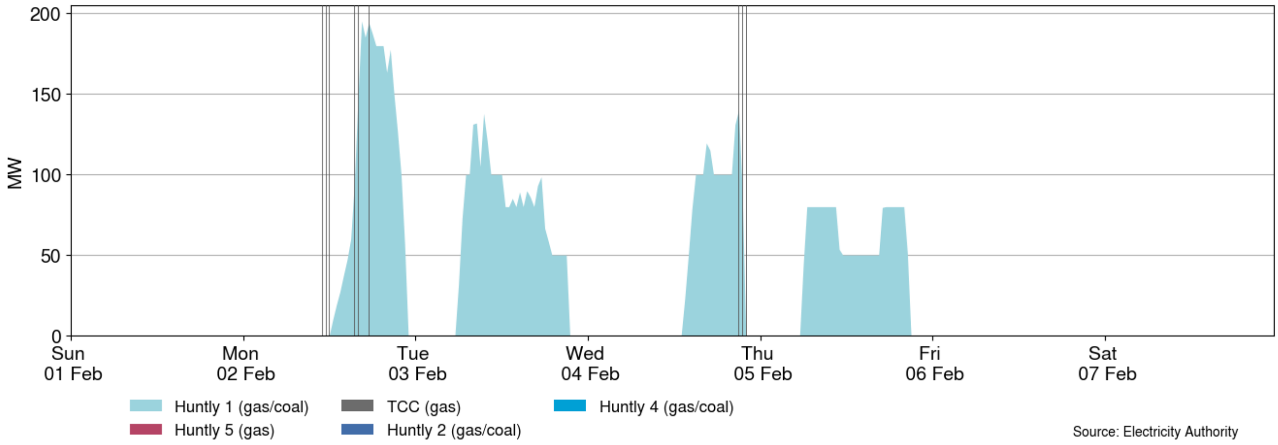
7.12. Positive Ōtāhuhu price differences above $50/MWh also occurred on Wednesday, up to $242/MWh, following the HVDC Pole 3 trip.

Figure 12: Difference between national marginal RTD price and simulated RTD price for Ōtāhuhu and Benmore, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 1-7 February



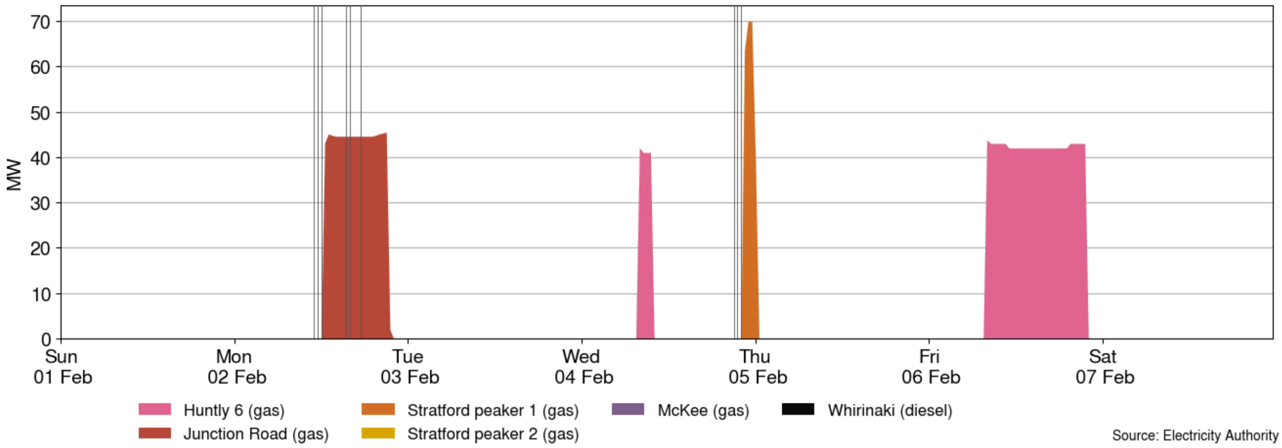
7.13. Figure 13 shows the generation of thermal baseload between 1-7 February. Huntly 1 ran each day from Monday until Thursday.

