17 February 2025

Trading conduct report 9-15 February

Market monitoring weekly report

Trading conduct report 9-15 February

1. Overview

1.1. Spot prices increased this week due to low wind, increased thermal generation, a dry outlook, low wind generation, hydro storage dropping to 73% nominally full, and unexpected thermal outages.

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 9-15 February:

(a) The average spot price for the week was $277/MWh, an increase of around $51/MWh compared to the previous week.

(b) 95% of prices fell between $150MWh and $377/MWh.

2.3. Prices continue to increase as:

(a) hydro storage continues to decrease

(b) forecasts remain dry

(c) wind was low

(d) thermal generation continues to increase

(e) several thermal units went on unplanned outages.

2.4. The highest price at Ōtāhuhu or Benmore this week was $438/MWh at 9pm on Thursday at Ōtāhuhu.

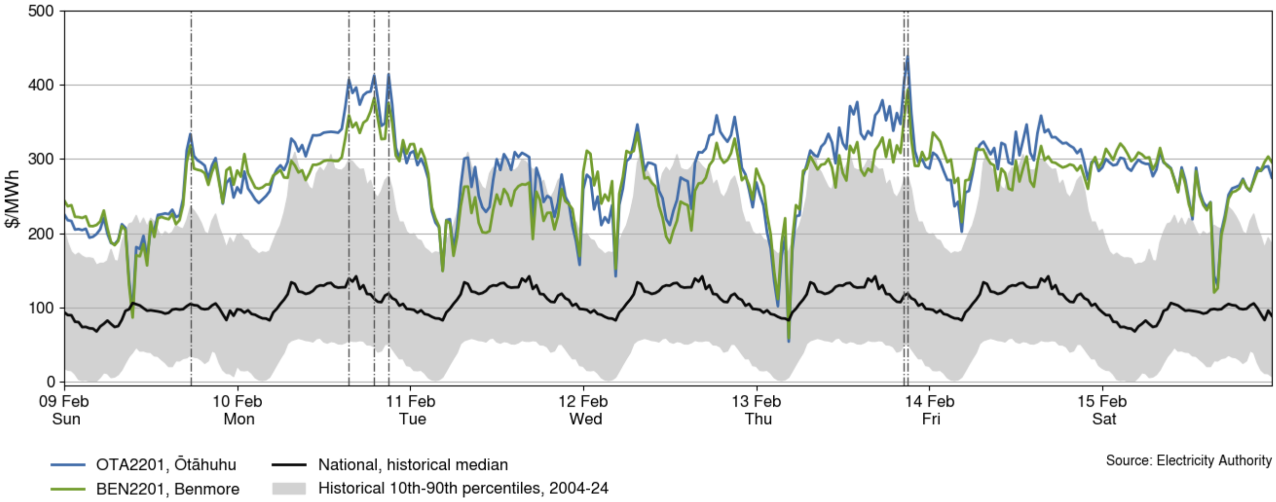
2.5. The highest price at Ōtāhuhu on Monday was $414/MWh. This also occurred at 9pm. This appears to be due to a regular uptick in demand around this time every day while generation offers reduce in the evening and low-priced generation from Manapōuri decreased. Wind was also very low on Monday and Thursday.

2.6. Monday had other prices above $400/MWh at 3.30pm and 7pm. These higher prices were due to low wind, demand being more than 80MW higher than forecast, and wind being lower than forecast two hours ahead of gate closure by 63MW and 114MW respectively. Demand was continuously under forecast the entire day.

2.7. Prices spiked to $334/MWh at Ōtāhuhu on Sunday at 5.30pm. Demand was 110MW higher than forecast and wind was 119MW lower than forecast at gate closure.

2.8. 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, 9-15 February

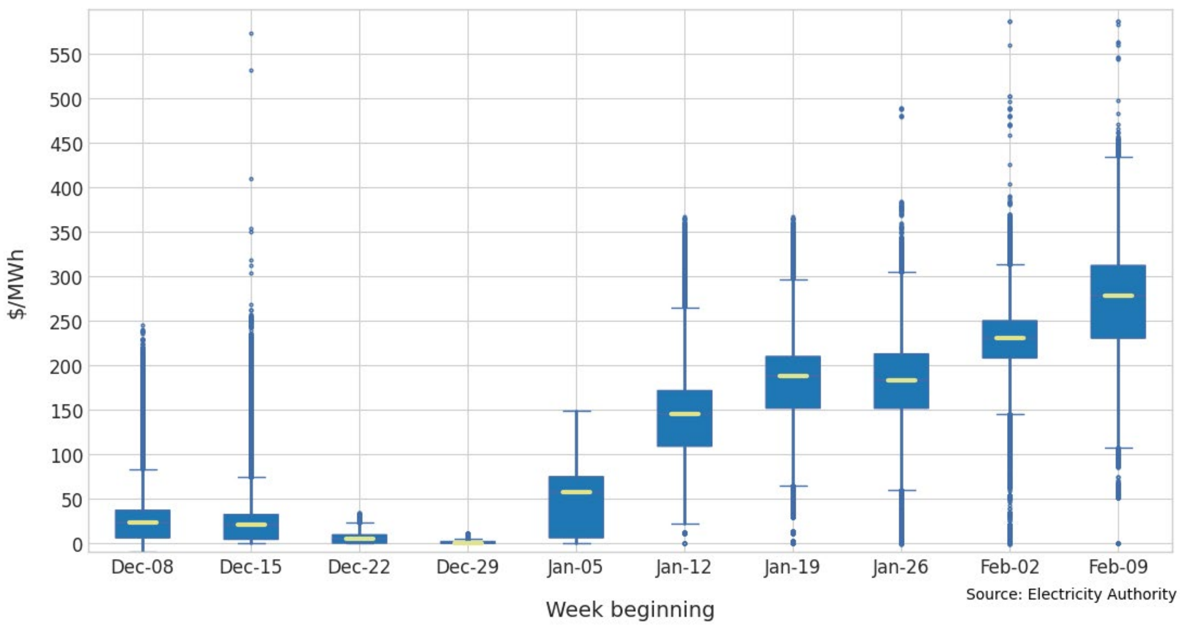


2.9. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.10. The distribution of spot prices this week was skewed higher than last week. The median price was $279/MWh and most prices (middle 50%) fell between $230/MWh and $312/MWh.

2.11. The highest price of the week at any node, $587/MWh, occurred at 6.30pm on Tuesday at Gore. Other Southland nodes were also high at this time. These high prices were due to line constraints in the area.

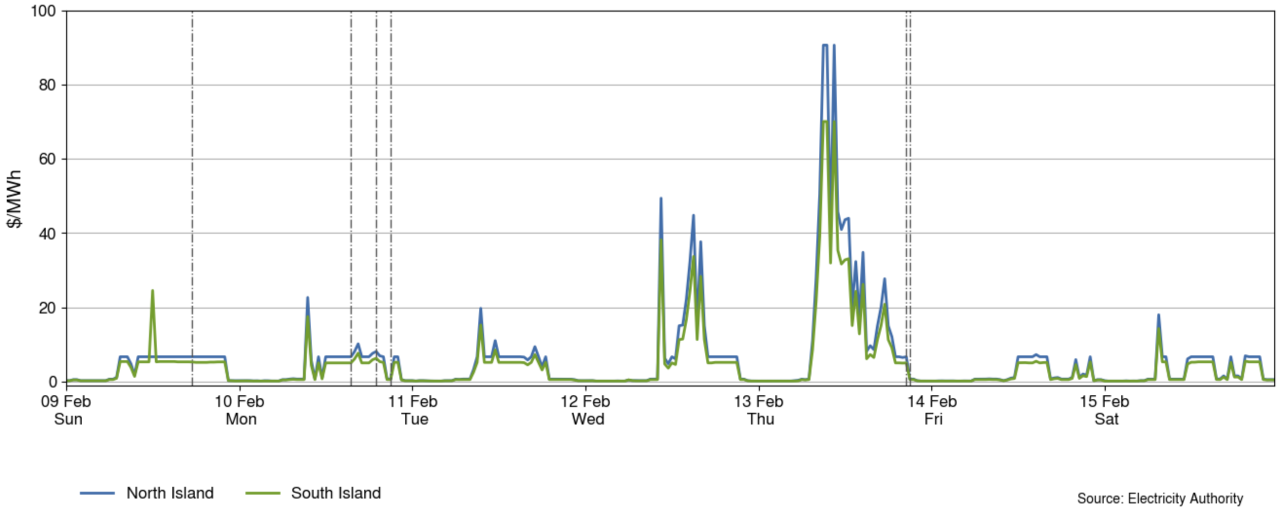
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

