15 April 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 7-13 April

1.1. Spot prices declined slightly this week, but prices were again mostly between $200-$300/MWh. No relevant spot price spikes occurred this week. Some reserve price spikes occurred this week, mainly related to high southward HVDC flows. Hydro storage increased considerably this week and is now at ~97% of its historical average after heavy rainfall over the South Island. The reliance on thermal generation decreased when hydro generation increased, aligned with the increase in hydro storage.

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 7-13 April:

(a) The average wholesale spot price across all nodes was $229/MWh.

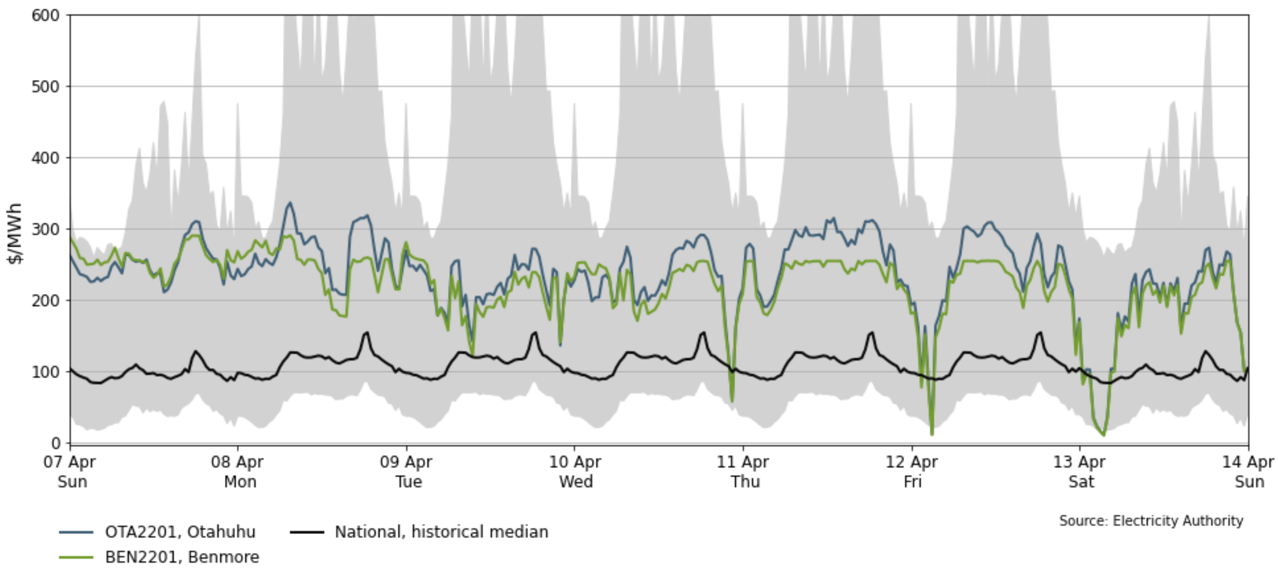
(b) 95% of prices fell between $80/MWh and $302/MWh.

2.4. This week, the majority of the spot prices were above the national historical median and mostly above $200/MWh. Rainfall over the South Island between Tuesday and Friday increased the hydro storage, but prices remained high. There were a few cases of prices above $300/MWh related to the prices being high due to low wind generation and/or low hydro storage.

2.5. Although prices remained mostly above $200/MWh this week, the average price decreased by $32/MWh compared to the previous week. The price dips between Wednesday and Saturday occurred when high hydro generation coincided with periods of low demand.

[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.