Figure 13: Thermal baseload generation, 1-7 February



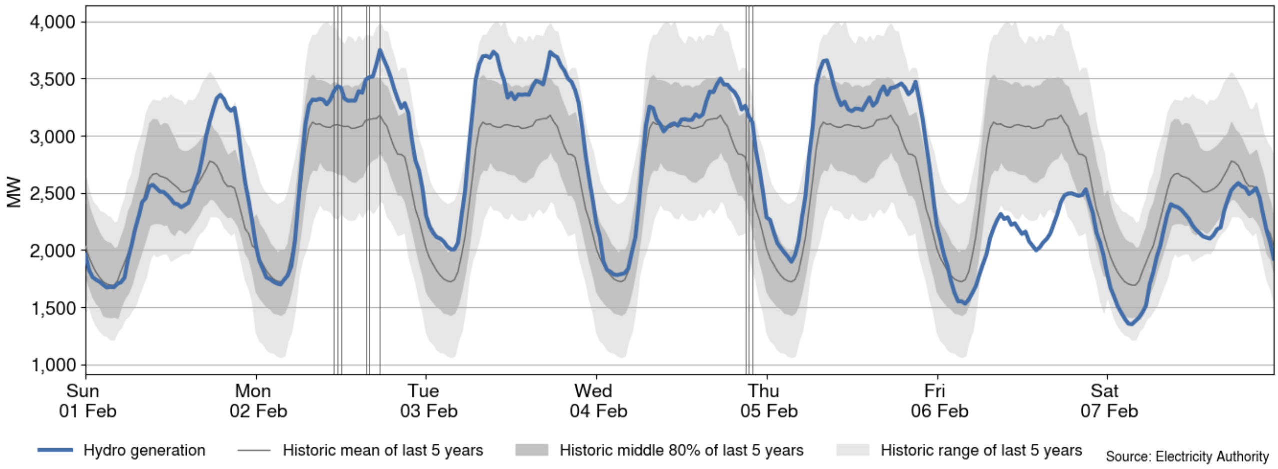
7.14. Figure 14 shows the generation of thermal peaker plants between 1-7 February. This week, Junction Road ran on Monday and Huntly 6 ran on Wednesday and Friday. Stratford peaker 1 ran on Wednesday evening following the HVDC Pole 3 outage.

Figure 14: Thermal peaker generation, 1-7 February



7.15. Figure 15 shows hydro generation between 1-7 February. Hydro generation was close to or higher than the historic mean between Sunday evening and Thursday. From Friday, hydro generation was mostly below the historic mean.

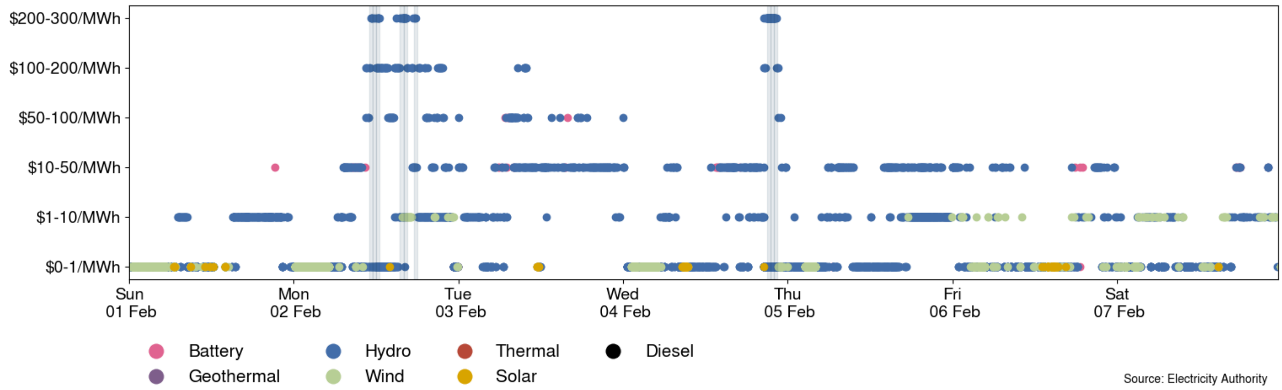
Figure 15: Hydro generation, 1-7 February



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.

