5 February 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for weeks of 28 January – 3 February

1.1. Prices were low at the start and end of the week now that hydro storage levels have increased. Mid-week saw some high prices due to a combination of high demand and tight supply, along with demand and wind forecasting errors. There was also large price separation for a time on Wednesday likely due to a constraint on the HVDC. Overall thermal generation was lower with only Huntly 5 running as baseload and peakers running to meet the higher demand requirements mid-week. Hydro storage continued to increase this week and is currently at ~104% of mean as of 5 February.

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, we also single 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. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range[1] of historic prices, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 28 January - 3 February:

(a) The average wholesale spot price across all nodes was $104/MWh.

(b) 95 percent of prices fell between $0.01/MWh and $500/MWh.

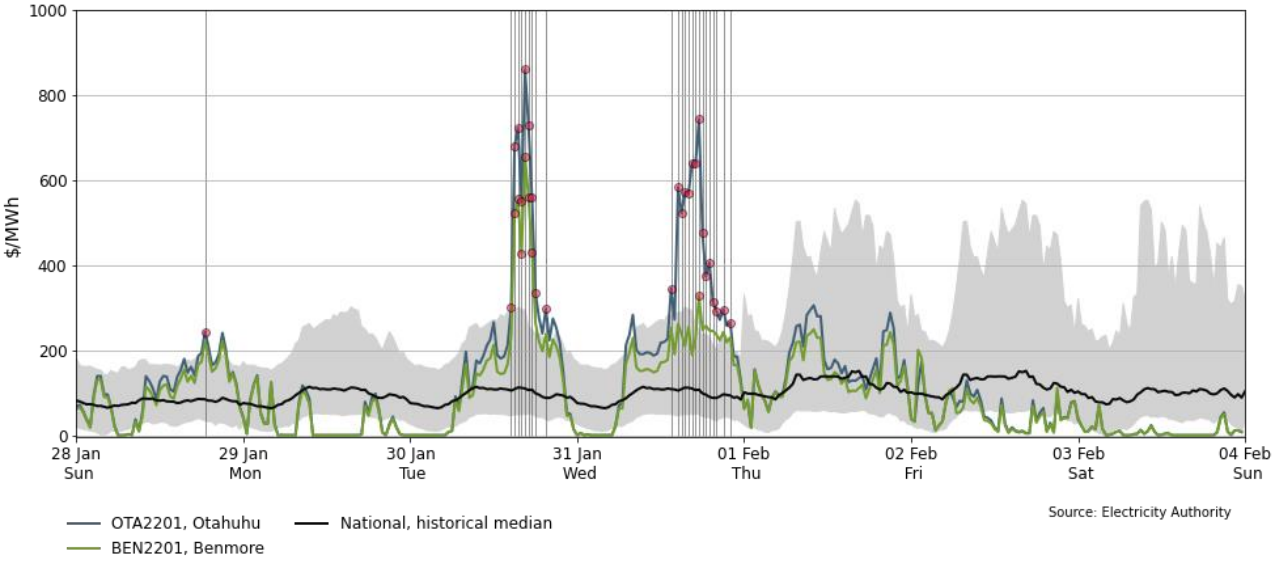
2.4. Overall, the majority of spot prices were within $0-$200/MWh meaning the weekly average price decreased by around $51/MWh compared to the previous week.

2.5. There were multiple price spikes on Tuesday afternoon. The highest price was at 4.30pm, where the price at Ōtāhuhu reached ~$861/MWh and ~$654/MWh at Benmore. The price spikes were related to demand forecasting errors, low and over forecast wind generation, and tight energy and reserve supply.

2.6. Wednesday afternoon saw high spot prices and price separation likely due to HVDC constraints. This was further exacerbated by a combination of high demand, low wind generation, and tight energy and North Island reserve supply. Under-forecast demand may have also contributed to these high spot prices.

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75th percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

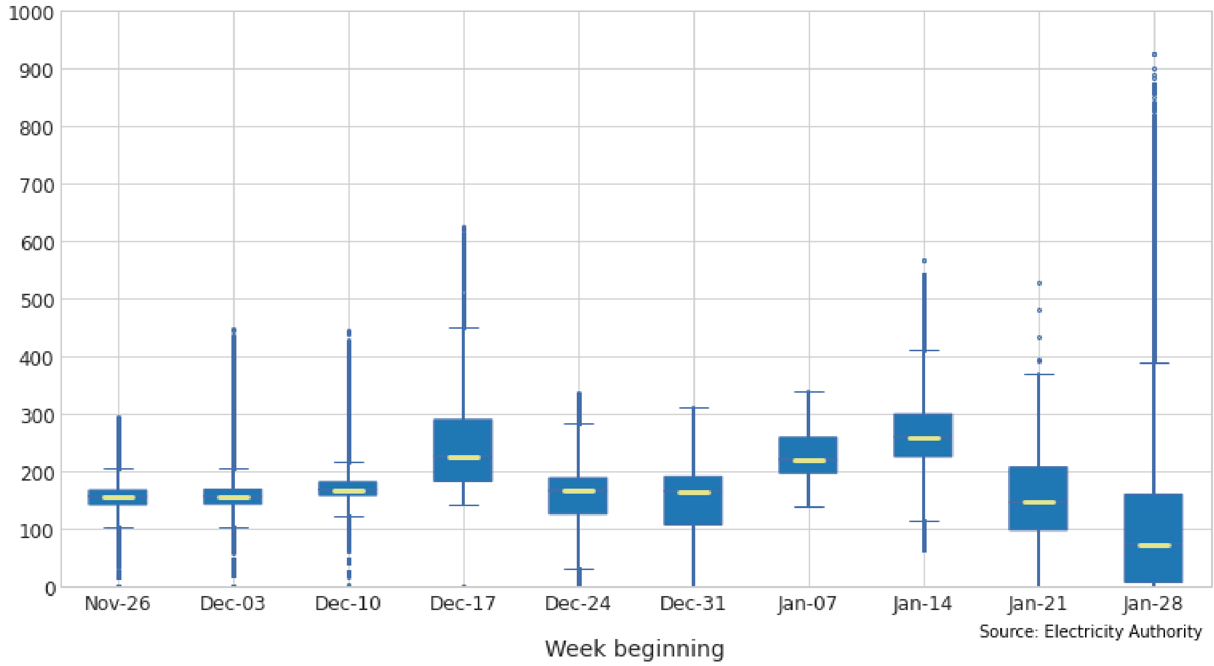
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 28 January - 3 February



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 box part shows the lower and upper quartiles (where 50%of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.8. There was a larger overall spread in prices with higher price outliers compared to the previous week. Most prices (middle 50%) were within \$7-\$160/MWh. The median value for the prices this week was lower than the previous nine weeks at \$73/MWh. This is likely due to the increase in hydro storage, which allows cheaper hydro to increase its output.

