25 March 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 17-23 March

1.1. Spot prices increased again this week, compared to the previous week, with prices mostly between $200-$300/MWh. There were two price spikes, one each on Wednesday and Thursday mornings, both related to high demand and low wind generation. There were also high amounts of wind generation outages. There were a few periods of reserve price spikes, related to tight reserve market conditions as large thermal generators set the North Island risk. Furthermore, on Sunday, a planned HVDC Pole 3 outage limited the reserve sharing capacity between the islands, but then HVDC capacity returned to normal. This week, TCC, Huntly 5, Huntly 4, and then Huntly 2 ran as baseload. Several peakers also supported baseload generation. Hydro storage decreased this week, now at ~88% of its historical average as of 23 March. There were several periods of high demand due to cold morning temperatures.

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 17-23 March:

(a) The average wholesale spot price across all nodes was $248/MWh.

(b) 95% of prices fell between $16/MWh and $325/MWh.

2.4. This week, and similar to the previous week, spot prices were largely above the national historical median, and mostly above $200/MWh, influenced, in part, by declining hydro storage and low wind generation. The average spot price increased by $35/MWh compared to the previous week.

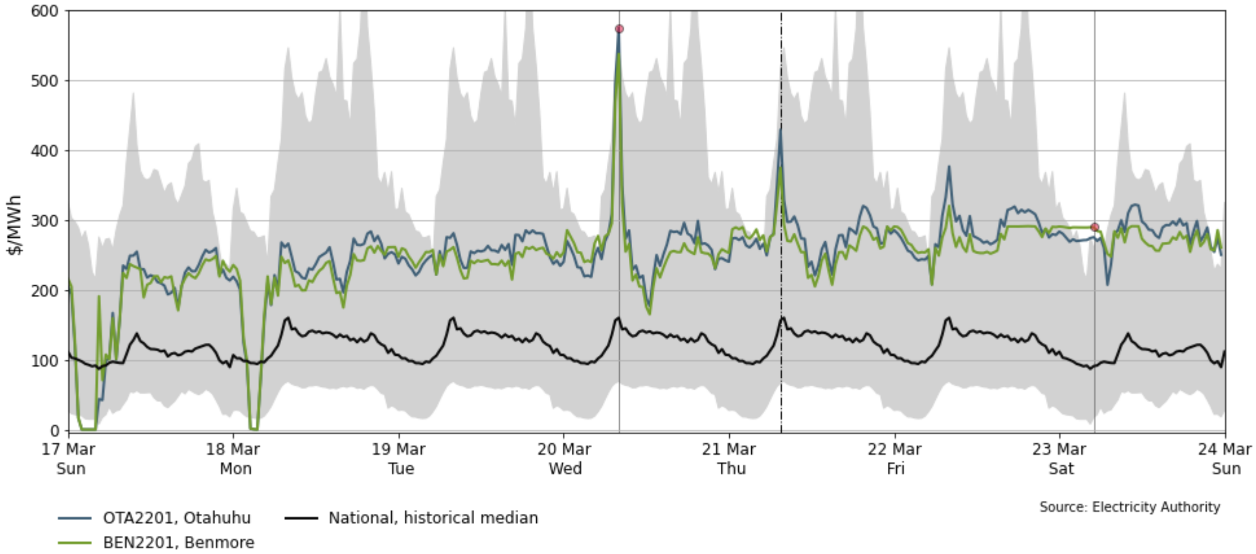
2.5. During the early hours of Sunday and Monday prices were low, due to low demand and high wind generation.

2.6. There were two price spikes this week, on Wednesday and Thursday. Wednesday morning saw the highest spot prices this week, $575/MWh at Ōtāhuhu and $537/MWh at Benmore. Prices reached $429/MWh at Ōtāhuhu and $375/MWh at Benmore during the price spike on

[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.

Thursday morning. The price spikes are aligned with times of high demand due to cold temperatures on those days and reflect the current hydro storage conditions and low wind generation. Higher overnight spot prices on Saturday reflected the low wind generation and subsequent reliance on hydro and thermal generation. No significant price separation was observed this week.

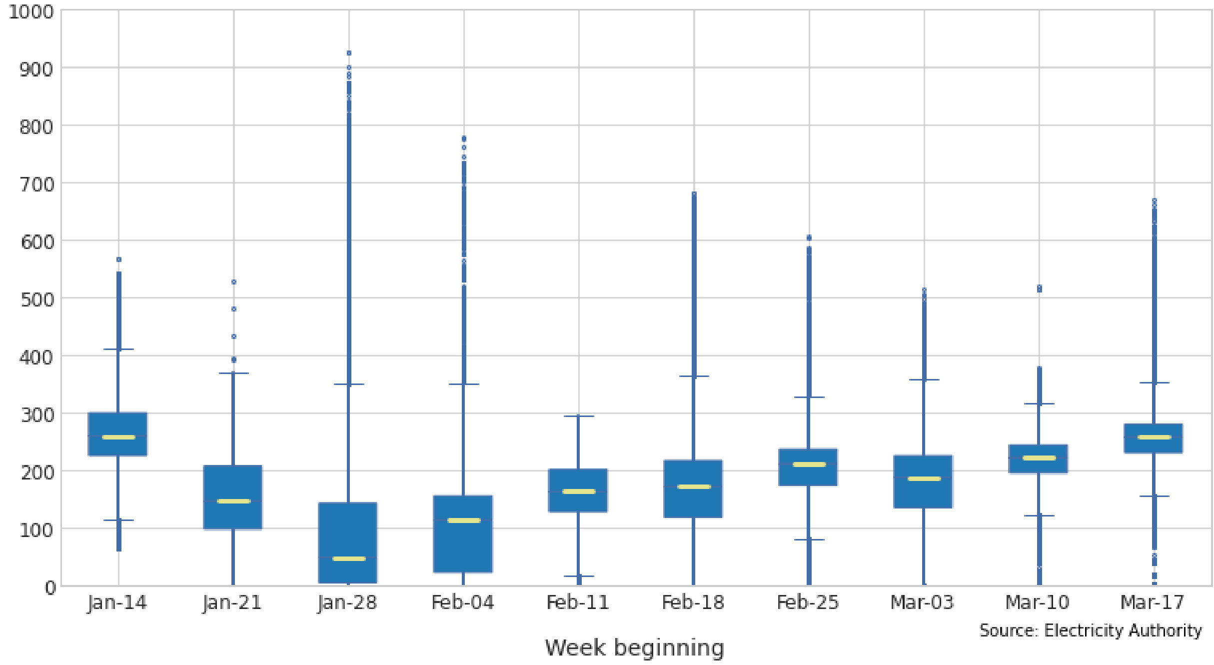
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 17-23 March



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. This week prices were higher compared to the previous week. The median price was $258/MWh, compared to $223/MWh in the previous week, a $35/MWh increase. The middle 50% of the prices were between $230-$280/MWh. Prices remain overall less volatile than those in late January, however, this week there were slightly more outliers than the previous week.