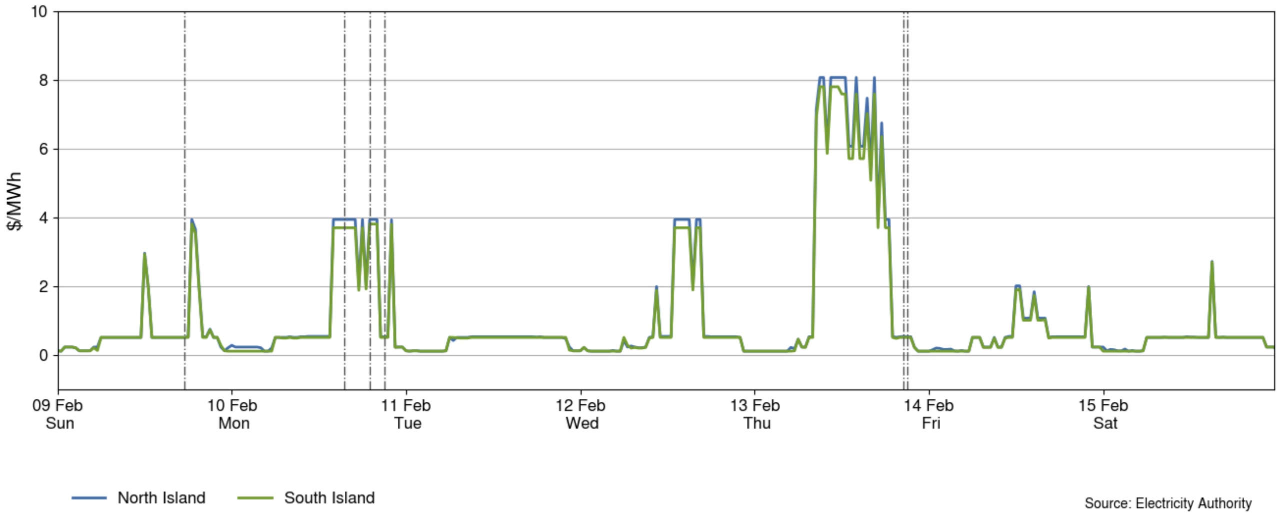
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh. FIR spiked above $80/MWh on Thursday morning. This was due to a reduction in available cheap FIR.

Figure 3: Fast instantaneous reserve price by trading period and island, 9-15 February



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 9-15 February



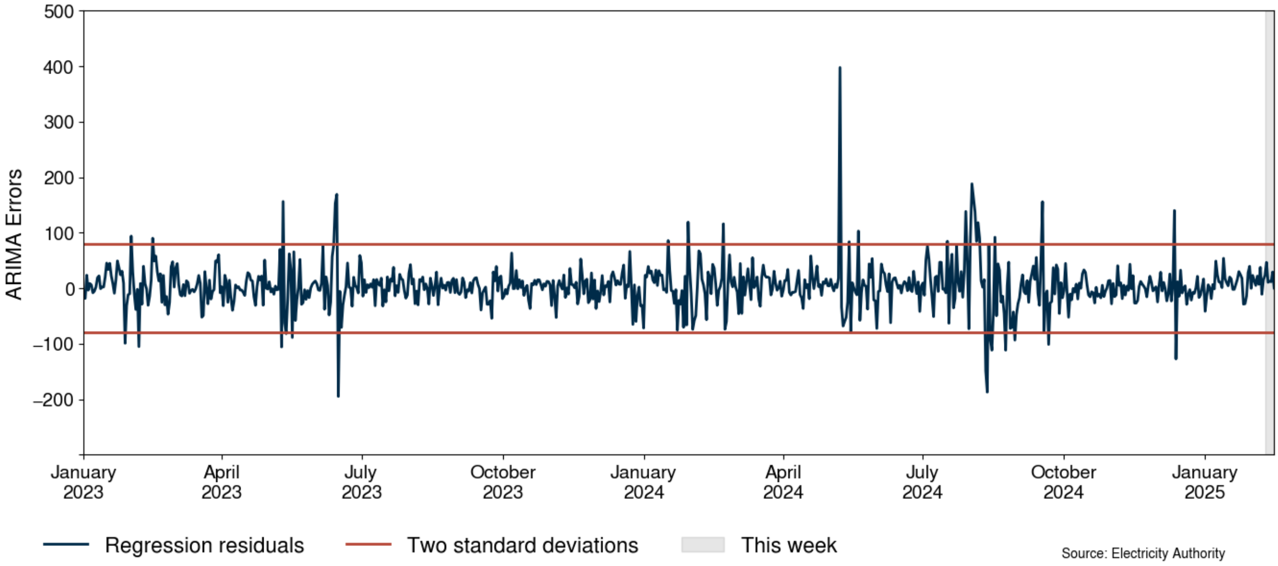
4. Regression residuals

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 the those predicted by the model.

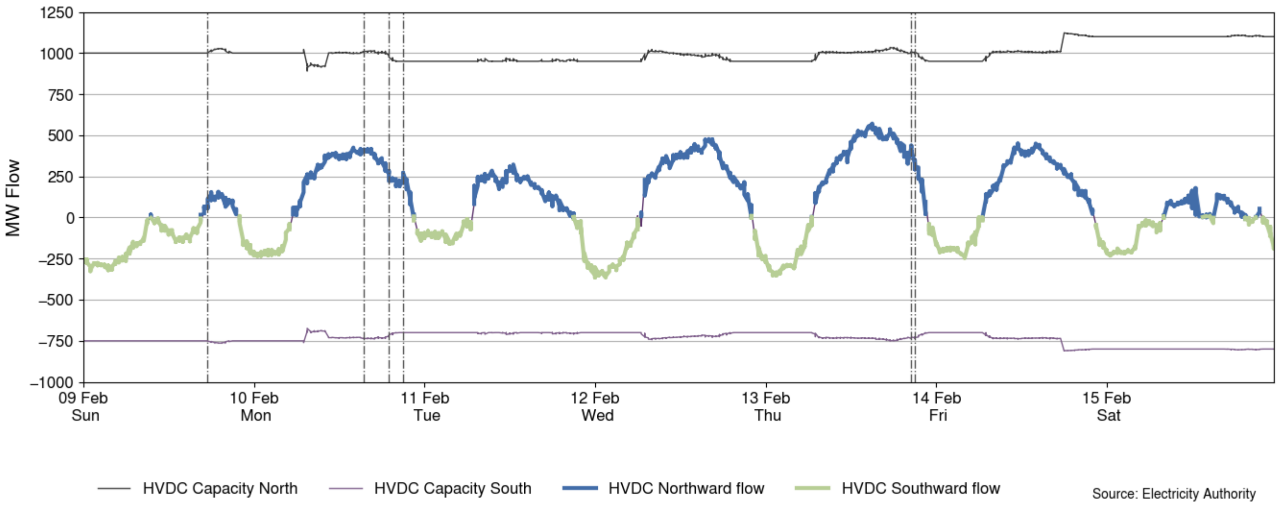
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 15 February 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 9-15 February. HVDC flows were mostly northward during the day and southward in the night. Northward flow was highest on Thursday, reaching 571MW at 3pm.

