10 February 2025

Trading conduct report 2-8 February

Market monitoring weekly report

Trading conduct report 2-8 February

1. Overview

1.1. Spot prices have increased this week due to consistent low wind, increased thermal generation, a continued low inflow sequence, a dry outlook, and hydro storage dropping to 77% nominally full.

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 2-8 February:

(a) The average spot price for the week was $226/MWh, an increase of around $54/MWh compared to the previous week.

(b) 95% of prices fell between $124/MWh and $289/MWh.

2.3. Prices are mostly above $200/MWh because:

(a) hydro storage is still decreasing

(b) hydro inflows have been low

(c) rain forecasts are dry for the next few weeks

(d) expensive thermal generation increased

(e) and wind was low.

2.4. The highest price of the week, occurring on Monday at 7pm, was $2,480/MWh at Cambridge. This was due to transmission line constraints in the area.

2.5. The highest price at Ōtāhuhu was $325/MWh at 9:00pm on Tuesday. This was due to the slight uptick in demand typical for this time, paired with the usual decrease of cheaper energy offers in the evening.

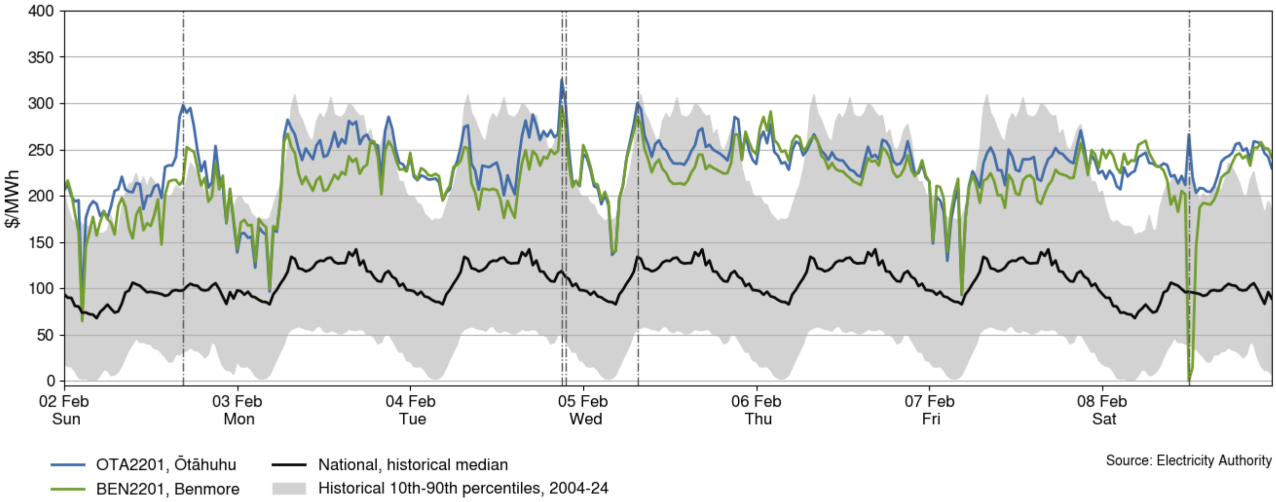
2.6. Prices spiked to $298/MWh at Ōtāhuhu on Sunday at 4.30pm while the price at Benmore was $217/MWh. Demand was ~100MW higher than forecast at this time, and 88MW of that error was in the North Island.

2.7. Prices also spiked to $300/MWh at Ōtāhuhu on Wednesday at 7.30am. Demand was 139MW higher than forecast at this time, likely due to a sudden temperature drop in Christchurch and Wellington. Wind was also very low the entire day and 61MW lower than forecast at the time of the spike.

2.8. There was major price separation on Saturday at 12pm. The price at Ōtāhuhu was $266/MWh while the price at Benmore was $0.03/MWh. This was due to a planned HVDC Bi-pole outage within this time period.

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.

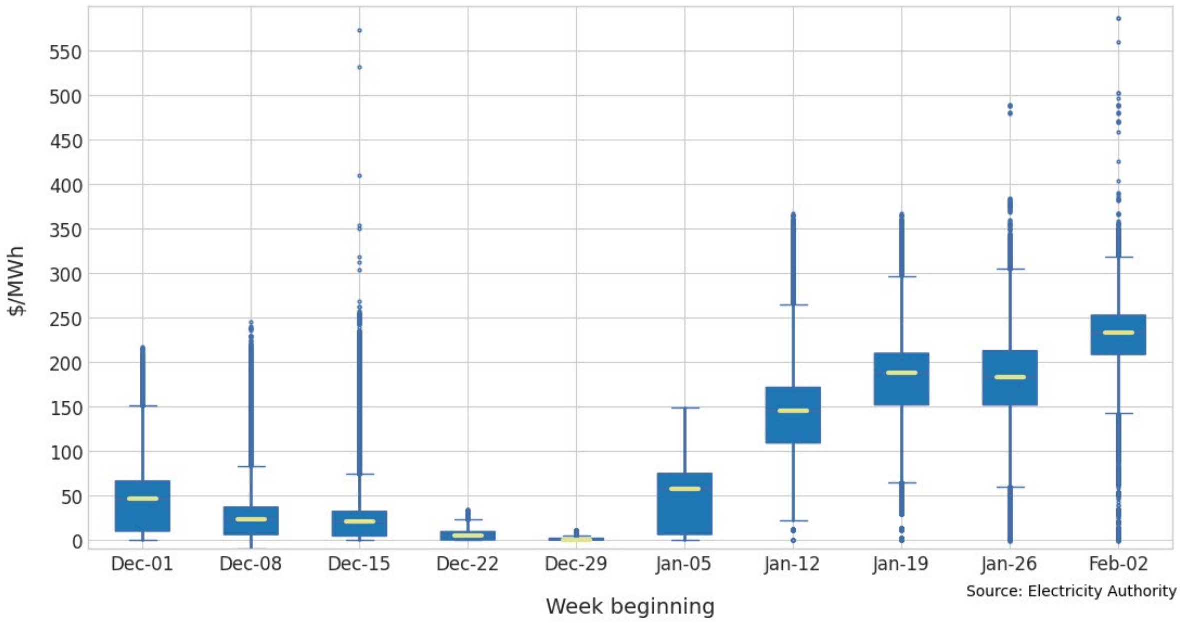
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 2-8 February



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 skewed higher than last week. The median price was $233/MWh and most prices (middle 50%) fell between $209/MWh and $253/MWh.

