23 February 2026

Trading conduct report 15-21 February 2026

Market monitoring weekly report

Trading conduct report 15-21 February 2026

1. Overview

1.1. This week the average spot price decreased by $16/MWh to $39/MWh. Overall, higher wind generation and lower demand reduced prices this week compared to last week, but multiple HVDC outages this week saw several North Island price spikes above $150/MWh. The proportion of wind and geothermal generation increased this week, while the proportion of hydro generation fell. National controlled storage decreased slightly to 92% nominally full and ~113% 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 15-21 February:

(a) The average spot price for the week was $39/MWh, a decrease of around $16/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $116/MWh.

2.3. Prices are lower this week compared to last week, due to higher wind generation and lower demand. Several price spikes above $150/MWh did occur this week due to multiple HVDC outages.[1]

2.4. Ōtāhuhu prices separated at times on Monday and Tuesday, with a maximum price of $327/MWh occurring at 12.30pm on Monday. These price spikes were a result of North Island reserve price spikes during unplanned HVDC pole outages which limited reserve sharing. Additionally, demand was up to 125MW higher than forecast and intermittent generation up to 231MW lower than forecast during these price spikes.

2.5. Some Benmore price separation up to $70/MWh occurred at times overnight on Monday and Tuesday during the unplanned HVDC pole outages. These prices were related to South Island reserve price spikes.

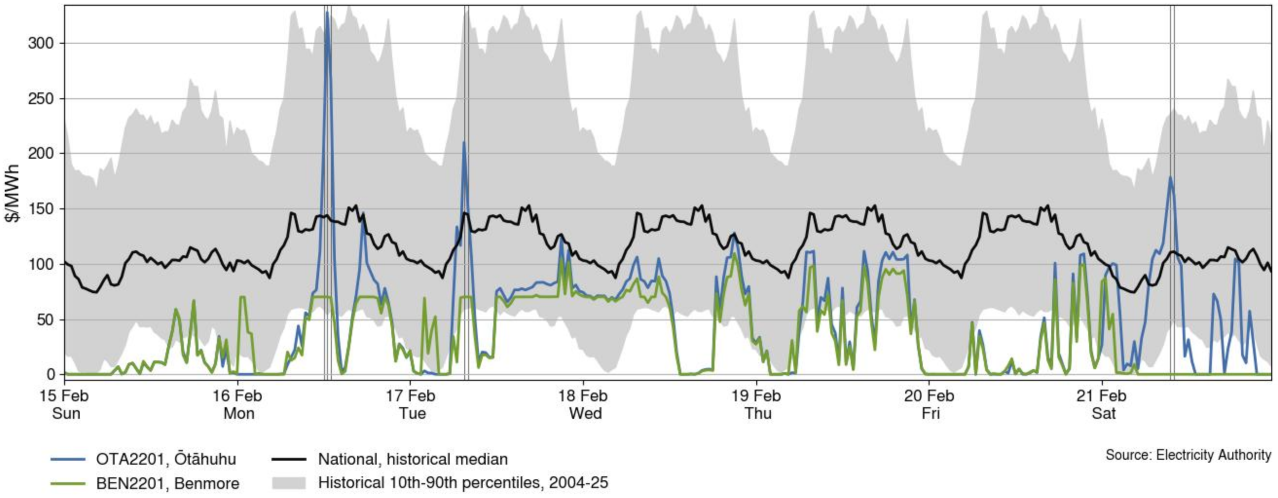
2.6. Ōtāhuhu prices also spiked above $150/MWh between 9.30am and 10.00am during the bi-pole HVDC outage on Saturday. Intermittent generation was between 128-142MW lower than forecast during these trading periods.

2.7. 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

[1] HVDC outages limit energy or reserve that can be shared between islands. This often leads to spikes in reserve prices, an increase in North Island thermal generation increasing North Island spot prices, and a decrease in South Island hydro with very low South Island spot prices.

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.

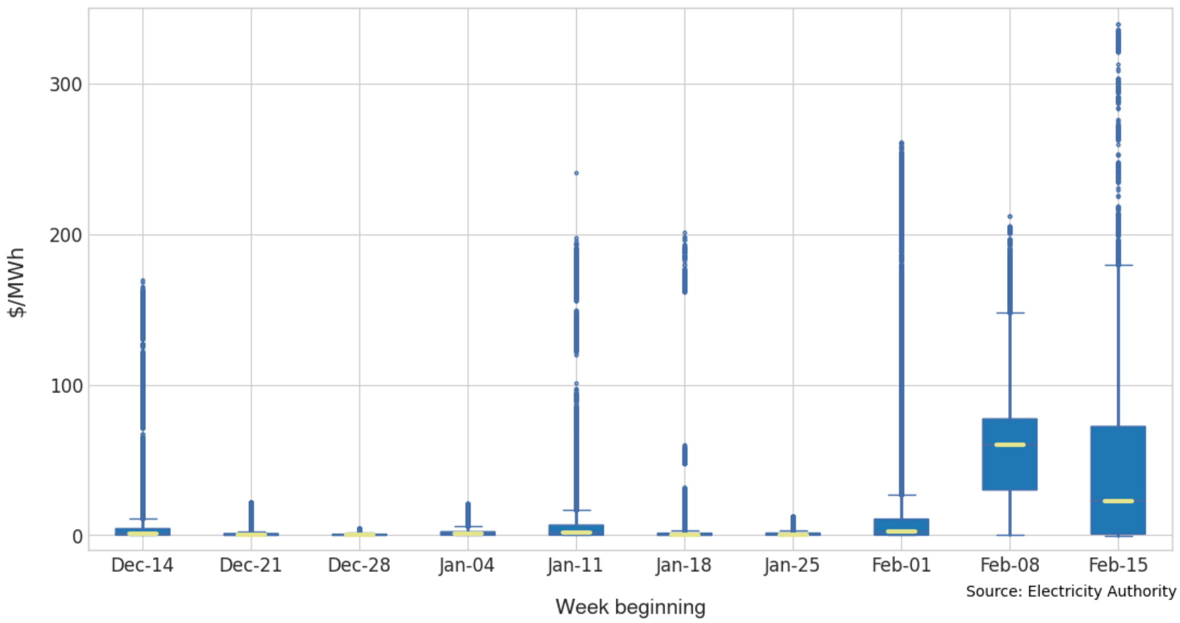
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 15-21 February



2.8. 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.

2.9. The distribution of spot prices this week was wider compared to last week. The median price was $23/MWh and most prices (middle 50%) fell between $0.71/MWh and $72/MWh.

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

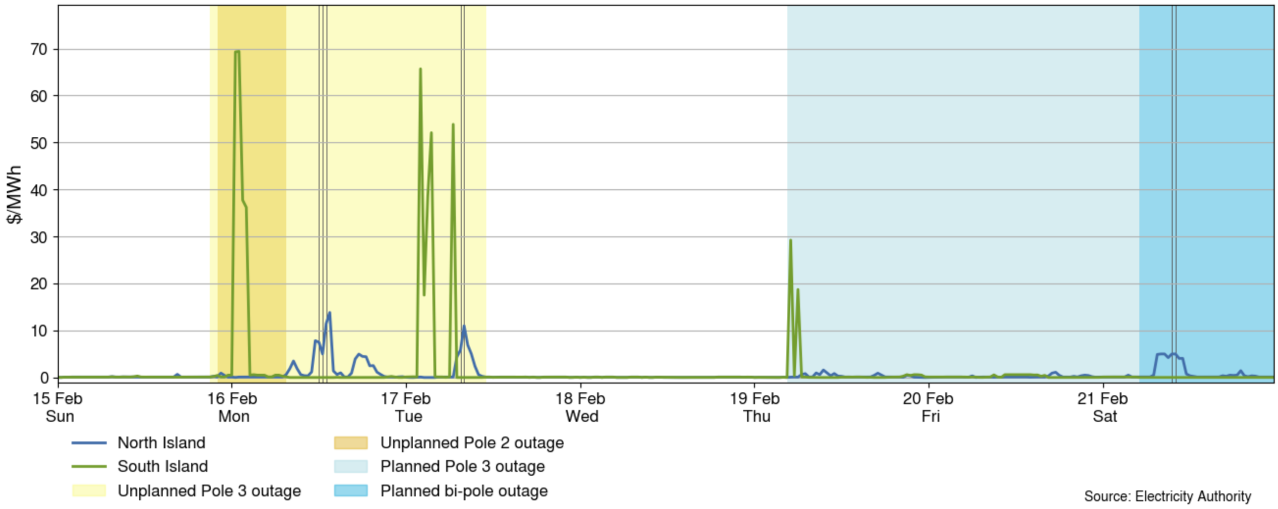


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $15/MWh, aside from some South Island price spikes on Monday, Tuesday, and Thursday.