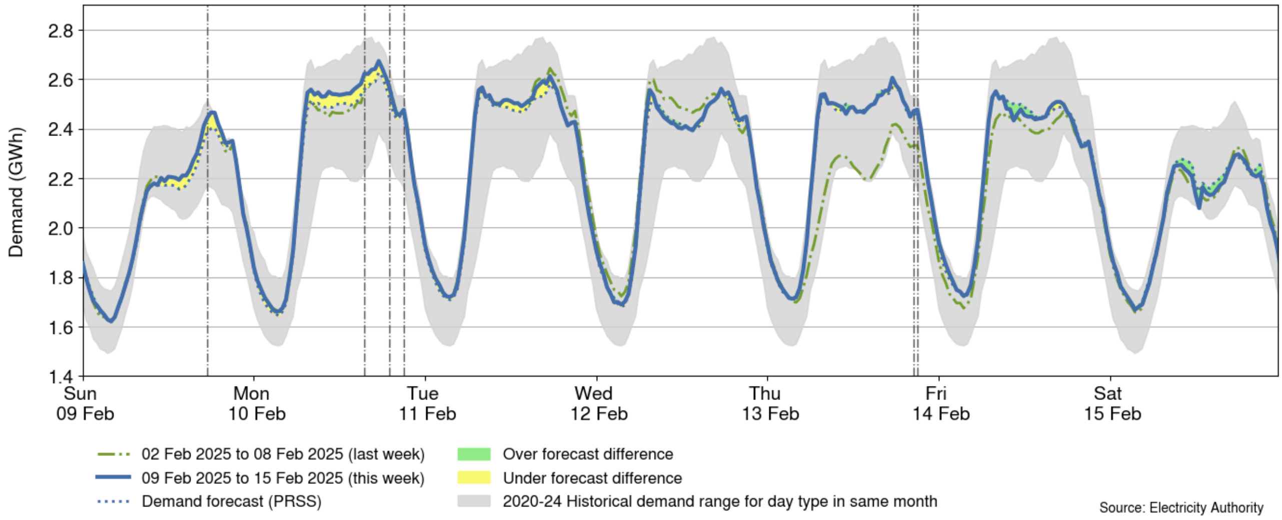
Figure 6: HVDC flow and capacity, 9-15 February



6. Demand

6.1. Figure 7 shows national demand between 9-15 February, compared to the historic range and the demand of the previous week. Demand was near the higher end of the historic range. Maximum demand was 2.67GWh at 5.30pm on Monday. Demand was higher than forecast in the first part of the week, especially on Monday. Demand dropped briefly on Friday at 10.30am due to an unplanned trip at Tiwai Aluminium Smelter. Demand also dropped on Saturday at 12.30pm due to a planned temporary Tiwai potline reduction.

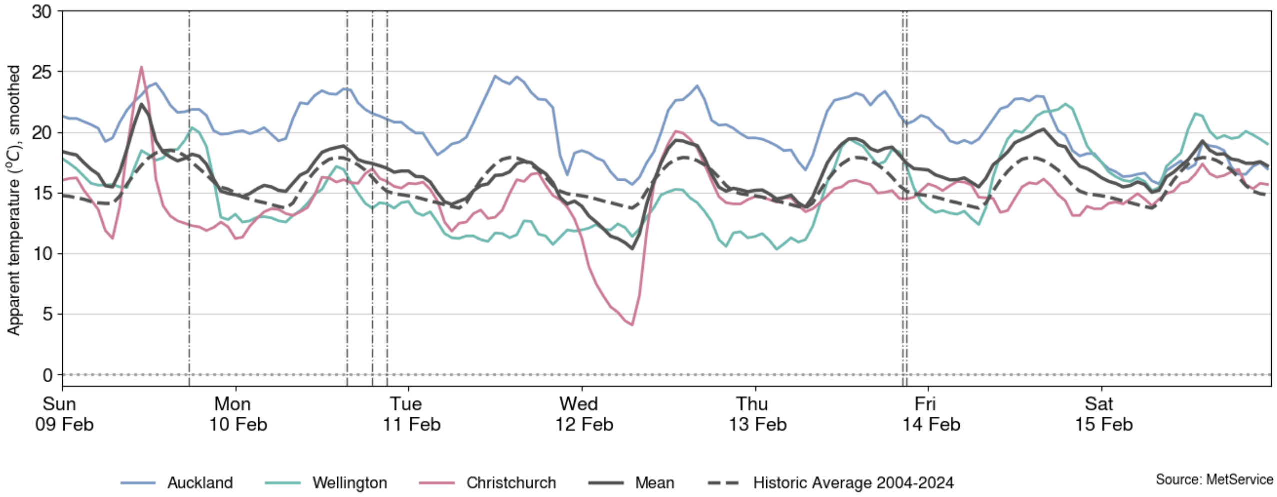
Figure 7: National demand, 9-15 February compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 9-15 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.

6.3. Apparent temperatures were mostly close to average this week. They ranged from 15°C to 25°C in Auckland, 10°C to 22°C in Wellington, and 4°C to 27°C in Christchurch.

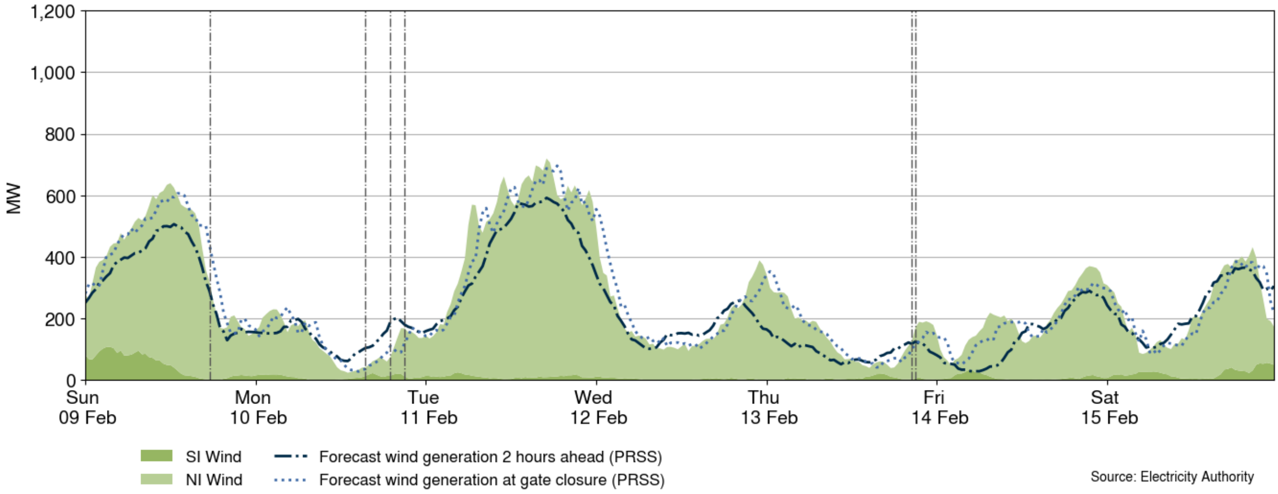
Figure 8: Temperatures across main centres, 9-15 February