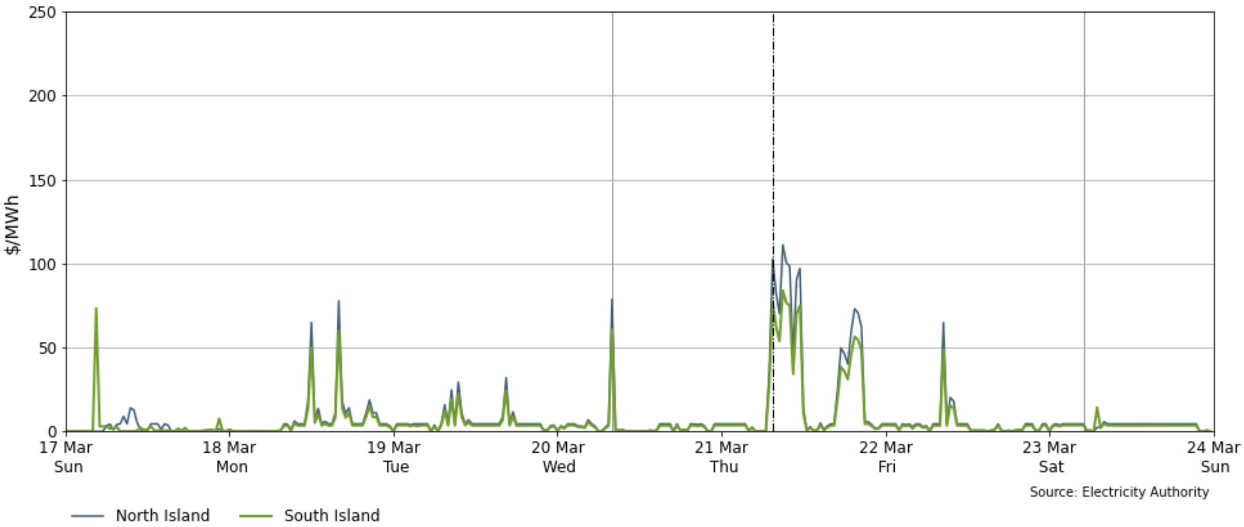
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

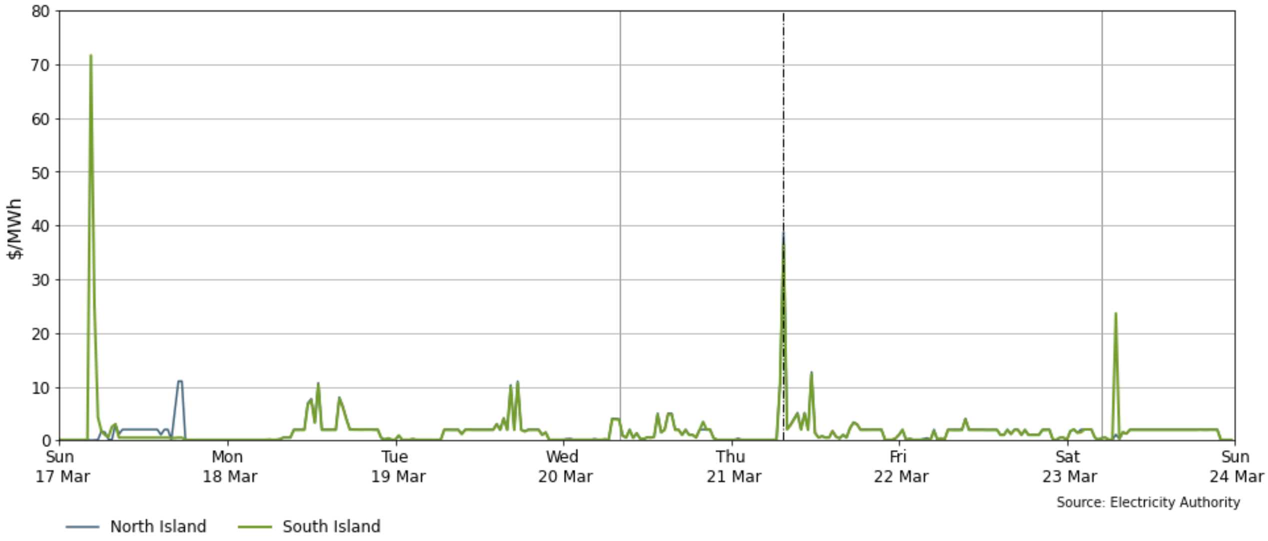
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh with a few price spikes during the week. FIR spikes occurred during periods of tight reserve market conditions when there were high reserve requirements, which was further exacerbated by periods of low wind generation. High FIR prices on Thursday also occurred when some hydro outages reduced the amount of FIR available.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 17-23 March



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly between $0-$10/MWh this week. A few SIR price spikes and price separations occurred this week. The price spike and price separation on Sunday are related to the planned HVDC Pole 3 outage. The Thursday spike is in line with the spot price spike, high Northward HVDC flow and tight reserve market conditions - with TCC setting the North Island risk.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 17-23 March



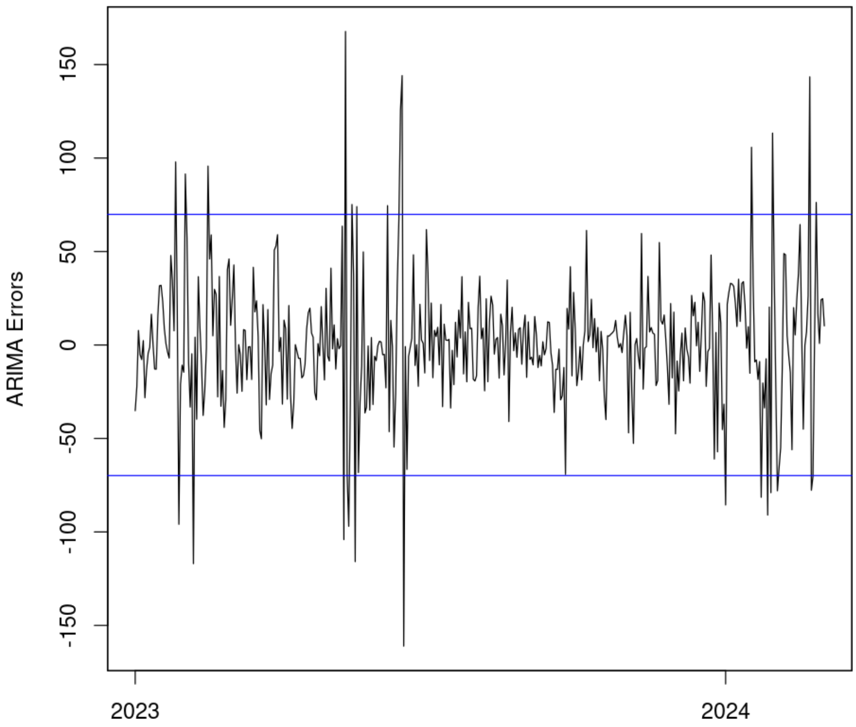
4. Regression residuals

4.1. 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.

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 for in the regression analysis.

4.3. This week there were no residuals above or below two standard deviations of the data, indicating actual and modelled prices were similar.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 23 March 2024

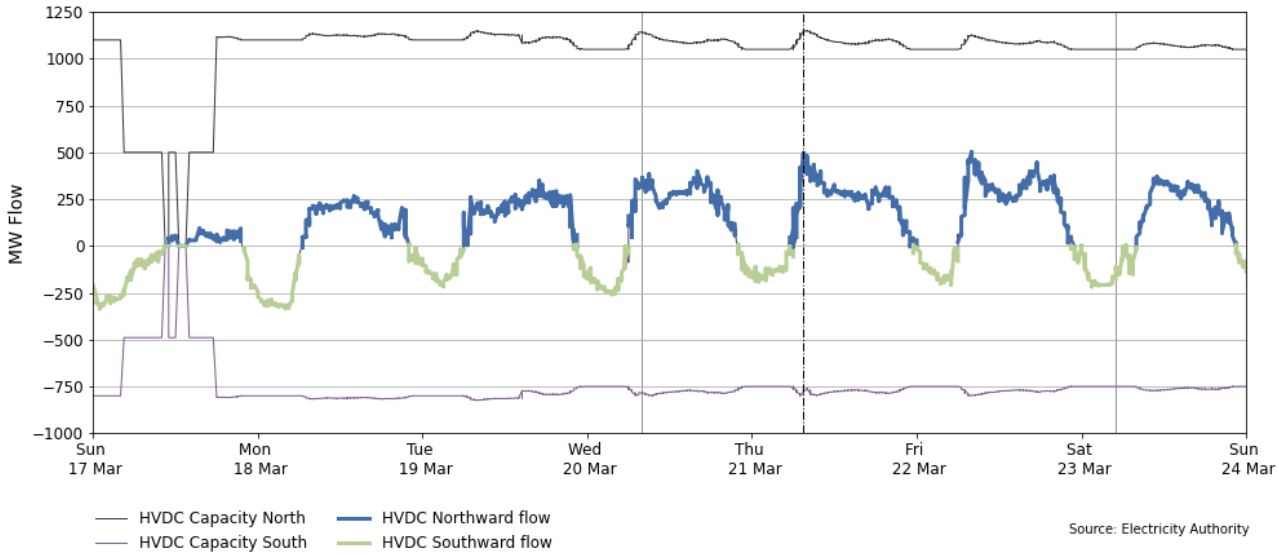


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 17-23 March. The HVDC capacity was limited during most of the day on Sunday, due to a planned Pole 3 outage. From late Sunday onwards, HVDC capacity returned to normal levels. HVDC flows this week were mostly northwards during daytime and southwards during nighttime. The southward flow was mostly below 250MW, related to low wind generation this week. The northward flow reached a maximum of ~500MW during Thursday's price spike. High overnight spot prices on Saturday occurred when the HVDC was flowing South, despite the North Island wind being low.