3.2. South Island FIR prices spiked up to $69/MWh in the early morning on Monday and Tuesday. These price spikes occurred during southward HVDC flow while Pole 3 was on unplanned outage, meaning that reserve sharing from the North Island was limited at the time. Similar South Island FIR price spikes occurred on Thursday morning during the planned Pole 3 outage.

Figure 3: Fast instantaneous reserve price by trading period and island, 15-21 February

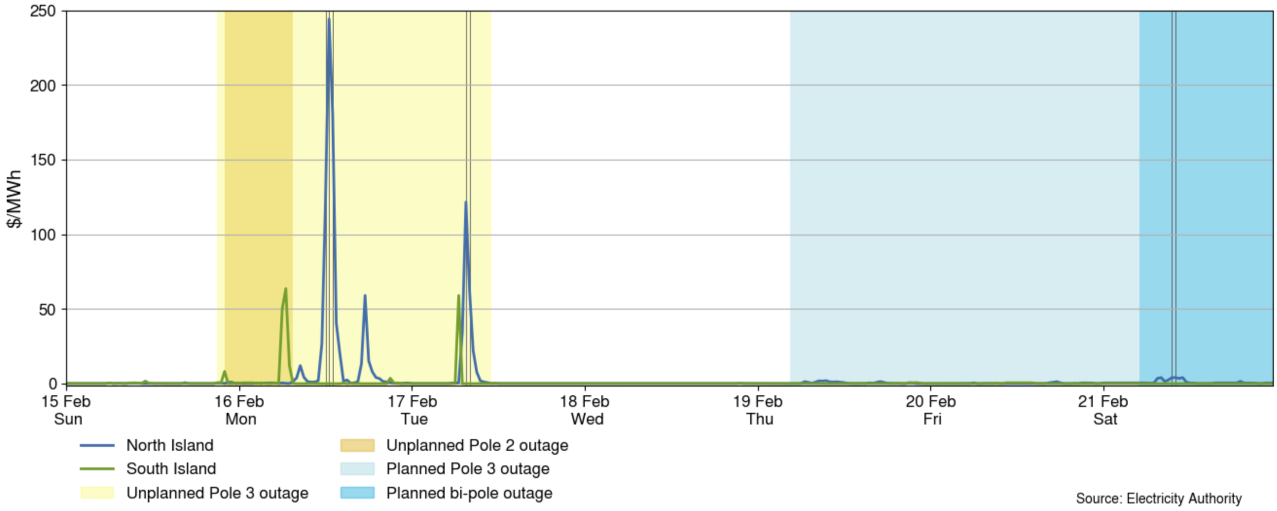


3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $25/MWh, aside from North Island and South Island price spikes on Monday and Tuesday.

3.4. North Island SIR prices spiked up to $244/MWh on Monday and Tuesday during northward HVDC flow during the unplanned HVDC Pole 3 outage which limited reserve sharing between the two islands.

3.5. Similarly, South Island SIR prices spiked up to $63/MWh at 6.00-6.30am on Monday and Tuesday at 6.30am during southward HVDC flow.

Figure 4: Sustained instantaneous reserve by trading period and island, 15-21 February



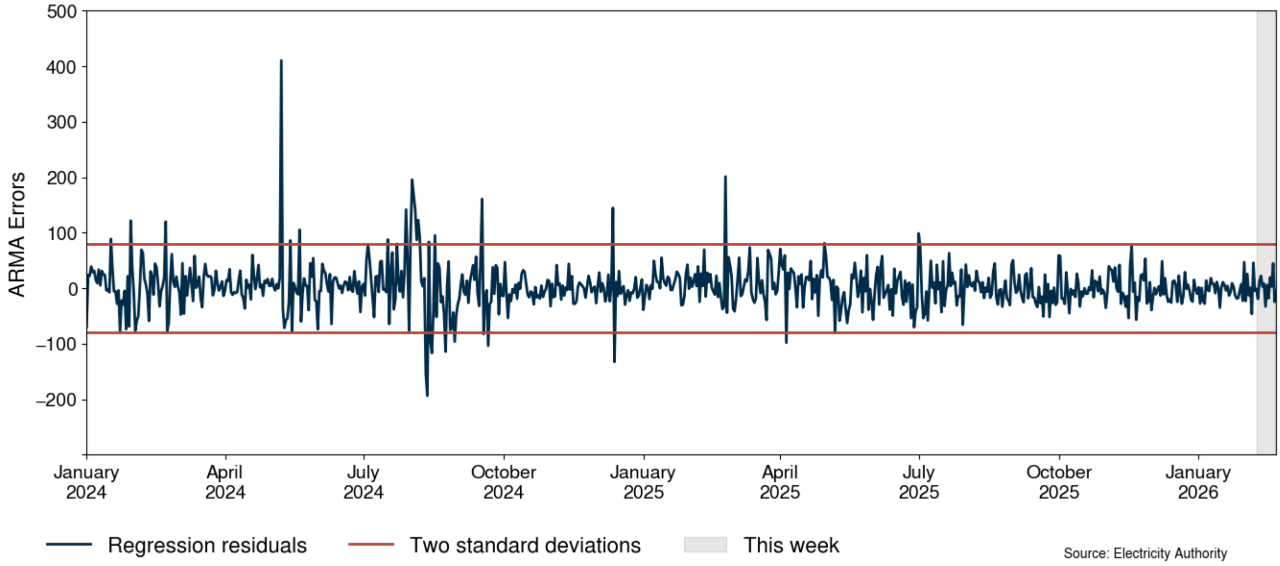
4. Regression residuals

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 - 21 February 2026



Source: Electricity Authority

5. HVDC

5.1. Figure 6 shows the HVDC flow between 15-21 February. This week saw mostly northward HVDC flows during the day and mostly southward overnight, with the HVDC experiencing several outages this week.

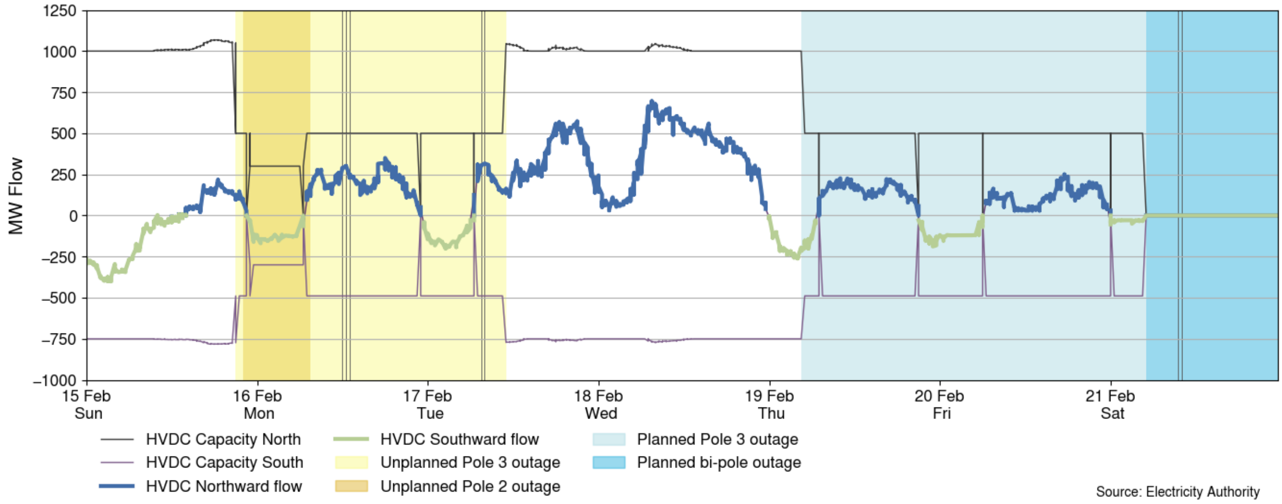
5.2. During stormy conditions this week, an unplanned Pole 3 outage[2] occurred on Monday at 9.07pm, lasting through until 11.00am Tuesday. HVDC Pole 2 also tripped[3] during this period and operated at reduced capacity until 7.30am Monday.