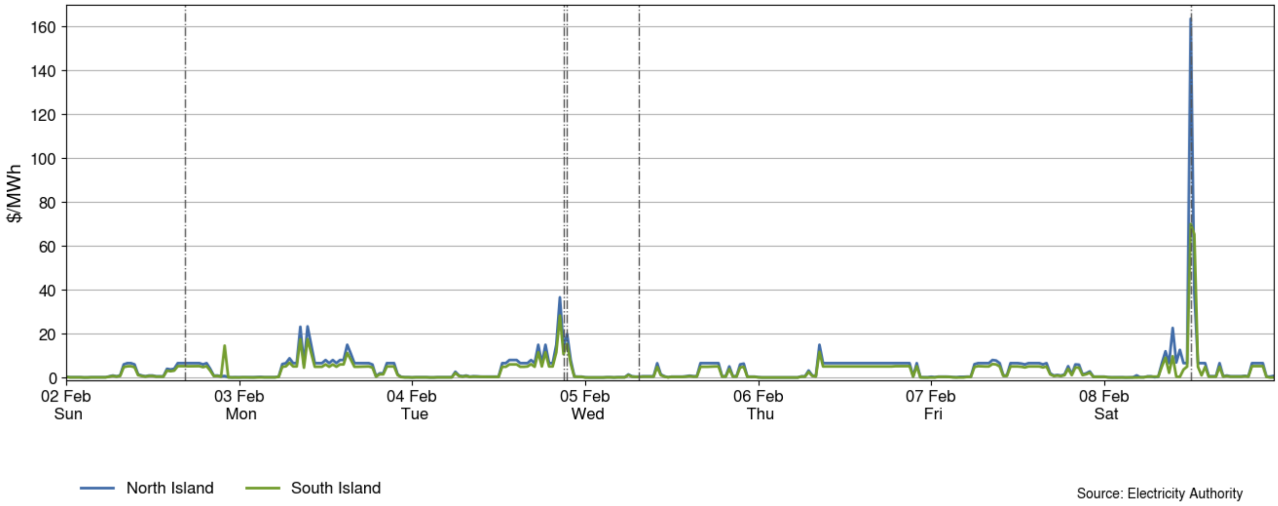
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

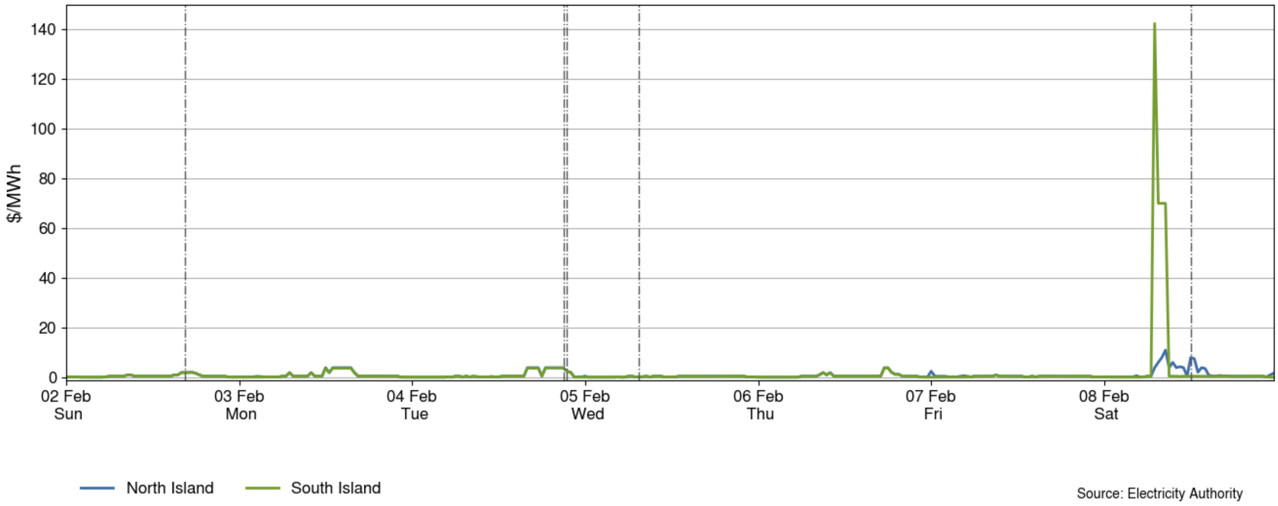
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh. They spiked to $163/MWh in the North Island and $70/MWh in the South Island during the HVDC Bi-pole outage.

Figure 3: Fast instantaneous reserve price by trading period and island, 2-8 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. South Island SIR prices spiked to $142/MWh at 7am on Saturday when the HVDC Pole 3 outage began. This was due to an increase in South Island reserves needed to cover the South Island risk while pole 3 was on outage.

Figure 4: Sustained instantaneous reserve by trading period and island, 2-8 February



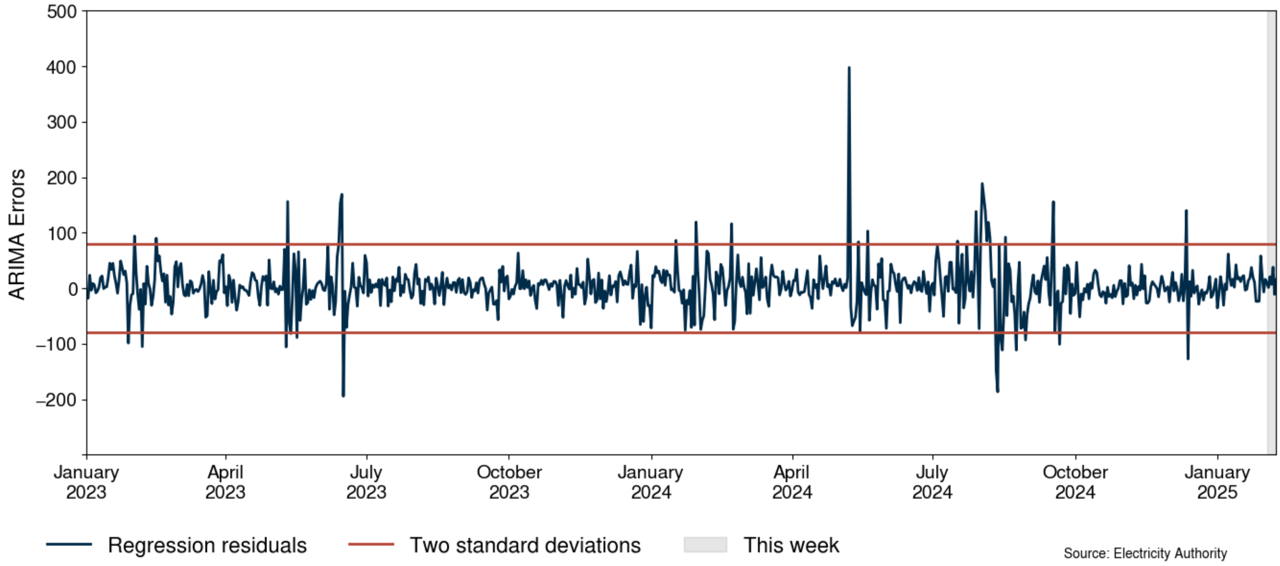
4. Regression residuals

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 - DD MM YYYY

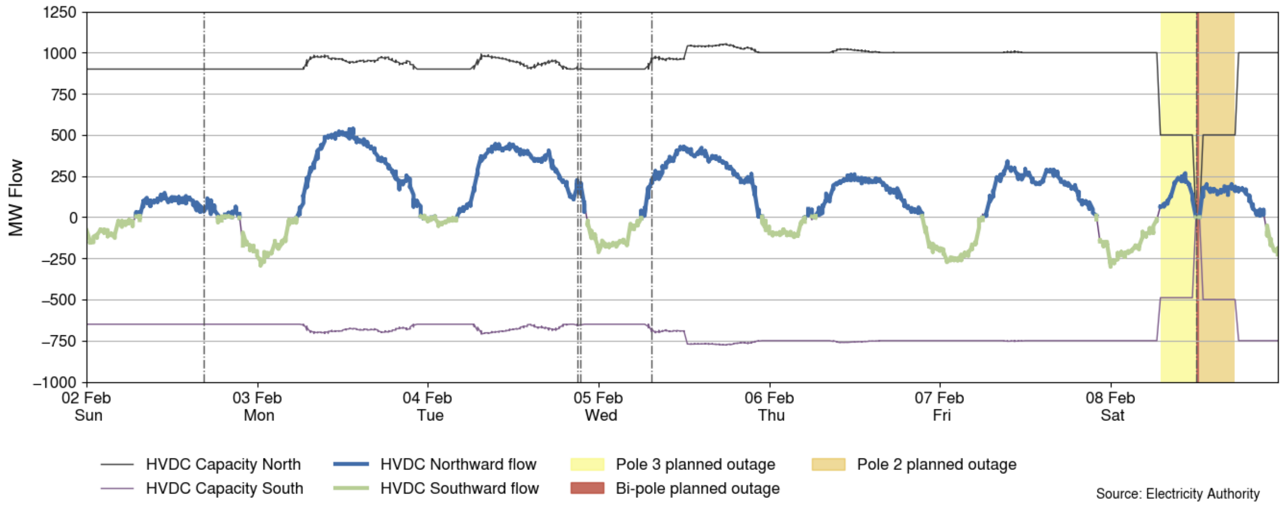


5. HVDC

5.1. Figure 6 shows the HVDC flow between 2-8 February. HVDC flows were mostly northward during the day and southward during the night. Maximum northward flow occurred at 1.30pm on Monday, reaching 538MW. Maximum southward flow occurred in the early hours of Saturday morning.