Figure 6: HVDC flow and capacity between 17-23 March

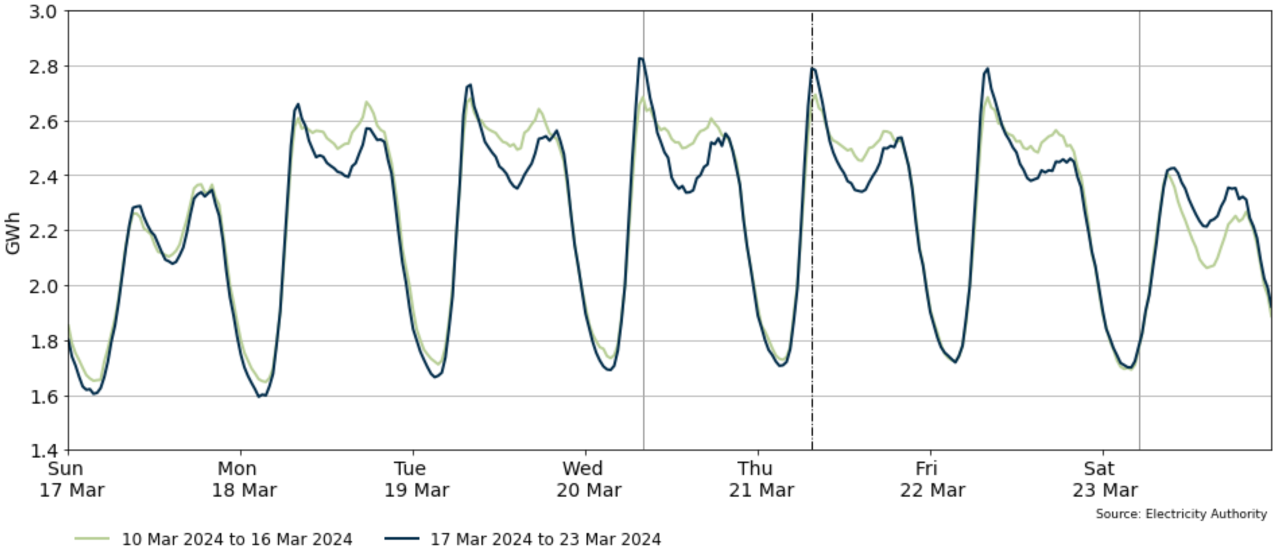


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 17-23 March, compared to the previous week. Weekday morning demand was higher this week due to colder mornings. Midday and evening demand was, however, lower than the previous week. Spot price spikes on Wednesday and Thursday occurred during high morning peak demand. Additionally, During the price spike on Wednesday, demand forecast was under-forecast by roughly 100MW.

Figure 7: National demand between 17-23 March compared to the previous week

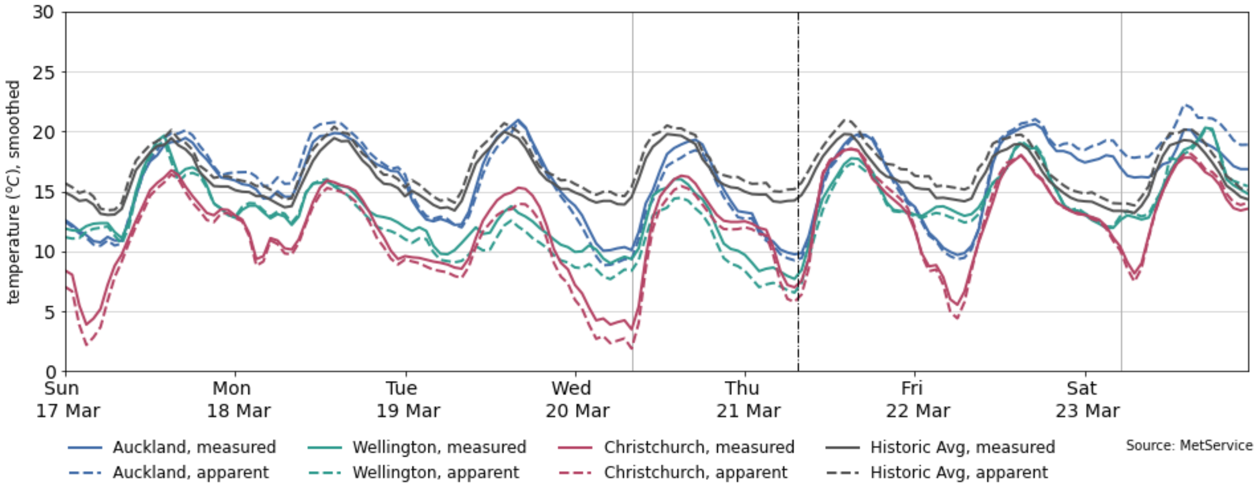


6.2. Figure 8 shows the hourly temperature at main population centres from 17-23 March. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures were mostly below or around the historical average this week, with Auckland temperatures floating around the average while Wellington and Christchurch were mostly below it.

6.4. From Wednesday onwards the autumn pattern of cold mornings and mild evenings became more pronounced. Temperatures in Auckland varied between 9ºC and 22ºC. Wellington temperatures fluctuated between 7ºC and 20ºC. Christchurch temperatures were between 2ºC and 19ºC this week. The spot price spikes on Wednesday and Thursday occurred when morning temperatures in Wellington, Christchurch and Auckland were all at or below 10 ºC.

Figure 8: Temperatures across main centres between 17-23 March

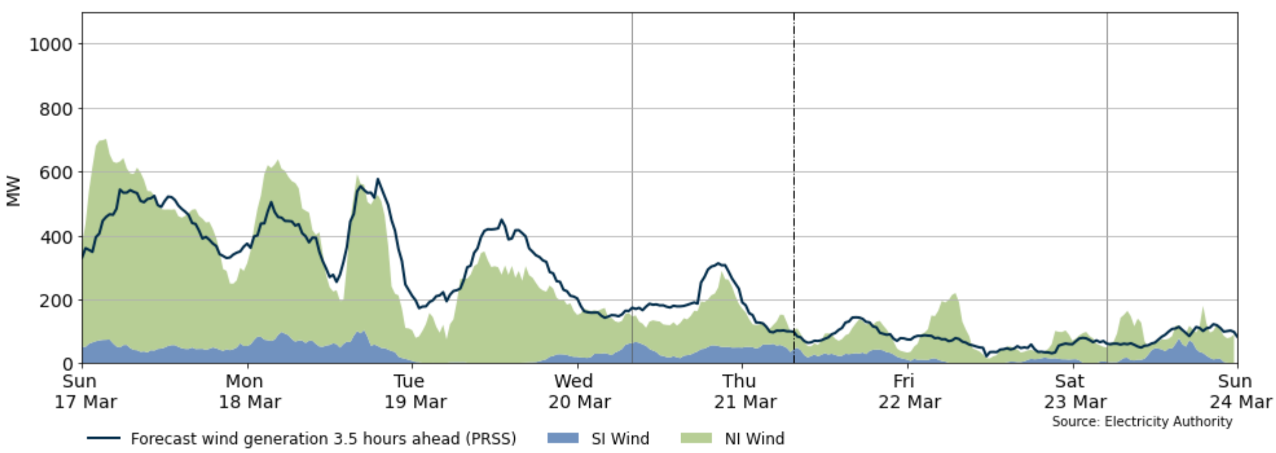


7. Generation

7.1. Figure 9 shows wind generation and forecast from 17-23 March. This week wind generation varied between 16MW and 702MW, with an average of 227MW.