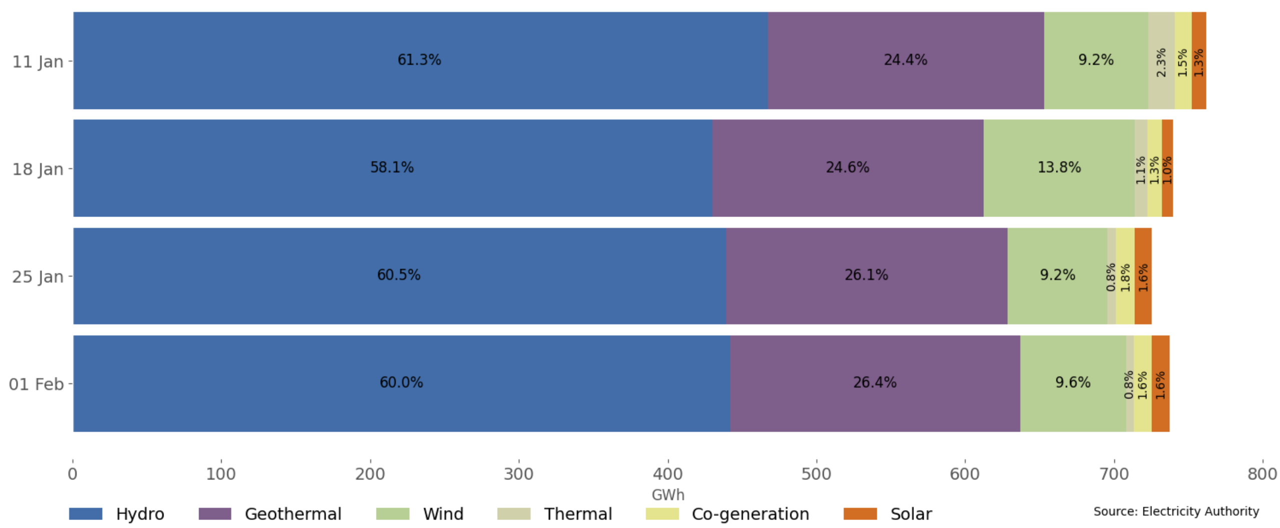
7.17. The highest prices this week were set by Mercury hydro and Huntly 1. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 1-7 February



7.18. As a percentage of total generation, between 1-7 February, total weekly hydro generation was 60.0%, geothermal 26.4%, wind 9.6%, thermal 0.8%, co-generation 1.6%, and solar (grid connected) 1.6%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 11 January and 7 February



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 1-7 February ranged between ~1,416MW and ~2,177MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 1-7 February

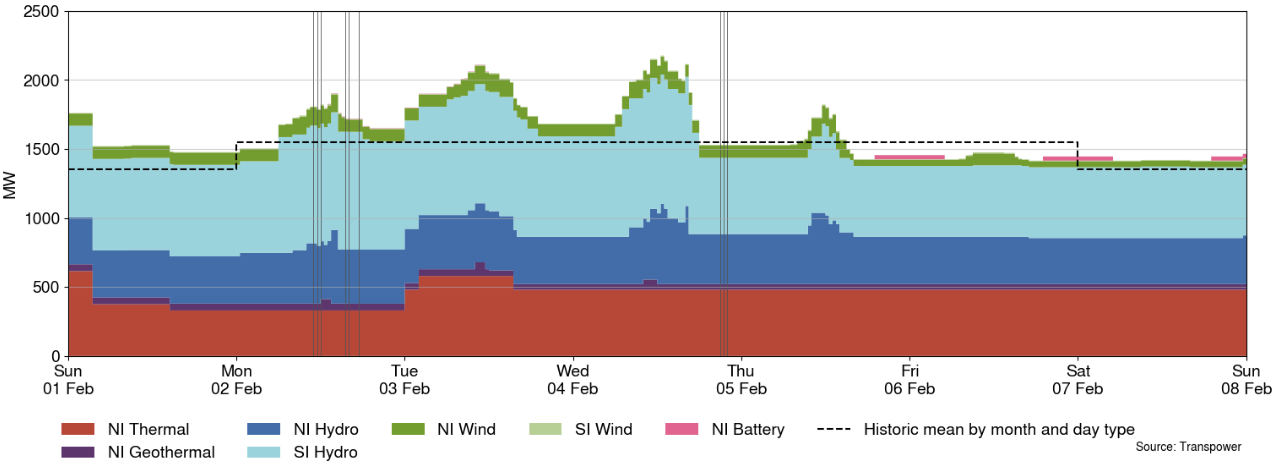
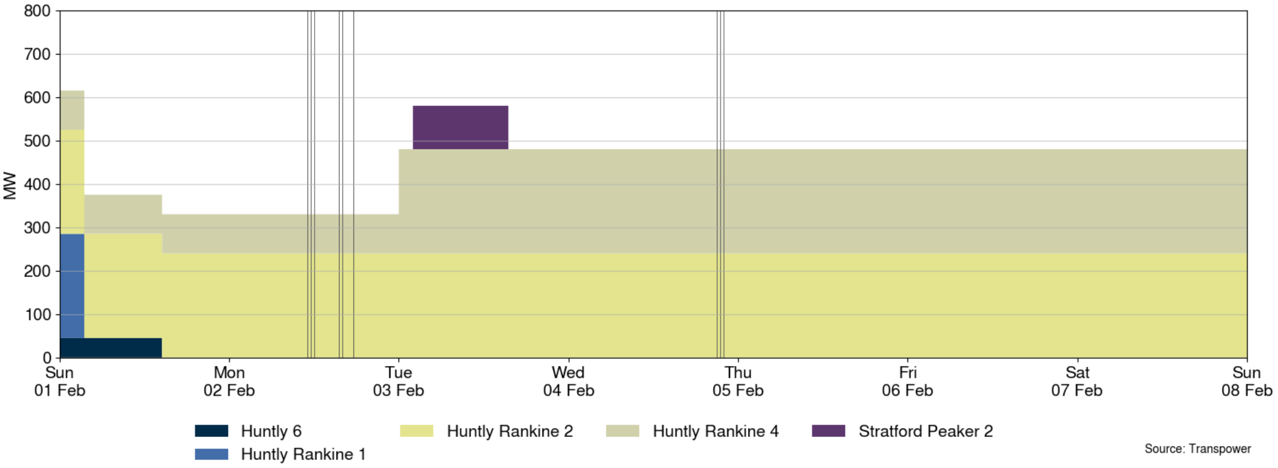