7. Generation

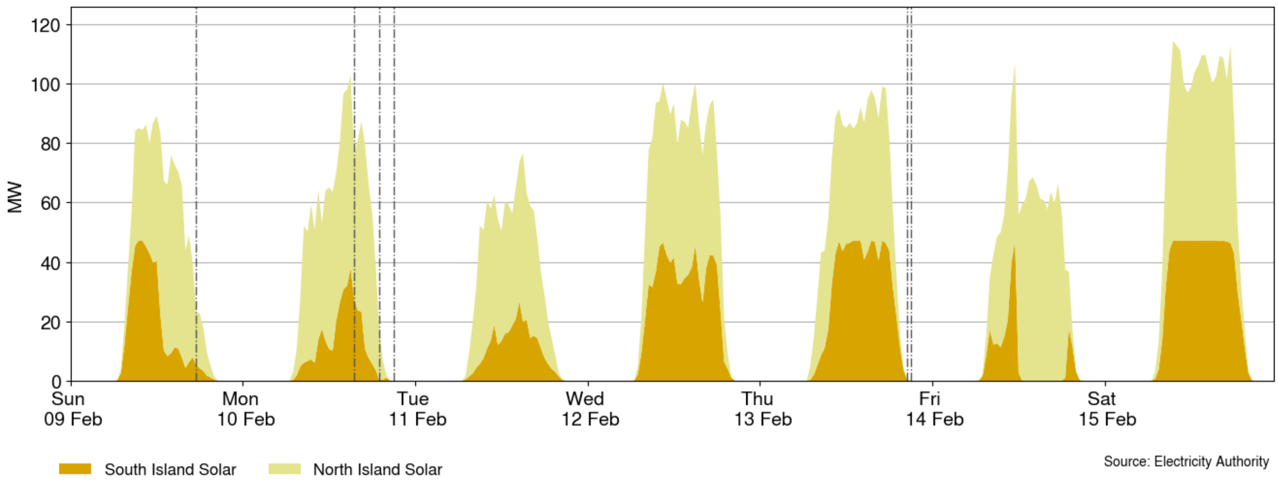
7.1. Figure 9 shows wind generation and forecast from 9-15 February. This week wind generation varied between 24MW and 720MW, with a weekly average of 259MW. Wind generation was mostly below 200MW on Monday, Wednesday and Thursday. Wind was higher on Sunday and Tuesday. Wind was consistently lower than forecasts on Monday afternoon and evening.

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



7.2. Figure 10 shows grid connected solar generation from 9-15 February. Solar generation was highest on Saturday, reaching 114MW at 9.30am.

Figure 10: Grid connected solar generation, 9-15 February



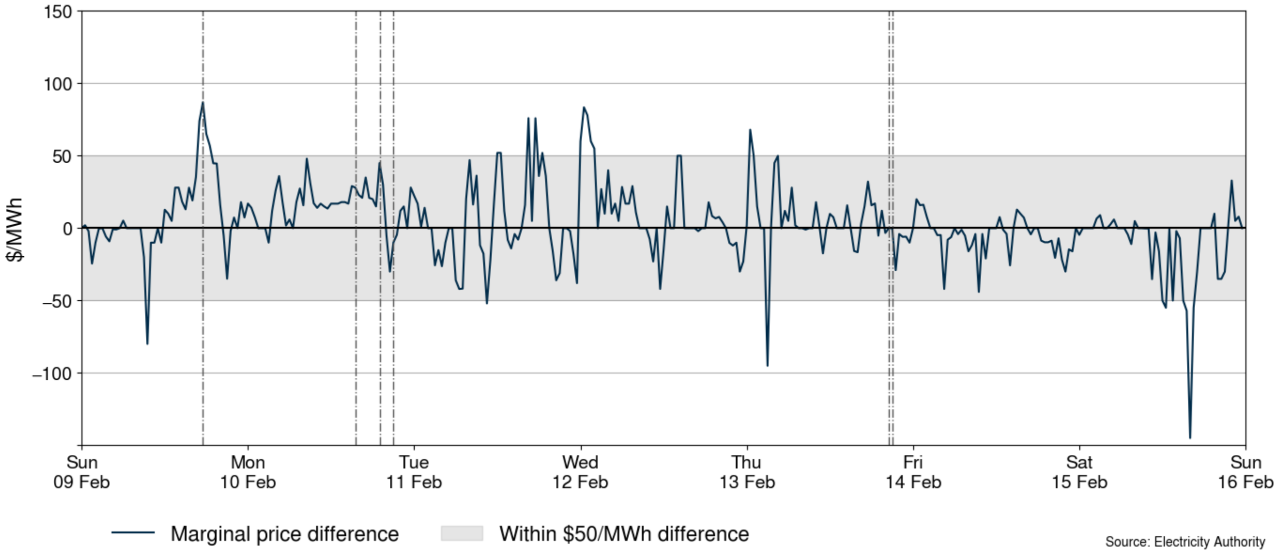
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind 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.

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

7.4. The highest positive marginal price difference was $87/MWh during the highest price on Monday, which occurred due to both demand and wind forecasting inaccuracies. The marginal price difference also reached above $50/MWh frequently midweek due to demand under forecasting Tuesday afternoon, and wind over forecasting Wednesday midnight-2am and Thursday.

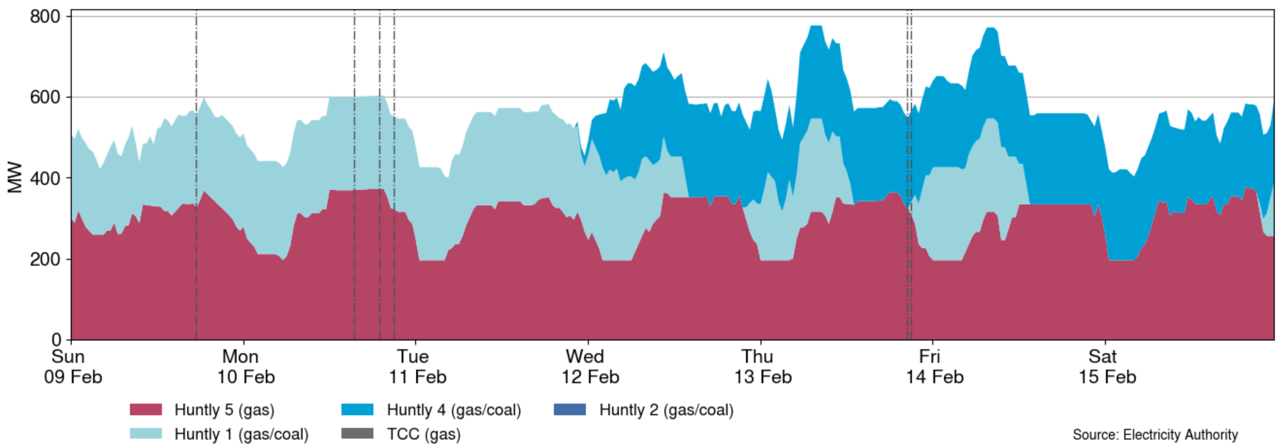
7.5. The lowest negative marginal price difference was -$145/MWh on Saturday at 4pm. This was due to demand being lower than forecast. The marginal price difference also spiked below -$50/MWh on Sunday and Thursday due to wind being higher than forecast.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 9-15 February



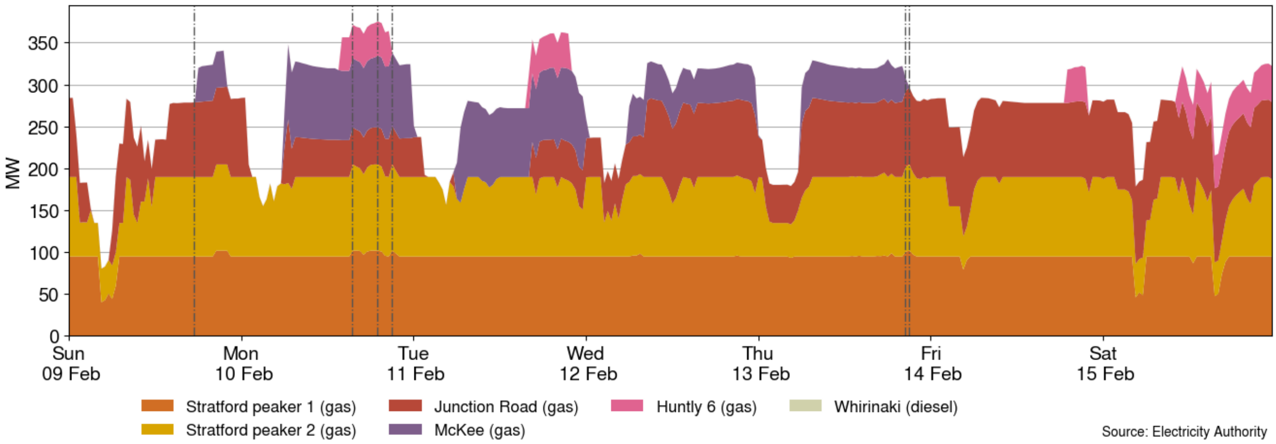
7.6. Figure 12 shows the generation of thermal baseload between 9-15 February. Huntly 5 generated baseload, with Huntly 1 generating every day except Saturday and Huntly 4 generating from Wednesday. Huntly 1 generation stopped on Wednesday, Thursday and Friday due to short notice outages. On Thursday and Friday, this was likely due to high ambient temperatures in the Waikato river inhibiting further Huntly running.