5.2. Several planned HVDC outages occurred on Saturday. Pole 3 was on outage from 7am-12pm, Pole 2 was on outage from 12.30-5.30pm, and both poles were on outage 12-12.30pm.

Figure 6: HVDC flow and capacity, 2-8 February

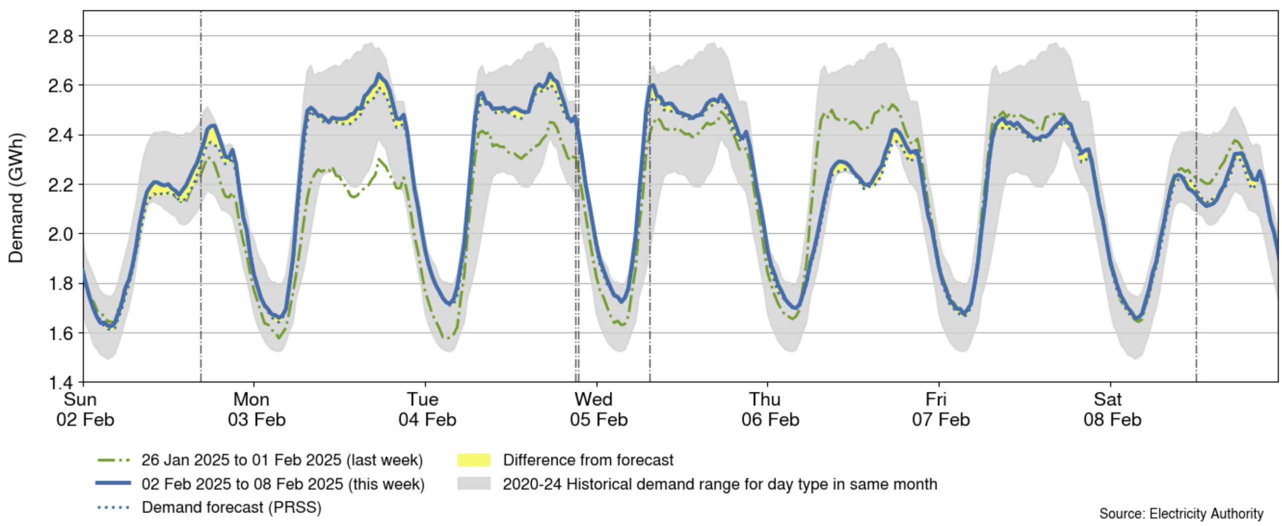


6. Demand

6.1. Figure 7 shows national demand between 2-8 February, compared to the historic range and the demand of the previous week. Demand was on the high end of the historic range Sunday to Wednesday. Maximum demand occurred on Tuesday at 5.30pm and was 2.64GWh. Demand was low on Thursday, due to Waitangi Day.

6.2. Demand was higher than forecast frequently this week, especially during afternoon peak times.

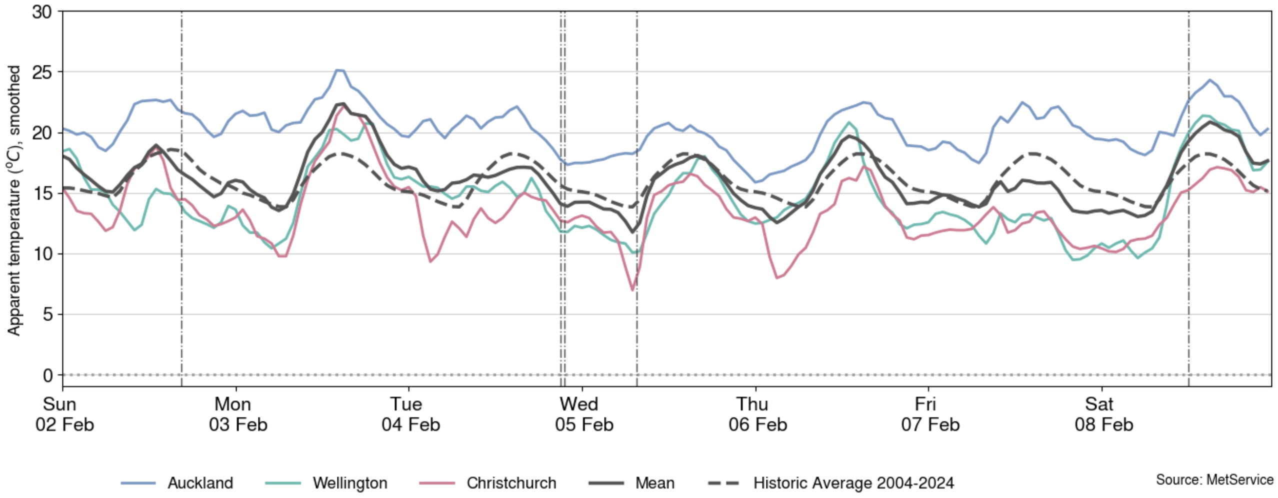
Figure 7: National demand, 2-8 February compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 2-8 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.

6.4. Apparent temperatures ranged from 16°C to 26°C in Auckland, 9°C to 22°C in Wellington, and 6°C to 23°C in Christchurch. They were above average on Monday and Saturday, and below average on Wednesday and Friday.

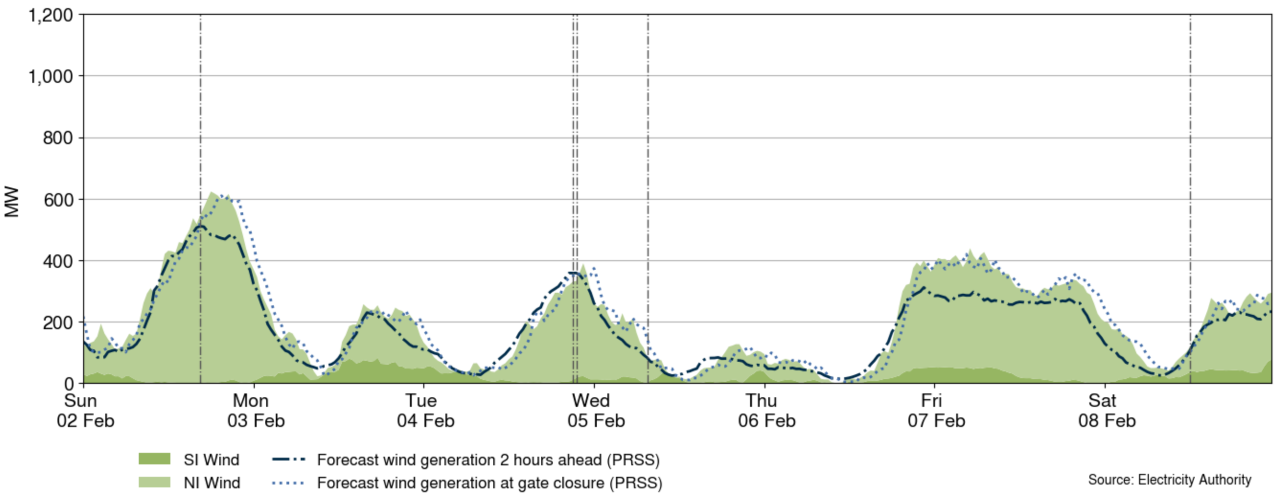
Figure 8: Temperatures across main centres, 2-8 February



7. Generation

7.1. Figure 9 shows wind generation and forecast from 2-8 February. This week wind generation varied between 0MW and 623MW, with a weekly average of 204MW. Wind generation was very low this week, especially from Monday to Thursday and Saturday.