Figure 19: Total MW loss from thermal outages, 1-7 February



8.2. Notable outages include:

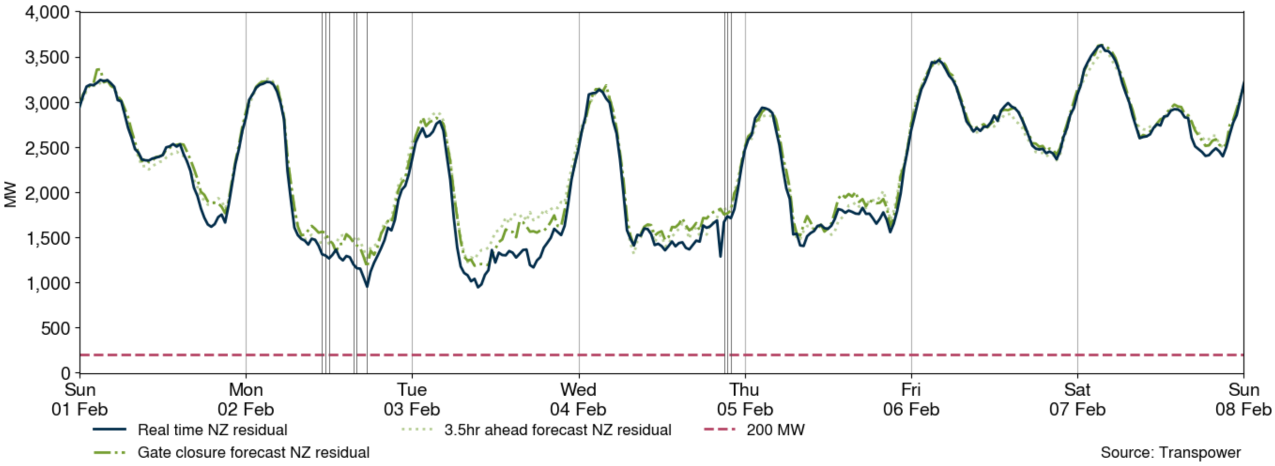
Plant	Partial or Full	End Date
Huntly 1	Full	1 February 2026
Huntly 4	Full	14 February 2026
Ōhau A	Partial	27 February 2026
Roxburgh unit 5	Full	26 February 2026
Rangipō unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 1-7 February. 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 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 953MW at 5.30pm on Monday.

Figure 20: National generation balance residuals, 1-7 February



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 7 February, national controlled storage decreased to 94% nominally full and ~115% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (98% full[3]) is now close to its historic 90th percentile, while Lake Takapō (95% full) is below its historic 90th percentile.