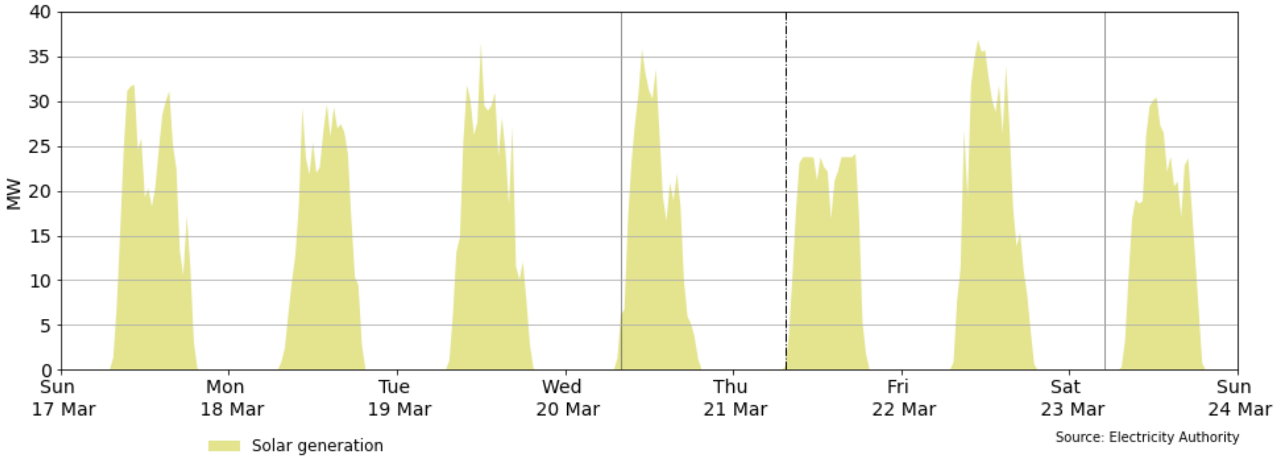
7.2. Wind generation was low this week, especially from Tuesday onwards. Several large wind farms had outages from Monday onwards, with often more than 200MW on outage. This combined with generally calmer conditions saw extended periods of wind generation of below 200MW this week. Wind generation was low during the Wednesday and Thursday price spikes, and overnight between Friday and Saturday.

Figure 9: Wind generation and forecast between 17-23 March



7.3. Figure 10 shows solar generation from 17-23 March. The Lodestone Edgecumbe solar farm is still under the commissioning process. The 32MW(DC)/24MW(AC) solar array is currently generating a maximum of 16MW. Solar generation this week saw a few overcast days impacting its generation, as shown in Figure 10.

Figure 10: Solar generation between 17-23 March



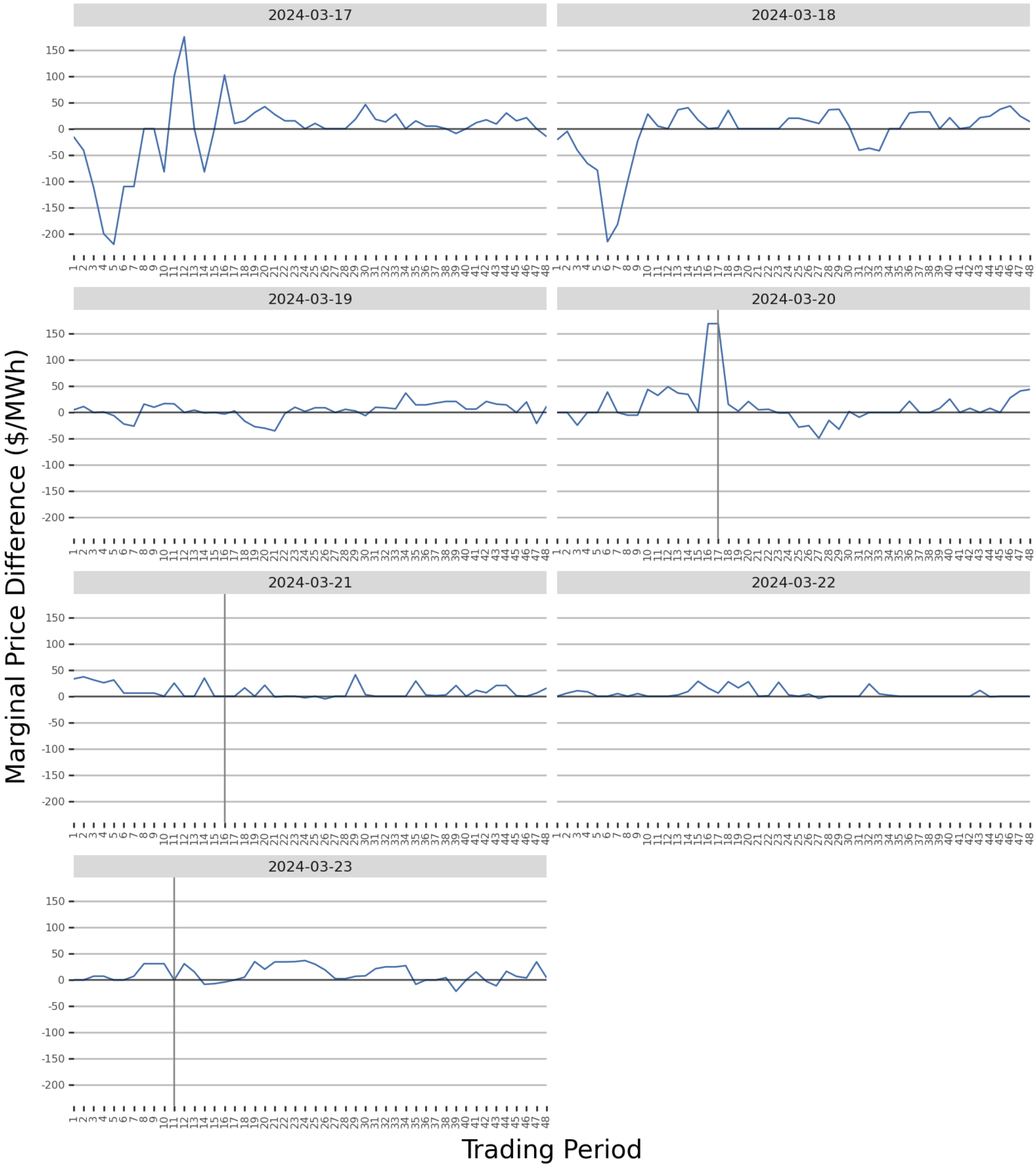
7.4. Figure 11 shows the difference between the real-time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1-hour ahead (PRSS) demand and wind forecasts at the national level. This plot highlights when forecasting inaccuracies are causing large differences between 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 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 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.

7.5. This week the largest difference between the RTD and PRSS prices occurred early on Sunday and Monday – when prices were lower than forecast.

7.6. On Wednesday, during the 8:00am price spike, the RTD price was $150/MWh higher than the 1-hour ahead PRSS price. During this trading period, demand was higher than forecast.