5.3. From Thursday at 5.00am, the planned outage of Pole 3 began, with the planned bi-pole outage commencing from 5.00am on Saturday.[4]

5.4. The highest northward flow occurred at 7.30am on Wednesday with a flow of 695MW.

[2] CAN Unplanned Outage HVDC Pole 3 7142036618.pdf
[3] CAN HVDC Pole 2 Reduced Capability 7137392383.pdf
[4] CAN Planned Outage HVDC Pole 2, HVDC Pole 3 7160636766.pdf

Figure 6: HVDC flow and capacity, 15-21 February

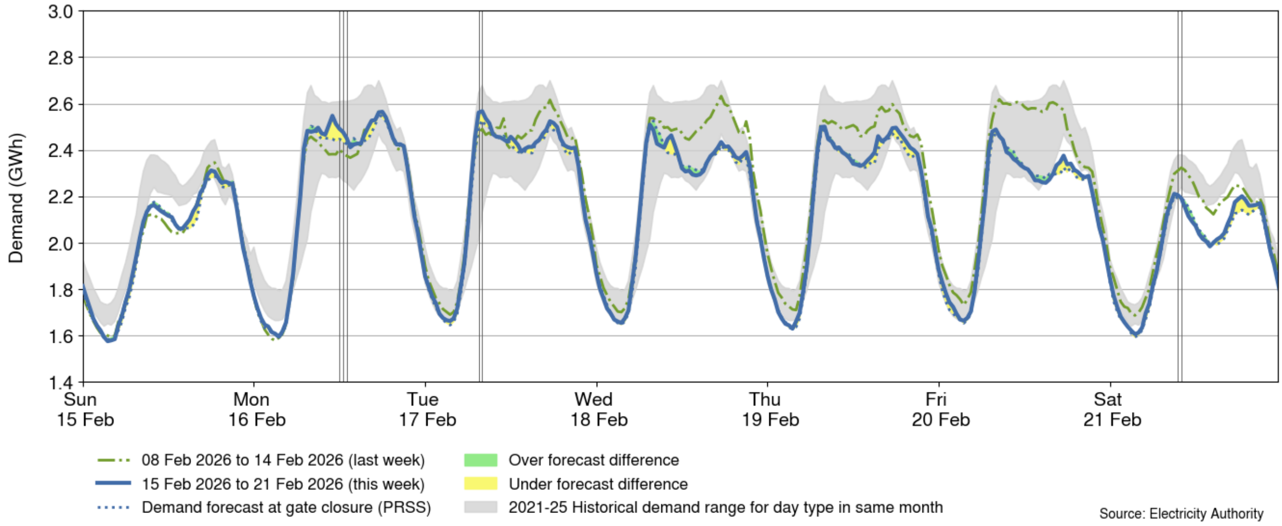


6. Demand

6.1. Figure 7 shows national demand between 15-21 February, compared to the historic range and the demand of the previous week. Demand was close to the previous week, until Tuesday evening, where demand became mostly lower than the previous week.

6.2. The highest demand of the week was around 2.57GWh at 8.00am on Tuesday. Demand forecasting errors on Monday occurred following load control near Christchurch.[5]

Figure 7: National demand, 15-21 February compared to the previous week

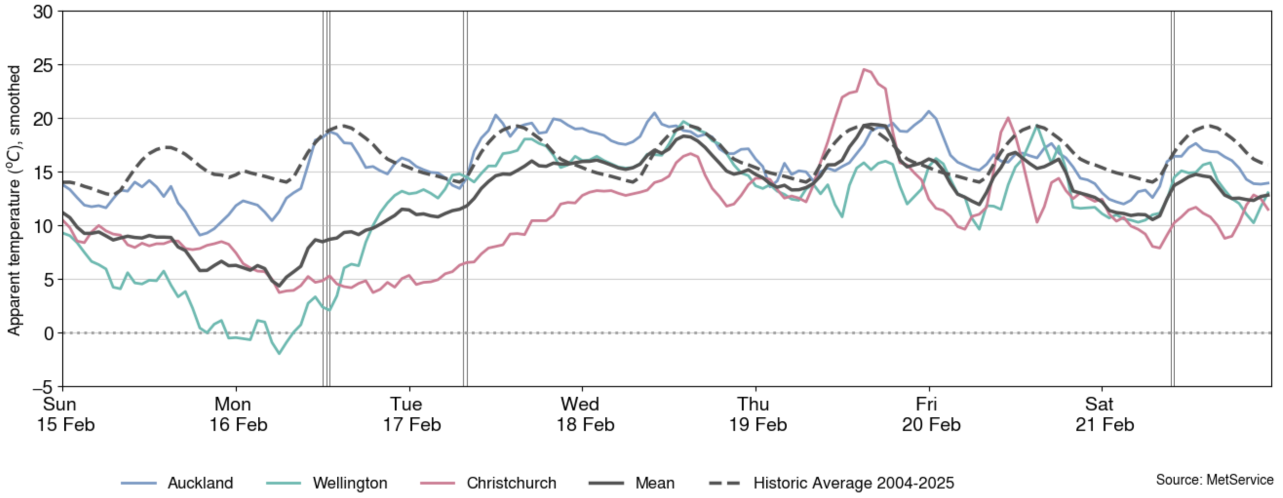


6.3. Figure 8 shows the hourly apparent temperature at main population centres from 15-21 February. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

[5] Demand error by POC - Sigma: 11.00am 16 February 2026; Orion Network Load Management: 16 February 2026.

6.4. Apparent temperatures ranged from 9°C to 21°C in Auckland, -2°C to 20°C in Wellington, and 3°C to 26°C in Christchurch. Windy conditions across the country lower temperatures on Sunday and into Monday.

Figure 8: Temperatures across main centres, 15-21 February



7. Generation

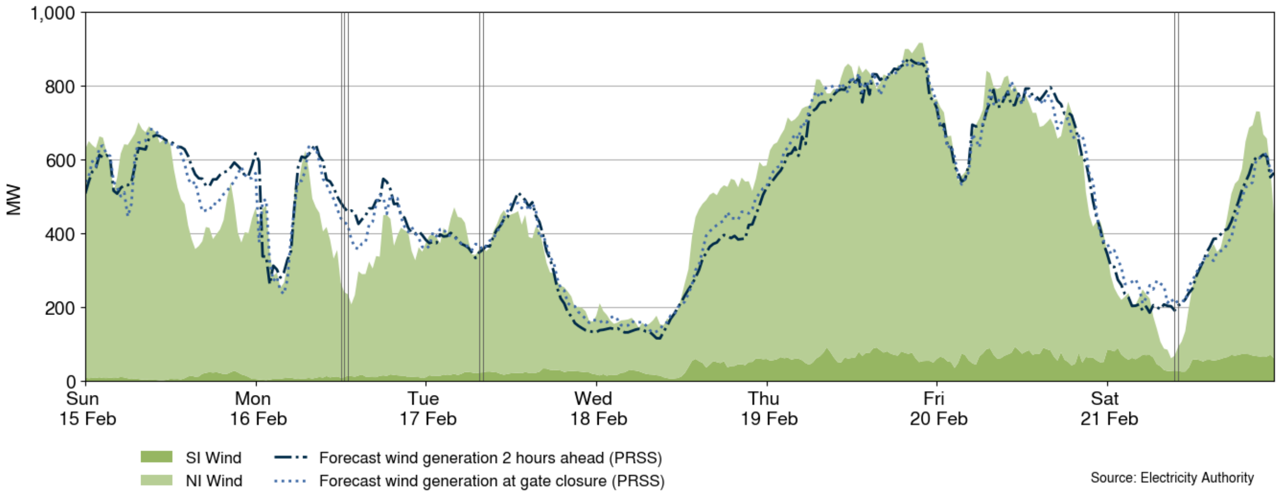
7.1. Figure 9 shows wind generation and forecast from 15-21 February. This week wind generation varied between 62MW and 917MW, with a weekly average of 488MW.