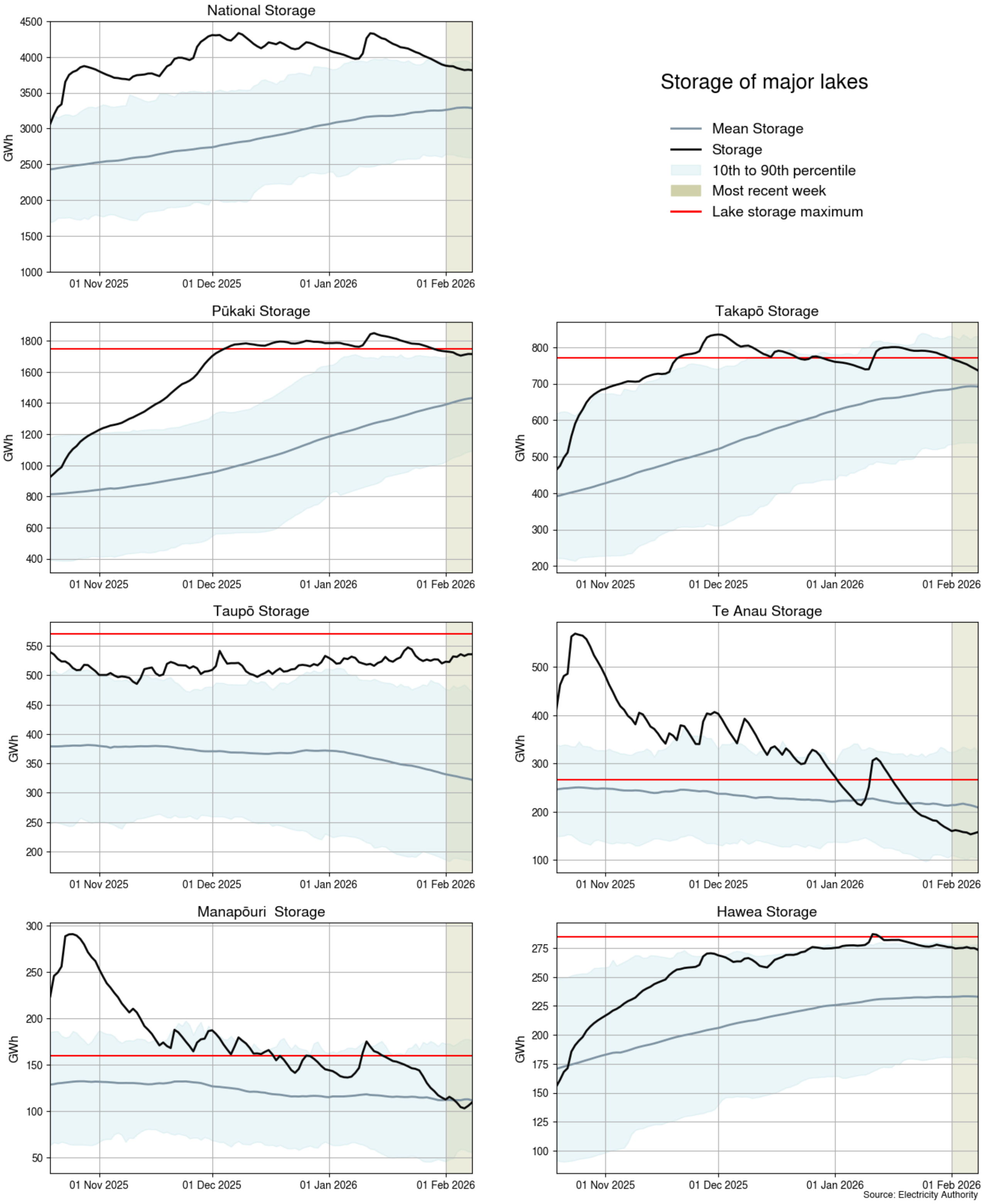
10.4. Storage at Lake Te Anau (60% full) is below its historic mean, with Lake Manapōuri (70% full) also now below its historic mean.

10.5. Storage at Lake Taupō (93% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (96% full) is close to its historic 90th percentile.

[3] 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 January 2026. The SRMCs for gas- and diesel-powered generation have decreased, while the SRMCs for coal-fuelled generation has remained stable.

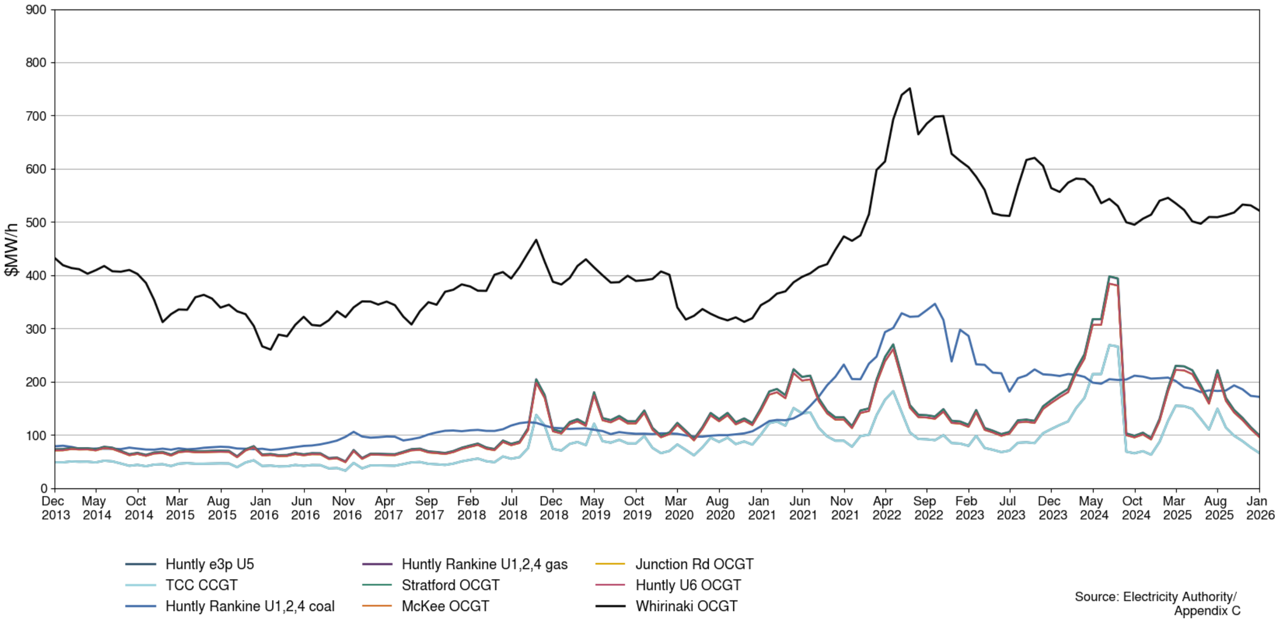
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$171/MWh. The cost of running the Rankines on gas is ~$99/MWh.