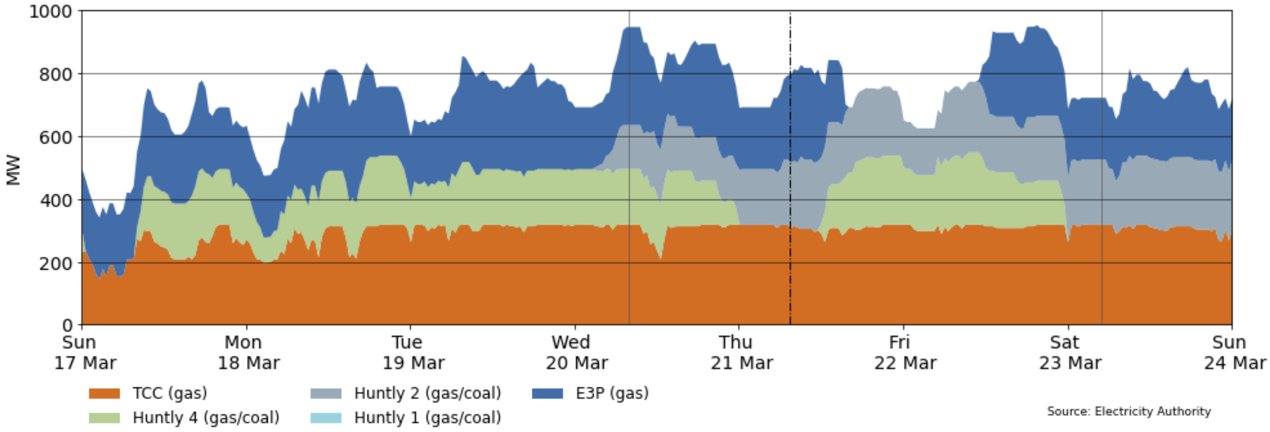
7.7. Except for Sunday, Monday, and Wednesday, all the other days this week saw the differences between PRSS and RTD marginal prices within the +/-$50/MWh range. Compared to the previous week, PRSS prices were generally more accurate.

Figure 11: Difference between national marginal RTD price and gate closure PRSS prices, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 17-23 March



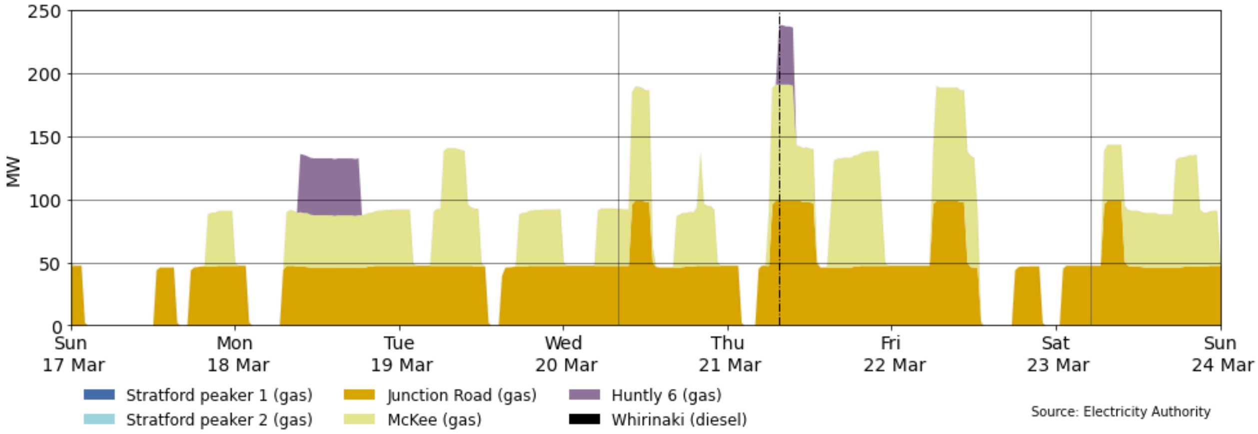
7.8. Figure 12 shows the generation of thermal baseload between 17-23 March. TCC provided the baseload this week with Huntly 5 (E3P) also ran for most of the week except for a portion of Thursday and Friday, possibly due to the unplanned outage at the Kupe gas field. Huntly 4 ran continuously between Sunday morning and Wednesday evening and from the middle of the day on Thursday up to the end of the day on Friday. Huntly 2 ran continuously from Wednesday onwards.

Figure 12: Thermal baseload generation between 17-23 March



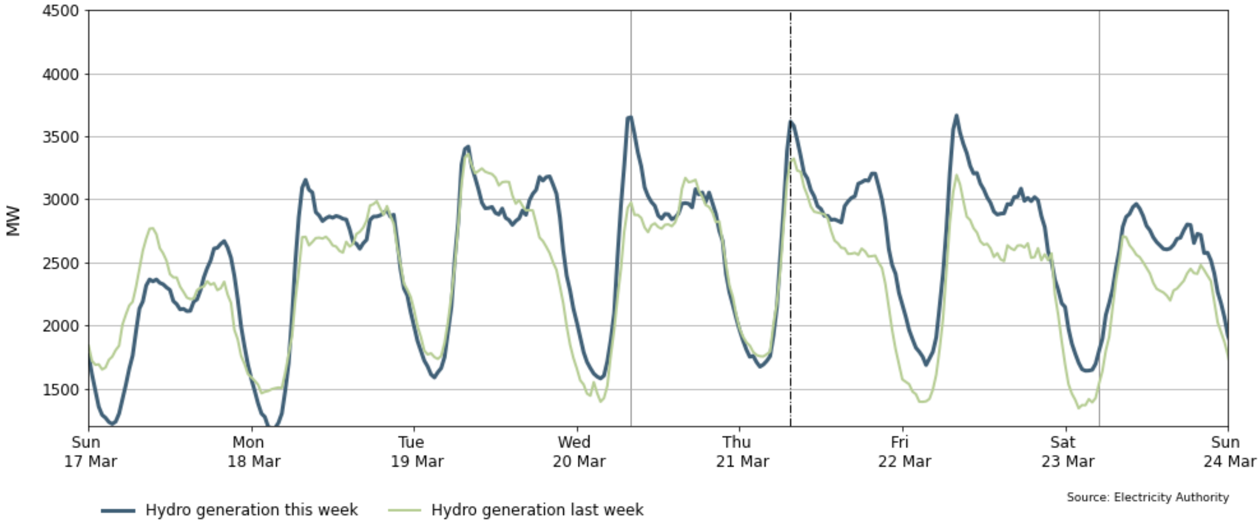
7.9. Figure 13 shows the generation of thermal peaker plants between 17-23 March. Peakers were required every day this week, especially during times of high demand and low wind generation such as Thursday during the price spike. Junction Road ran every day. McKee and Huntly 6 also ran this week, the latter only on Monday and during Thursday's price spike.

Figure 13: Thermal peaker generation between 17-23 March



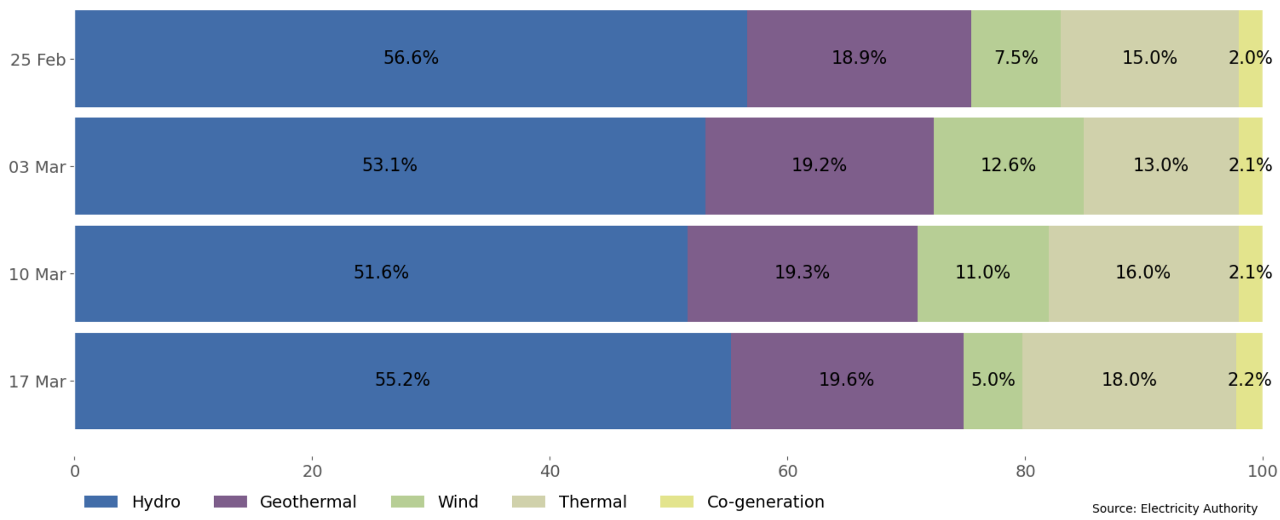
7.10. Figure 14 shows hydro generation between 17-23 March. Hydro generation was often higher than the previous week, except for times when wind generation was high, such as on Sunday and Monday. Hydro generation closely followed the demand this week. Due to low wind generation, hydro generation was higher overnight as well.