7.2. High winds on Sunday and Monday limited some wind generation from occurring. Offers from West Wind farm were priced up from Sunday morning based on the likelihood of damage to components, replacement and labour costs, and lost generation if West Wind were to operate through the storm. West Wind later went on outage between 11.51am to 5.00pm on Monday as plant safety concerns emerged.

7.3. Wind generation declined from Tuesday, before increasing above 800MW by Thursday evening. Then, wind declined steeply on Saturday morning before increasing again by the evening.

7.4. Wind forecasting errors on Sunday and Monday were a result of an amalgamation of errors across multiple wind farms, while Saturday's errors were mostly driven by errors at Waipipi wind farm.

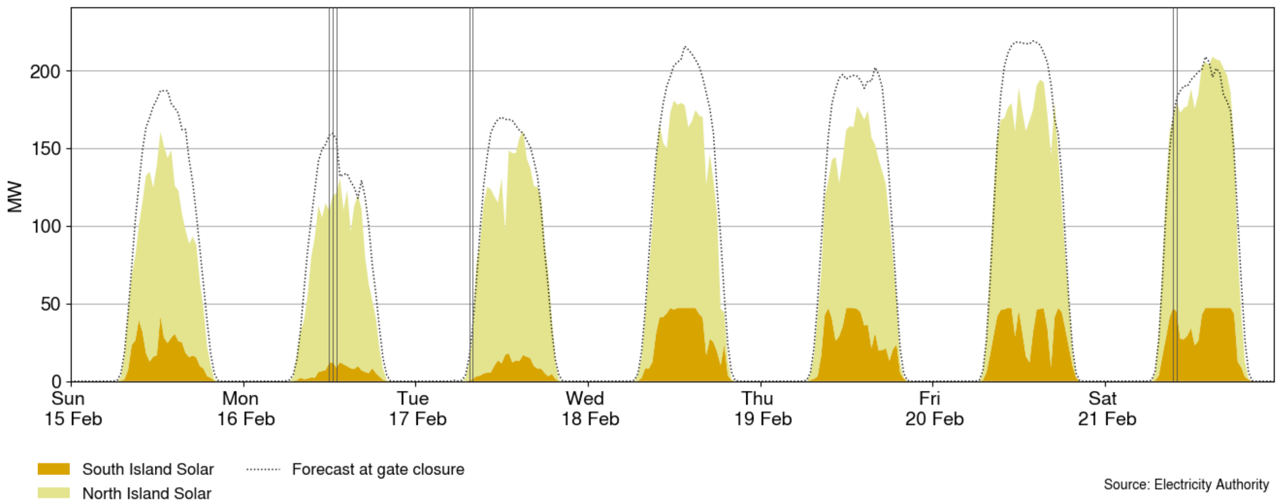
Figure 9: Wind generation and forecast, 15-21 February



7.5. Figure 10 shows grid connected solar generation from 15-21 February. Solar generation reached above 130MW daily, peaking on Saturday at 3.00pm at around 209MW.

7.6. Large solar forecasting errors between Sunday and Friday were primarily from the Twin Rivers solar farm.

Figure 10: Grid connected solar generation, 15-21 February

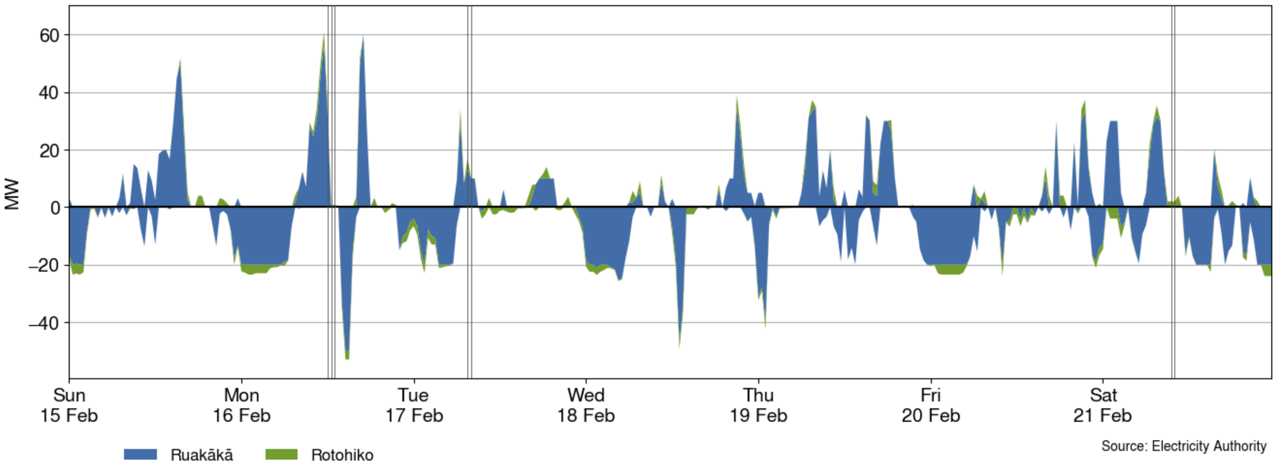


7.7. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.8. This week, the batteries mostly discharged during the day or overnight when prices were higher. High prices on Monday and Saturday occurred after the batteries had already depleted from discharge earlier in the morning.

7.9. The batteries mostly charged this week when prices were relatively lower overnight or during the day.

Figure 11: Grid scale battery charge and discharge, 15-21 February



7.10. 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[6]) 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.

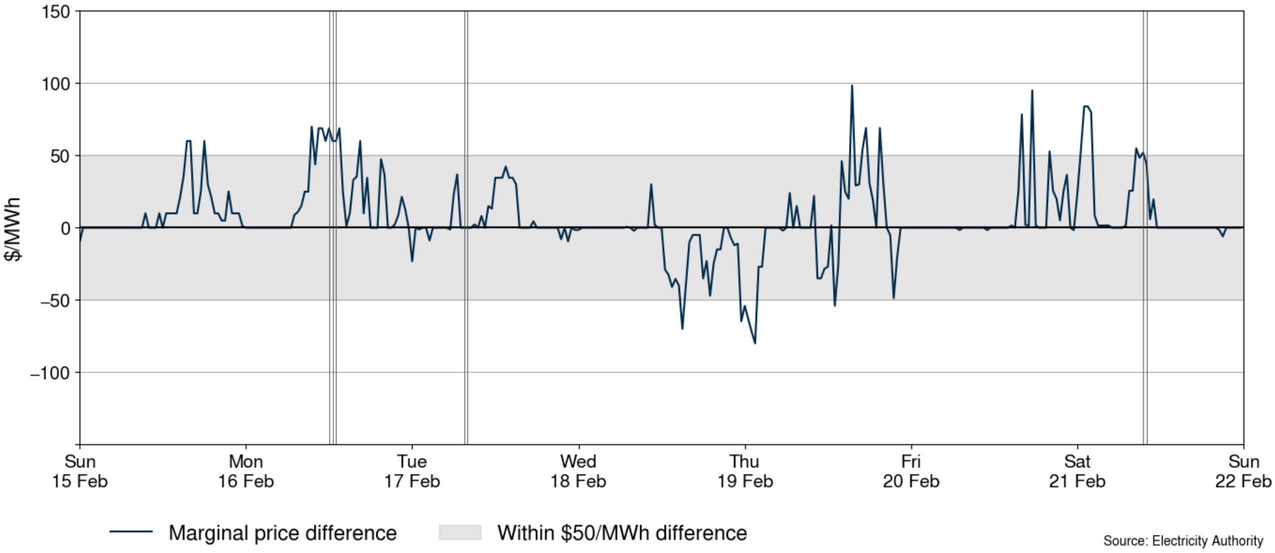
7.11. Several trading periods this week had a marginal price difference above or below $50/MWh.

7.12. Thursday saw positive price differences up to $98/MWh, which occurred at 3.30pm on Thursday. At this time, demand was 107MW higher than forecast, with intermittent generation 58MW lower than forecast.

7.13. The largest negative difference was $80/MWh which occurred at 1.30am on Thursday. Demand was 18MW lower than forecast and wind generation was 68MW higher than forecast at this time.