11.5. The SRMC of gas-fuelled thermal plants is currently between $66/MWh and $99/MWh.

11.6. The SRMC of Whirinaki is ~$521/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



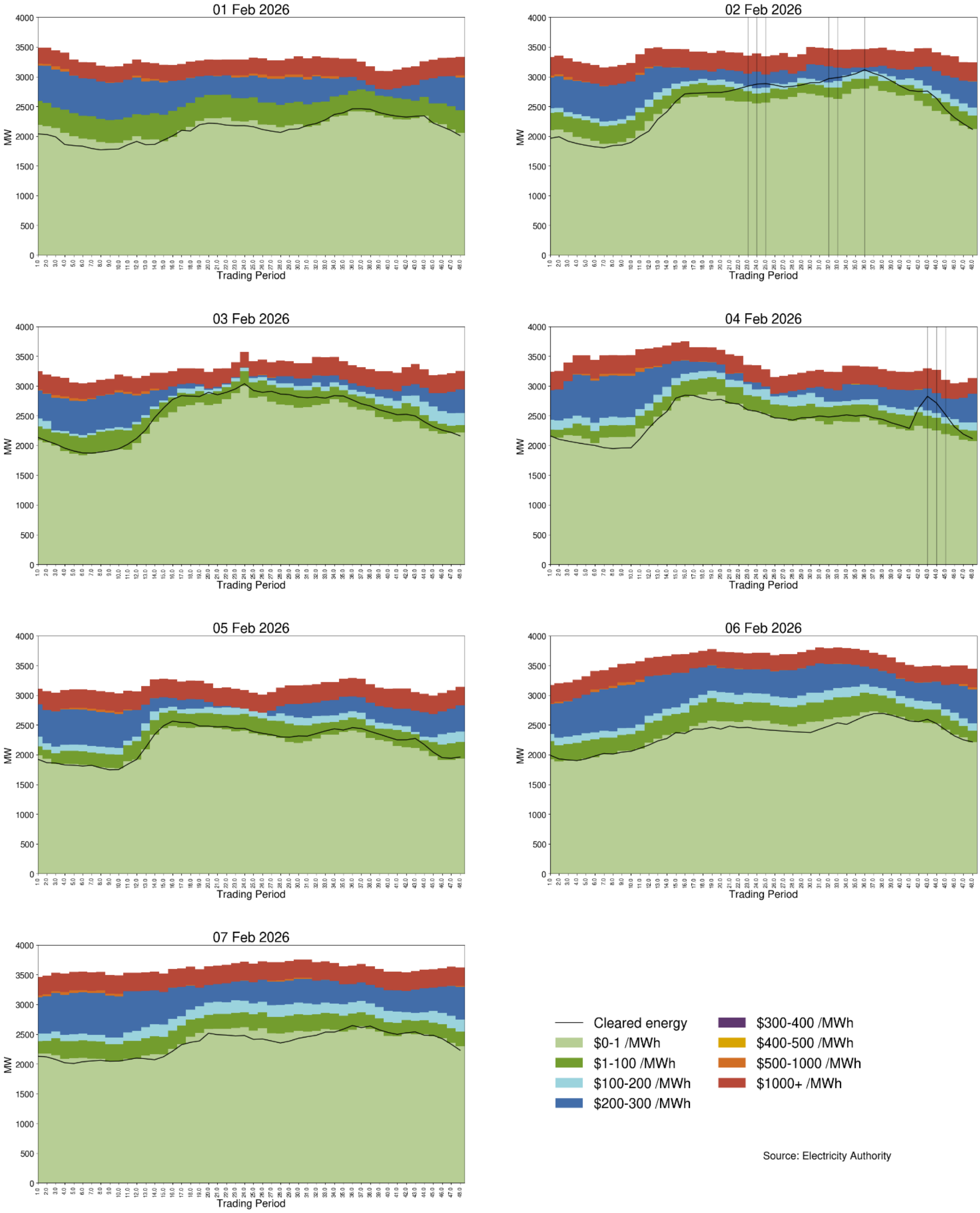
12. Offer behaviour

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. In the North Island most offers cleared below $100/MWh, except at times between Monday and Wednesday. On Monday and Wednesday, some energy cleared between $200-300/MWh, while on Tuesday some energy cleared between $100-200/MWh.