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

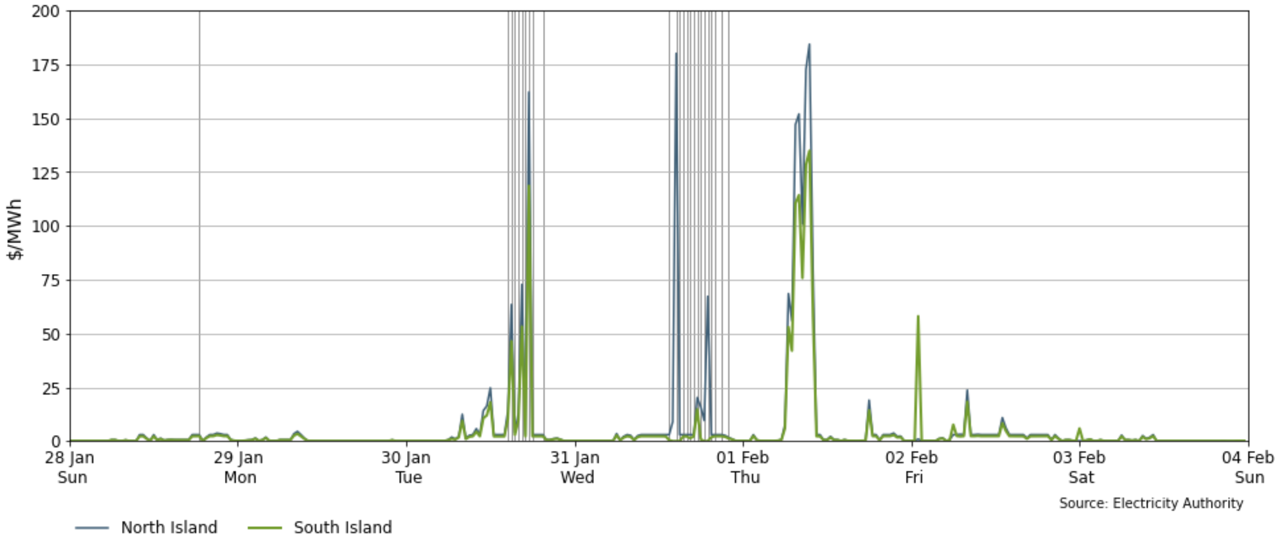


3. Reserve prices

3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were more volatile this week, with a combination of factors, especially between Tuesday and Thursday leading to high FIR prices. The highest FIR prices were on Thursday at 9.30am, when the North Island FIR reached $184/MWh and the South Island FIR also spiked to $135/MWh during this same trading period.

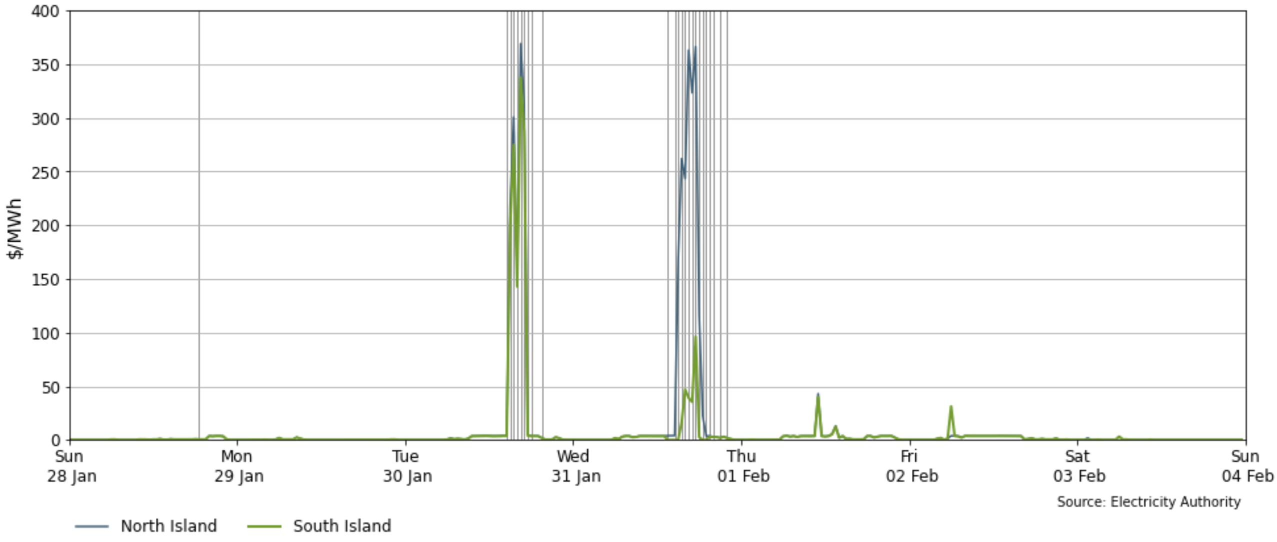
3.2. Tuesday and Wednesday's spikes occurred in line with the high spot prices, with price separation on Wednesday coinciding with price separation for energy prices. At 3.00pm, 4.30pm and 5.30pm on Tuesday North Island FIR prices ranged from $63-$162/MWh, with South Island FIR prices ranging from $46-$119/MWh. There was one large North Island FIR price on Wednesday at 2.30pm, reaching $180/MWh.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island



3.3. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh, except during some trading periods on Tuesday and Wednesday. Between 3.00pm and 5.00pm on Tuesday North Island SIR prices ranged from $156-$369/MWh and South Island SIR ranged from $143-$337/MWh. SIR spikes on Tuesday and Wednesday coincided with high energy prices and price separation, as tight supply resulted in needing to dispatch high cost generation as energy and reserve.

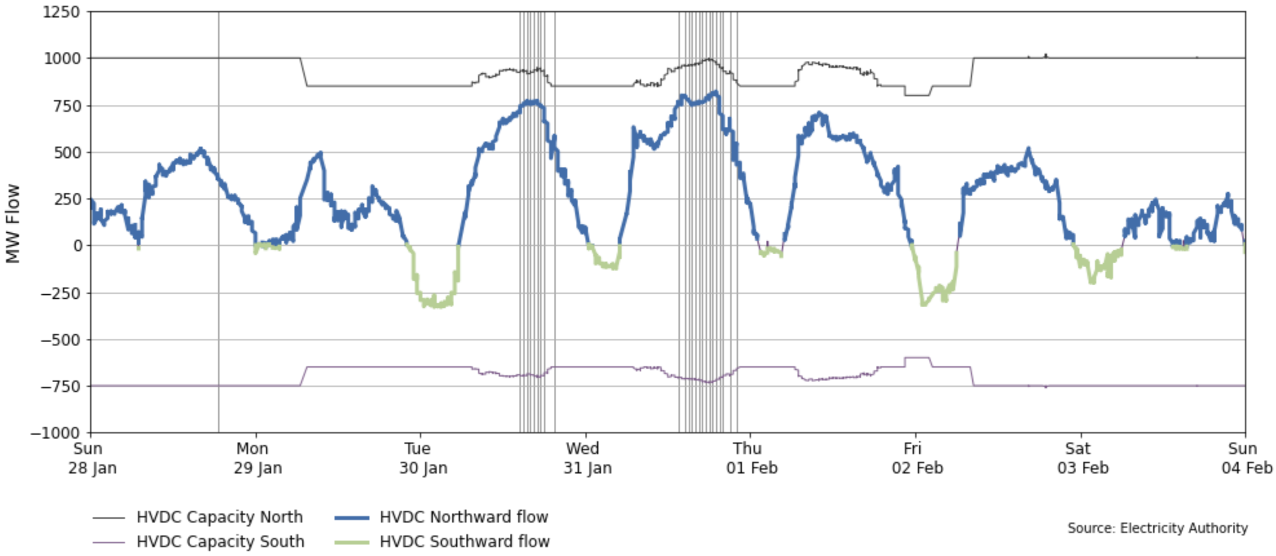
Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 28 January – 3 February. HVDC flows were mostly northwards this week except overnight where flows were southwards. On Tuesday and Wednesday during the price spikes, HVDC was operating northwards and at least one pole was operating close to its maximum capacity. This leads to high North Island reserve requirements and inter island price separation.