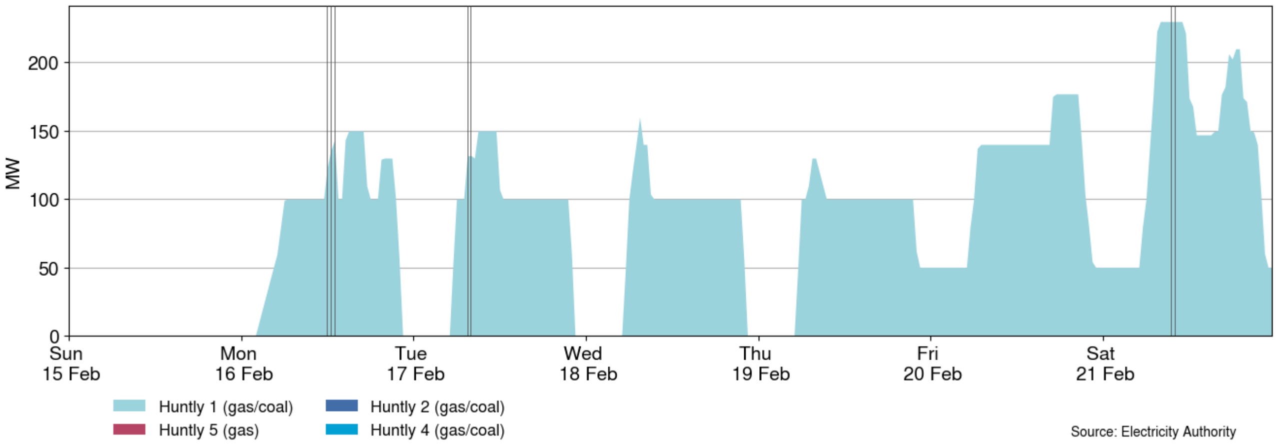
[6] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 15-21 February



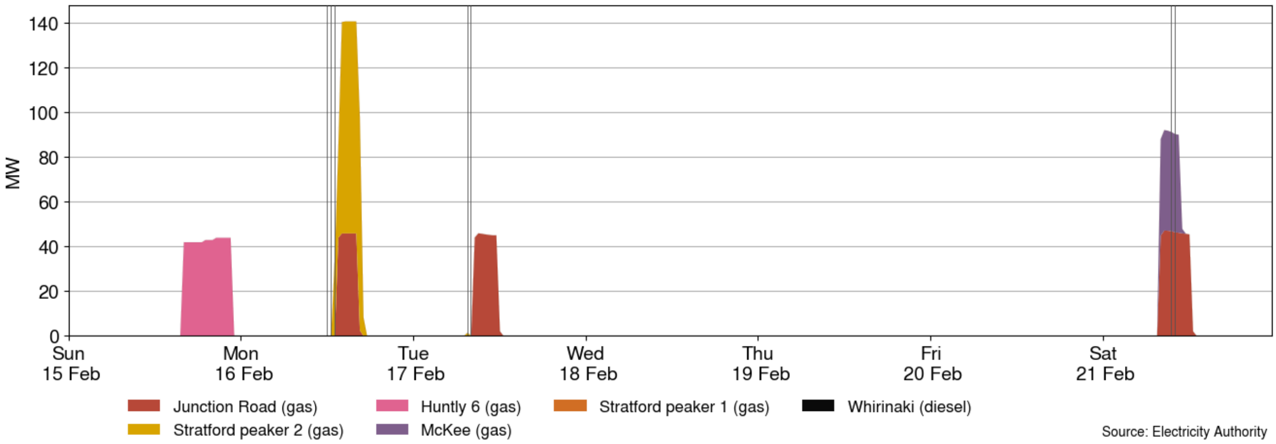
7.14. Figure 13 shows the generation of thermal baseload between 15-21 February. Huntly 1 ran each day between Monday and Saturday, with generation highest during the bi-pole HVDC outage on Saturday.

Figure 13: Thermal baseload generation, 15-21 February



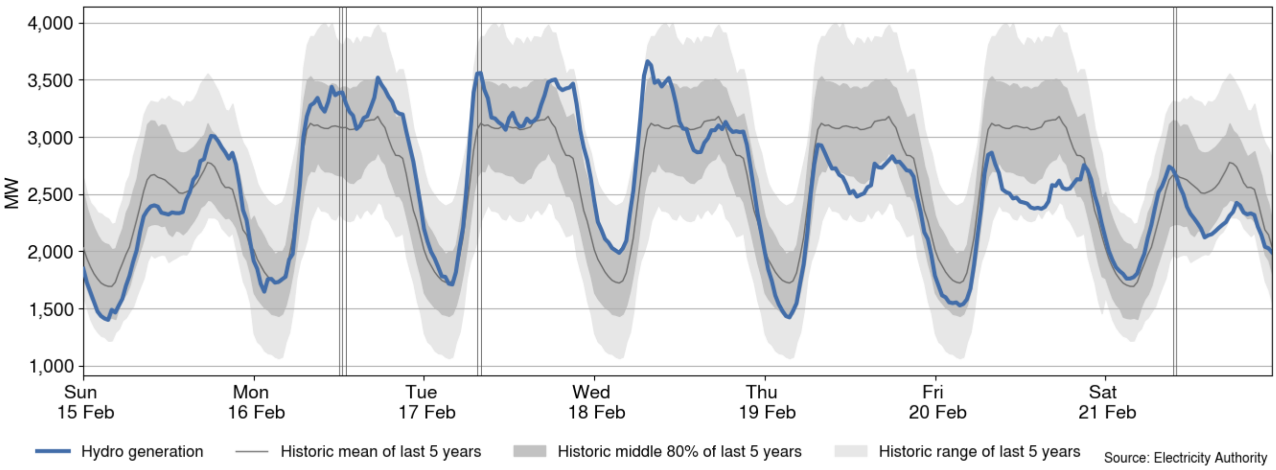
7.15. Figure 14 shows the generation of thermal peaker plants between 15-21 February. Huntly 6 ran on Sunday, Stratford peaker 2 ran on Monday, and McKee ran on Saturday. Junction Road ran on Monday, Tuesday and Saturday.

Figure 14: Thermal peaker generation, 15-21 February



7.16. Figure 15 shows hydro generation between 15-21 February. Hydro generation was mostly close to or above the historic mean between Sunday evening and Wednesday morning, before falling to close to or below mean for the rest of the week.

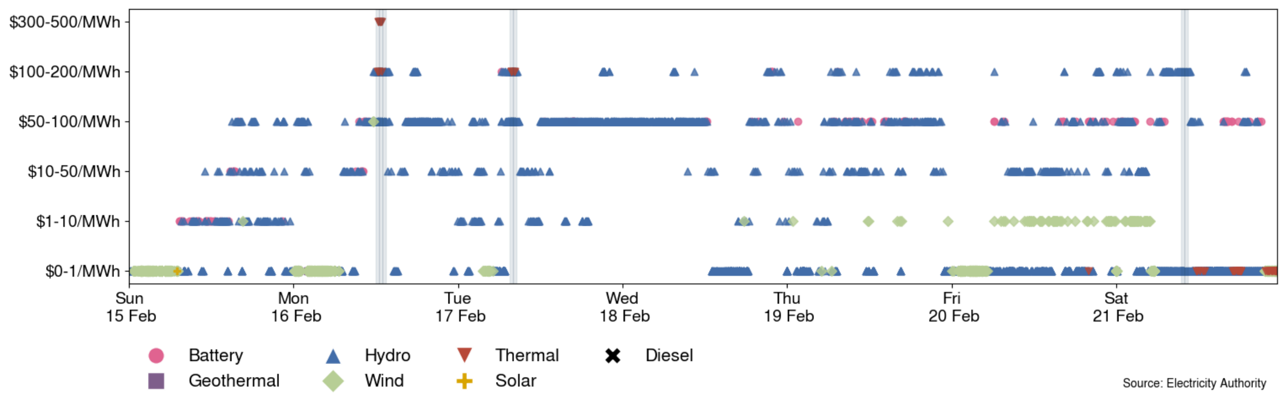
Figure 15: Hydro generation, 15-21 February



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.