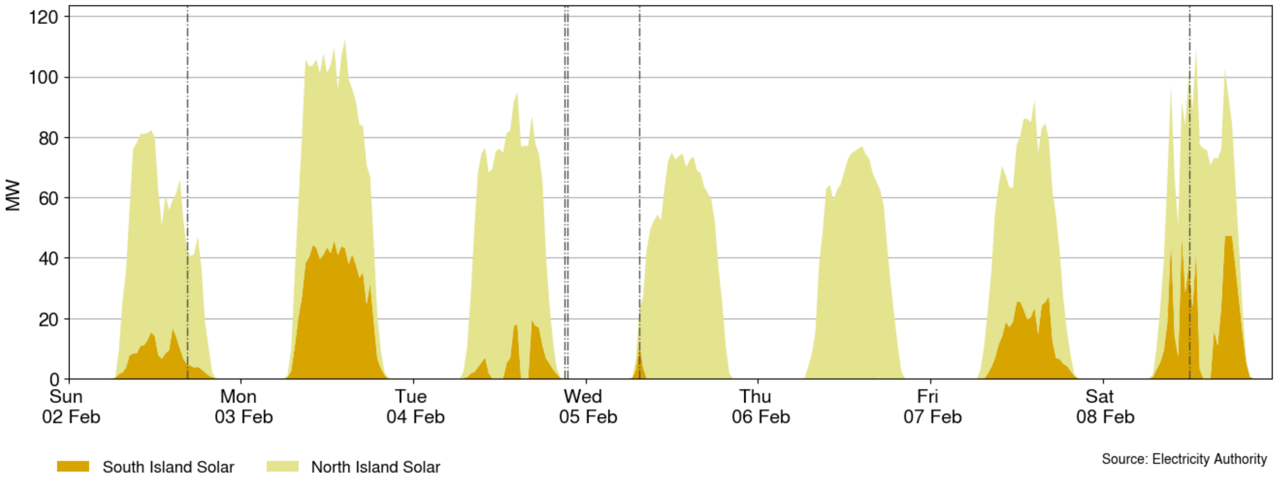
Figure 9: Wind generation and forecast, 2-8 February



7.2. Figure 10 shows grid connected solar generation from 2-8 February. Solar generation reached above 80MW every day except Wednesday and Thursday. Maximum generation was 112MW on Monday at 2.30pm. The South Island wind farm Lauriston was still commissioning this week.[1]

[1] CAN Lauriston Solar Farm is to be classified as a Secondary 5991385984.pdf

Figure 10: Grid connected solar generation, 2-8 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[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 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.

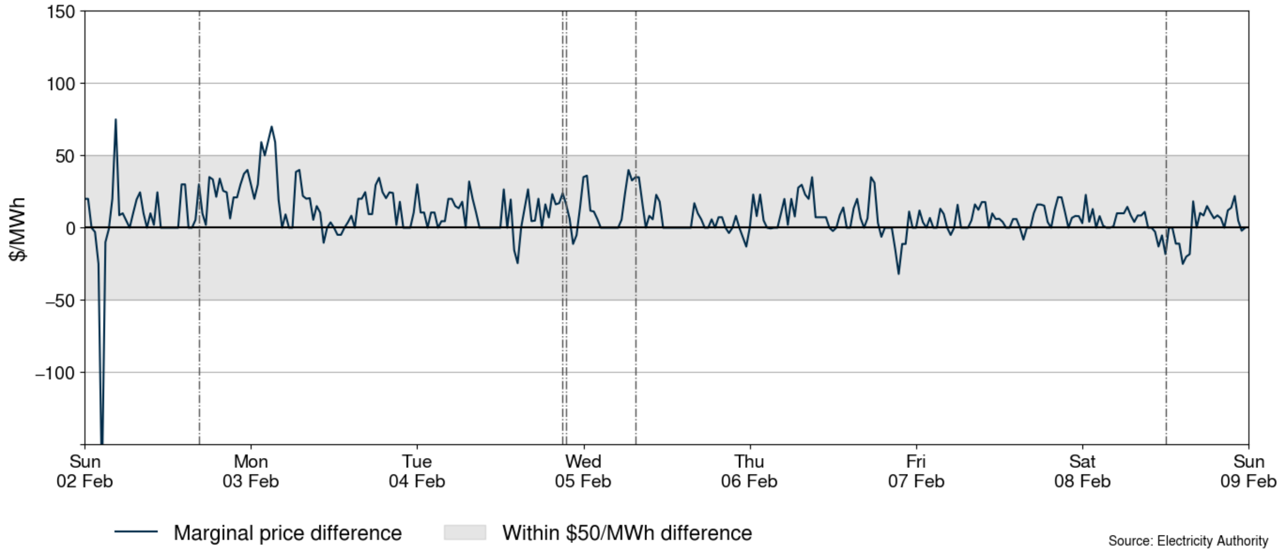
7.4. The largest marginal price difference this week was at 2.30am on Sunday when the actual price was $180/MWh lower than expected. This corresponds to a sharp increase in wind generation that led to wind being 93MW higher than forecast at gate closure.

7.5. The actual price was over $50/MWh higher than expected in the early hours of Monday morning. This corresponds to a sharp drop in wind causing wind to be lower than forecasts at gate closure.

7.6. The marginal price difference also spiked above +$50/MWh on Sunday at 4.30am. Demand was ~40MW higher than forecast.

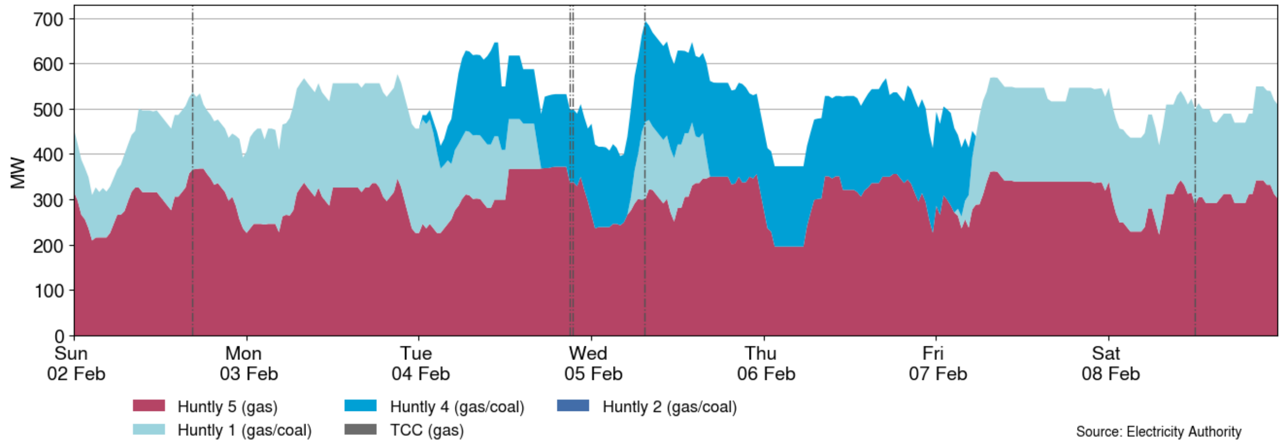
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 2-8 February