Figure 14: Hydro generation between 17-23 March



7.11. As a percentage of total generation, between 17-23 March, total weekly hydro generation was 55.2%, geothermal 19.6%, wind 5.0%, thermal 18.0%, and co-generation 2.2%, as shown in Figure 15. The relative increase in hydro generation this week is related to both the HVDC capacity returning to full, and the relative decrease in wind generation compared to the previous week.

Figure 15: Total generation by type as a percentage each week between 7 January and 23 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 17-23 March ranged between ~1500MW and ~2800MW. This is much higher than we typically see this time of year as several wind farms had large outages this week. Figure 17 shows the thermal generation capacity outages.

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) Huntly 2 was on partial outage between 15-18 March and on full outage on 19 March

(d) Huntly 4 was on outage on 23 March

(e) Poihipi geothermal plant is on outage until 26 March 2024

(f) Turitea Wind Farm was on outage between 19-20 March

(g) West Wind Wind Farm is on outage between 18-25 March 2024

(h) Te Uku Wind Farm was on outage on 19 March

(i) Mill Creek Wind Farm was on outage between 23-24 March

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

Figure 16: Total MW loss due to generation outages between 17-23 March

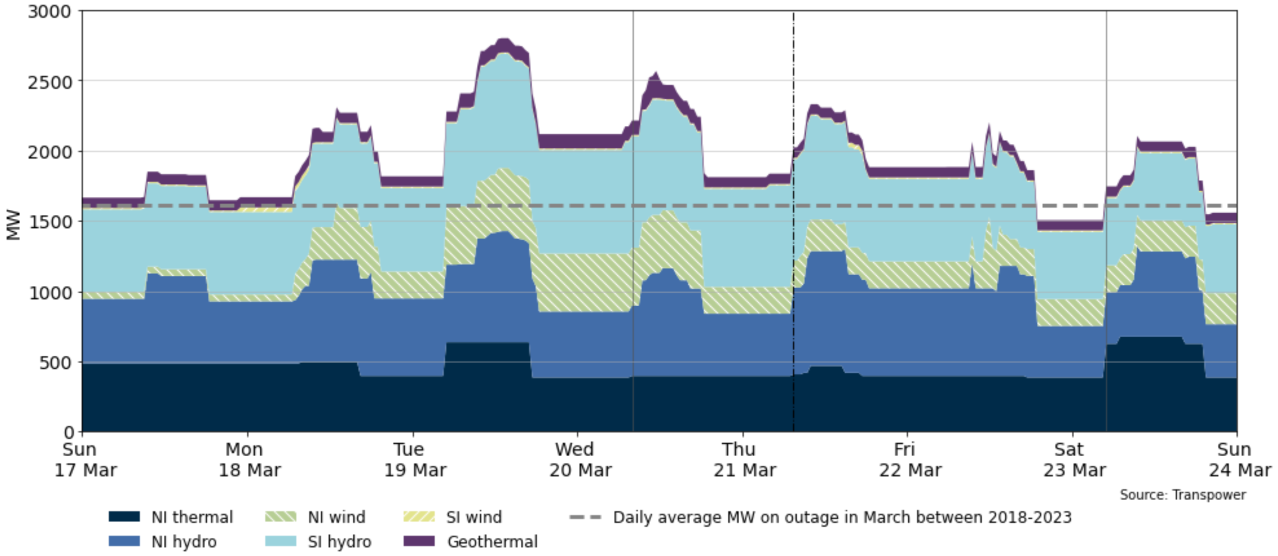
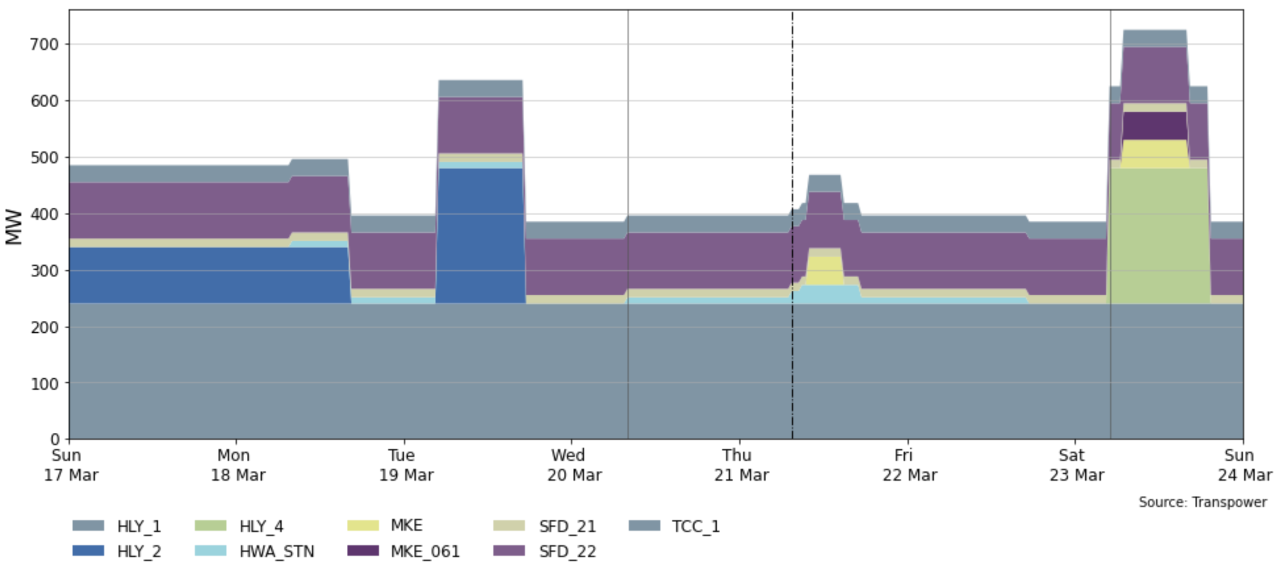