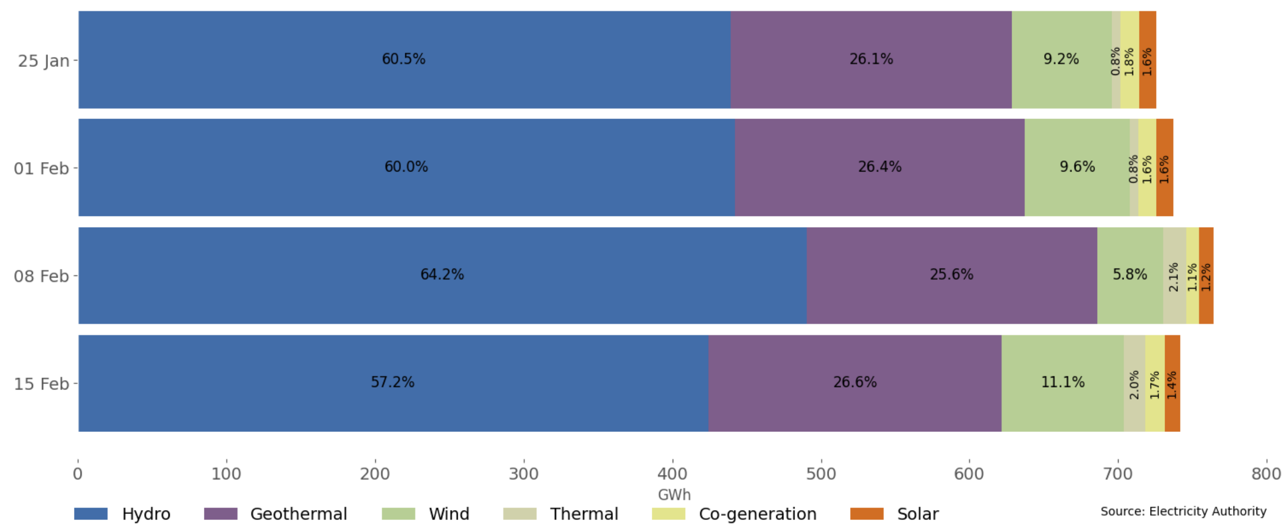
7.18. The highest prices were set by Huntly 1 on Monday. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 15-21 February



7.19. As a percentage of total generation, between 15-21 February, total weekly hydro generation was 57.2%, geothermal 26.6%, wind 11.1%, thermal 2.0%, co-generation 1.7%, and solar (grid connected) 1.4%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 25 January and 21 February



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 15-21 February ranged between ~1,411MW and ~2,207MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 15-21 February

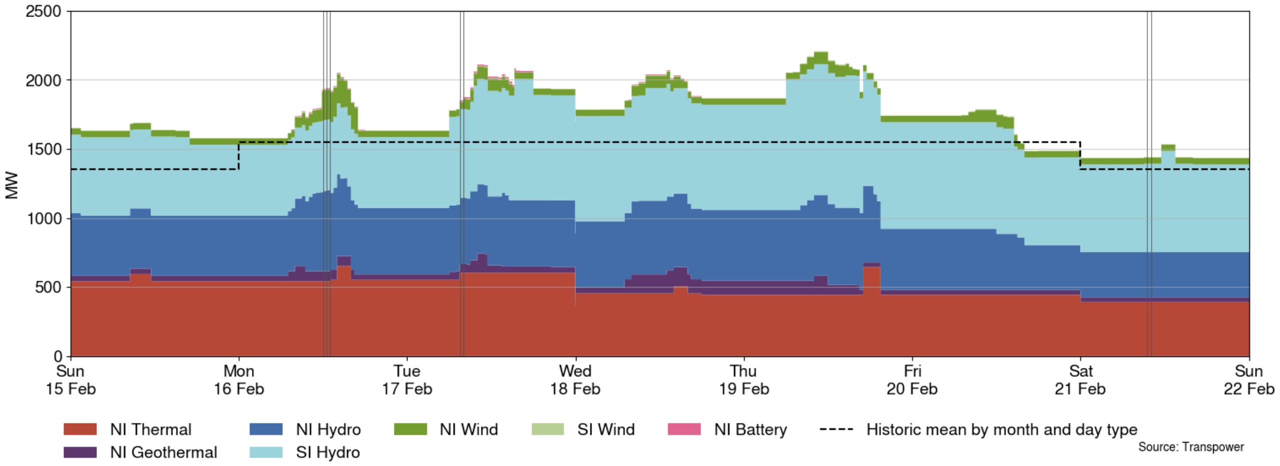
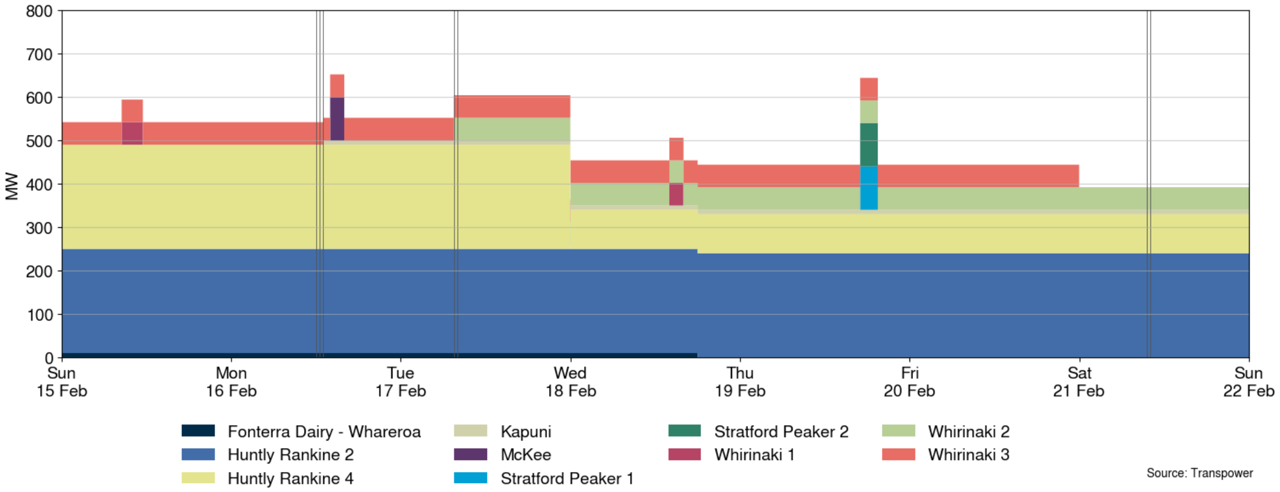


Figure 19: Total MW loss from thermal outages, 15-21 February



8.2. Notable outages include:

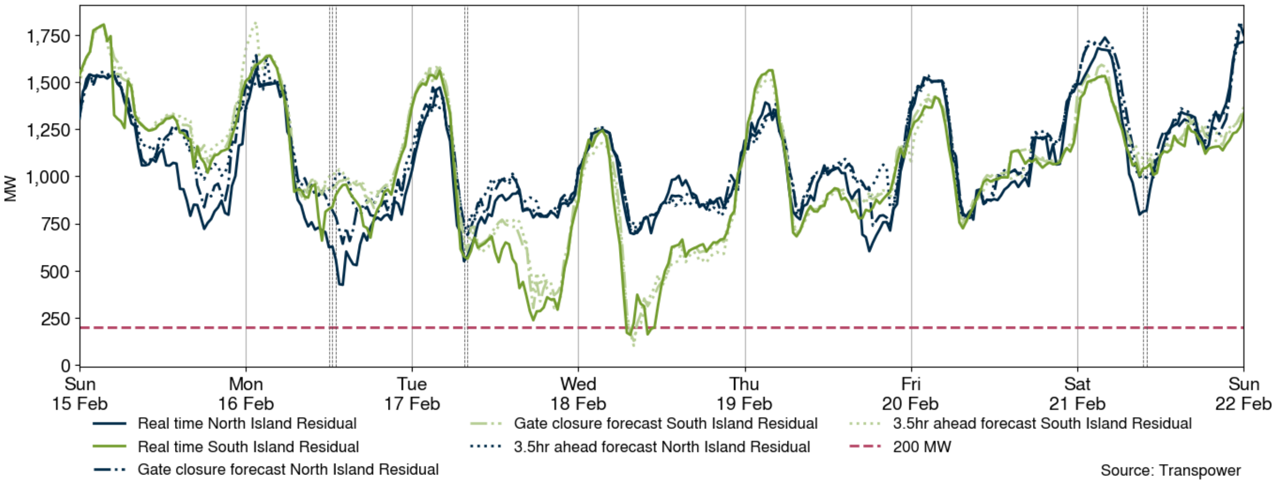
Plant	Partial or Full	End Date
Manapōuri unit 7	Full	20 February 2026
Roxburgh unit 5	Full	22 February 2026
Huntly 4	Partial/Full	2 March 2026
Ōhau A	Full	6 March 2026
Rangipō unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

9.1. Figure 20 shows the generation balance residuals for the North and South Islands between 15-21 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. The lowest North Island residual this week was 424MW on Monday at 2.00pm, during the unplanned HVDC Pole 3 outage. The lowest South Island residual this week was 159MW at 7.30am on Wednesday.