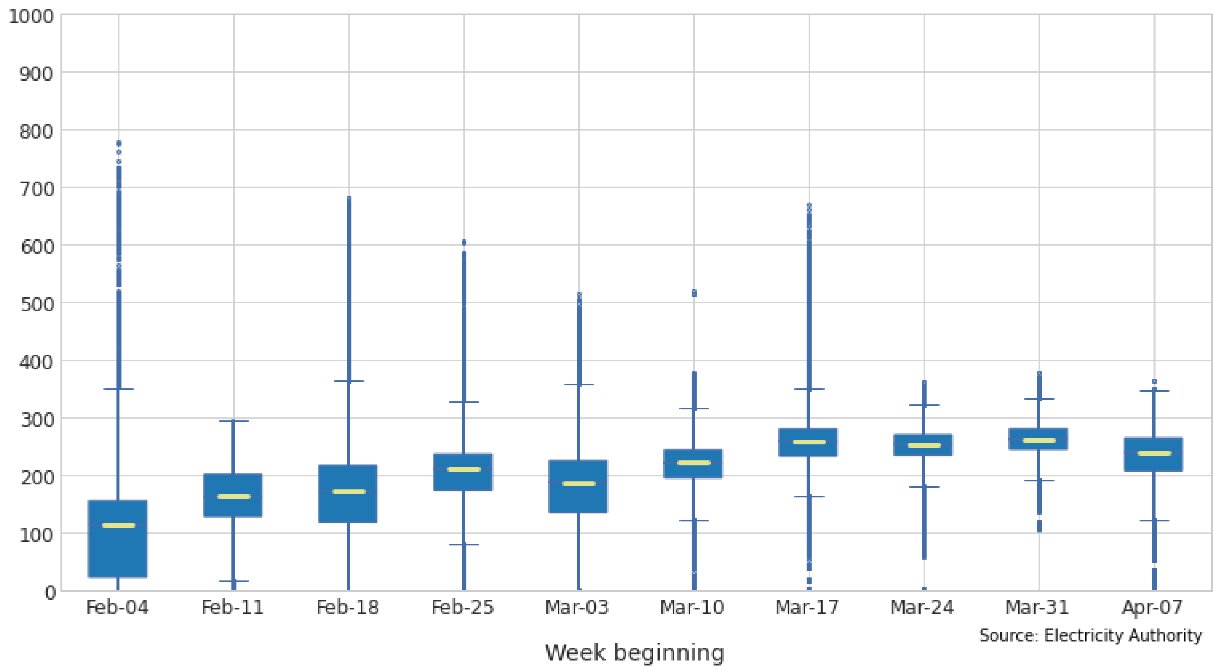
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 7-13 April



2.6. 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.

2.7. Spot prices were less condensed this week, as there were several instances of prices dipping below \$100/MWh. This week's median price was \$239/MWh, compared to \$263/MWh in the previous week, a \$24/MWh decrease. The middle 50% of the prices were between \$207-\$264/MWh.

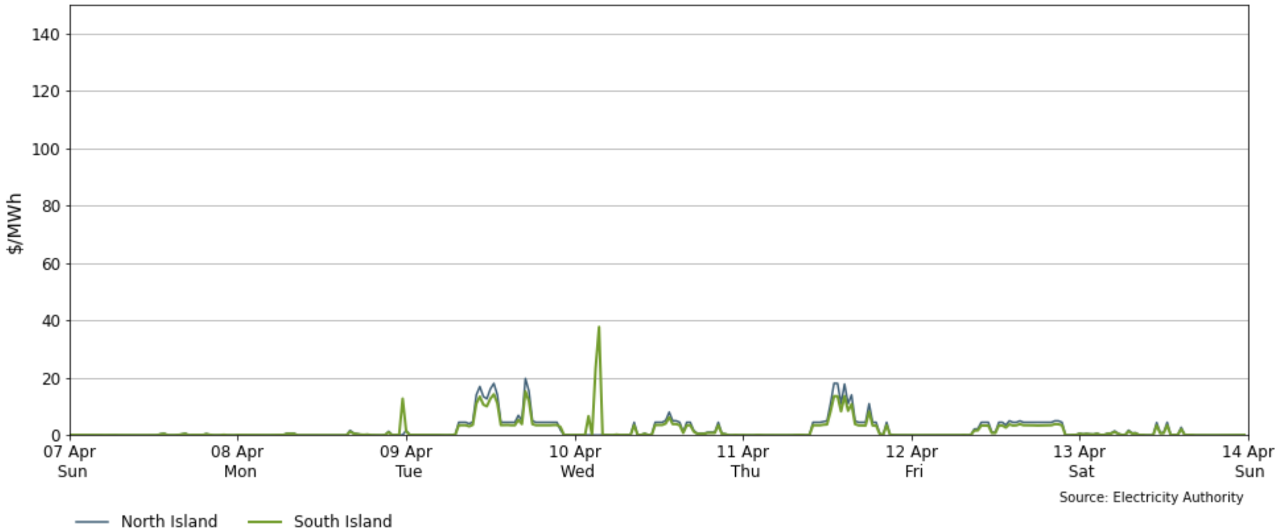
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