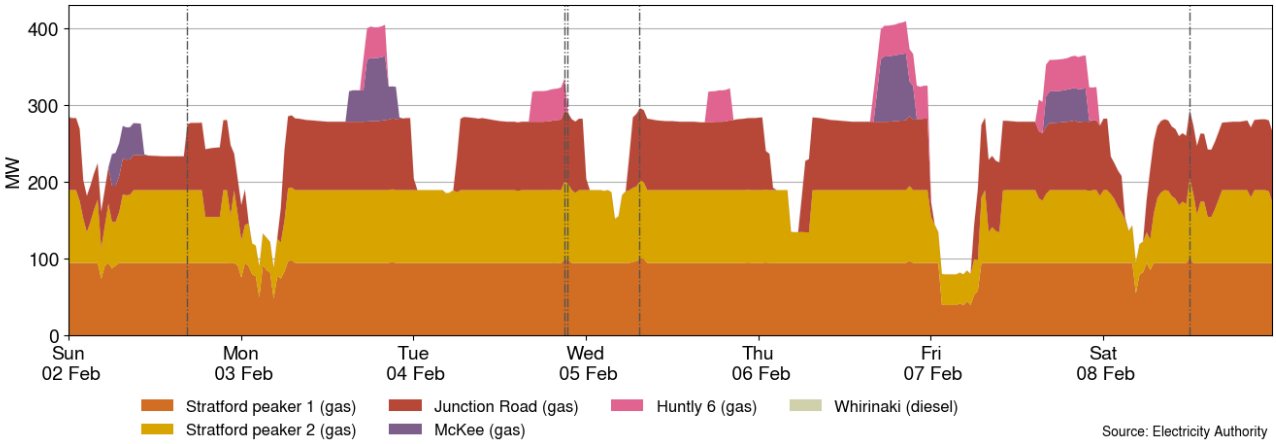
7.7. Figure 12 shows the generation of thermal baseload between 2-8 February. Huntly 5 generated baseload this week, with Huntly 1 generating every day except Thursday and Huntly 4 generating Tuesday to Saturday.

Figure 12: Thermal baseload generation, 2-8 February



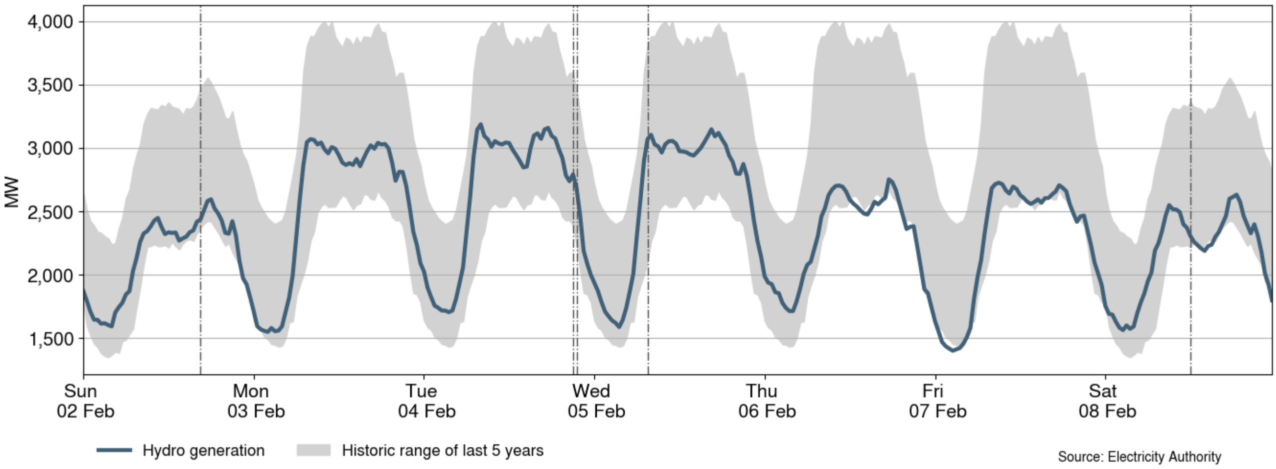
7.8. Figure 13 shows the generation of thermal peaker plants between 2-8 February. Both Stratford Peakers generated baseload. Junction Road generated every day. Mckee and Huntly 6 also generated on select days.

Figure 13: Thermal peaker generation, 2-8 February



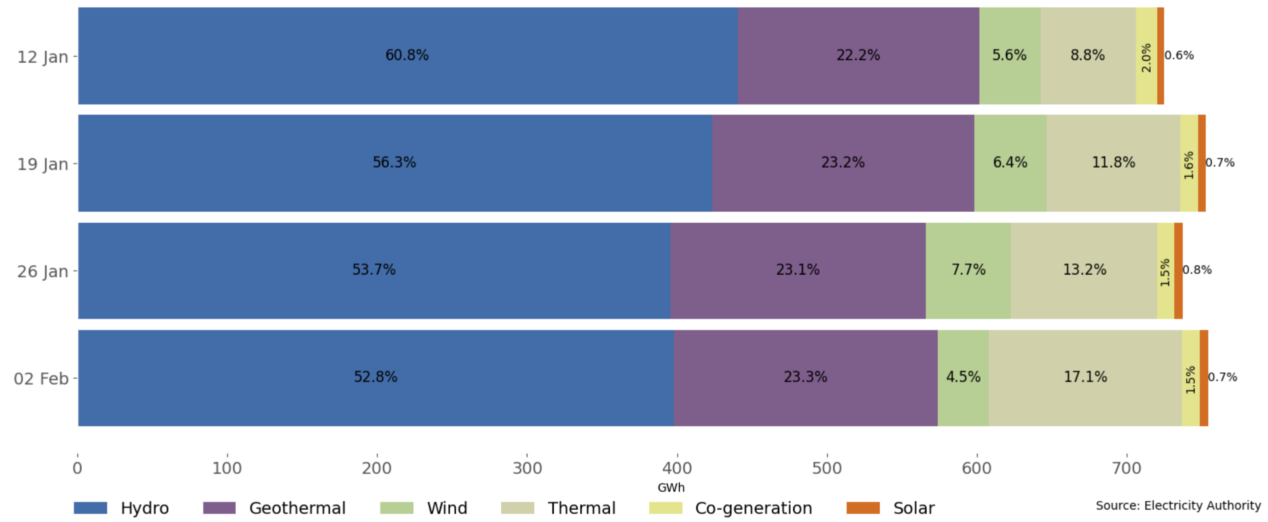
7.9. Figure 14 shows hydro generation between 2-8 February. Hydro generation was near the bottom of the historic range every day except Monday to Wednesday when demand was higher.

Figure 14: Hydro generation, 2-8 February



7.10. As a percentage of total generation, between 2-8 February, total weekly hydro generation was 52.8%, geothermal 23.3%, wind 4.5%, thermal 17.1%, co-generation 1.5%, and solar (grid connected) 0.7%, as shown in Figure 15. The proportion of thermal generation increased by ~4% this week as the proportion of wind and hydro generation decreased. Even though the proportion of hydro generation decreased this week, the amount of hydro generation was roughly the same as last week.