Figure 17: MW loss from thermal outages between 17-23 March

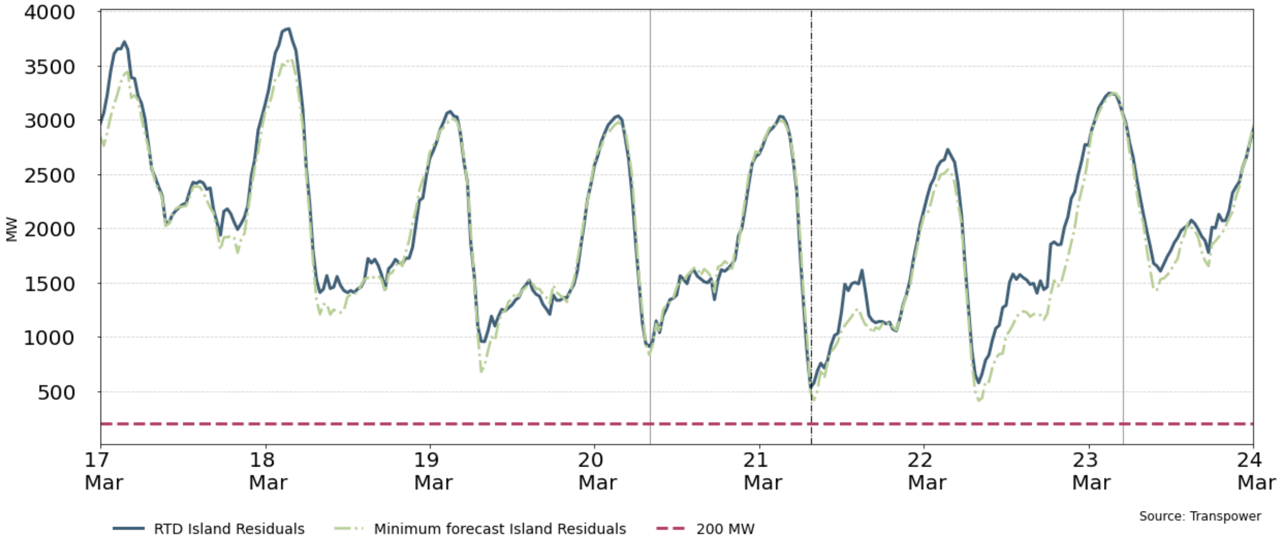


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 17-23 March. 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. National generation residual levels were healthy this week, reaching a minimum of ~535MW on Thursday morning, during which demand was high and wind generation was low. The minimum North Island generation residual levels reached a minimum of ~320MW on Friday morning.

Figure 18: National generation balance residuals between 17-23 March



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. Hydro storage decreased this week, now sitting at 70% nominally full and ~88% of the historical average for this time of the year (as of 23 March).

10.3. Storage at all lakes decreased this week. As of 23 March:

(a) Lake Taupō is below its 90th percentile but way above its historical average.

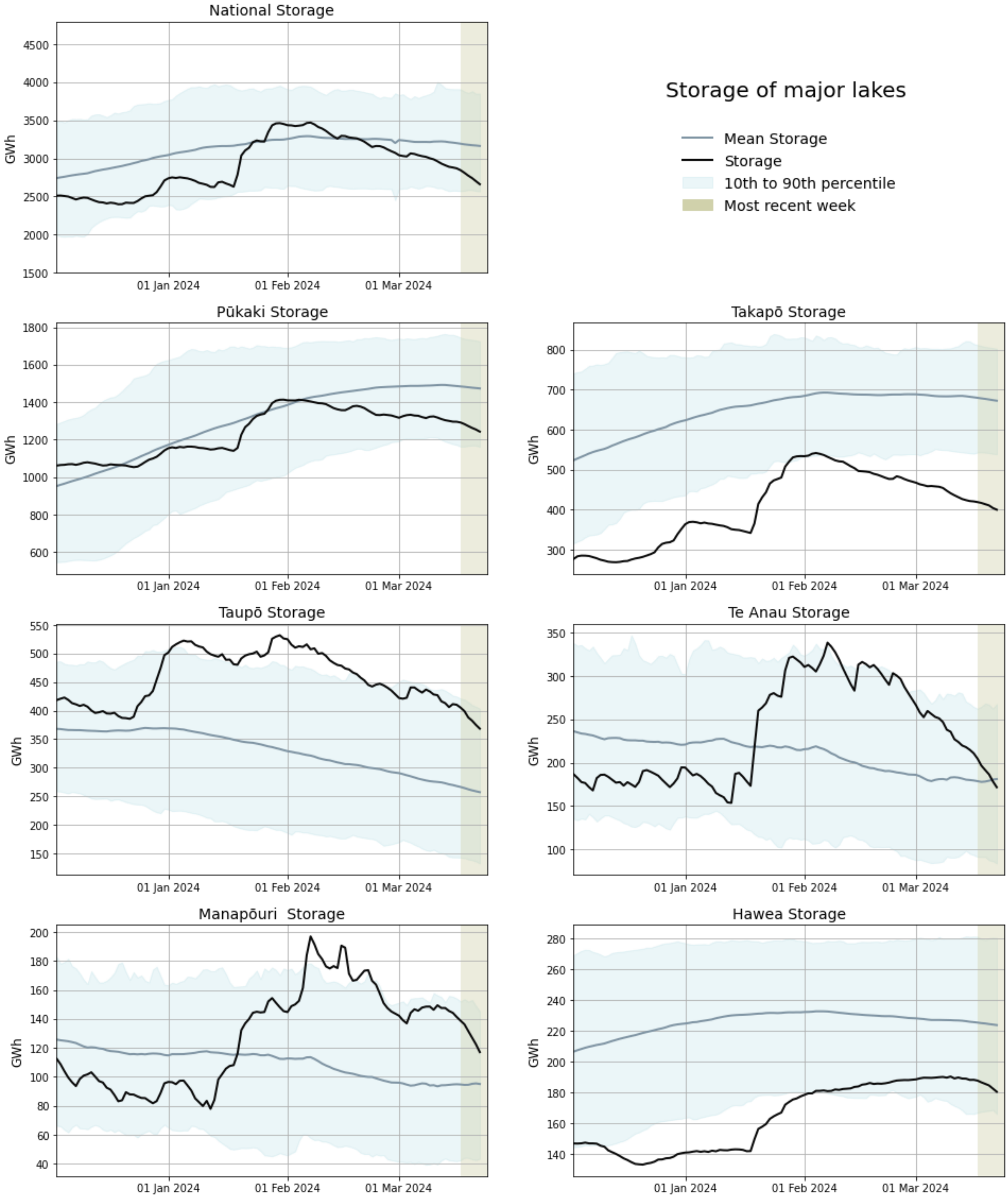
(b) Lake Pūkaki is now trending towards its 10th percentile after another week of decline.

(c) Lake Takapō storage decreased this week, remaining below its 10th percentile.

(d) Lake Manapōuri and Te Anau both saw a decrease in storage. Te Anau is now below its historical average and Manapōuri is trending towards its historical average.

(e) Lake Hawea storage also decreased this week, but it is still above its 10th percentile.

Figure 19: Hydro storage



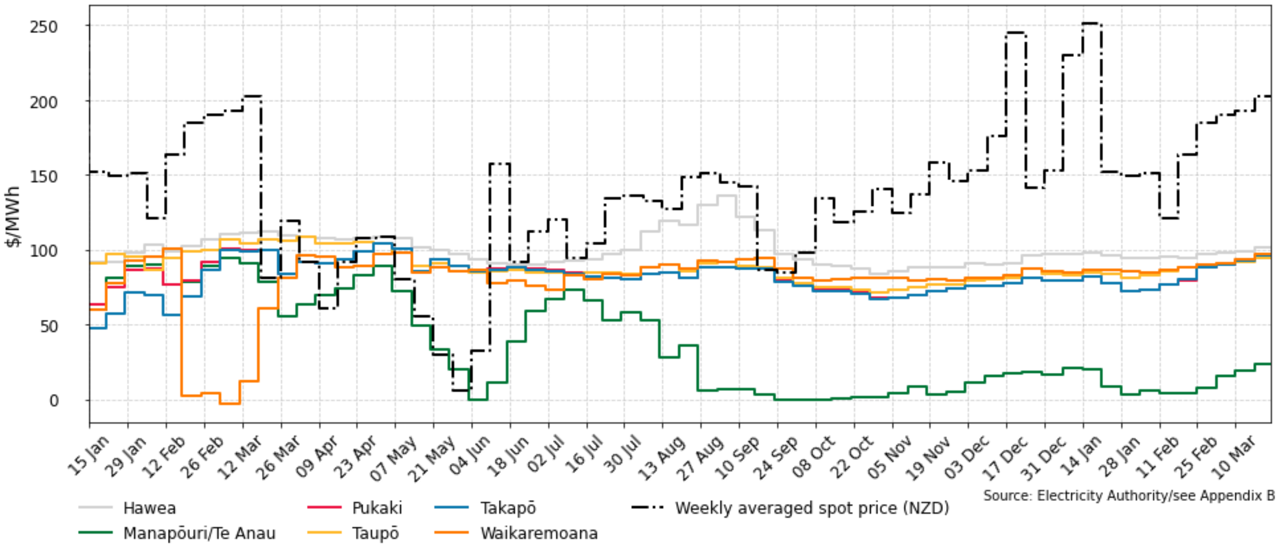
Source: Electricity Authority

11. JADE water values

11.1. 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 20 shows the national water values between 8 January 2023 and 23 March 2024 obtained from JADE calculated 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.