Figure 12: Thermal baseload generation, 9-15 February



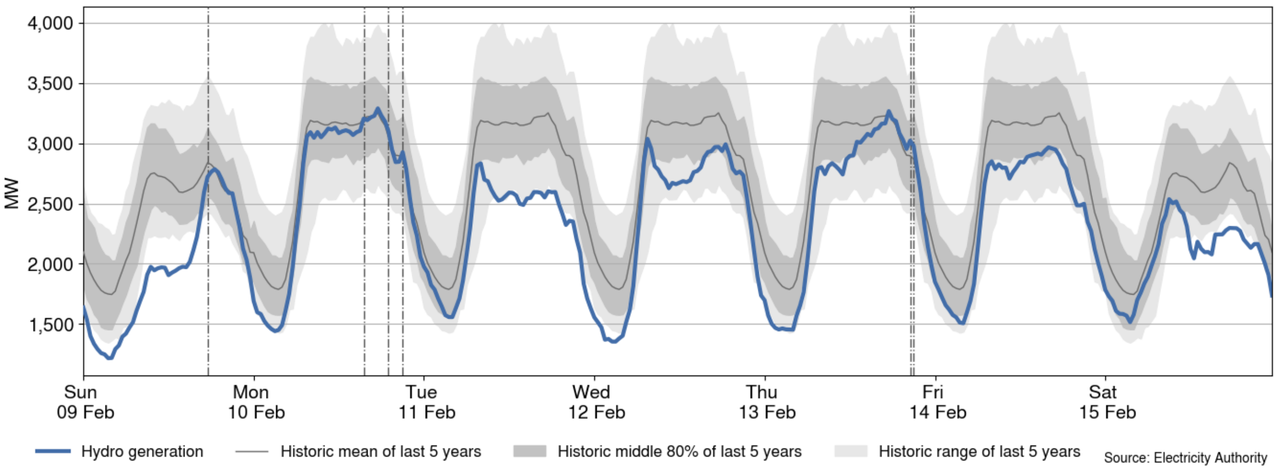
7.7. Figure 13 shows the generation of thermal peaker plants between 9-15 February. Both Stratford Peakers generated continuously. Junction Road generated every day, McKee generated every day up to Thursday and Huntly 6 generated Monday, Tuesday, Friday and Saturday.

Figure 13: Thermal peaker generation, 9-15 February



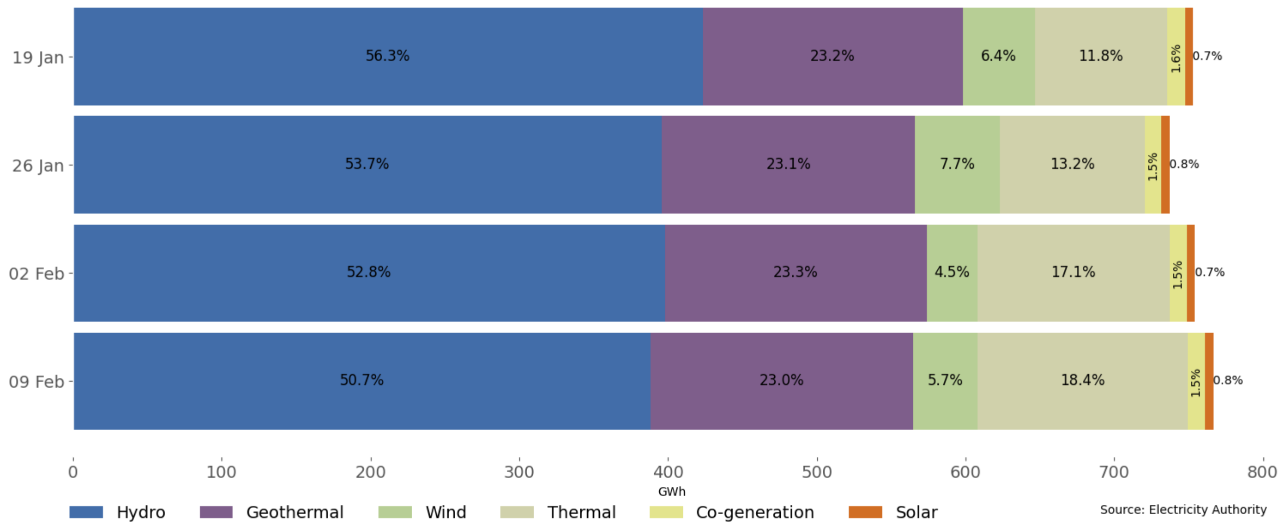
7.8. Figure 14 shows hydro generation between 9-15 February. Hydro generation was mostly below the historic mean this week but was slightly higher on Sunday, Monday and Thursday afternoons and evenings.

Figure 14: Hydro generation, 9-15 February



7.9. As a percentage of total generation, between 9-15 February, total weekly hydro generation was 50.7%, geothermal 23.0%, wind 5.7%, thermal 18.4%, co-generation 1.5%, and solar (grid connected) 0.8%, as shown in Figure 15. The proportion of thermal generation increased again this week as the proportion of hydro generation decreased, but the total amount of renewable generation remained approximately the same.

Figure 15: Weekly total generation by type in GWh, annotated with percentage of total generation, between 19 January and 15 February



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 9-15 February ranged between ~1,397MW and ~2,396MW. It was unexpectedly high this week because of several unplanned and short notice outages due to unforeseen issues. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC is on outage until 21 March (although it does not typically generate in summer regardless).

(b) Huntly 2 is on outage until 28 February.

(c) Manapōuri unit 4 is on outage until 18 September.

(d) Manapōuri unit 6 was on outage 7-12 February (extended from 10 February).

(e) Clyde unit 1 is on outage until 25 June.

(f) Clyde unit 3 was on unplanned outage 14-15 February.

(g) Benmore unit 3 was on outage 11 February.

(h) Te Uku was on unplanned outage 11 February

(i) Huntly 5 was on outage for short periods 5 and 6 February.

(j) Te Huka 3 is on unplanned outage until 18 February.

8.3. Thermal outages this week, as shown in Figure 17, that were unplanned or short notice include:

(a) Huntly 1 outages (short notice)

(b) Junction Road outages (unplanned)

(c) Huntly 6 outage (unplanned)

(d) McKee outages (unplanned)