Figure 15: Weekly total generation by type in GWh, annotated with percentage of total generation, 12 January and 8 February



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 2-8 February ranged between ~1,209MW and ~2,096MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 28 February (formerly 2 March).

(b) Huntly station was on partial outage on 4 February (unplanned due to unforeseen consent breach).

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

(d) Manapōuri unit 1 was on outage 3-4 February.

(e) Manapōuri unit 6 was on outage 7-10 February.

(f) Manapōuri unit 7 was on outage 5 February.

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

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

(i) Takapō B was on outage 8 February.

Figure 16: Total MW loss from generation outages, 2-8 February

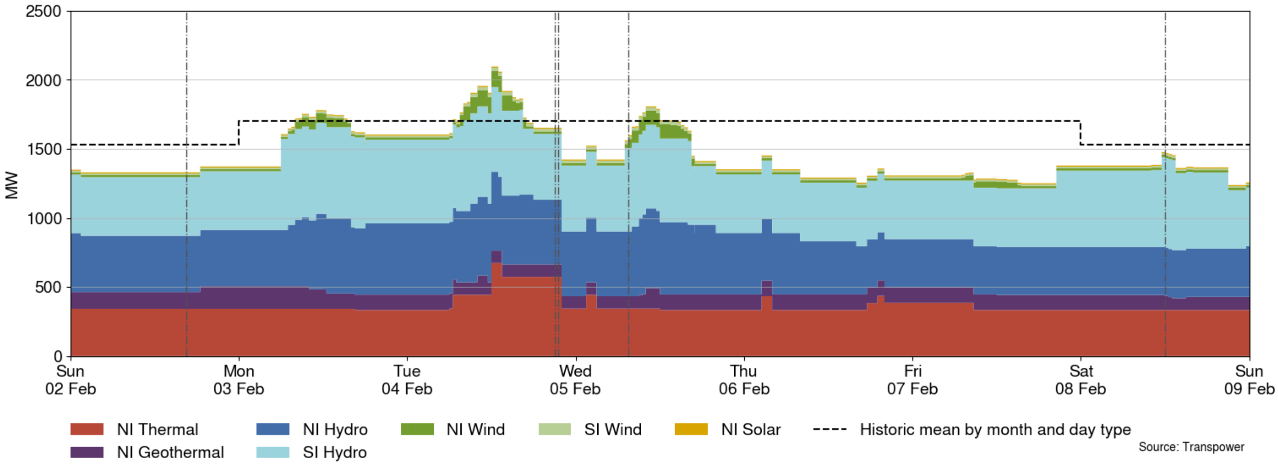
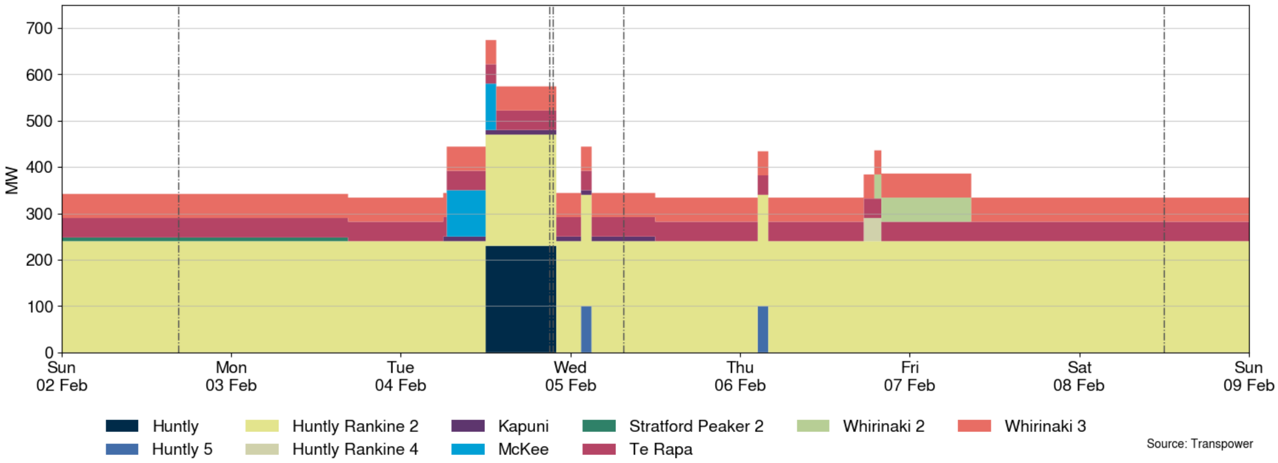


Figure 17: Total MW loss from thermal outages, 2-8 February

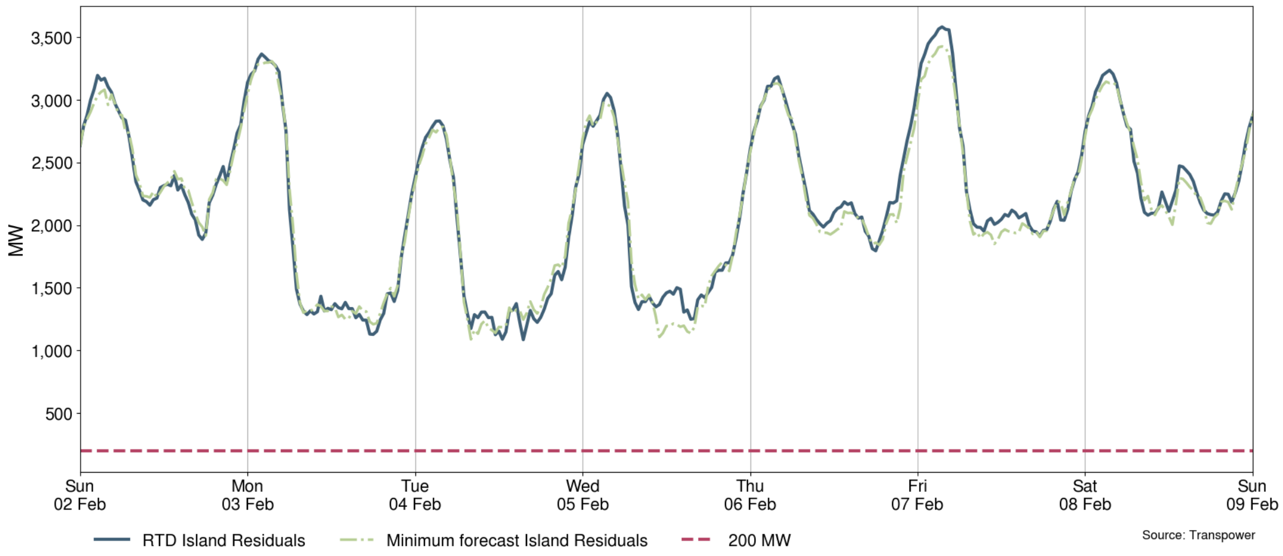


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 2-8 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 ~494MW at 6.30pm on Monday.

Figure 18: National generation balance residuals, 2-8 February



10. Storage/fuel supply

10.1. Figure 19 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 has continued to decrease. As of 8 February, storage was 77% nominally full and ~94% of the historical average for this time of the year.