Figure 5: HVDC flow and capacity



5. Regression residuals

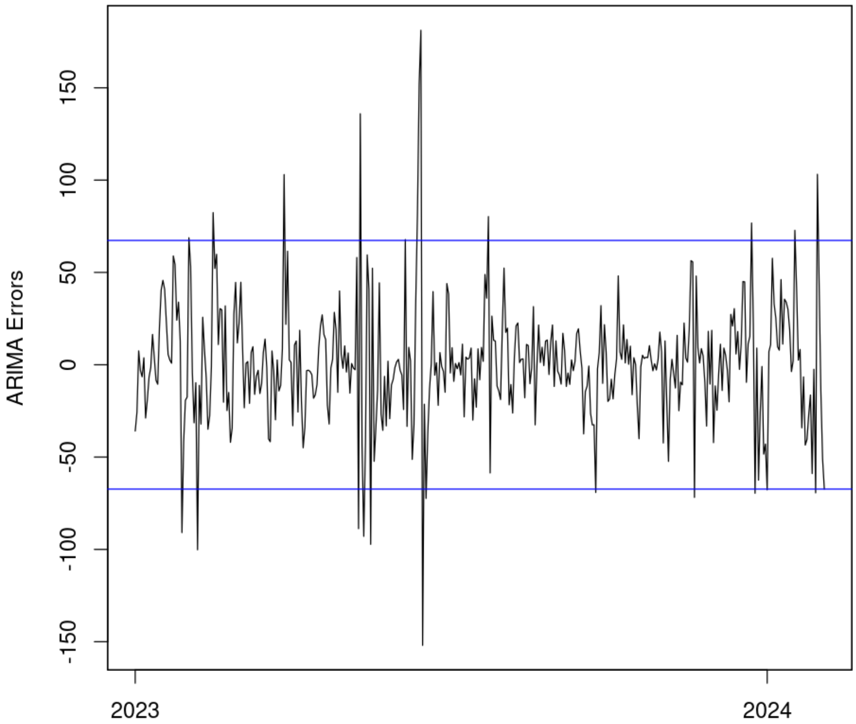
5.1. The Authority's monitoring team uses a regression model to model spot price. The residuals show how close the predicted prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A on the trading conduct webpage.

5.2. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than 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 for in the regression analysis.

5.3. This week there was one residual on Tuesday that was above two standard deviations of the data. This shows the model did not expect actual prices to be as high. This may indicate prices were higher than expected for the market conditions, though it may also be due to forecasting errors not captured in the model. We will be doing some further analysis on the high prices on Tuesday.

5.4. On Monday, the residual sat just below two standard deviations of the data indicating actual prices were lower than the model predicted. Saturday's residual was also around two standard deviations below. Both of these days saw very low prices.

Figure 6: Residual plot of estimated daily average spit prices from 1 January 2023 - 3 February 2024

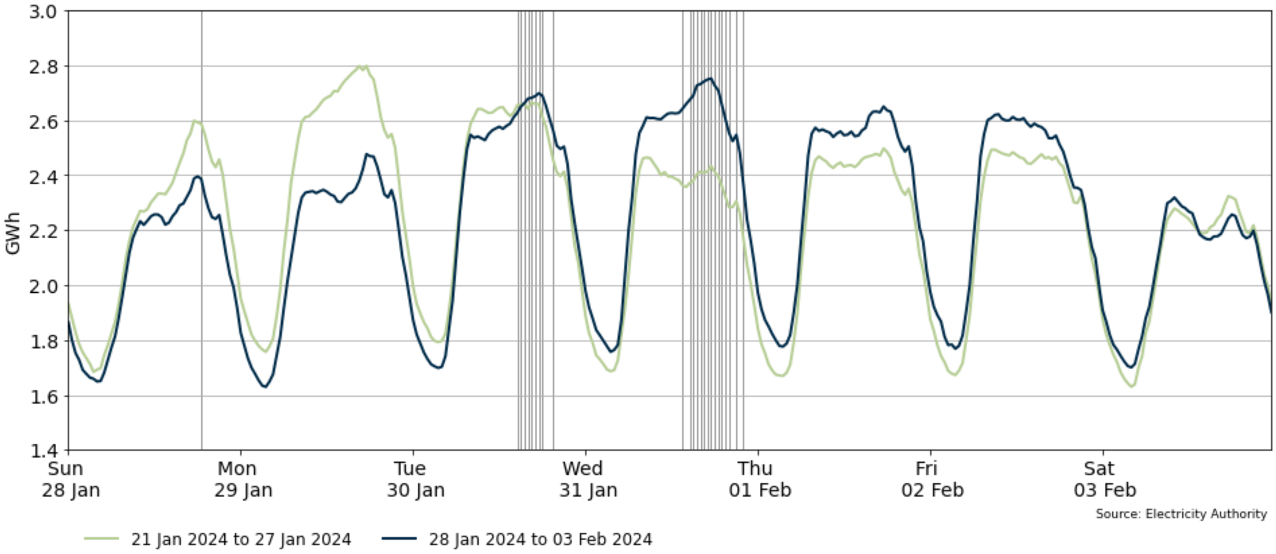


Source: Electricity Authority/see Appendix A

6. Demand

6.1. Figure 7 shows national demand between 28 January – 3 February, compared to the previous week. Demand was low on Monday, with several regions celebrating their anniversary possibly contributing to this lower demand. Wednesday to Friday saw higher demand compared to the previous week. The highest peak in demand happened on Wednesday afternoon, reaching ~2.75GWh (5.5GW). This coincided with higher temperatures across the country and cooling loads might have contributed to the increase in demand.

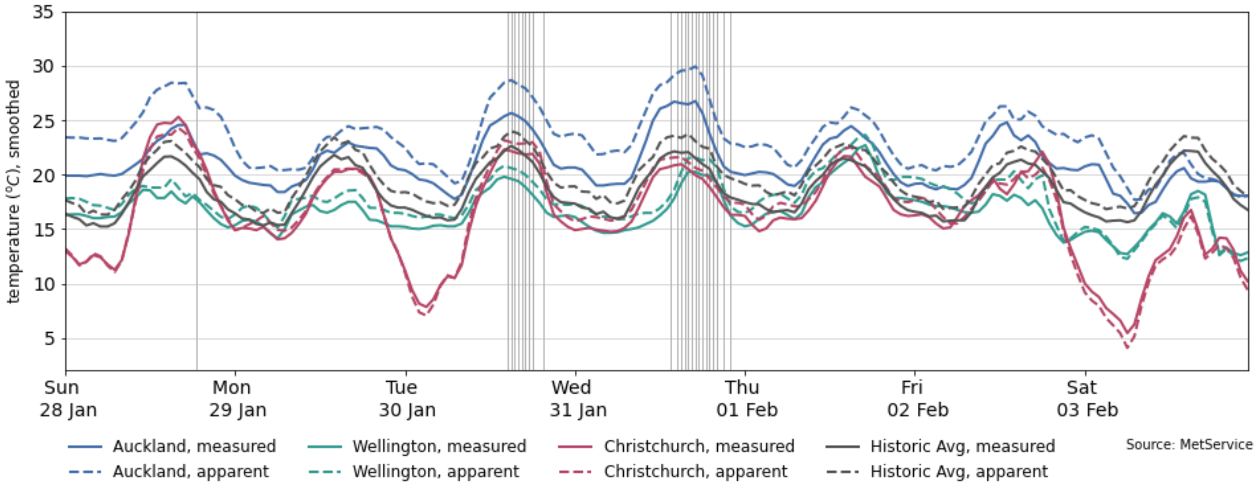
Figure 7: National demand between 28 January - 3 February compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 28 January – 3 February. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Auckland saw above-average temperatures during most of the week with apparent temperatures reaching 30ºC on Wednesday. Temperatures in Wellington were below the national average, but still ranged between 15ºC and 20ºC. Christchurch had the largest variation in temperature ranging from ~4ºC to 24ºC, with most temperatures below the national historic average.

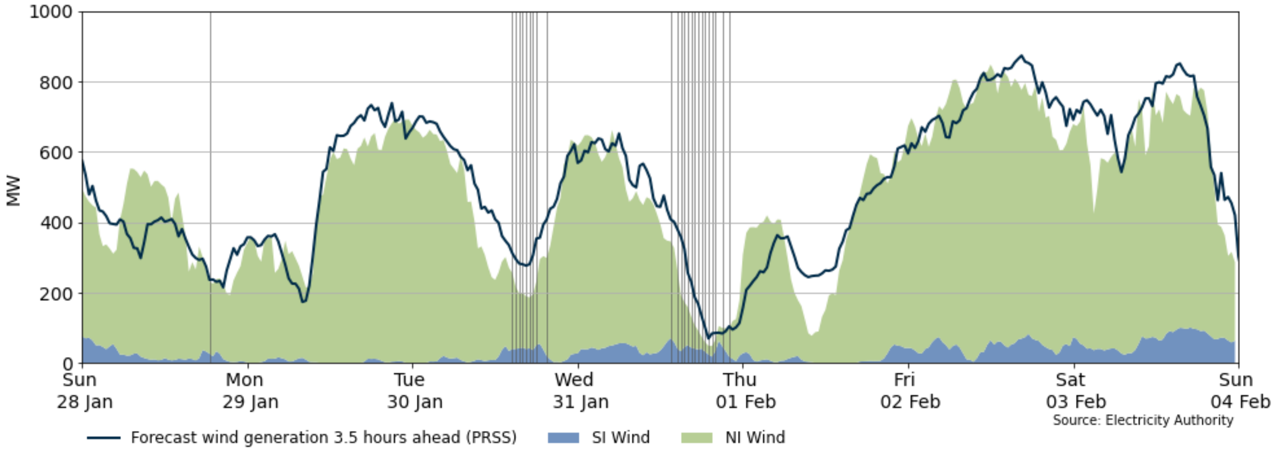
Figure 8: Temperatures across main centres



7. Generation

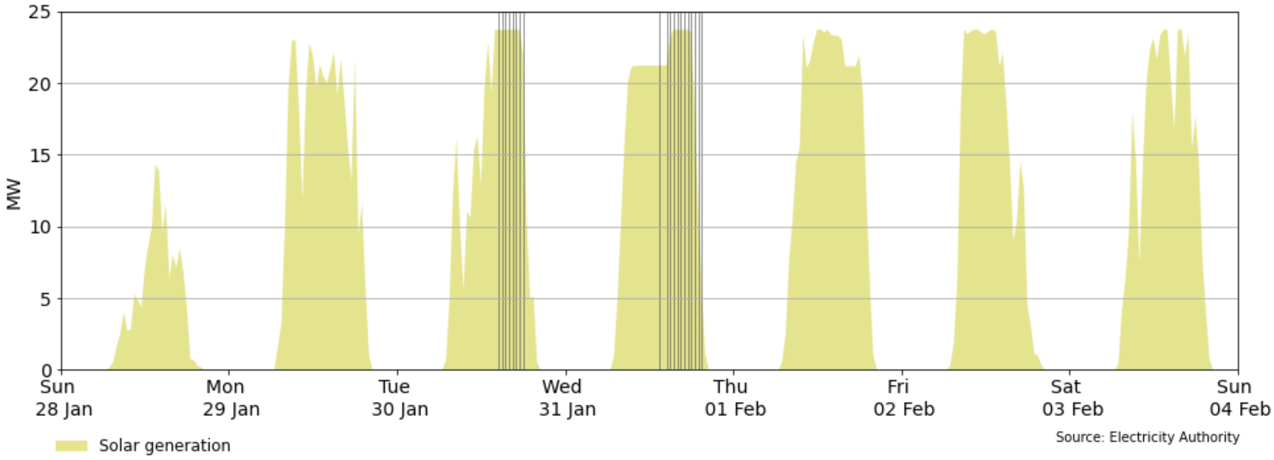
7.1. Figure 9 shows wind generation and forecast from 28 January - 3 February. This week wind generation varied between 49MW and 848MW, with an average of 481MW. Wind generation was low during the price spikes on Tuesday and Wednesday. Wind forecast inaccuracies may have also contributed to the high prices these days, where forecasts for some trading periods were ~100MW higher than actual generation.

Figure 9: Wind generation and forecast between 28 January - 3 February



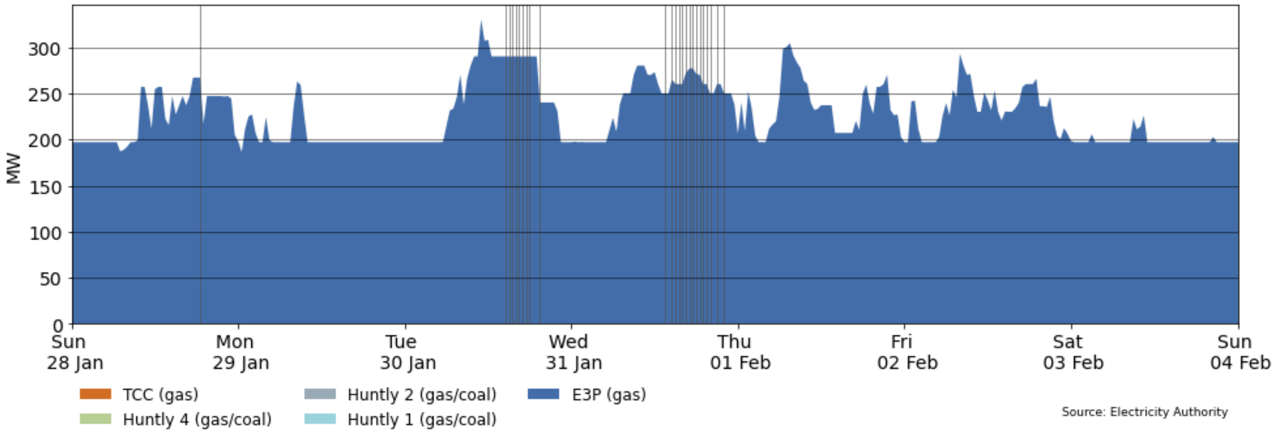
7.2. Figure 10 shows solar generation from 28 January – 3 February. Except for Sunday, solar generation crossed the 20MW threshold (around 80 percent of nominal capacity) all week. Overcast events might be related to the fluctuations seen in the first half of the week and on Saturday.

Figure 10: Solar generation between 28 January - 3 February



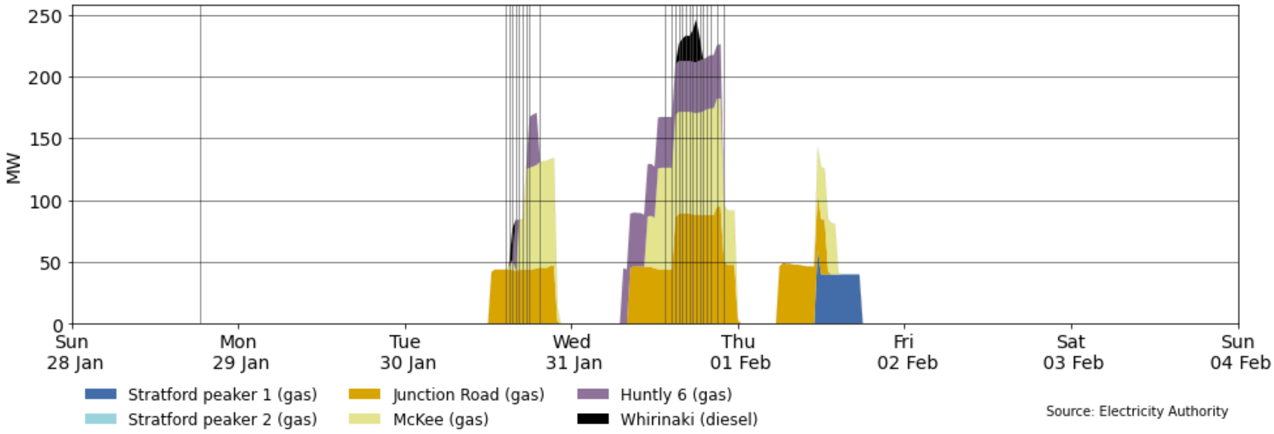
7.3. Figure 11 shows the generation of thermal baseload between 28 January – 3 February. Huntly 5 (E3P) ran as baseload for the whole week, generating at least 200MW. Although not generating at full capacity, it was able to ramp up during the peak demand periods.

Figure 11: Thermal baseload generation between 28 January - 3 February



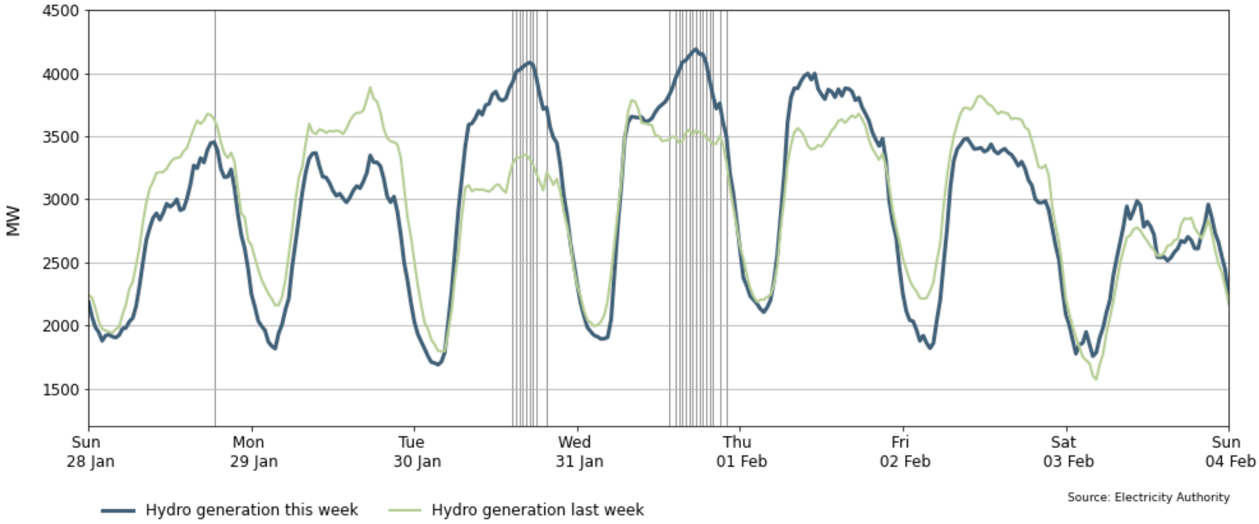
7.4. Figure 12 shows the generation of thermal peaker plants between 28 January – 3 February. Peaker generation this week occurred between Tuesday and Thursday where demand was high. This likely contributed to the spikes in prices over those days. On Wednesday Whirinaki was constrained on.

Figure 12: Thermal peaker generation between 28 January - 3 February



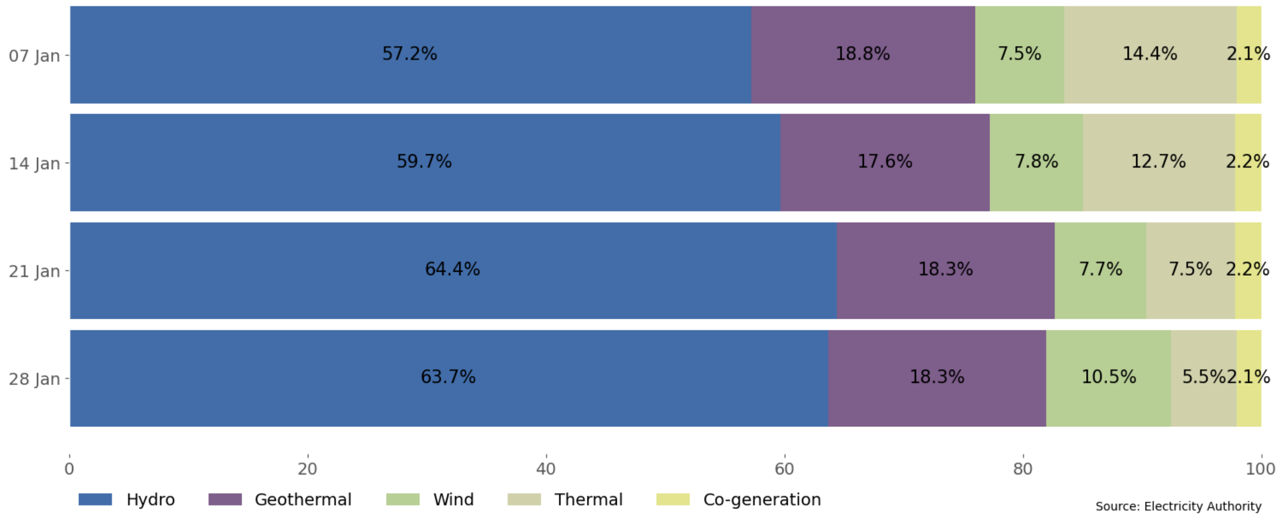
7.5. Figure 13 shows hydro generation between 28 January – 3 February. Hydro ramped up during the Tuesday and Wednesday evening peak, aligned to the increase in demand. Compared to the previous week, hydro generation was higher between Tuesday and Thursday, but was lower on Friday, likely due to increased wind generation.

Figure 13: Hydro generation between 28 January - 3 February



7.6. As a percentage of total generation, between 28 January – 3 February, total weekly hydro generation was 63.7%, geothermal 18.3%, wind 10.5%, thermal 5.5%, and co-generation 2.1%.

Figure 14: Total generation b type as a percentage each week between 7 January and 3 February



8. Outages

8.1. Figure 15 shows generation capacity on outage. Total capacity on outage between 28 January – 3 February ranged between ~1300MW and ~1900MW.

8.2. Notable outages include:

(a) Stratford 2 is on outage until 1 May 2024

(b) Huntly 1 is on outage from 31 January-29 April

(c) Stratford 1 was on outage from 1-2 February

(d) Huntly 6 was on outage from 28-30 January

(e) One unit at Whirinaki was on outage from 16 January-1 February

(f) Several North and South Island hydro generators were on outage this week.

Figure 15: Total MW loss due to generation outages

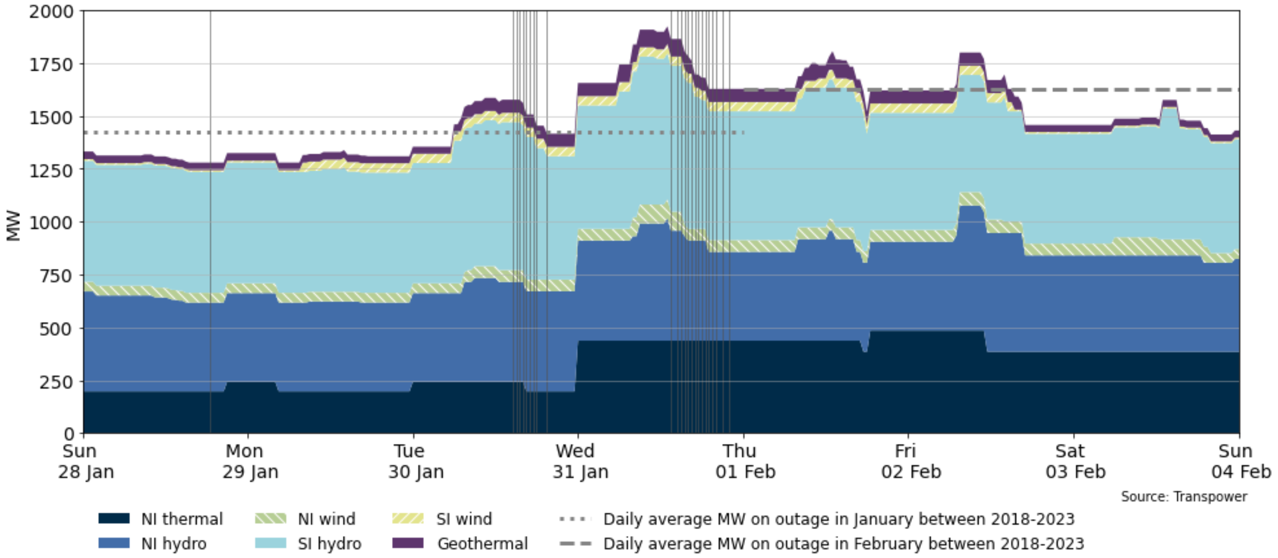
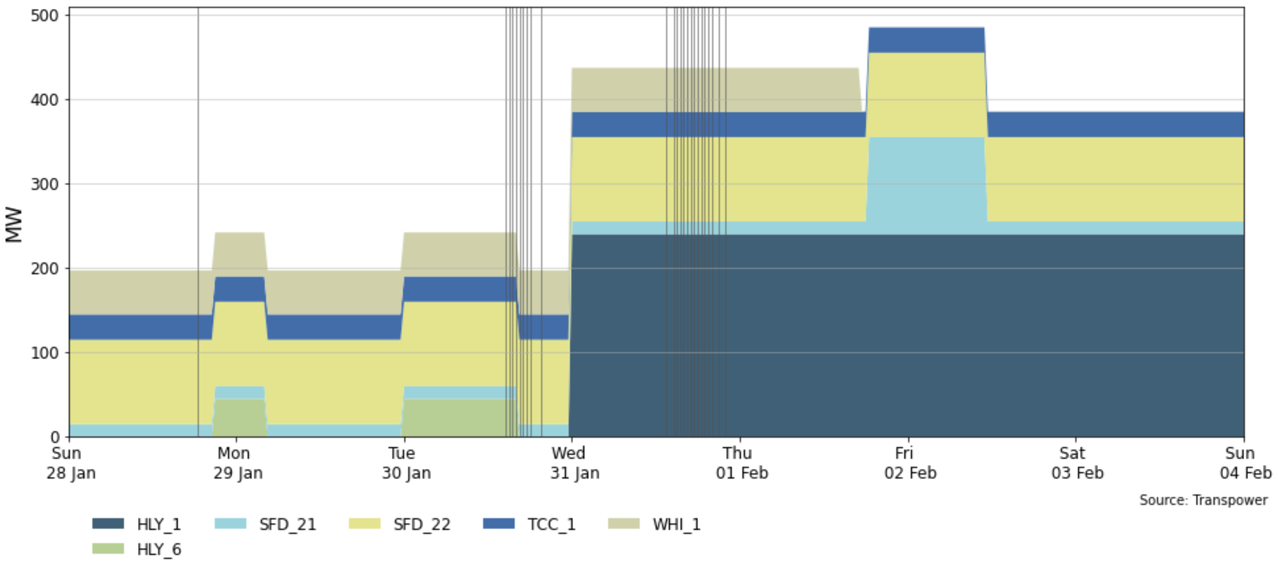


Figure 16: MW loss from thermal outages



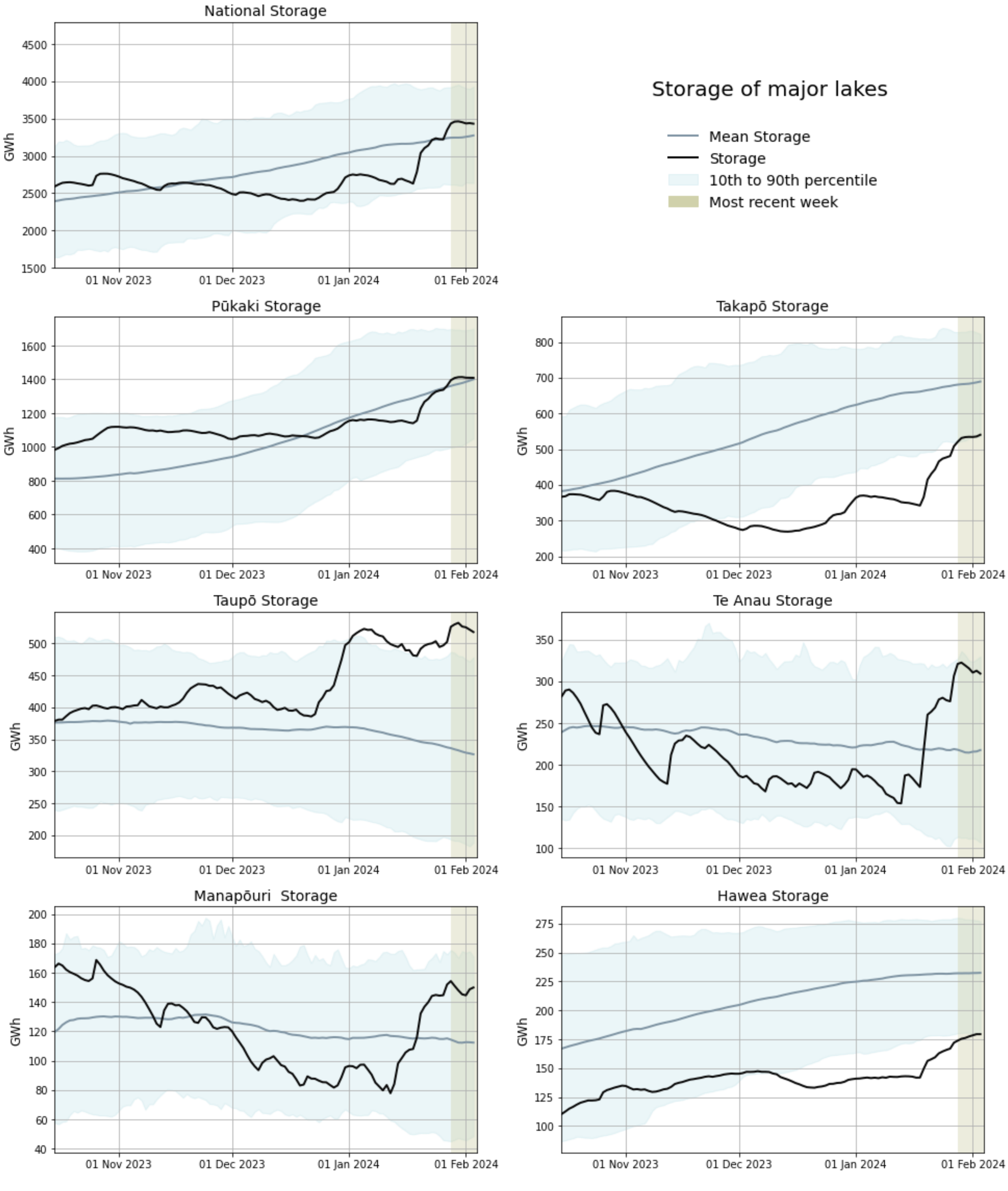
9. Storage/fuel supply

9.1. Figure 17 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.

9.2. National controlled storage continued to increase at the start of the week and remains above historic mean. As of 5 February, controlled storage was 84.1% nominally full and ~104% of the historical average for this time of the year.

9.3. Lake Taupō remained high and above its historic 90th percentile for this time of year. Pūkaki is around its historic average level. Takapō remains close to its historic 10th percentile although it saw a small steady increase to storage across the week. Hawea storage has continued to show steady increases but remains around its 10th percentile region. Manapōuri and Te Anau are still above their respective historic average levels, with Te Anau close to its 90th percentile region.

Figure 17: Hydro storage



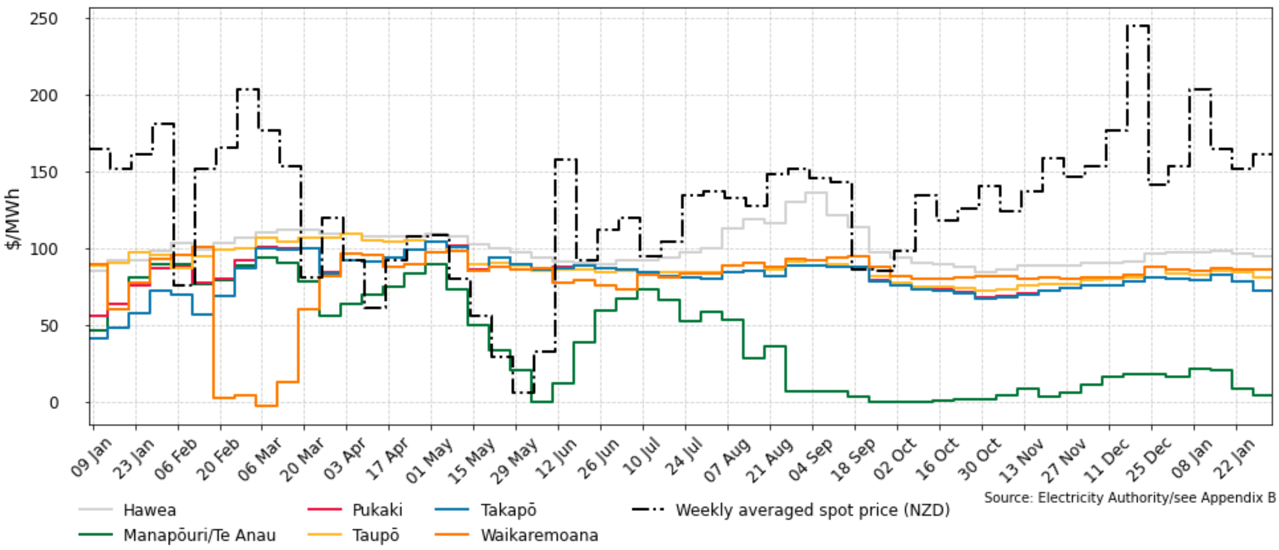
Source: Electricity Authority

10. JADE water values

10.1. The JADE[2] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 18 shows the national water values between 8 January 2023 and 3 February 2024 obtained from JADE calculated as at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B.

10.2. Compared to the previous week, water values decreased over all the major storage lakes, except Waikaremoana, due to increased storage levels. The Manapōuri/Te Anau water value is now ~$3.60/MWh, less than half of the previous week's value. Pūkaki and Takapō water values decreased from around $78/MWh to around $72/MWh.

Figure 18: JADE water values across various reservoirs between 8 January 2023 and 3 February 2024



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 19 shows an estimate of thermal SRMCs as a monthly average up to 1 February 2024. The SRMC for coal and diesel have not seen much change from the previous month. The gas SRMC has seen some decreases although it remains relatively high.

[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

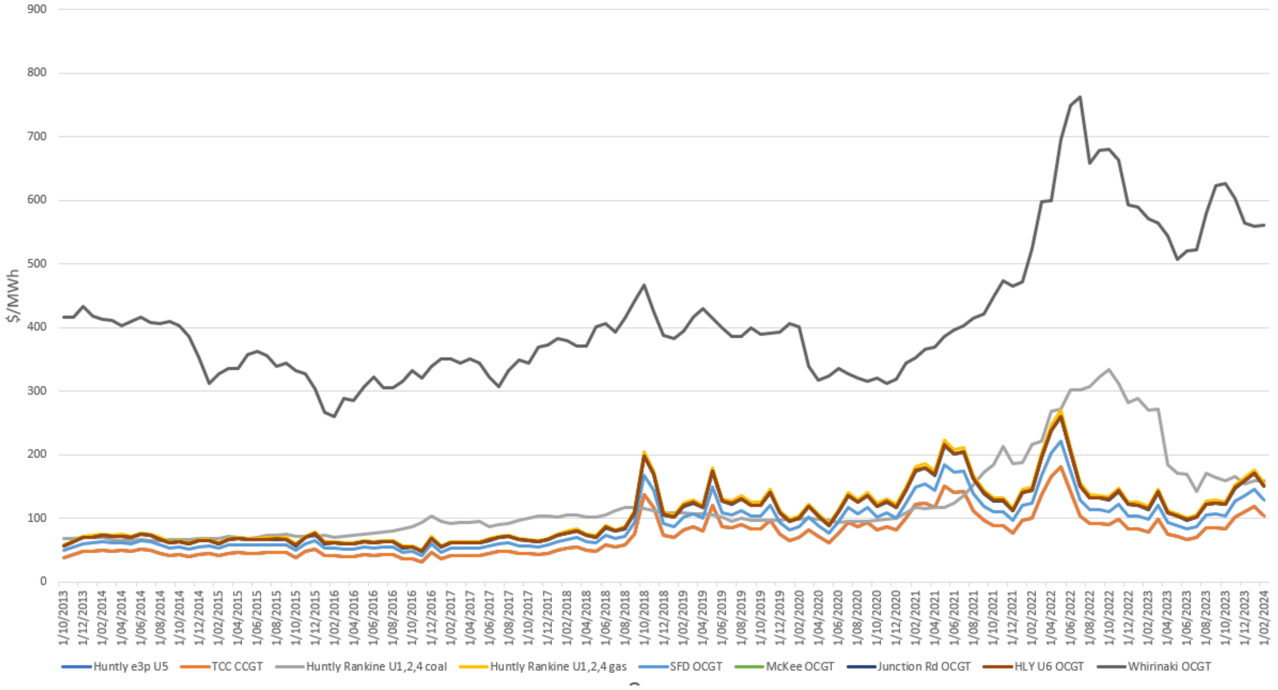
11.4. The latest SRMC of coal-fueled Rankine generation is ~$159MWh. This is now similar to the cost of running the Rankines on gas at ~$156/MWh, whereas the coal SRMC was lower than gas the previous month.