Figure 16: Total MW loss from generation outages, 9-15 February

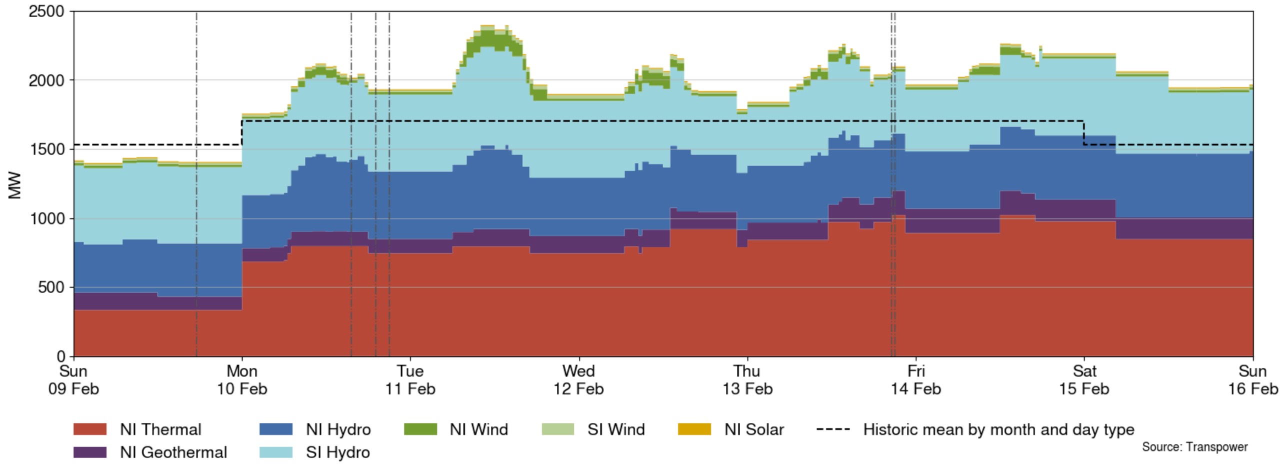
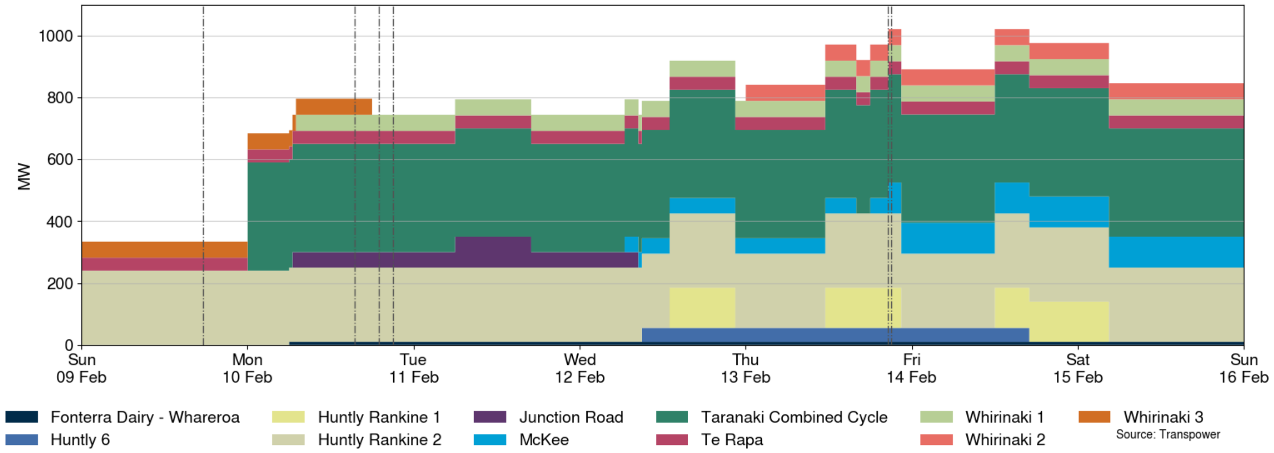


Figure 17: Total MW loss from thermal outages, 9-15 February



9. Generation balance residuals

9.1. Figure 18 and Figure 19 show the national generation balance residuals between 9-15 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 minimum North Island residual this week was ~276MW at 5.30pm on Monday. During this time there was maximum weekly demand and low wind generation.

Figure 18: National generation balance residuals, 9-15 February

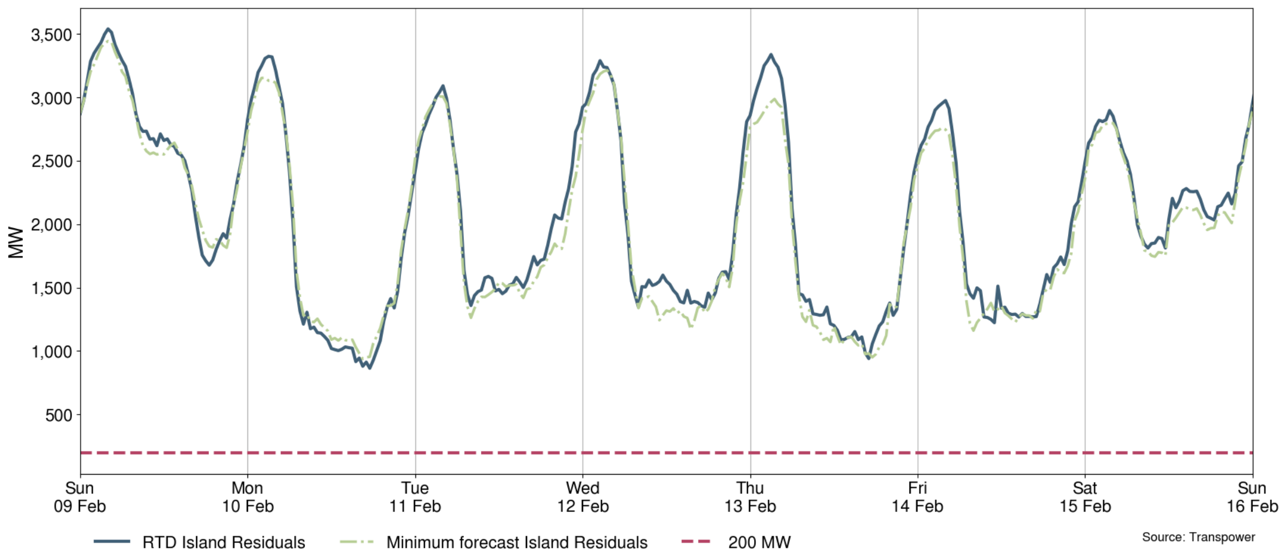
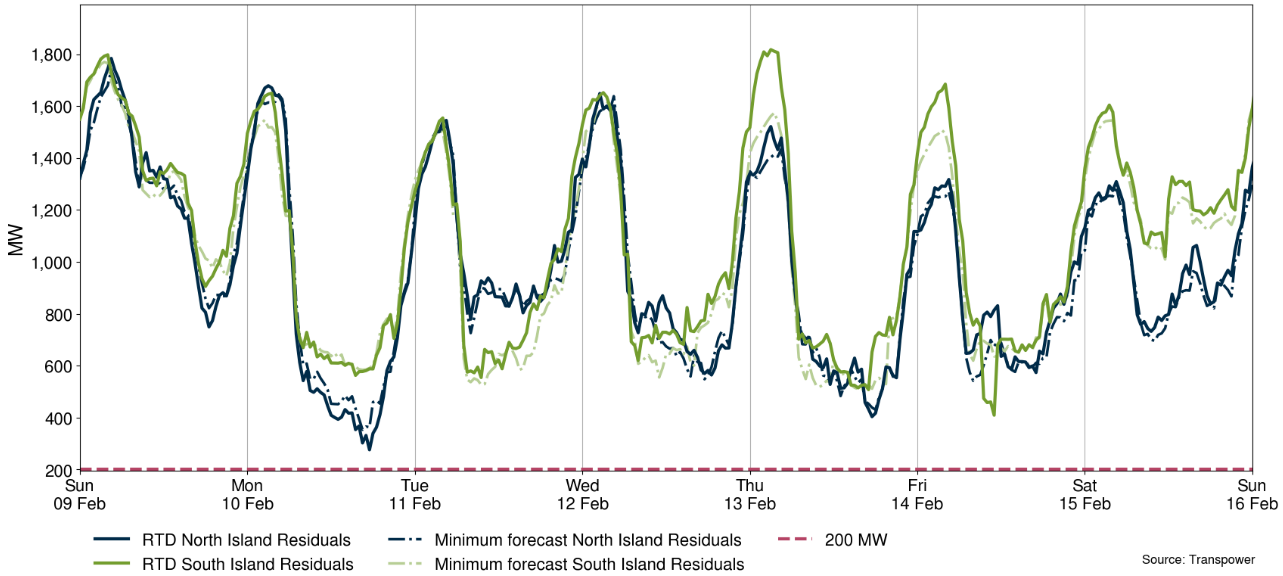


Figure 19: North and South Island generation balance residuals, 9-15 February



10. Storage/fuel supply

10.1. Figure 20 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. National controlled storage continues to decrease. As of 15 February, storage was 73% nominally full and ~90% of the historical average for this time of the year.