Figure 20: North and South Island generation balance residuals, 15-21 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 21 February, national controlled storage decreased to 92% nominally full and ~113% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (97% full[7]) is close to its historic 90th percentile, while Lake Takapō (91% full) is now close to its historic mean.

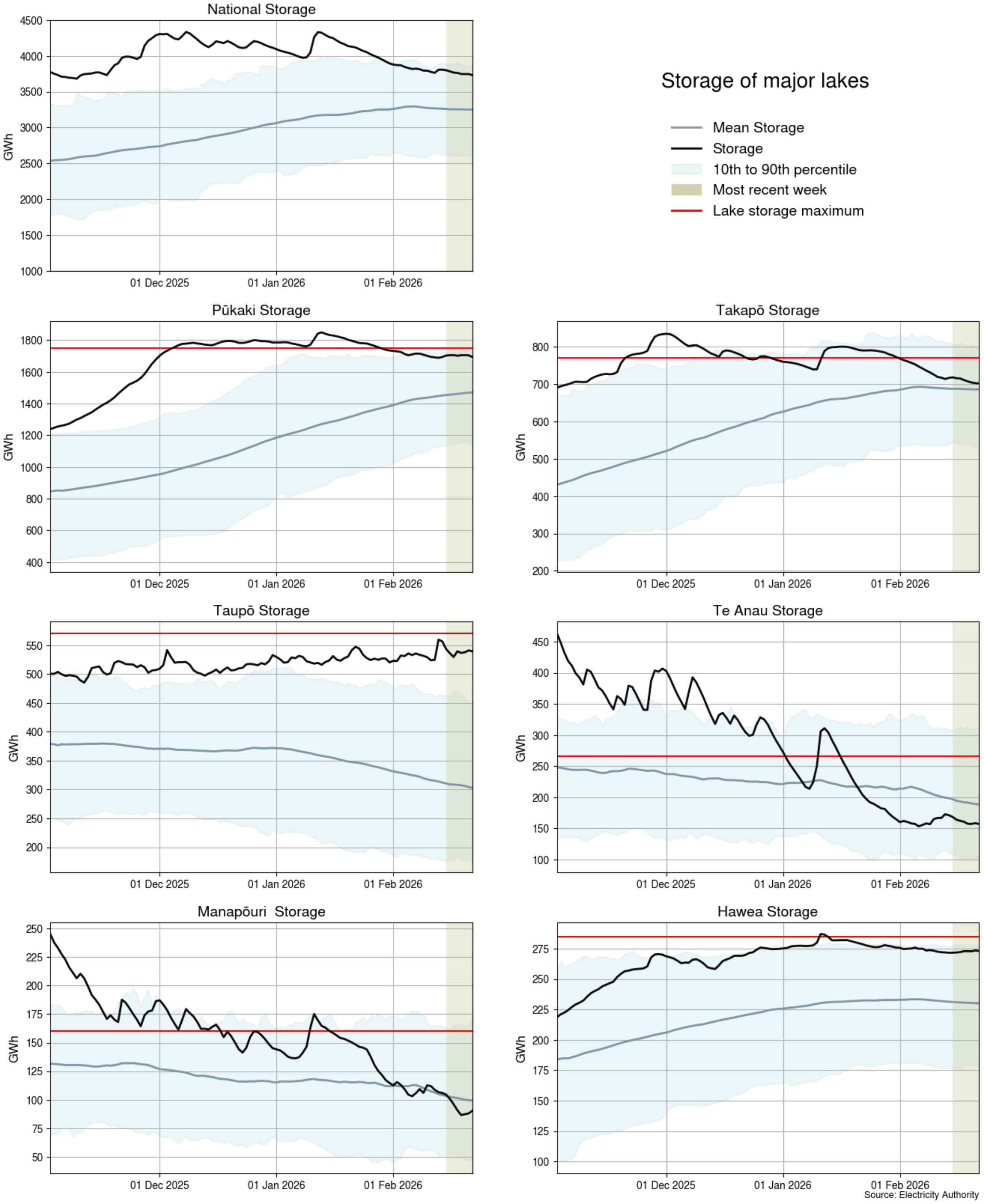
10.4. Storage at Lake Te Anau (59% full) is below its historic mean, with Lake Manapōuri (58% full) now also below its historic mean.

10.5. Storage at Lake Taupō (94% full) remains 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

[7] 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.

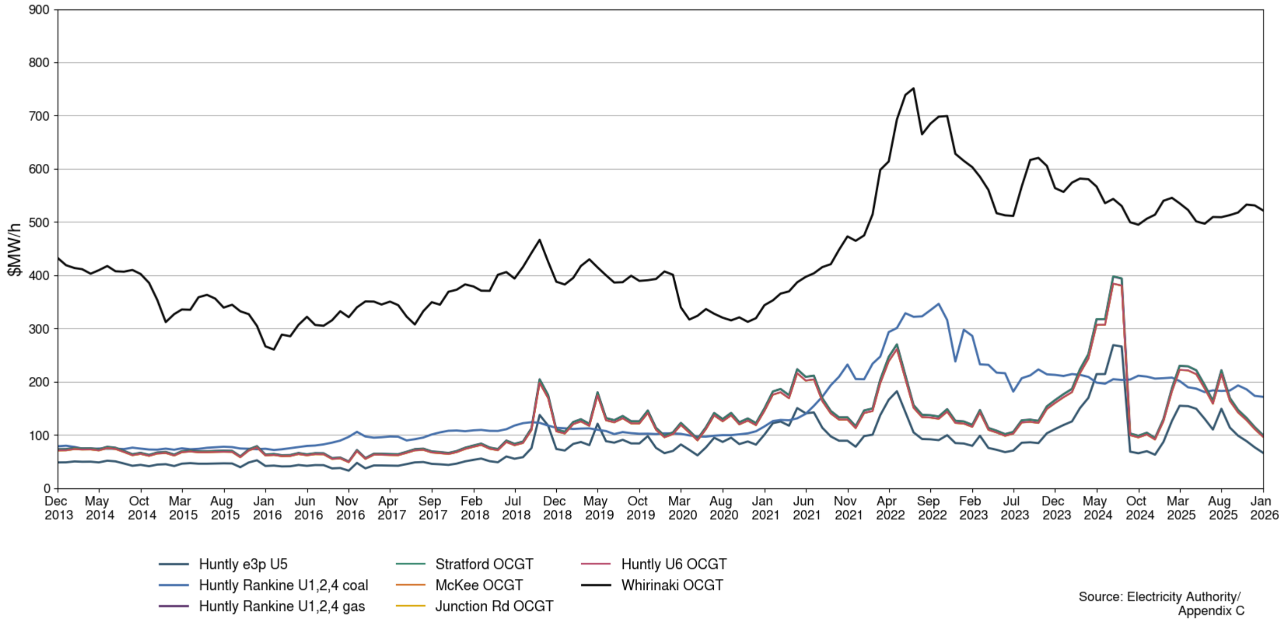
11.4. The latest SRMC of coal-fueled Rankine generation is ~$171/MWh. The cost of running the Rankines on gas is ~$99/MWh.