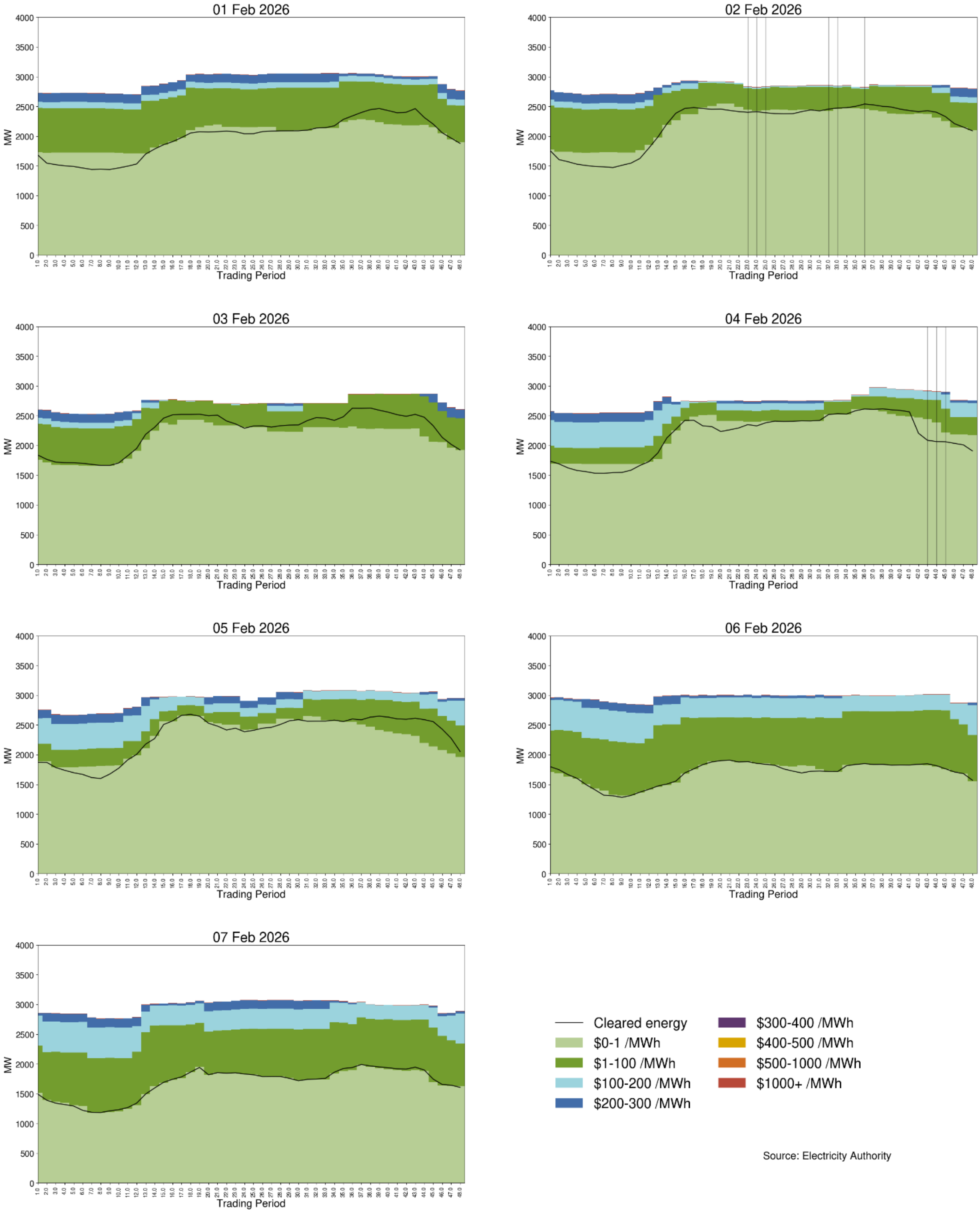
12.3. On Thursday morning, offers in the $200-300/MWh range reduced during a partial outage at Aratiatia.