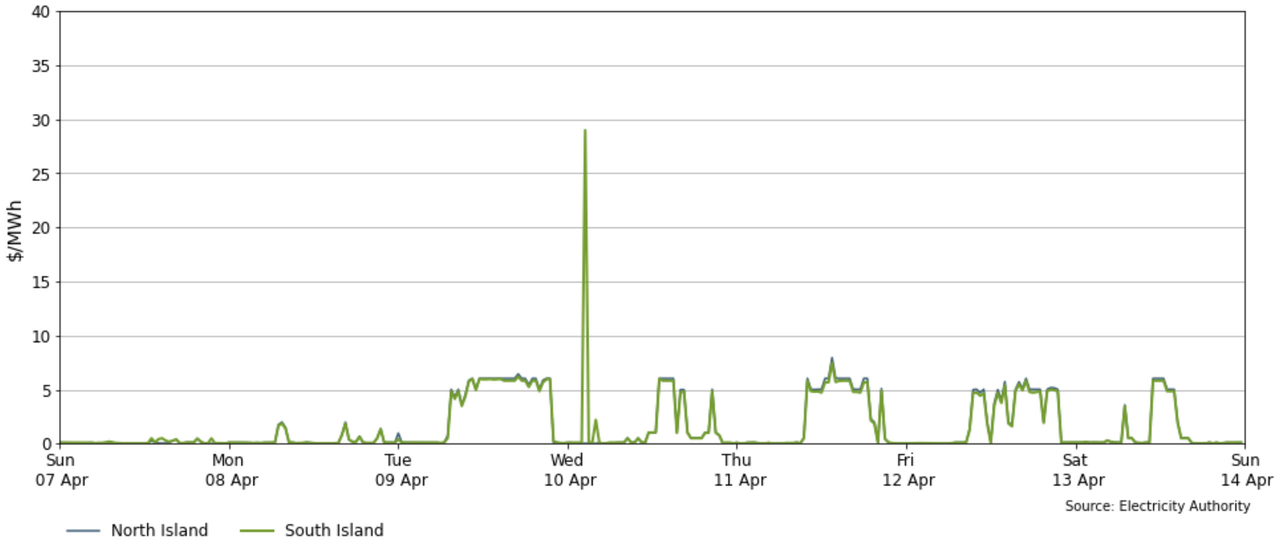
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh, except for a few spikes, the largest one occurring in the early hours of Wednesday, reaching ~$38/MWh in the South Island, and was related to high southward HVDC flows.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 7-13 April



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. The SIR prices on both islands were mostly below $10/MWh this week. The South Island saw mainly one SIR price spike, reaching a maximum of $29/MWh on Wednesday when there was high HVDC southward flow.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 7-13 April



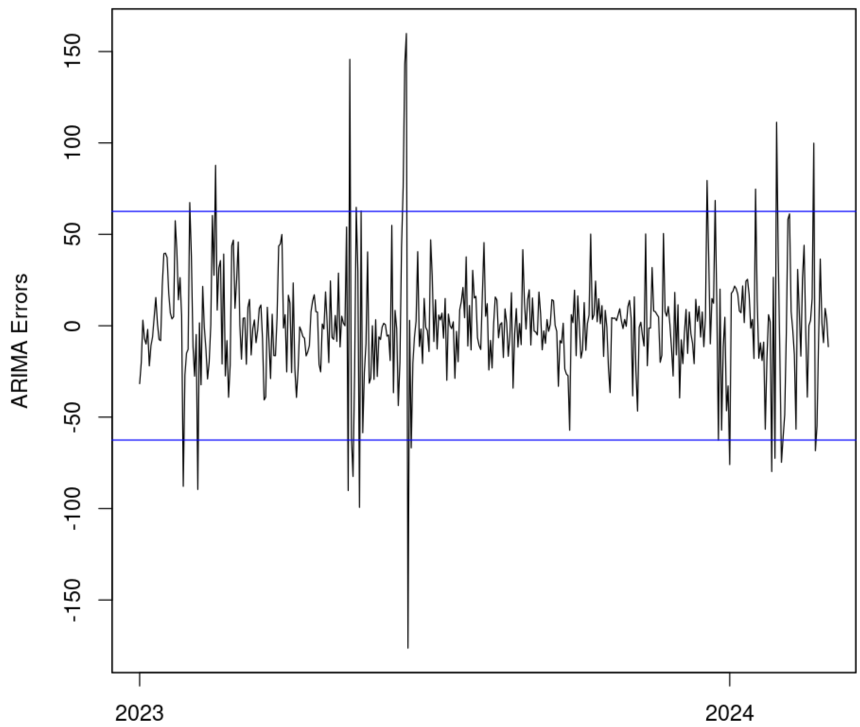
4. Regression residuals

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, the Wednesday price was above the threshold, indicating that prices were slightly higher than expected on that day. This could be due to prices remaining high during times of high wind and lower demand due to low hydro storage and the reliance on thermal generation.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 13 April 2024