10.3. Lake Pūkaki (82% full) has decreased to approximately its historic mean.

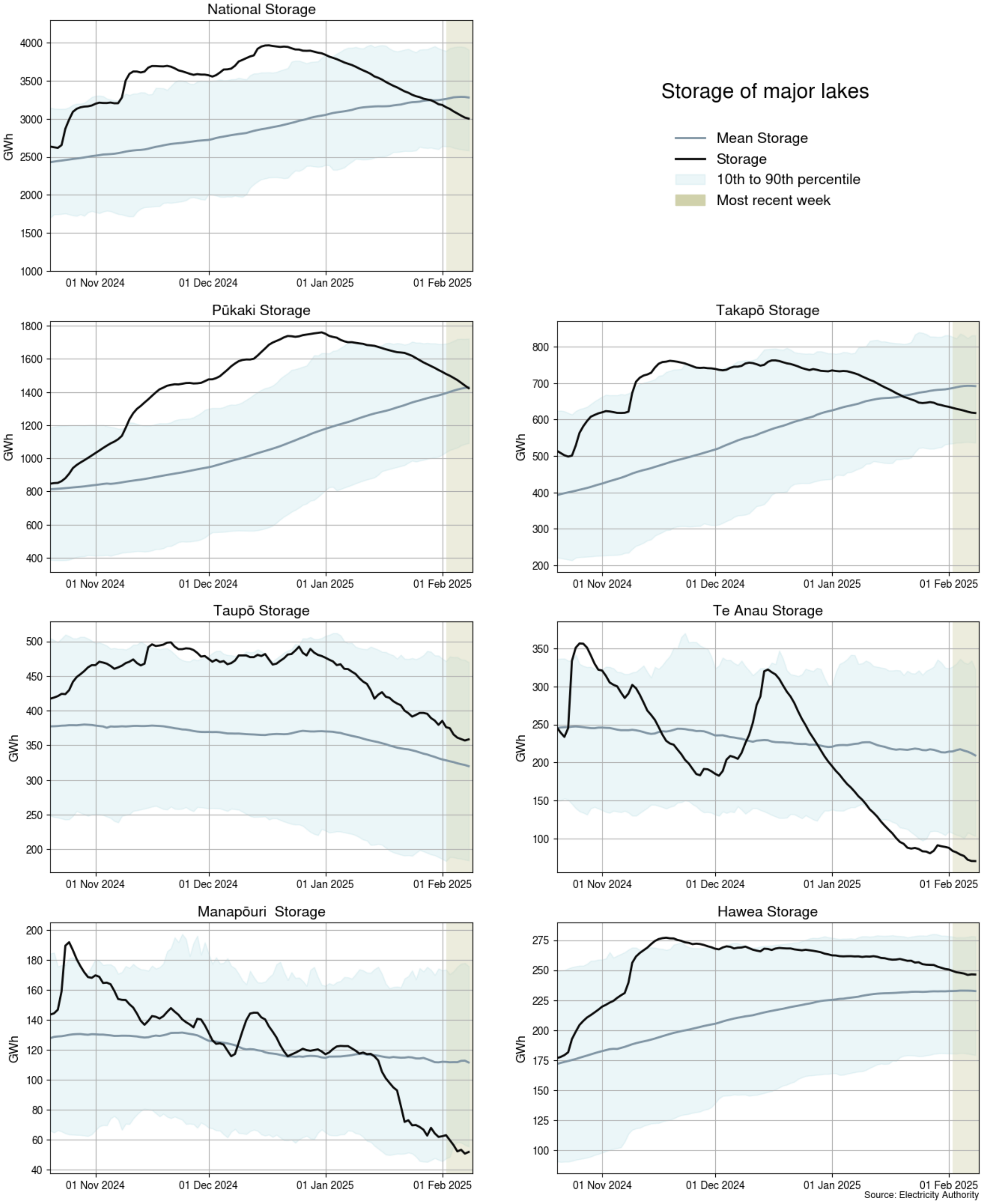
10.4. Lakes Hawea (86% full) and Taupō (62% full) decreased and are still between their respective historical mean and 90th percentile.

10.5. Lake Takapō (80% full) decreased and is still between its respective historical mean and 10th percentile.

10.6. Manapōuri has decreased to below its historic 10th percentile.

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

Figure 19: 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 20 shows an estimate of thermal SRMCs as a monthly average up to 1 January. The SRMC for gas fuelled generation has increased compared to last month and the SRMC for coal and diesel fuelled generation remains similar to last month.

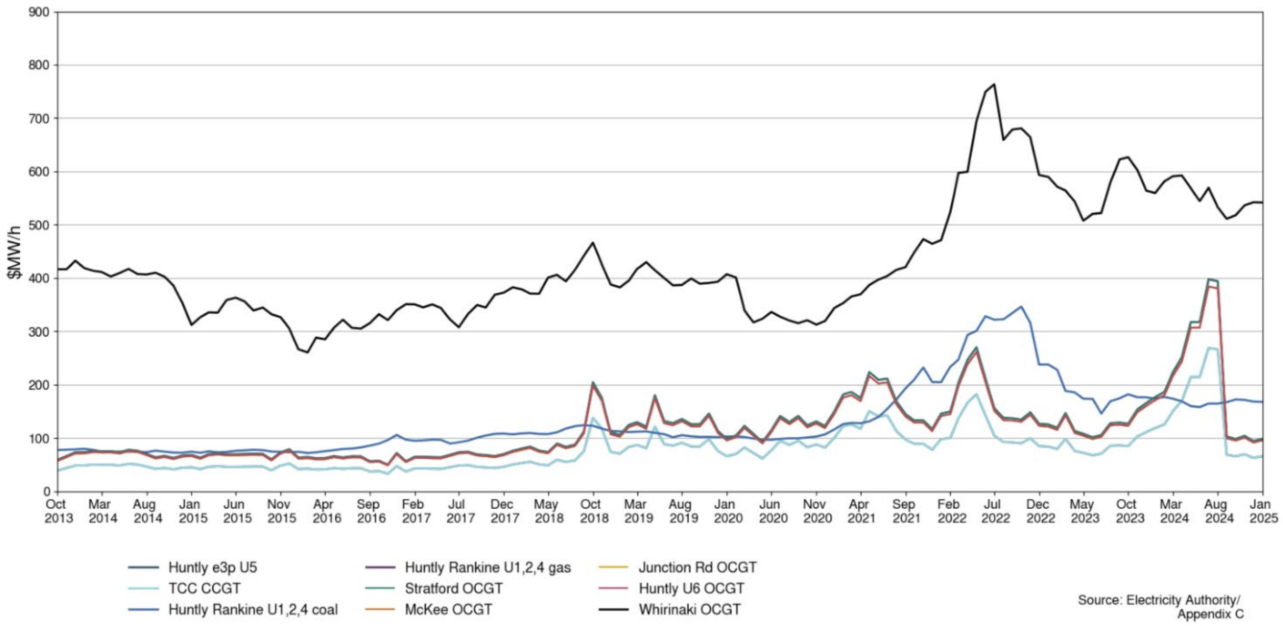
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$167/MWh, with the cost of running the Rankines on gas remaining lower at ~$98/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $66/MWh and $98/MWh.