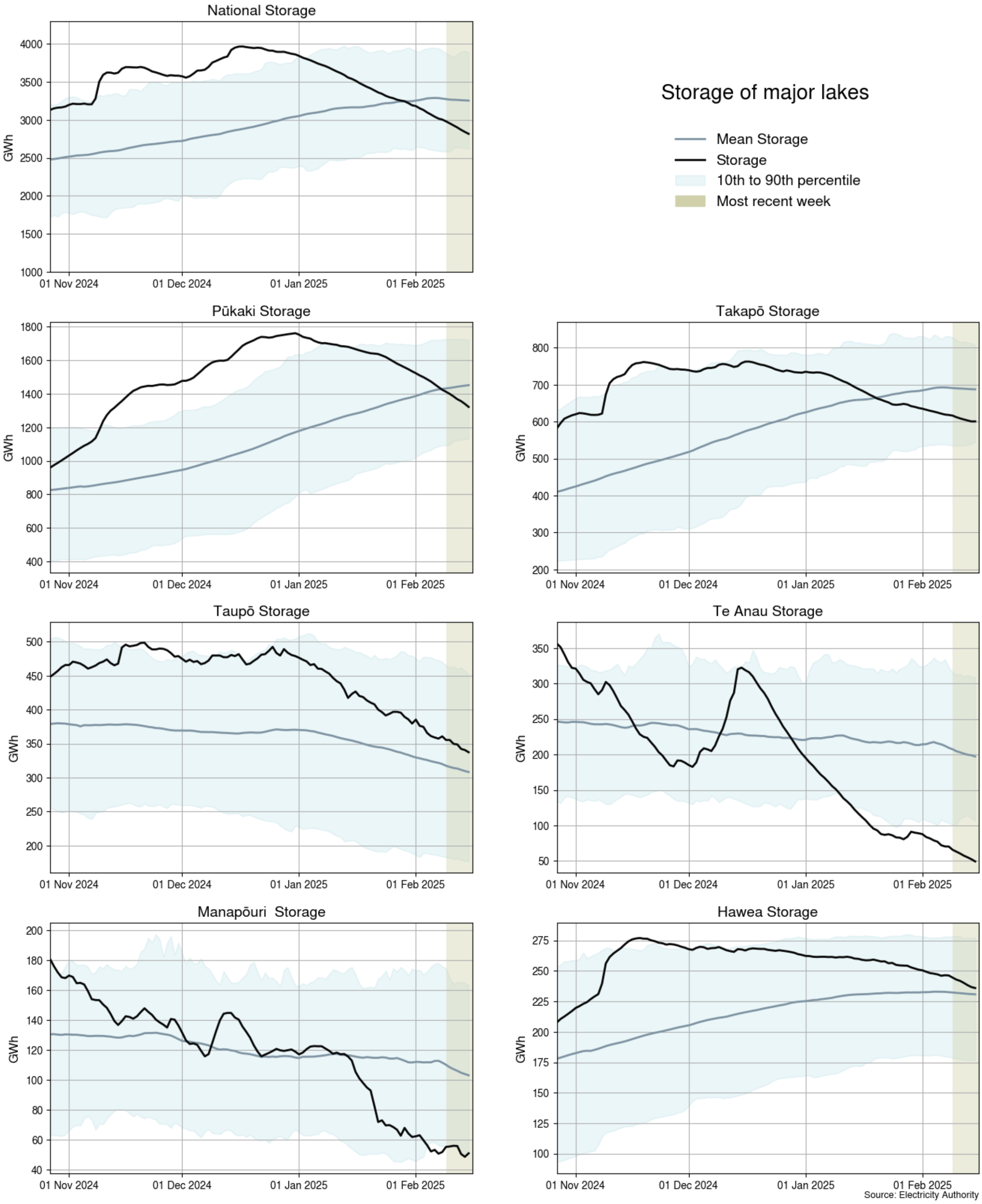
10.3. Lakes Pūkaki (76% full) and Takapō (78% full) have decreased and are between their respective historical mean and 10th percentile.

10.4. Lakes Hawea (83% full) and Taupō (59% full) decreased and are still between their respective historical mean and 90th percentile.

10.5. Manapōuri has fluctuated around its historic 10th percentile.

10.6. Lake Te Anau has decreased and is still below its historical 10th percentile.

Figure 20: 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 21 shows an estimate of thermal SRMCs as a monthly average up to 1 February. The SRMC for gas fuelled generation has increased compared to last month, the SRMC for coal remains similar and the SRMC for diesel fuelled generation has decreased.

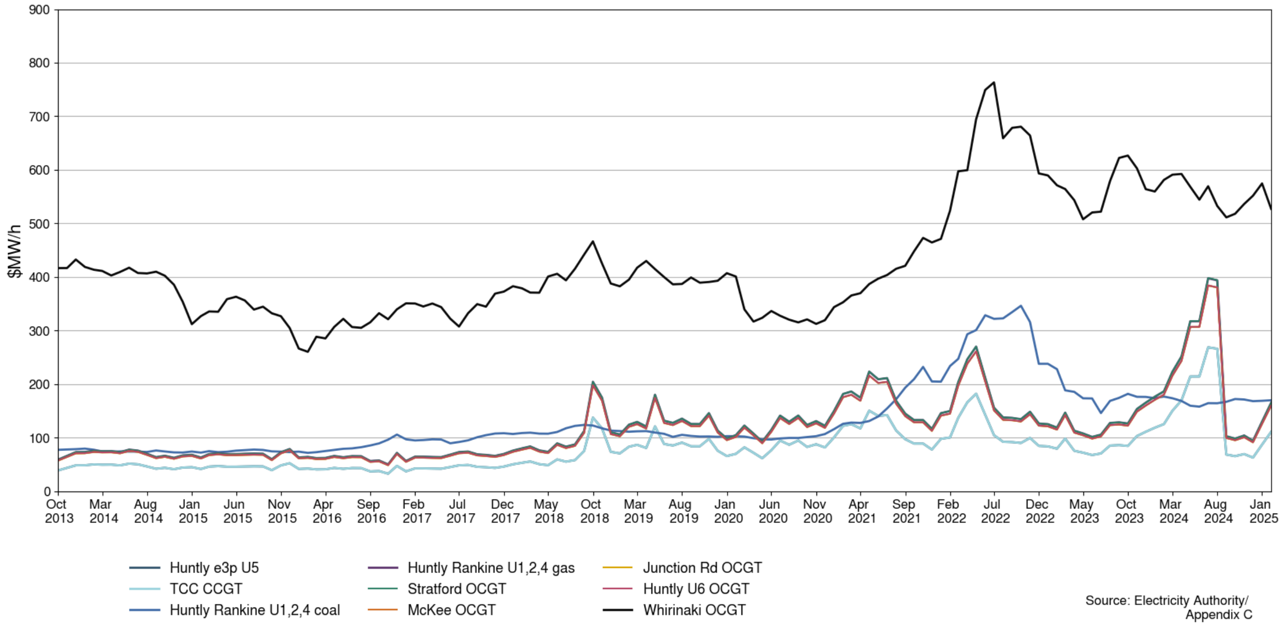
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$170/MWh, with the cost of running the Rankines on gas slightly lower at ~$165/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $111/MWh and $165/MWh.