Figure 23: Daily North Island offer stacks



12.4. In the South Island, all energy cleared below $100/MWh this week. Most energy on Sunday, Friday and Saturday cleared below $1/MWh.

Figure 24: Daily South Island offer stacks

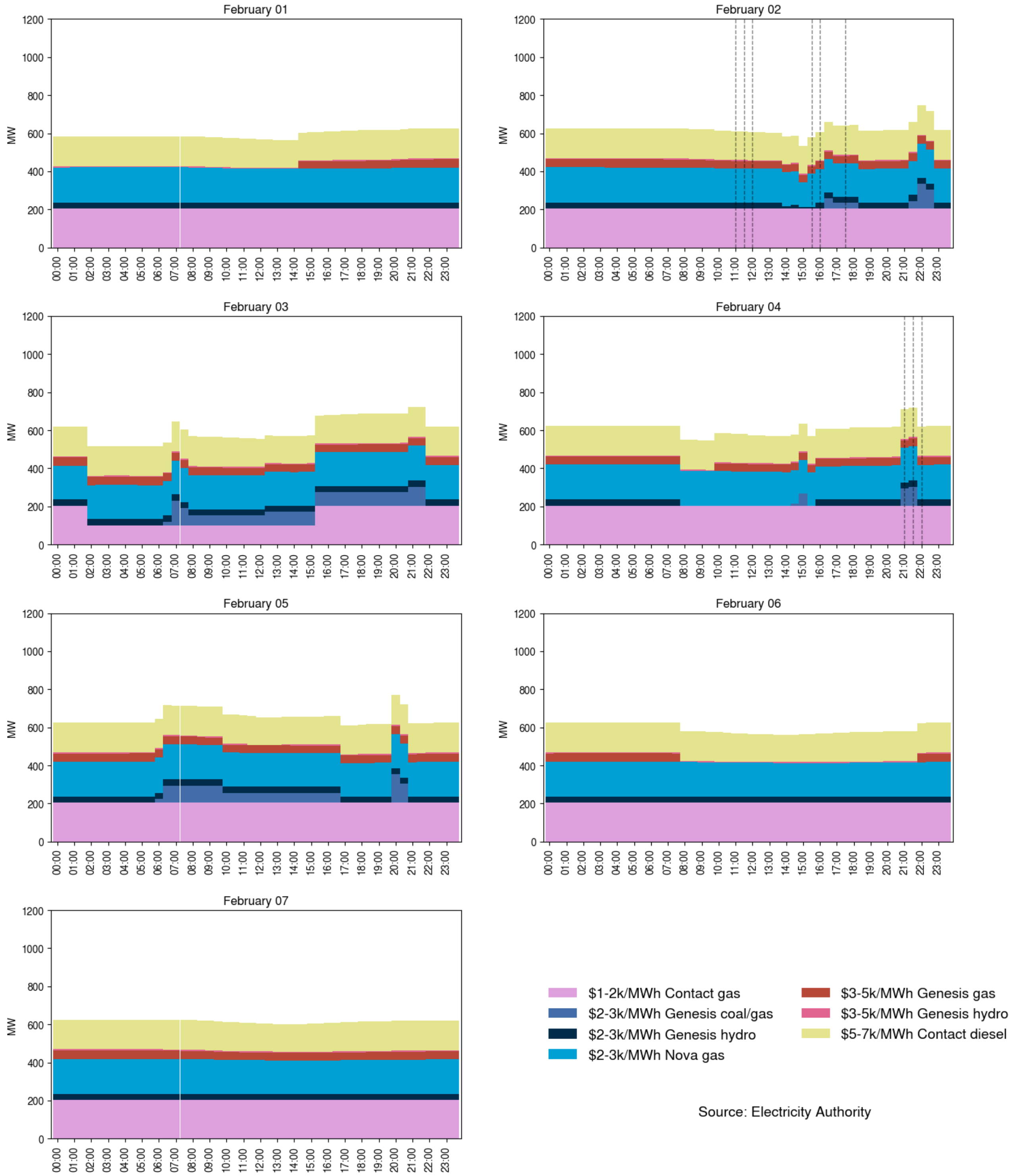


12.5. Figure 25 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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, wind 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 610MW per trading period was priced above $1,000/MWh this week, which is roughly 12% of the total energy available.

Figure 25: 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. We are contacting Genesis regarding Huntly 1 running on Monday 2 February and looking further into Matahina offers 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
12/01/2026-17/01/2026	Several	Further analysis	Mercury	Waikato	Offers
21/01/2026-24/01/2026	Several	Further analysis	Genesis	Waikaremoana	Offers
02/02/2026	Several	Further analysis	Genesis	Huntly	Generation
04/02/2026-05/02/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers