19 February 2024

ELECTRICITY AUTHORITY TE MANA HIKO

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 11–17 February

1.1. Spot prices were within the 10^{th}-90^{th} percentiles this week. On Sunday, prices were low due to a combination of low demand and high wind. Prices increased from Thursday onwards, with wind generation dropping off and thermal ramping up to meet demand. Hydro generation also ramped back once more thermal generation turned on. However, there were no price spikes or large price separations this week. Thermal generation was higher this week, with Huntly 5 and TCC running as baseload. Huntly 4 also ran on Wednesday. Hydro storage decreased a bit this week, currently at ~101% of mean as of 17 February. Large amounts of hydro generation continue to be on outage.

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 11-17 February:

(a) The average wholesale spot price across all nodes was $157/MWh.

(b) 95 percent of prices fell between $1/MWh and $246/MWh.

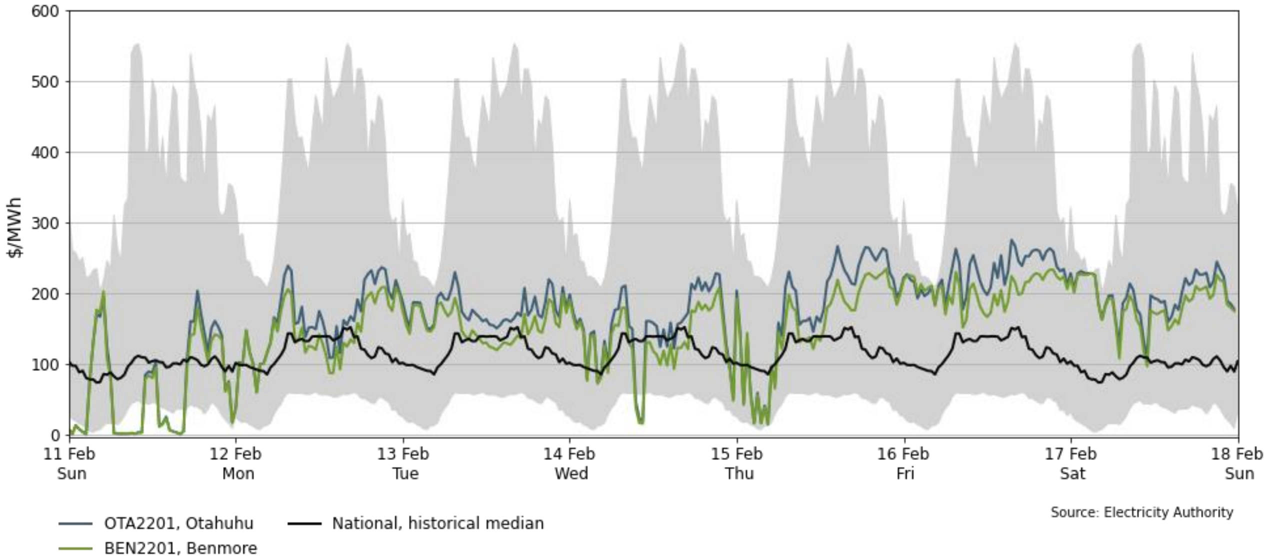
2.4. The week started with very low prices on Sunday. From Monday until Thursday, most prices were between $100-$200/MWh, which was mainly above the historical average but still within the 10^{th}-90^{th} percentiles.

2.5. Prices increased from Thursday afternoon until the end of the week, mostly in the $200-$300/MWh range.

2.6. The weekly average price increased by around $43/MWh compared to the previous week. There were no price spikes above $300/MWh this week at Benmore or Ōtāhuhu.

[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 75^{th} percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75^{th} percentile (or third quartile value) and IQR is your inter-quartile range.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 11-17 February

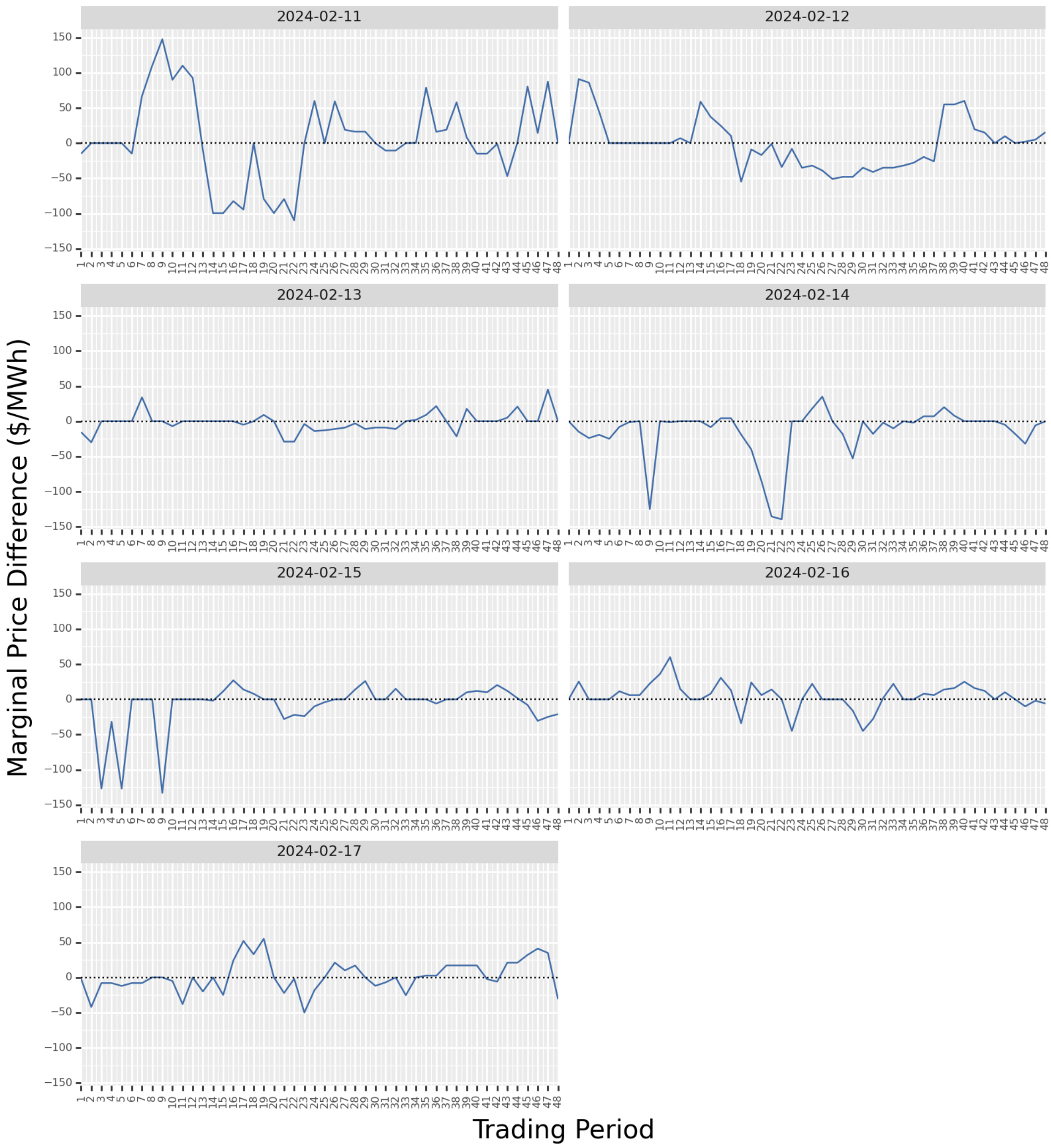


2.7. Figure 2 shows the difference between the real time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1 hour ahead (PRSS) demand and wind forecasts. This plot highlights when forecasting inaccuracies are causing large differences between pre-dispatch and final prices. When the difference is positive this means that the 1 hour out forecasting inaccuracies resulted in the spot price being higher than anticipated - usually demand is *under forecast* and or wind is *over forecast*. While 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 price will rarely be the same, but 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.

2.8. There were several trading periods on Sunday, Wednesday, and Thursday when the RTD price was over $100/MWh less than the 1 hour ahead PRSS price. These were times when wind generation was under forecast, meaning there was more wind generation than expected, causing lower prices.

2.9. Early on Sunday morning the RTD price was over $100/MWh greater than the 1 hour ahead PRSS price. This was a time when wind generation was lower than expected.

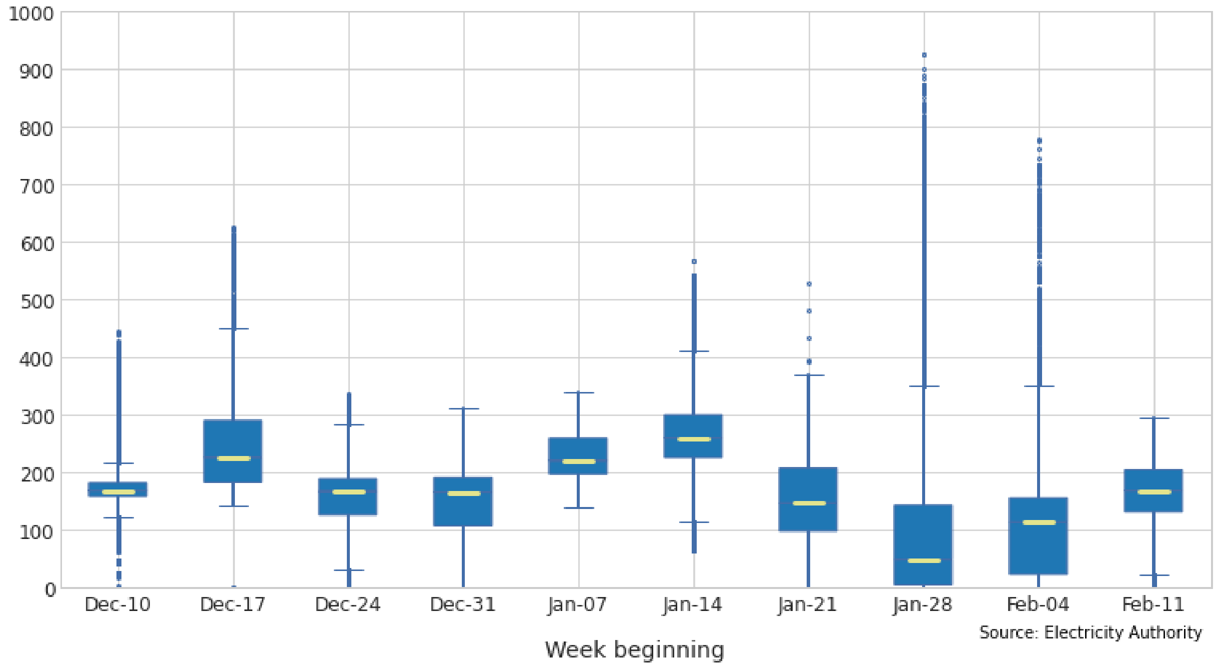
Figure 2: Difference between RTD price and gate closure PRSS prices, with the difference due to one-hour ahead wind and demand forecast inaccuracies



2.10. Figure 3 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.

2.11. This week saw a more condensed distribution of prices with no outlying high prices. Overall, most prices were higher with the middle 50% of prices this week between $131-$204/MWh, sitting above last week's median price of $118/MWh. This week's median price was $168/MWh.

Figure 3: Boxplots showing the distribution of spot prices this week and the previous nine weeks



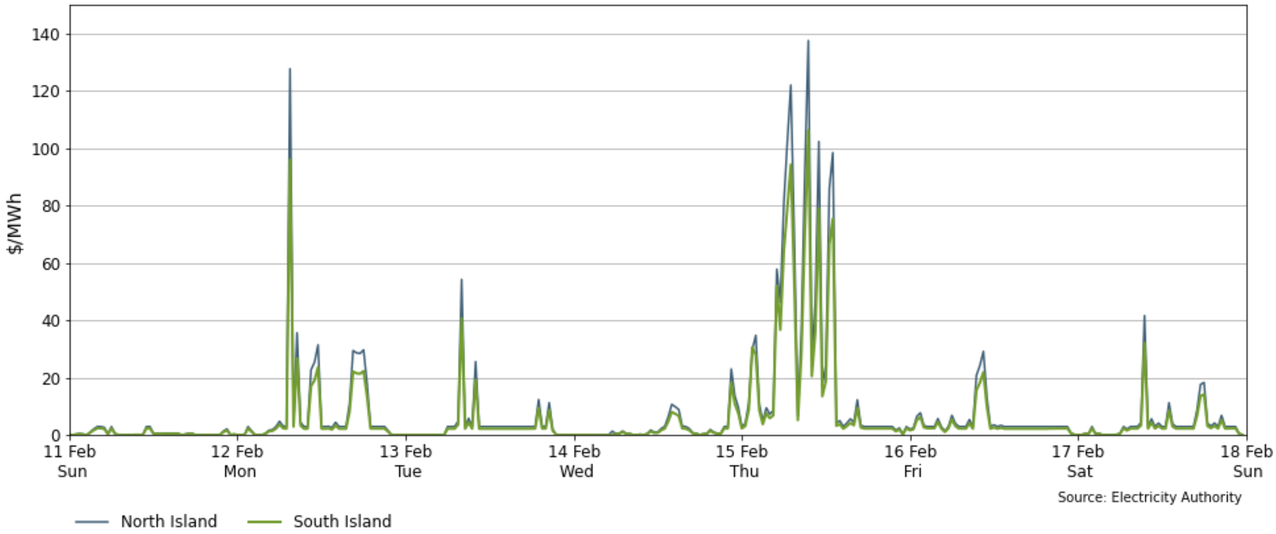
3. Reserve prices

3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 4. There were several FIR price spikes this week, most notably on Monday and Thursday, with prices reaching above $100/MWh during those days.

3.2. Several hydro plants which provide FIR were on outage this week. Between Monday and Friday there were outages at Clyde, Roxburgh, and Benmore. Because of reserve sharing across the HVDC, when there are fewer cheaper hydro reserve providers, typically more expensive reserves are dispatched, causing the FIR prices to spike. Also this week thermal plants, both baseload and peakers, which do not typically provide reserves, tended to run.

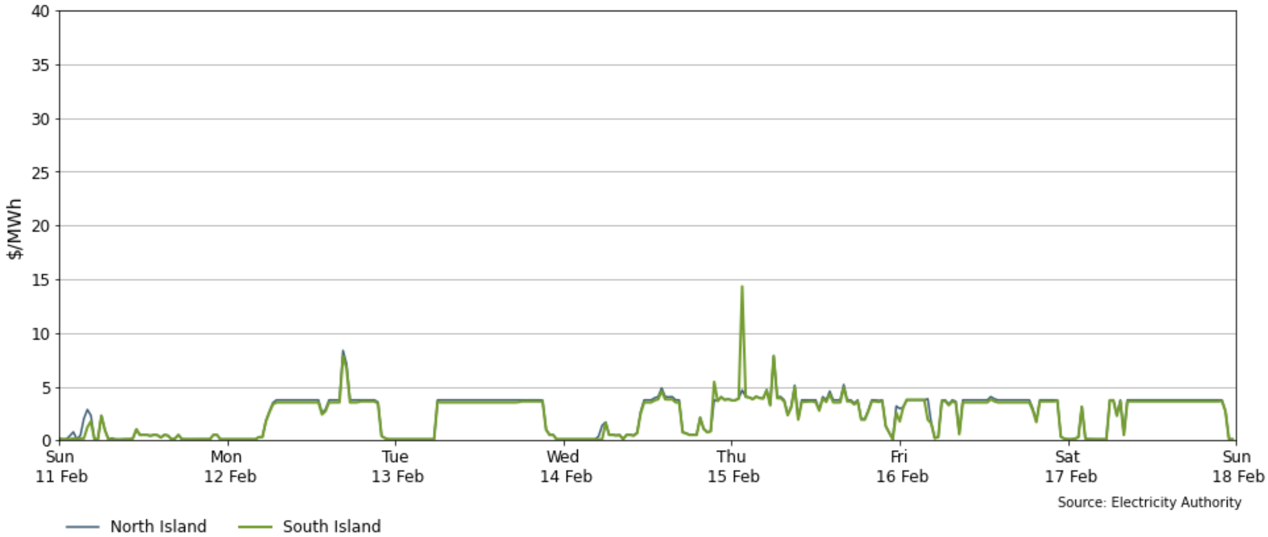
3.3. Several FIR price spikes on Thursday occurred when wind generation was high and the wind farms, Tararua, Te Rere Hau and Te Uku combined to set the North Island risk. This required 200 MW at times of North Island FIR. During this time energy-reserve co-optimisation also reduced the total amount of reserves available on each island, which led to an overall lower price for the market, but higher reserve price.

Figure 4: Fast Instantaneous Reserve (FIR) price by trading period and island between 11-17 February



3.4. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 5. SIR prices were mostly within the $0-$5/MWh range, with one price above $10/MWh in the South Island on Thursday, which coincided with a FIR spike.

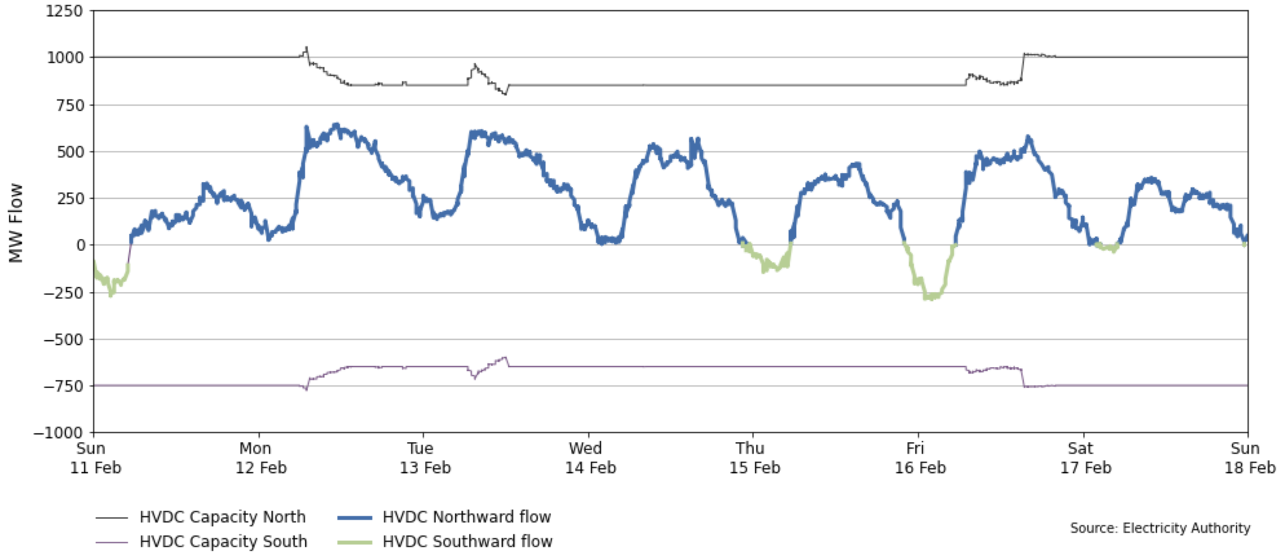
Figure 5: Sustained Instantaneous Reserve (SIR) by trading period and island between 11-17 February



4. HVDC

4.1. Figure 6 shows HVDC flow between 11-17 February. HVDC flows were mainly northwards during the week, with overnight southward flow on Sunday and between Wednesday and Saturday, when wind generation was high.

Figure 6: HVDC flow and capacity between 11-17 February



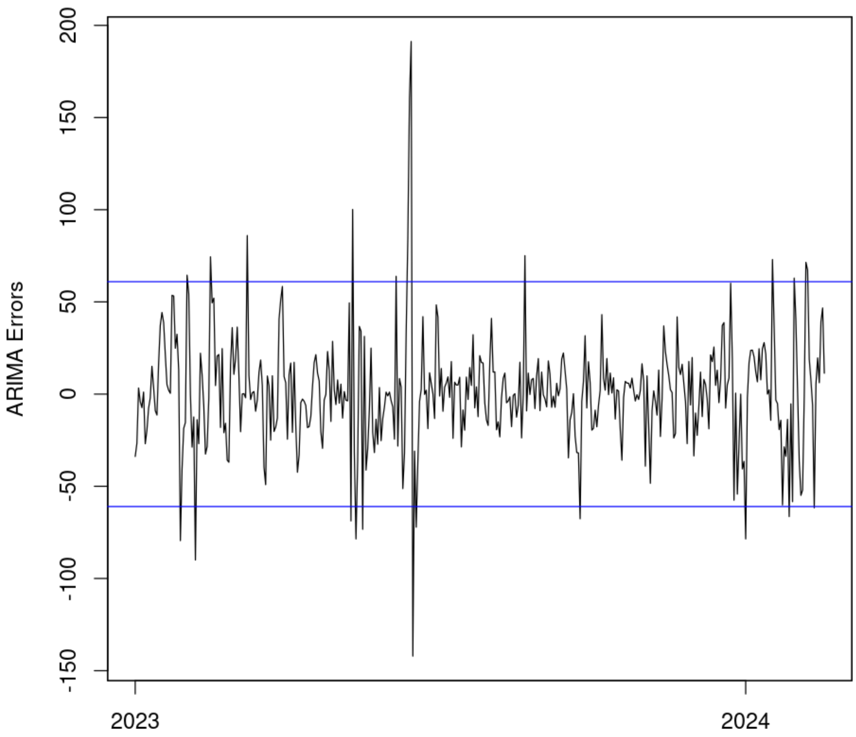
5. Regression residuals

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 7 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 for in the regression analysis.

5.3. This week there was one residual below the two standard deviations of the data on Sunday, meaning prices were lower than the model expected. On Sunday spot prices were overall low due to high wind generation and low demand.

Figure 7: Residual plot of estimated daily average spit prices from 1 January 2023-17 February 2024

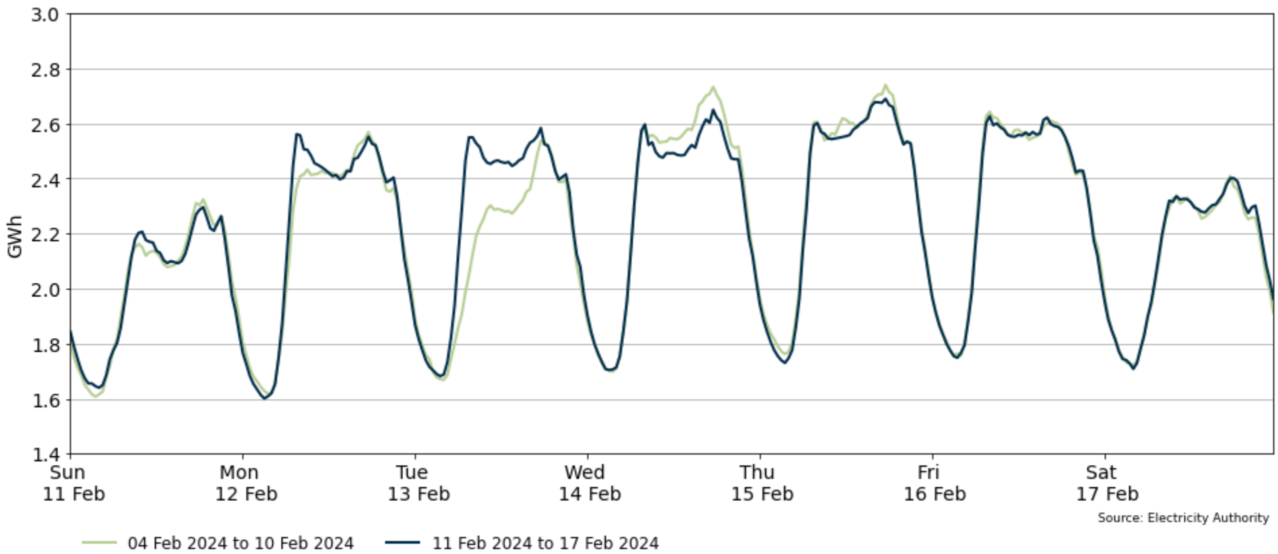


Source: Electricity Authority/see Appendix A

6. Demand

6.1. Figure 8 shows national demand between 11-17 February. Demand was generally similar to the previous week. On Tuesday demand was considerably higher than last week due to Waitangi Day holiday on the previous Tuesday. Wednesday and Thursday had lower demand this week compared to the previous week, likely related to higher temperatures.

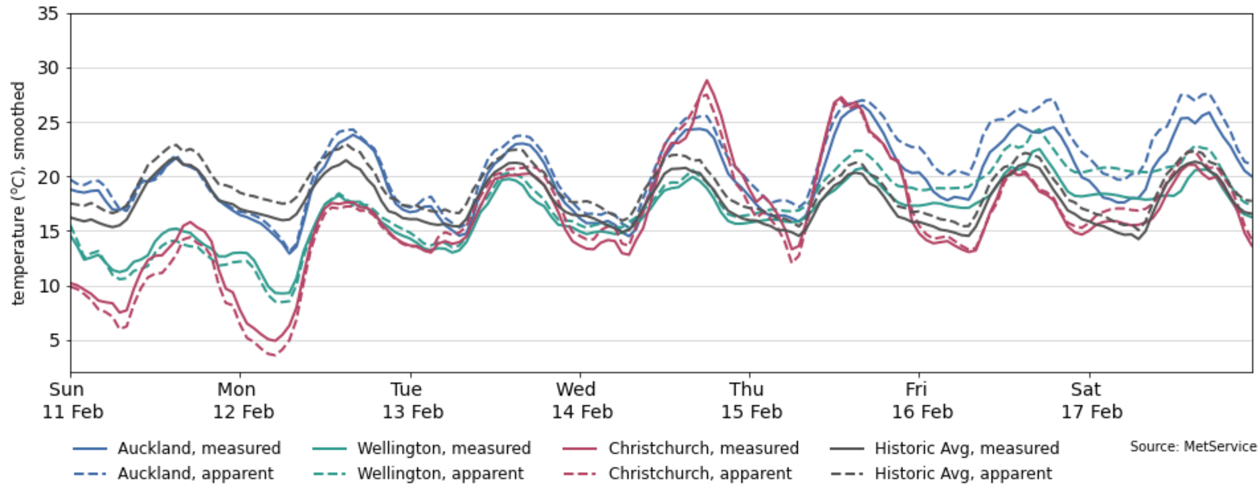
Figure 8: National demand between 11-17 February compared to the previous week



6.2. Figure 9 shows the hourly temperature at main population centres from 11-17 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. Temperatures this week were below the historical average earlier in the week with higher-than-average temperatures across the latter half of the week. Apparent temperatures in Auckland varied between ~13ºC and ~28ºC. In Christchurch apparent temperatures varied between ~4ºC and ~28ºC, with the maximum happening on Wednesday.

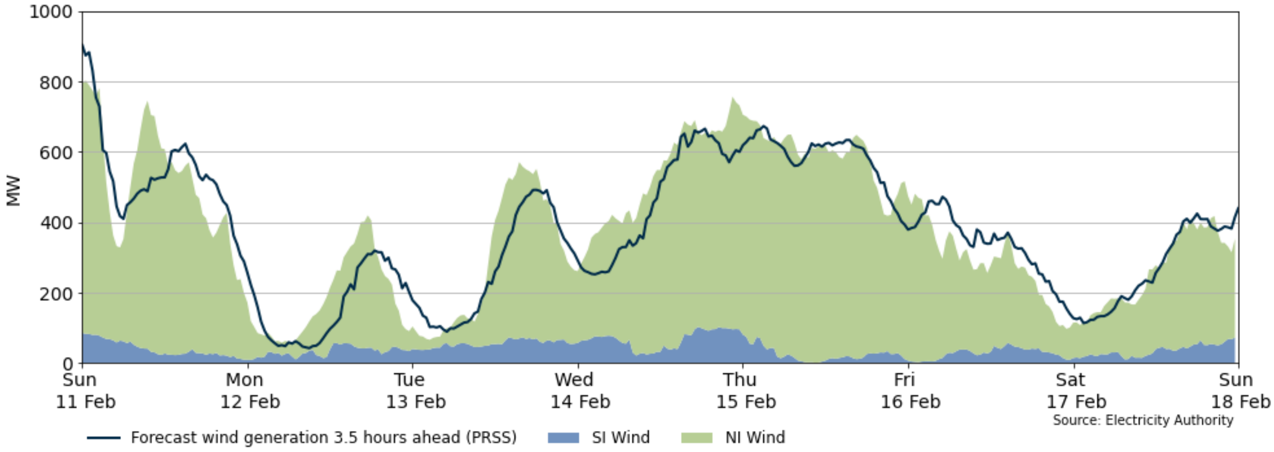
Figure 9: Temperatures across main centres between 11-17 February



7. Generation

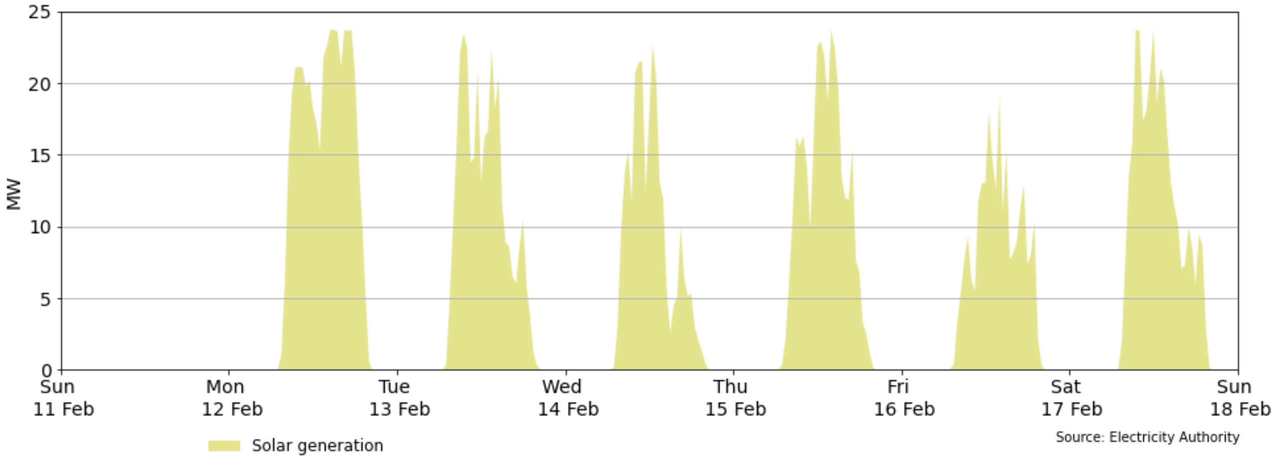
7.1. Figure 10 shows wind generation and forecast from 11-17 February. This week wind generation varied between 58MW and 803MW, with an average of 381MW. Wind generation was above 400 MW most of the time from Wednesday until Friday while being more variable during the other days.

Figure 10: Wind generation and forecast between 11-17 February



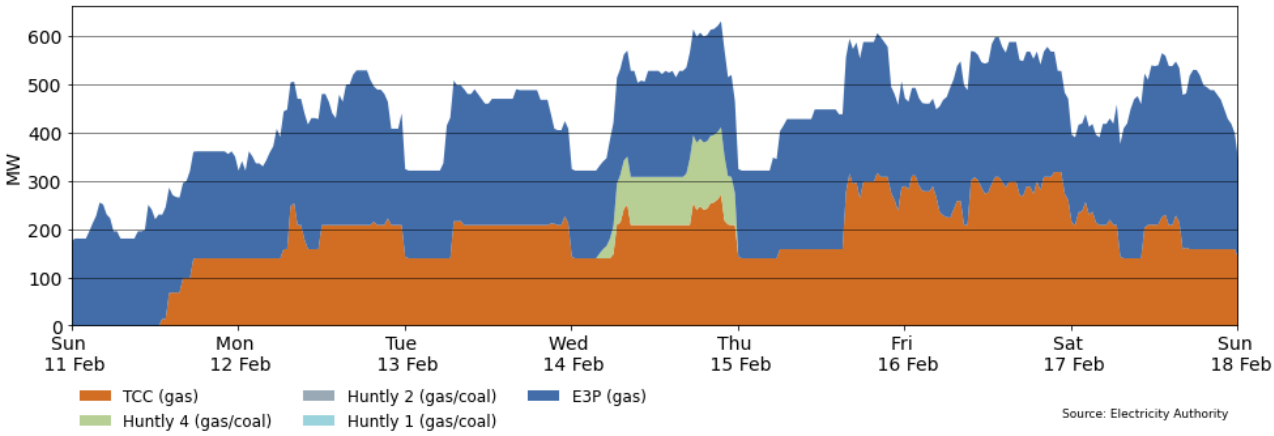
7.2. Figure 11 shows solar generation from 11-17 February. Solar generation was more variable this week compared to last week, likely due to more overcast days this week. On Sunday, a Top Energy outage required Kaitaia solar farm to be completely switched off.

Figure 11: Solar generation between 11-17 February



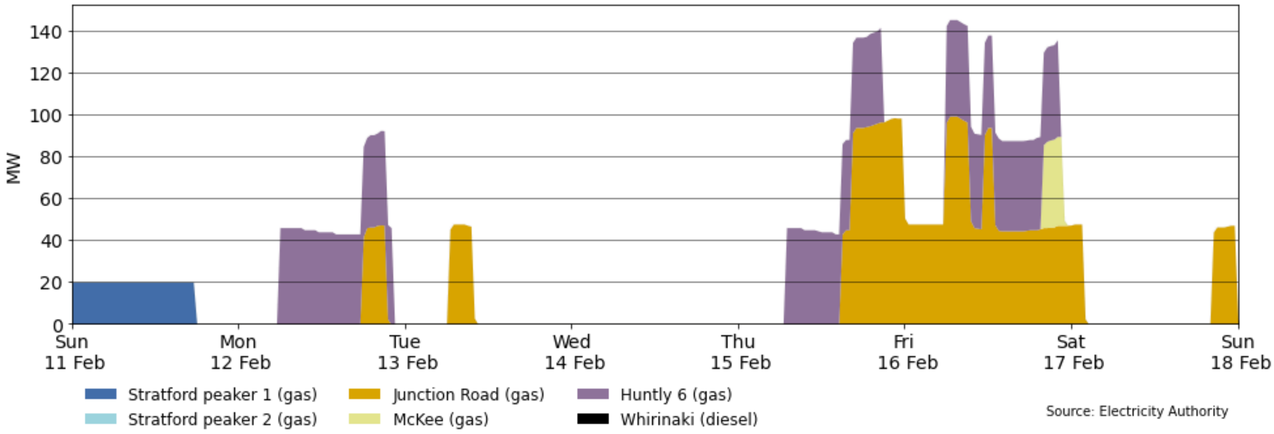
7.3. Figure 12 shows the generation of thermal baseload between 11-17 February. This week Huntly 5 and TCC ran all week providing baseload. Huntly 4 ran on Wednesday at ~100-150MW throughout the day. To accommodate this, Huntly 5 reduced its generation by 40-80 MW compared to the day before. However, when Huntly 4 turned off, Huntly 5 resumed running at ~280MW.

Figure 12: Thermal baseload generation between 11-17 February



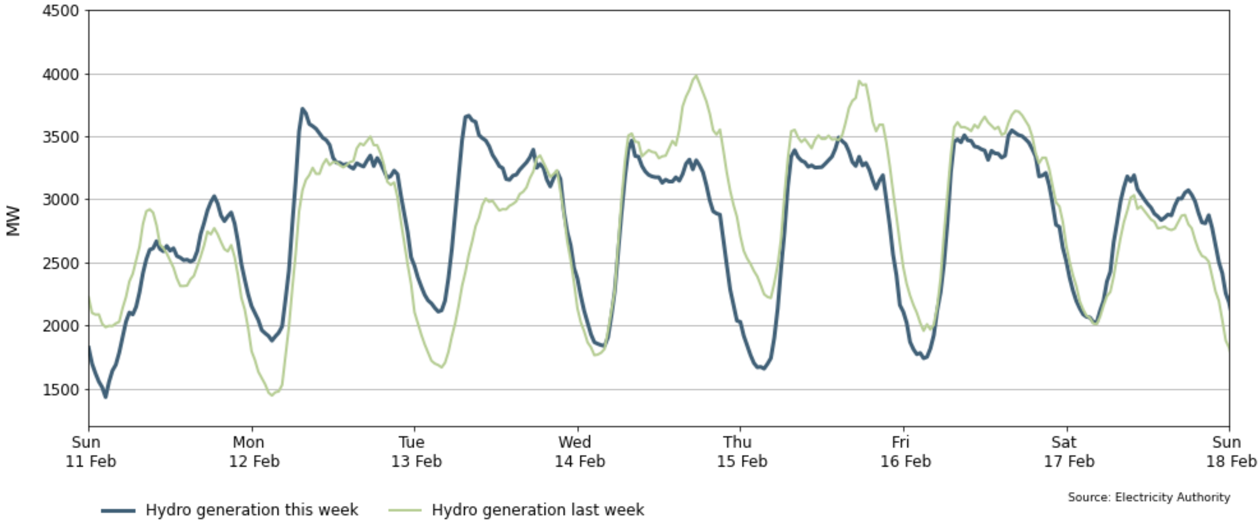
7.4. Figure 13 shows the generation of thermal peaker plants between 11-17 February. On Sunday Stratford 1 provided 20MW of generation during most of the day. Huntly 6 and Junction Road Peaker covered most peak generation this week. Huntly 6 ran on Monday and then on Thursday and Friday. Junction Road ran for a few trading periods on Monday and Tuesday, and then consistently from Thursday afternoon to early Saturday morning.

Figure 13: Thermal peaker generation between 11-17 February



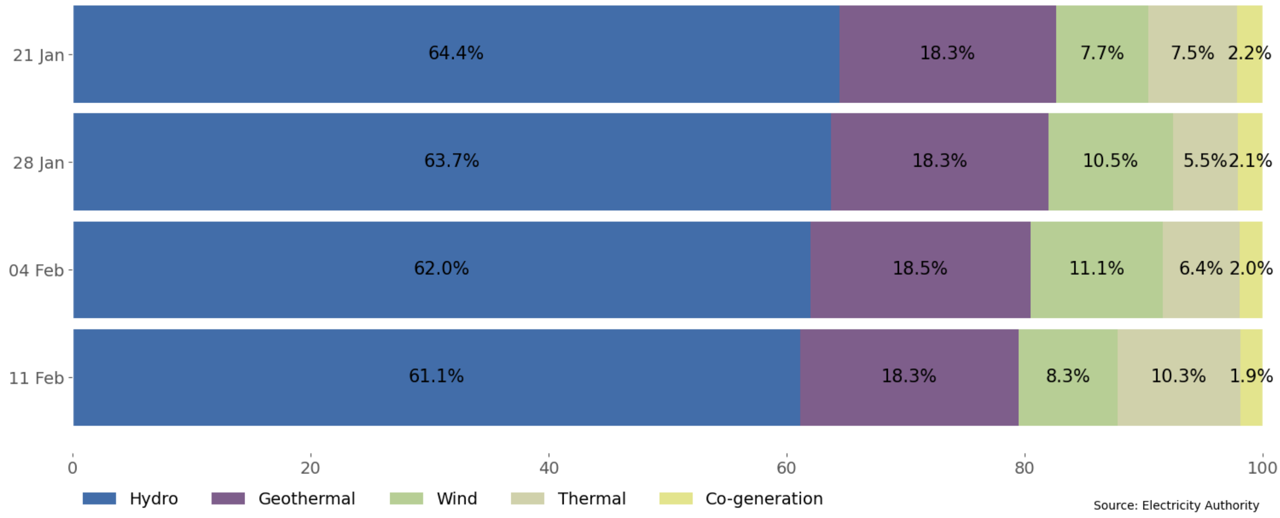
7.5. Figure 14 shows hydro generation between 11-17 February. Hydro generation was higher than previous week earlier in the week until Wednesday. Between Wednesday and Friday hydro generation was lower due to lower demand and increased thermal generation. On Tuesday hydro generation was considerably higher than the previous week due to Waitangi Day impacting demand the week before.

Figure 14: Hydro generation between 11-17 February



7.6. As a percentage of total generation, between 11-17 February, total weekly hydro generation was 61.1%, geothermal 18.3%, wind 8.3%, thermal 10.3%, and co-generation 1.9%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week between 21 January and 11 February



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 11-17 February ranged between ~1520MW and ~2060MW. Figure 17 shows the thermal generation capacity on outage.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 29 April 2024

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

(c) Stratford 1 was on outage on 11-12 February

(d) Poihipi geothermal plant is on outage until 22 March 2024

(e) Several North and South Island hydro units were on outage this week.

Figure 16: Total MW loss due to generation outages

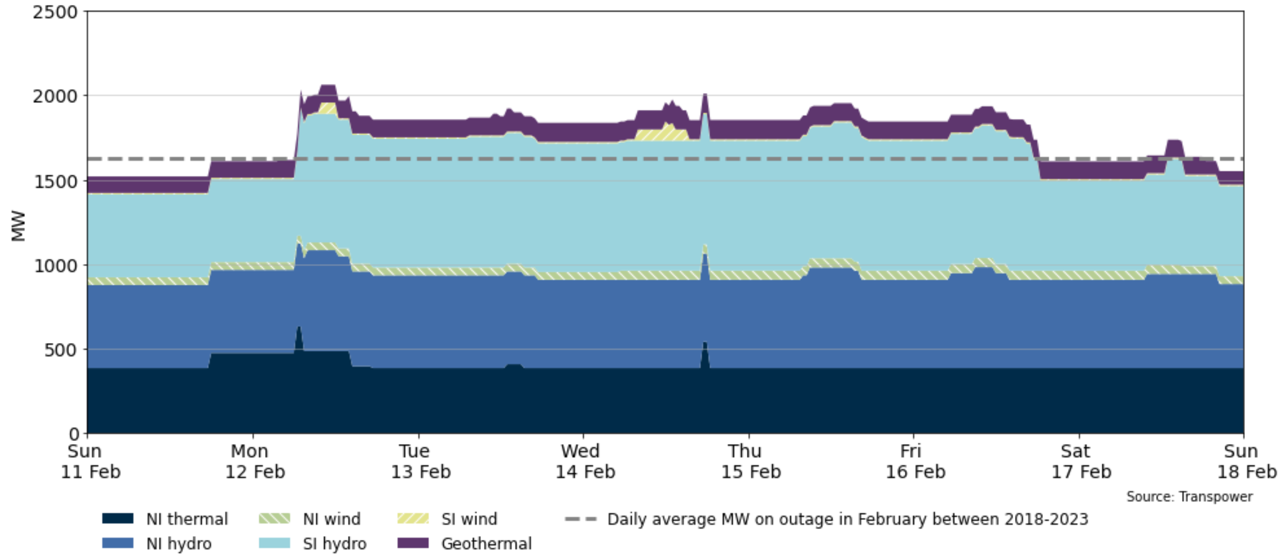
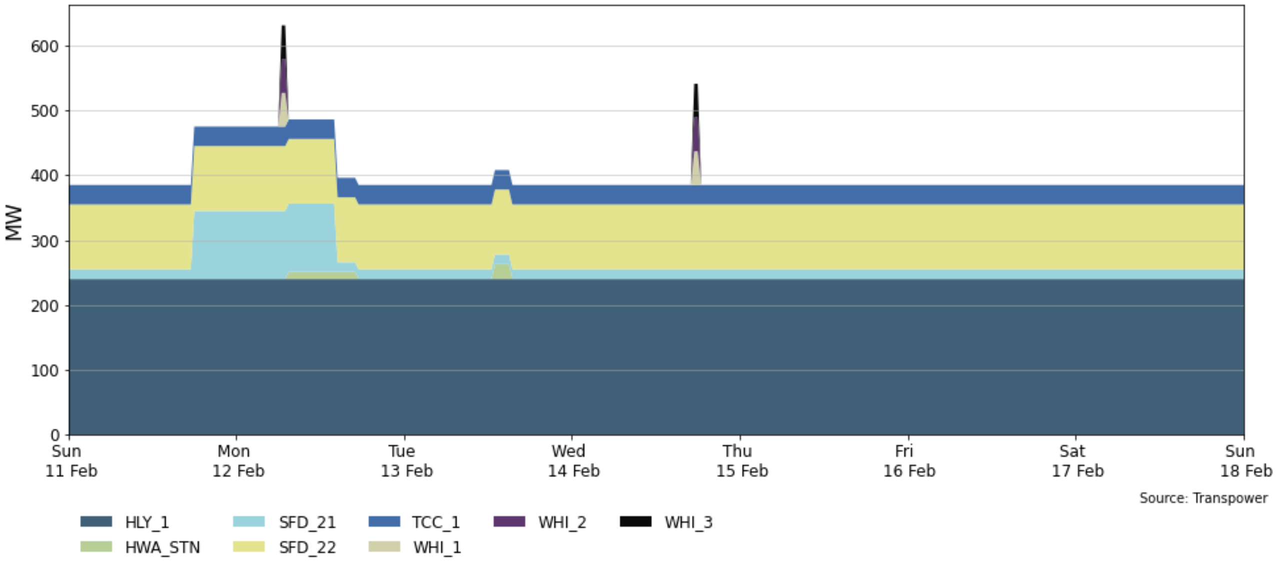


Figure 17: MW loss from thermal outages



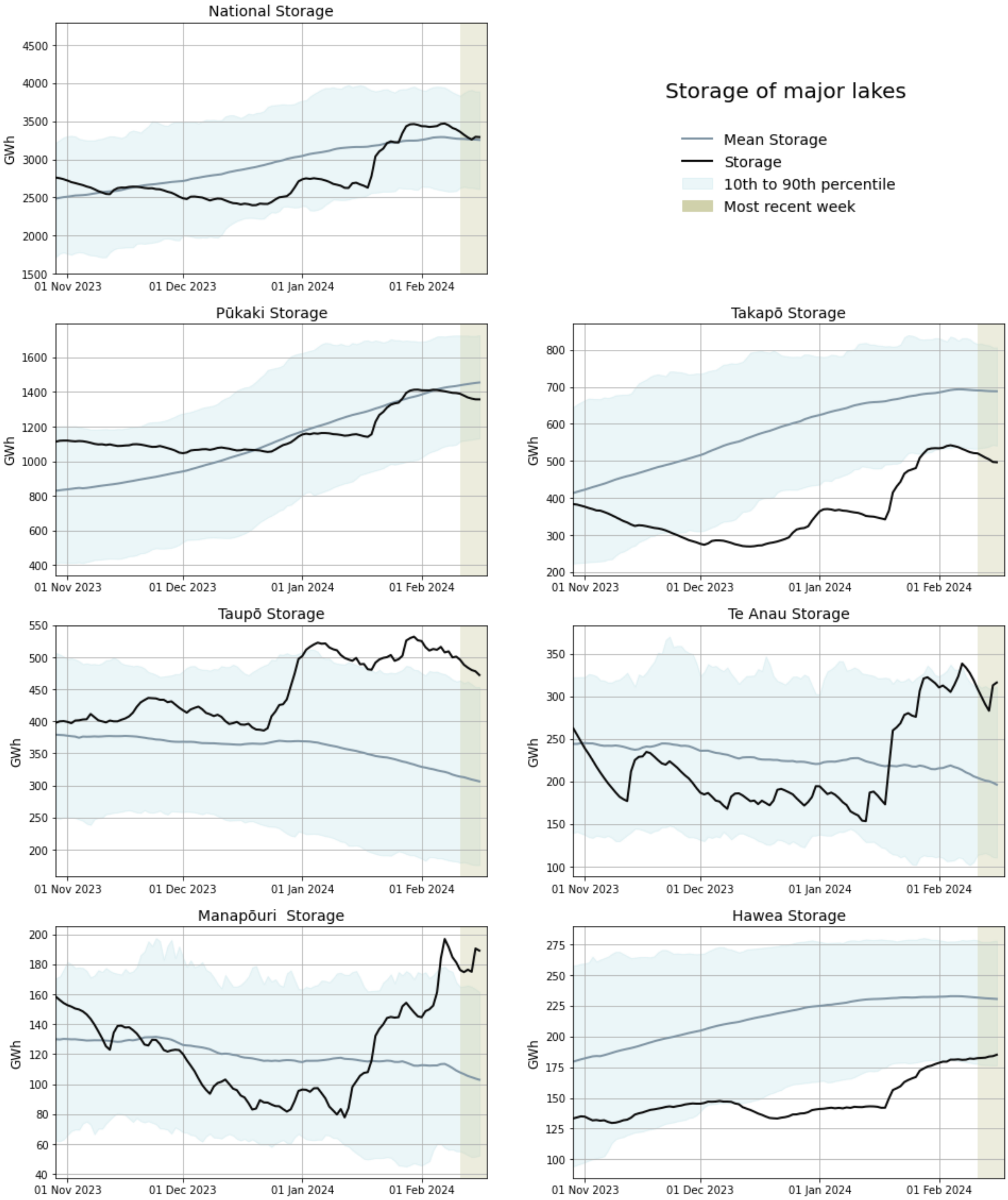
9. Storage/fuel supply

9.1. Figure 18 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 decreased this week compared to last week, now sitting at 82% nominally full and ~101% of the historical average for this time of the year (as of 17 February).

9.3. Most lakes saw a decrease in their storage levels. Storage at lake Taupō decreased this week but remains above its 90th percentile at around 475 GWh. Pūkaki storage is just below its historical average. Takapō is still below its 10th percentile. Lakes Manapōuri and Te Anau are above their 90th percentile and close to their high operating ranges. Hawea had a small increase this week.

Figure 18: Hydro storage



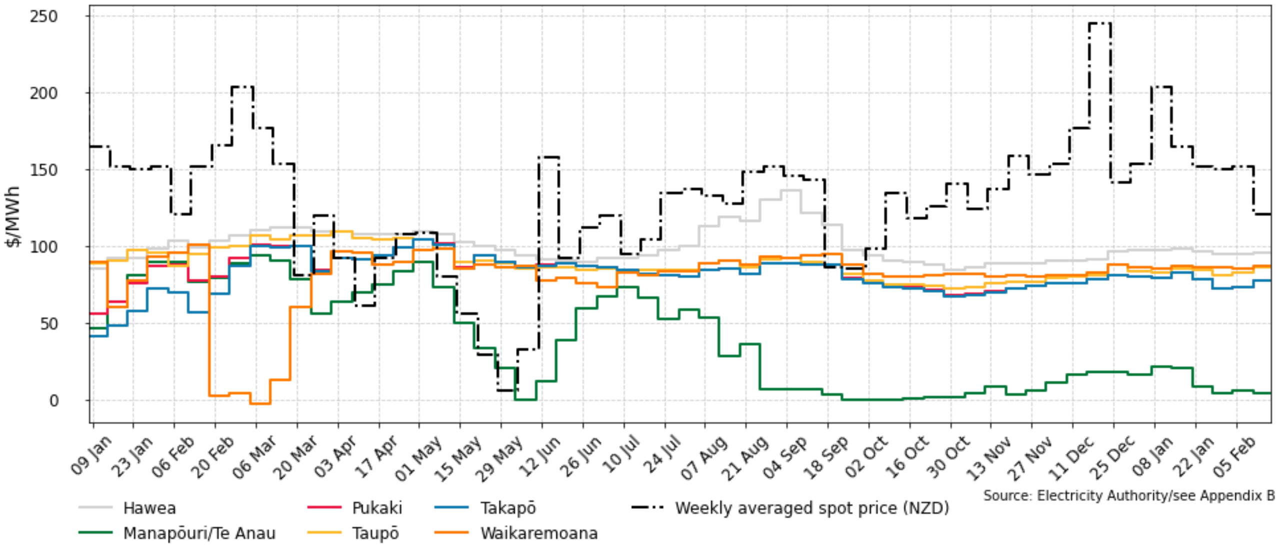
Source: Electricity Authority

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 19 shows the national water values between 8 January 2023 and 17 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 the water values increased for all major lakes except Manapōuri. The latter saw ~$1/MWh decrease while the other lakes saw an increase of around ~$1-3/MWh in their water values.

Figure 19: JADE water values across various reservoirs between 8 January 2023 and 17 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 20 shows an estimate of thermal SRMCs as a monthly average up 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.

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.

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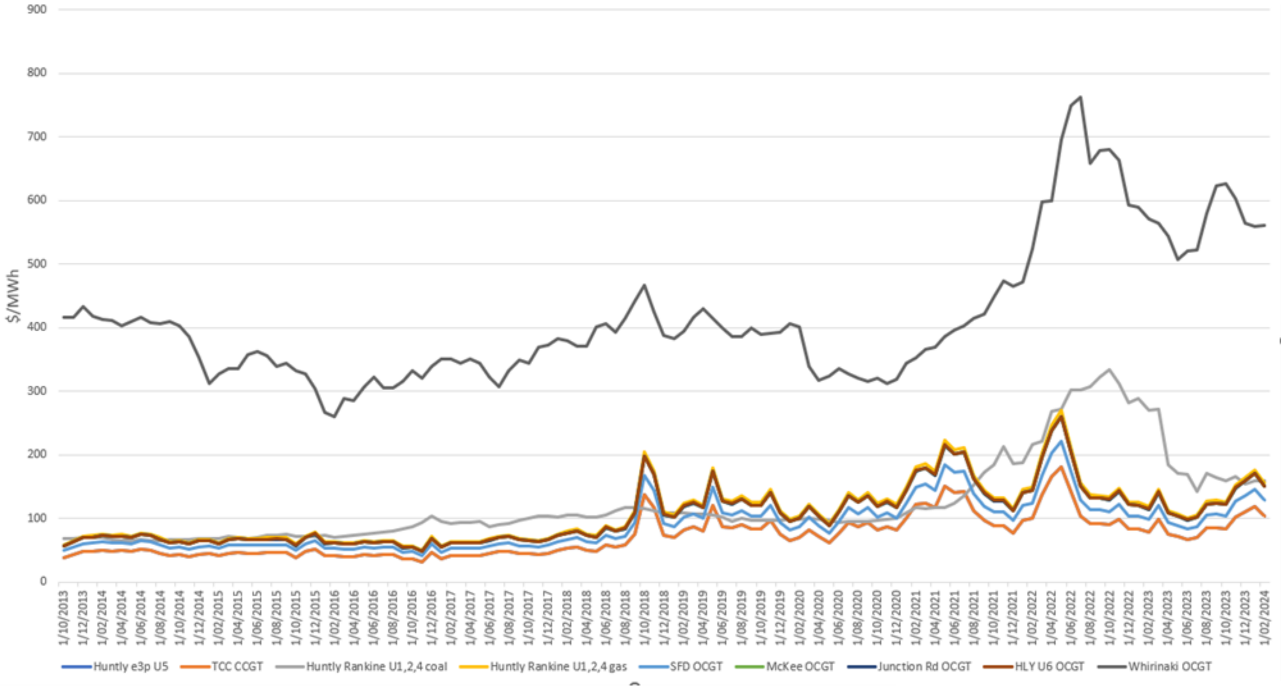
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

11.5. 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 20: Estimated monthly SRMC for thermal fuels



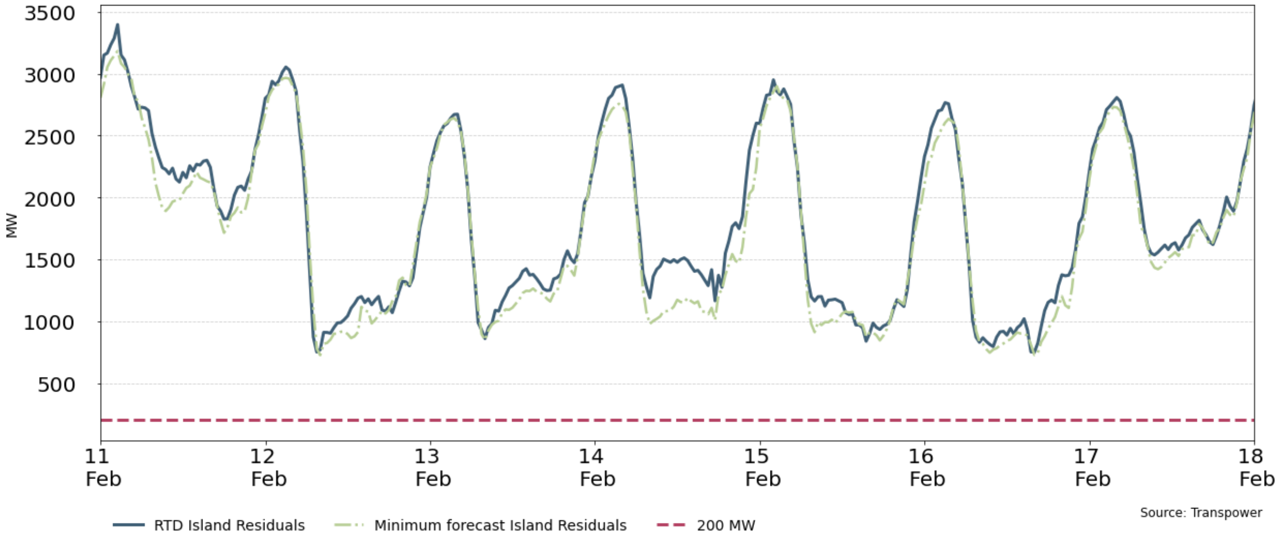
Source: Electricity Authority/see Appendix C

12. Generation balance residuals

12.1. Figure 21 shows the generation balance residuals between 11-17 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. Generation residuals were healthy this week, with residuals being well above 200MW, reaching a minimum of ~750MW on Friday afternoon.

Figure 21: Generation balance residuals between 11-17 February

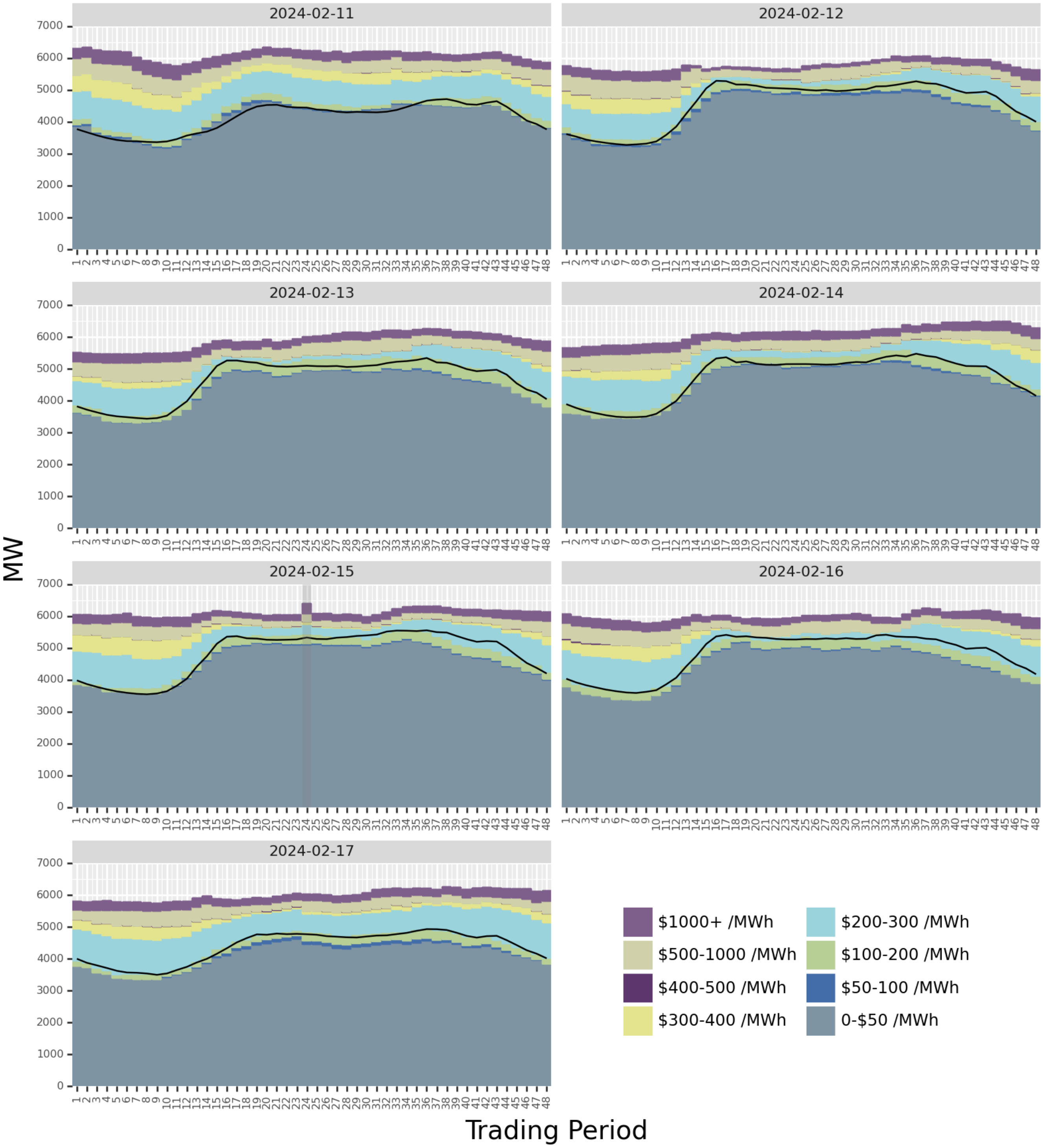


13. Offer behaviour

13.1. Figure 22 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

13.2. Earlier in the week offers cleared mostly in the $100-$200/MWh range or below. From Wednesday onwards, most morning offers cleared in the $100-$200/MWh while later in the day offers cleared between $200-$300/MWh.

Figure 22: Daily Offer stacks[3]



[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, prices generally appeared to be consistent with supply and demand conditions.

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.