11.5. The SRMC of gas-fueled 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



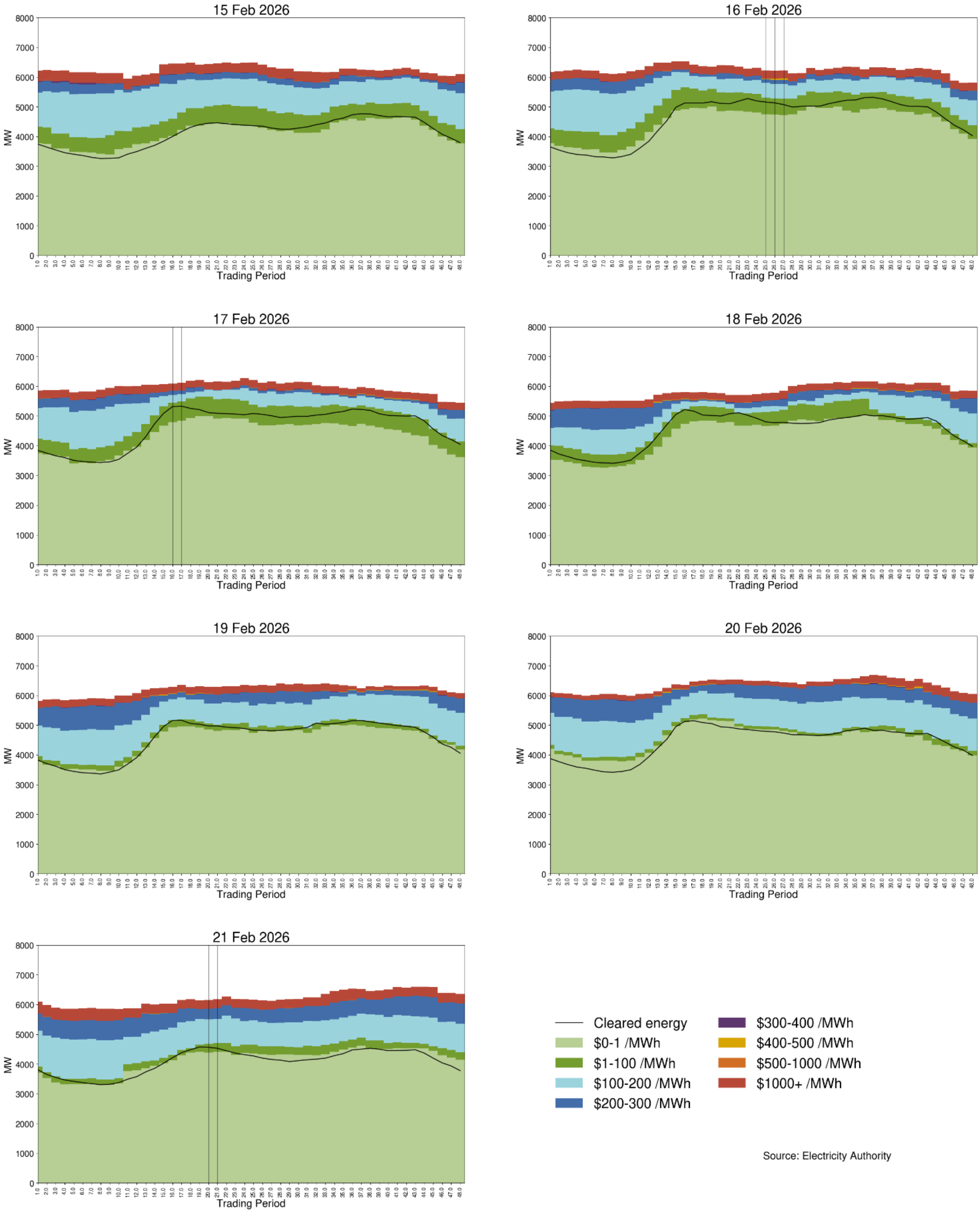
12. Offer behaviour

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. Most offers this week cleared below $100/MWh, aside from a few trading periods on Wednesday where energy cleared in the $100-200/MWh range. Prior to this, Meridian hydro offers were priced up from the $1-100/MWh range into the $100-200/MWh range. The monitoring team is looking into these offer changes further.

12.3. High priced Mercury hydro offers also increased from Wednesday into the $200-300/MWh band this week.

Figure 23: Daily offer stacks



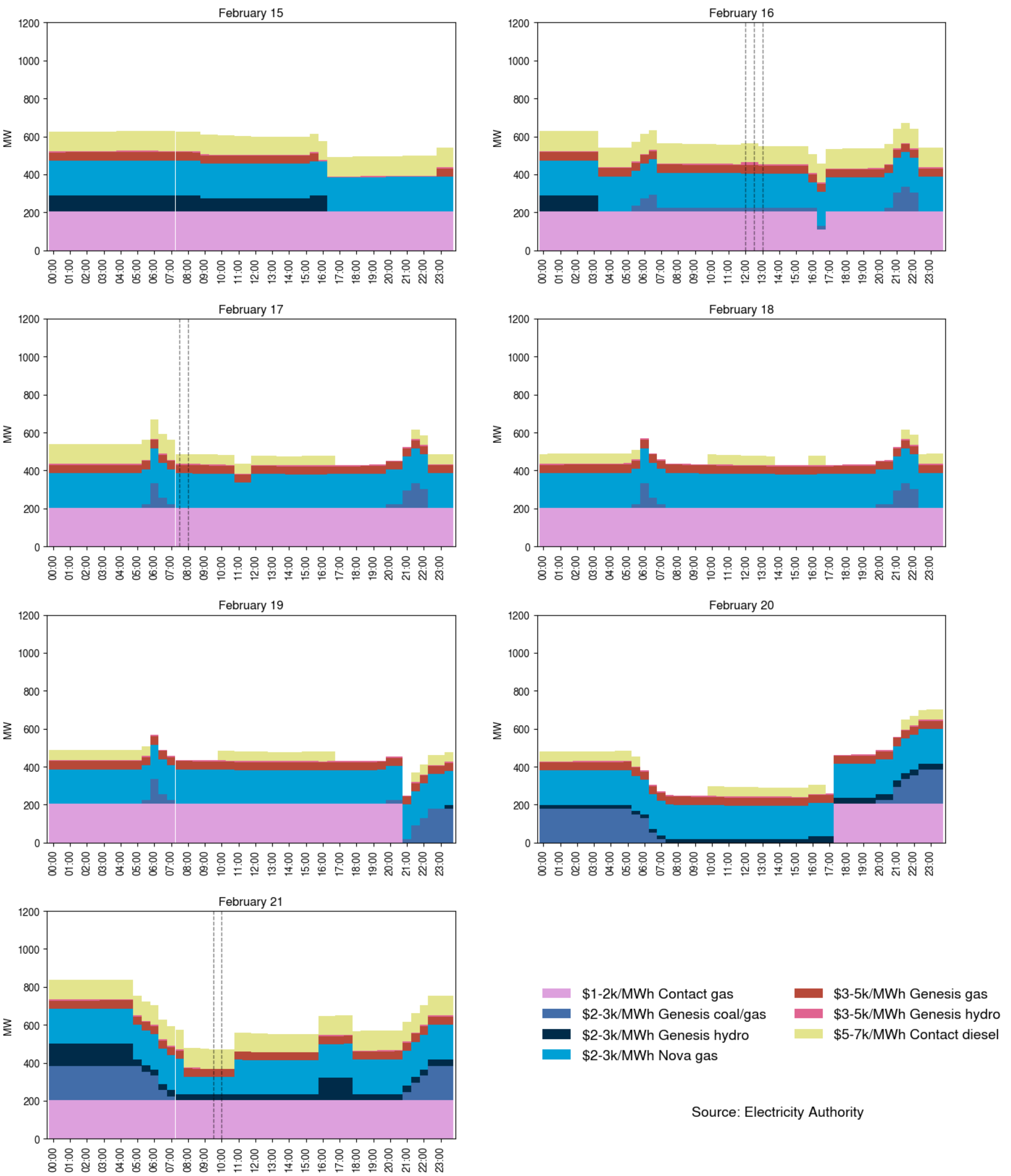
Source: Electricity Authority

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 520MW 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. The monitoring team is looking into Meridian hydro offers further this week.

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

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
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
18/02/2026-21/02/2026	Several	Further analysis	Meridian	Waitaki scheme	Offers