11.2. Compared to the previous week, all reservoirs saw an increase in price between ~$2.60/MWh (Taupō) and ~$4.20/MWh (Manapōuri/Te Anau), as hydro storage continues to decline.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 23 March 2024



12. Prices versus estimated costs

12.1. 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).

12.2. 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.

12.3. Figure 21 shows an estimate of thermal SRMCs as a monthly average up to 1 March 2024. The SRMCs for coal and diesel have seen small changes from the previous month. The gas SRMC has increased this month, likely due to current gas availability and demand.

12.4. The latest SRMC of coal-fueled Rankine generation is ~$156MWh. The cost of running the Rankines on gas is now more expensive at ~$236/MWh.

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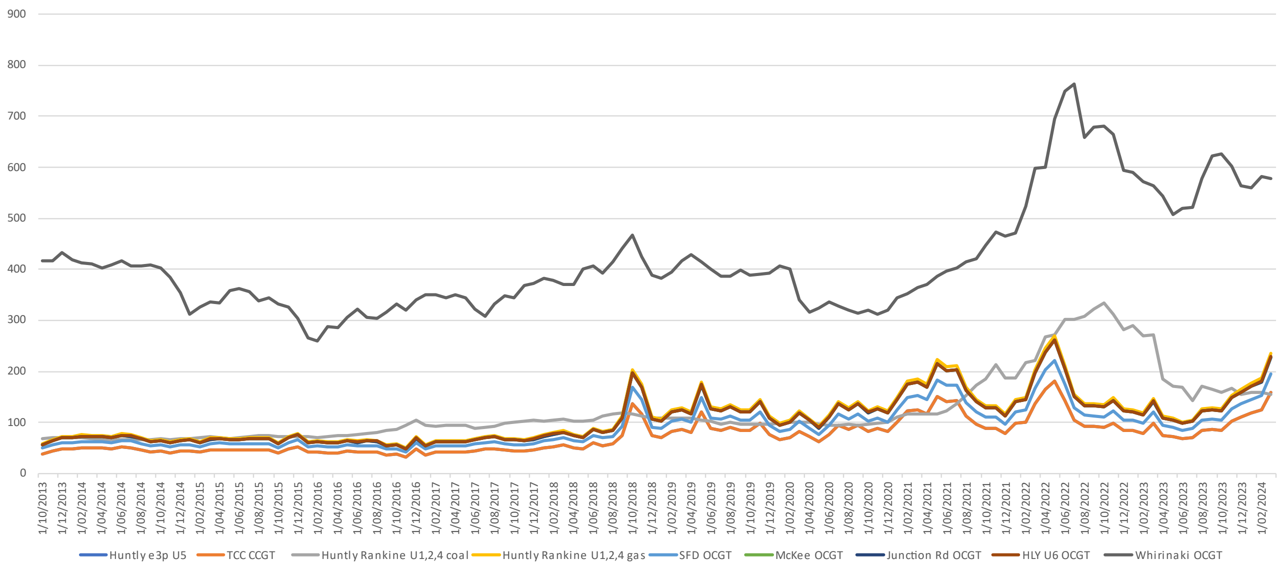
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas-fueled thermal plants is currently between ~$159/MWh and ~$236/MWh.

12.6. The SRMC of Whirinaki is ~$578/MWh.

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

Figure 21: Estimated monthly SRMC for thermal fuels



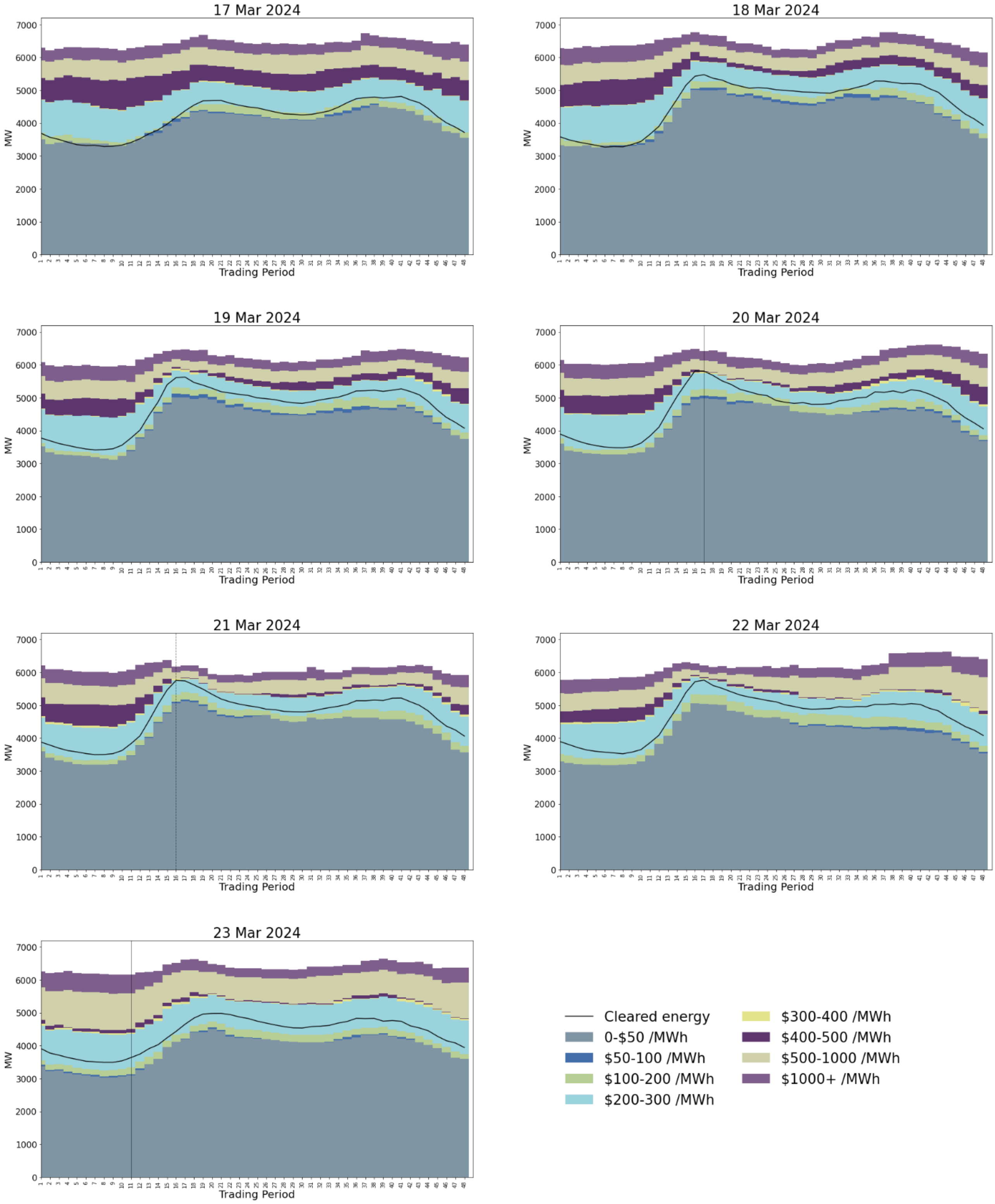
Source: Electricity Authority/see Appendix C

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. Most of the offers during the week were cleared in the $200-$300/MWh region. On Wednesday during the price spike, offers reached the $500-$1000/MWh region. On Thursday offers reached the $300-400/MWh price band. Over the week more energy in the $400-$500/MWh was shifted into the $500-$1000/MWh band.

Figure 22: 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, 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
21/01/2024-27/01/2024	Several	Further analysis	Mercury	Waikato hydro dams	High hydro offers
22/02/2024	32	Further analysis	Genesis	Tokaanu	Offer prices
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Hydro offers