11.6. The SRMC of Whirinaki is ~$527/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

Figure 21: Estimated monthly SRMC for thermal fuels

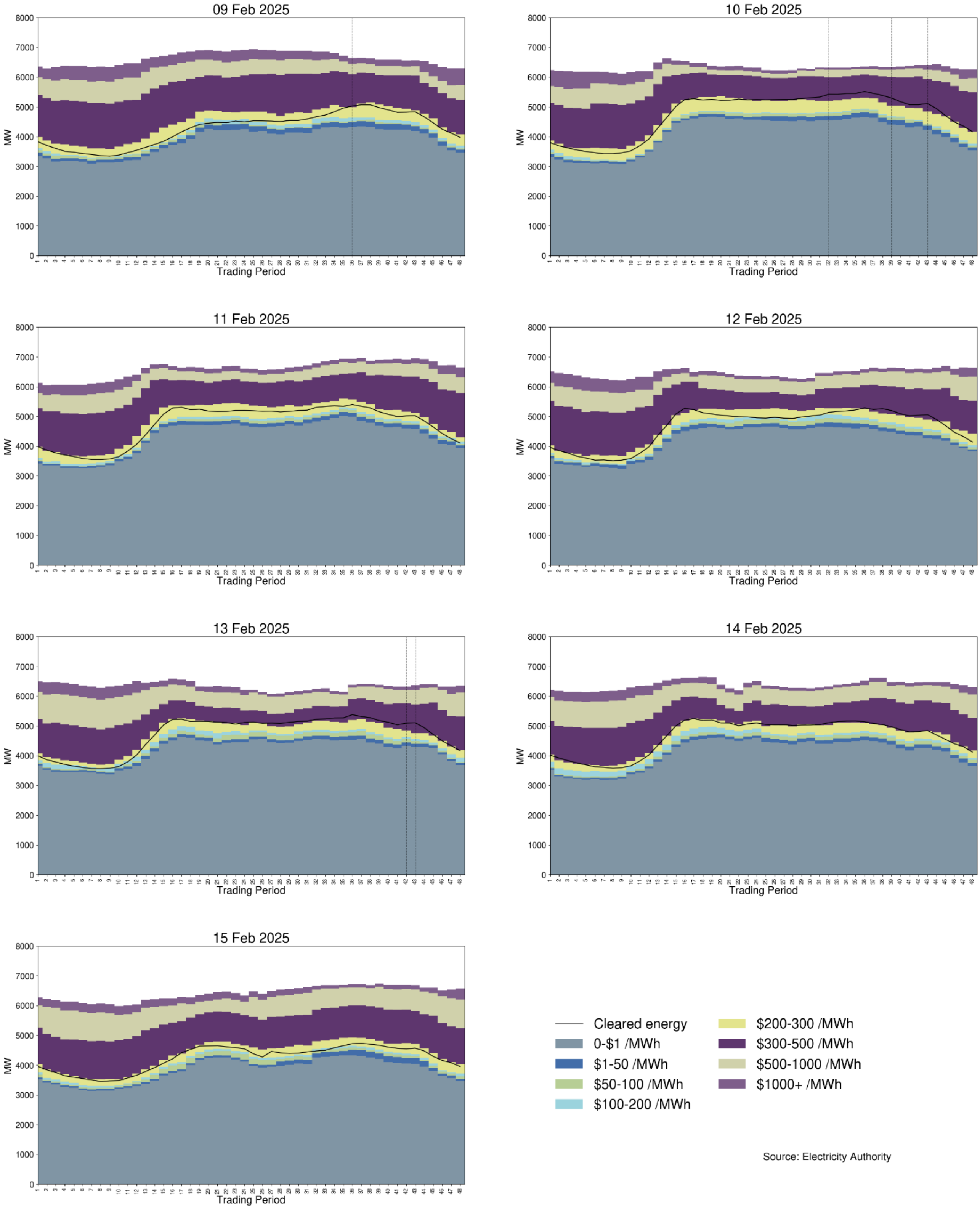


12. Offer behaviour

12.1. Figure 22 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 were clearing in the $200-300/MWh band this week.

Figure 22: Daily offer stacks



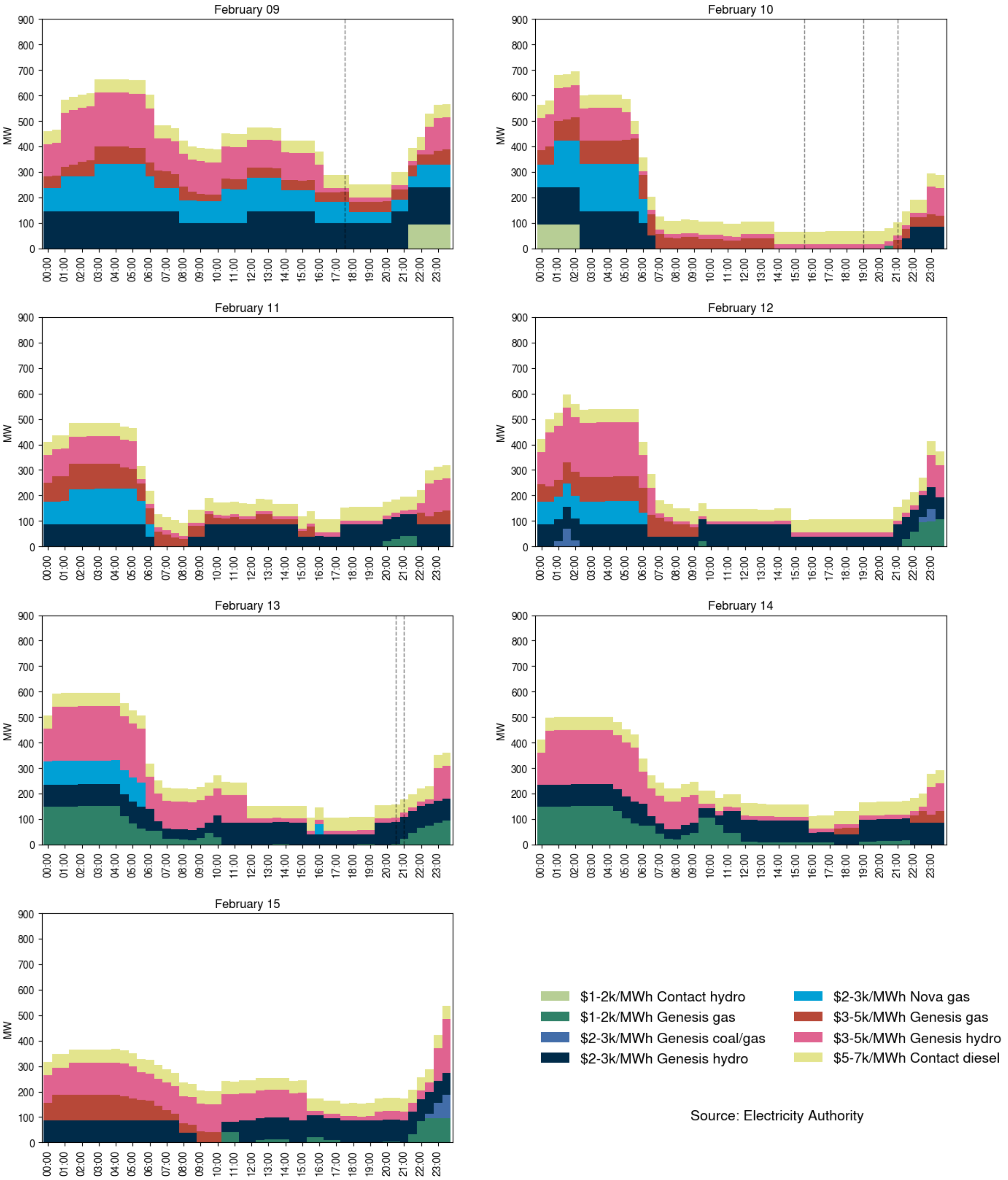
Source: Electricity Authority

12.3. Figure 23 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.4. 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.

12.5. On average 286MW per trading period was priced above $1,000/MWh this week, which is roughly 5.3% of the total energy available. This is approximately 1.5% less high priced energy than last week.

Figure 23: 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. However, the monitoring team will be looking further into unplanned outages that occurred 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
14/06/2023-15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
26/01/2025-1/02/2025	Several	Further analysis	Genesis	Takapō	Hydro offers
29/01/2025	34-40	Further analysis	N.A	N.A	Reserve prices
9/02/2025-15/02/2025	Several	Further analysis	Nova	McKee and Junction road	Reasons behind unplanned outages