11.6. The SRMC of Whirinaki is ~$541/MWh.

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

Figure 20: Estimated monthly SRMC for thermal fuels

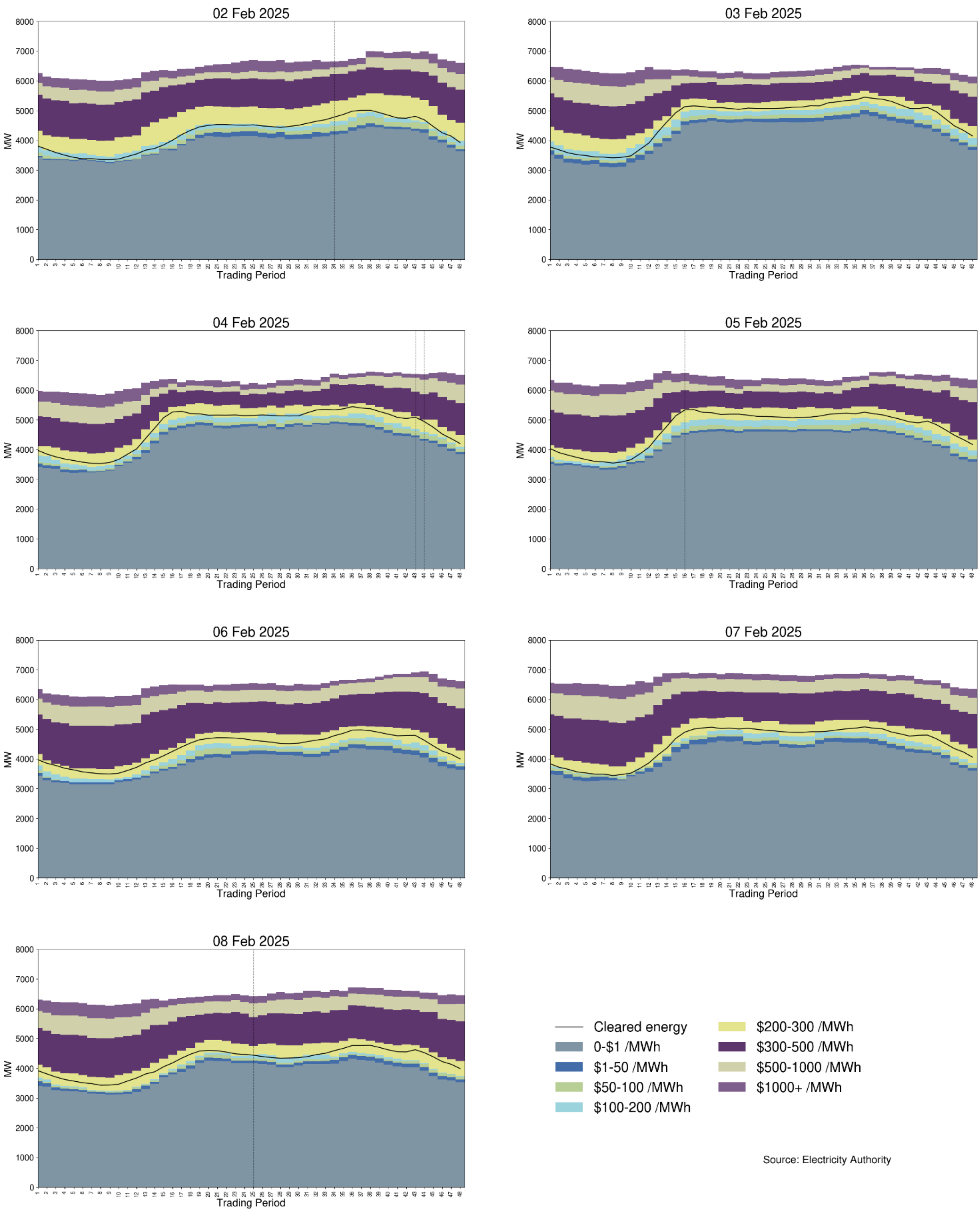


12. Offer behaviour

12.1. Figure 21 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 21: Daily offer stacks

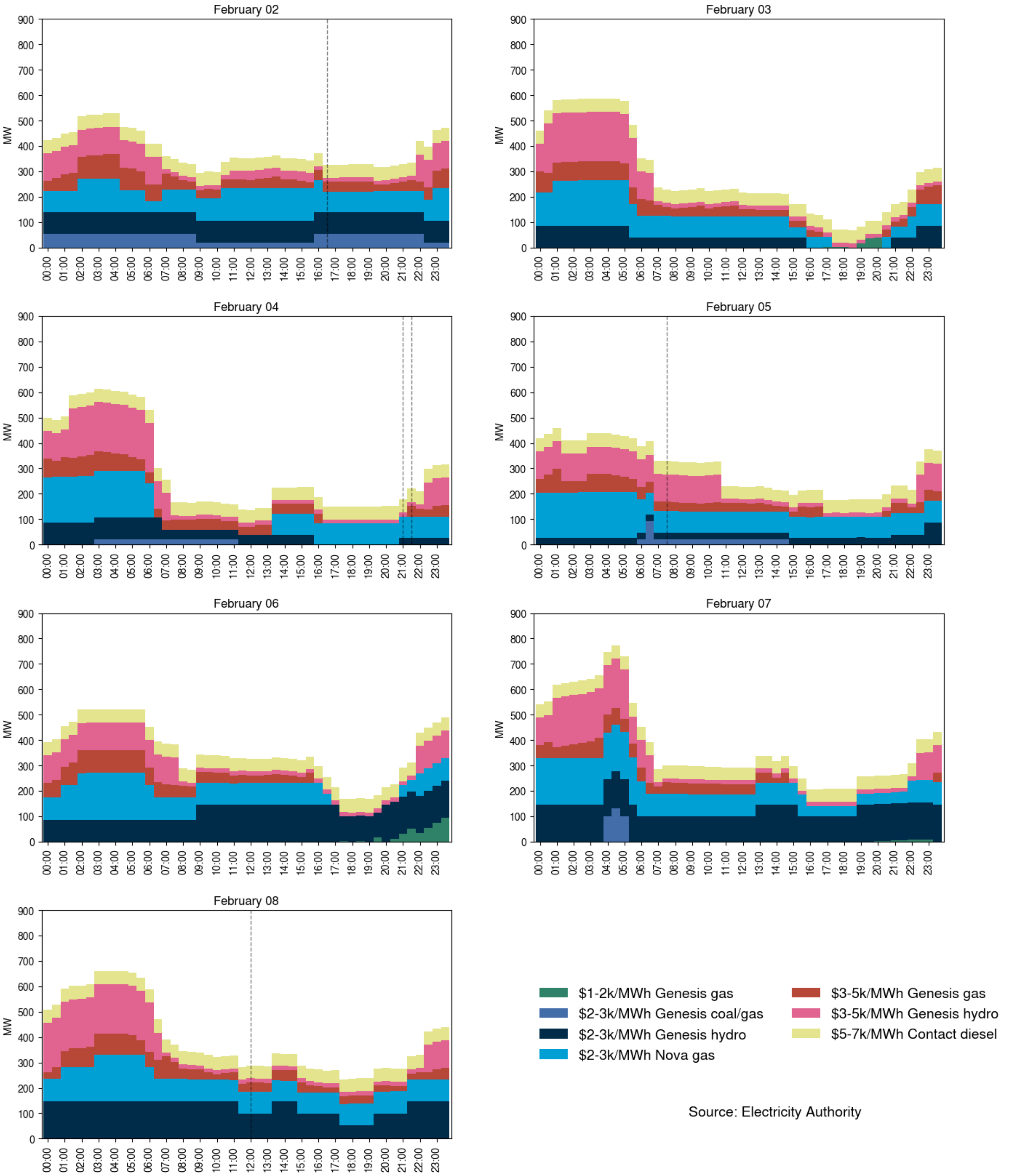


12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

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 377MW per trading period was priced above $1,000/MWh this week, which is roughly 6.8% of the total energy available. This is approximately 1% less high priced energy than last week. The highest proportion of high priced energy occurred at night.

Figure 22: 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
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 Energy	Clutha scheme	Hydro offers
12-18/12/2024	Several	Further analysis	Genesis	Tokaanu	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