11.5. The SRMC of gas fueled thermal plants is currently between $105/MWh and $156/MWh.

11.6. The SRMC of Whirinaki is ~$560/MWh.

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

Figure 19: Estimated monthly SRMC for thermal fuels



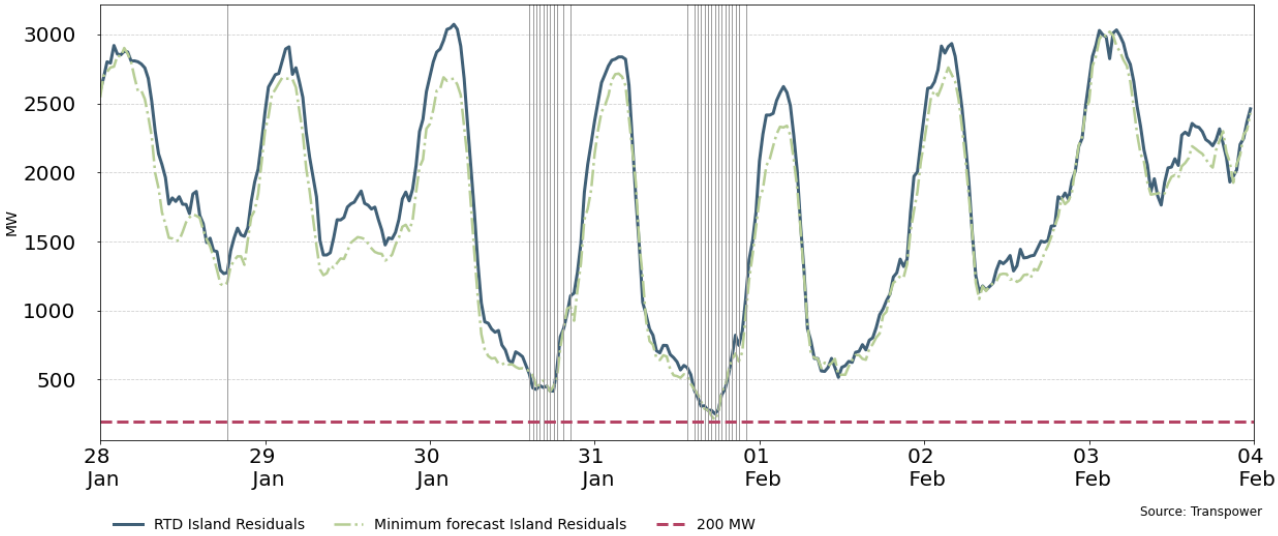
Source: Electricity Authority/see Appendix C

12. Generation balance residuals

12.1. **Error! Reference source not found.** shows the generation balance residuals between 28 January - 3 February. 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 the real time dispatch (RTD) residuals.

12.2. The RTD residual generation on Tuesday and Wednesday was close to the 200MW threshold coinciding with the times we saw a number of the high prices. This lower generation balance demonstrates how available supply can influence prices as we also saw tight supply with reserves during these periods.

Figure 20: Generation balance residuals 28 January - 3 February



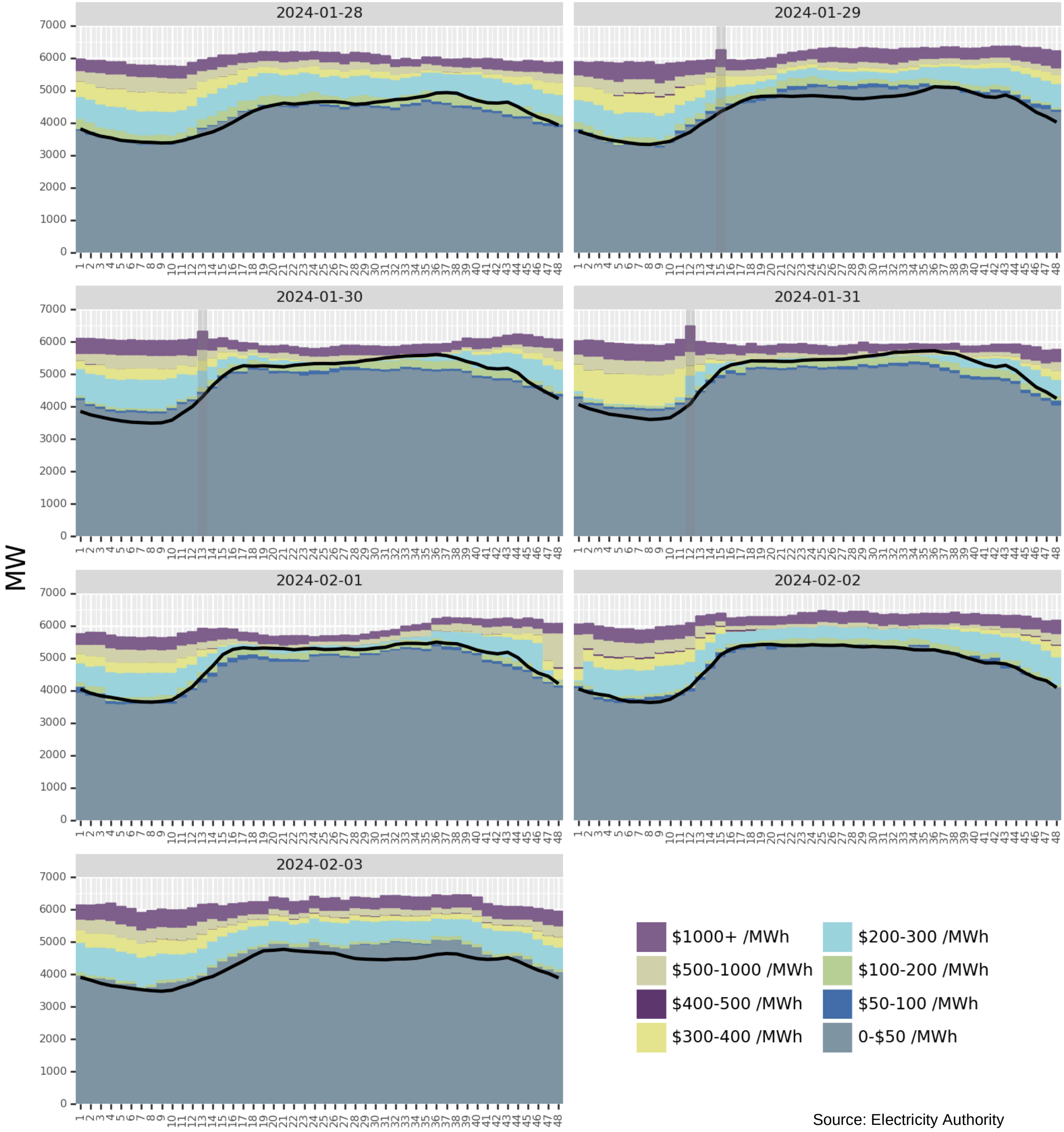
13. Offer behaviour

13.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

13.2. At the start of the week offers mostly cleared in the $0/MWh to $200/MWh range. Overall, the $100-$200/MWh and $200-$300/MWh offer bands was relatively thin between Tuesday and Thursday, with cheaper hydro and lower thermal commitment reducing the quantity of mid-priced offers. Low wind on these days often pushed the clearing price into higher priced peaker or hydro offers.

13.3. On Thursday there was a slight increase in $100-$200/MWh priced offers, and most spot prices cleared in this range. However, there were a few trading periods in the morning and afternoon reaching the $200/MWh-$300/MWh band. On Friday and Saturday, there was an increase in $200-$300/MWh priced offers, however with the higher wind generation and lower demand, most prices cleared between $0/MWh-$100/MWh, often in the $0/MWh to $50/MWh range.

Figure 21: Daily Offer stacks[3]



Source: Electricity Authority

[3] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

14. Ongoing work in trading conduct

14.1. This week, there were high spot and reserve prices related to a combination of factors, with one being tight energy and reserve supply. The Authority will conduct further analysis on why this occurred, as indicated in Table 1.

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

Table 1: Trading periods identified for further analysis

Date	TP	Status	Participant	Location	Enquiry topic
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers.
22/09/2023-30/09/2023	Several	Further analysis	Contact	Multiple	High hydro offers.
17/01/2024-19/01/2024	Several	Further analysis	Genesis, Contact	Multiple	High energy prices associated with high energy offers.
21/01/2024-27/01/2024	Several	Further analysis	Mercury	Waikato hydro dams	High hydro offers.
30/01/2024-01/02/2024	Several	Further analysis	Several	Multiple	High reserve prices related to reserve offers.