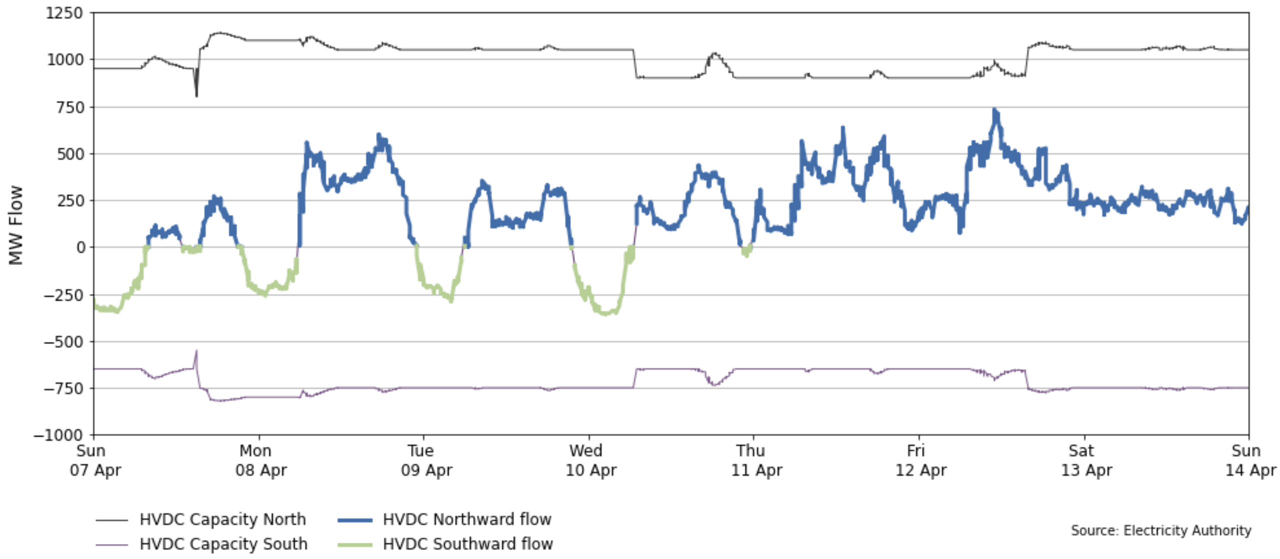


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 7-13 April. The HVDC flow was mostly northwards this week. Until Wednesday, the HVDC was flowing north during the day and southwards overnight. From Wednesday onwards, the HVDC flows were predominantly northwards due to the increase in hydro generation. The northward flow was highest on Monday and Friday when wind generation was low.

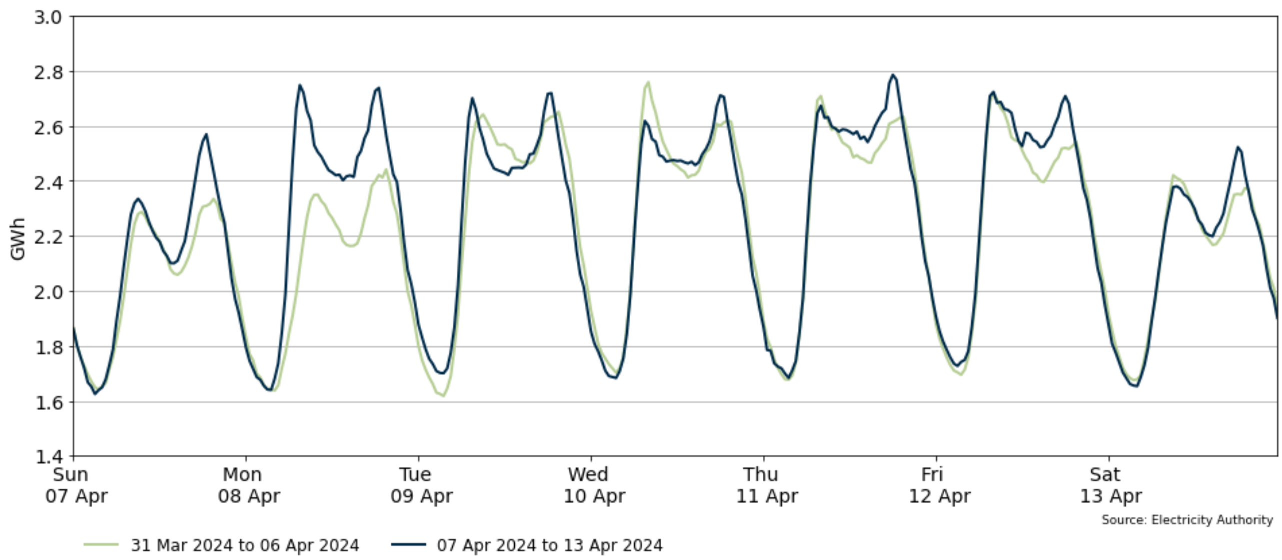
Figure 6: HVDC flow and capacity between 7-13 April



6. Demand

6.1. Figure 7 shows national demand between 7-13 April, compared to the previous week. Demand was slightly higher when compared to last week, especially during evening peaks. On Monday, demand was higher than the previous week due to the Easter Monday holiday. High temperatures from Tuesday to Friday likely drove morning demand down compared to the previous week. In the afternoon on Friday, a drop in temperatures likely caused an increase in demand.

Figure 7: National demand between 7-13 April compared to the previous week

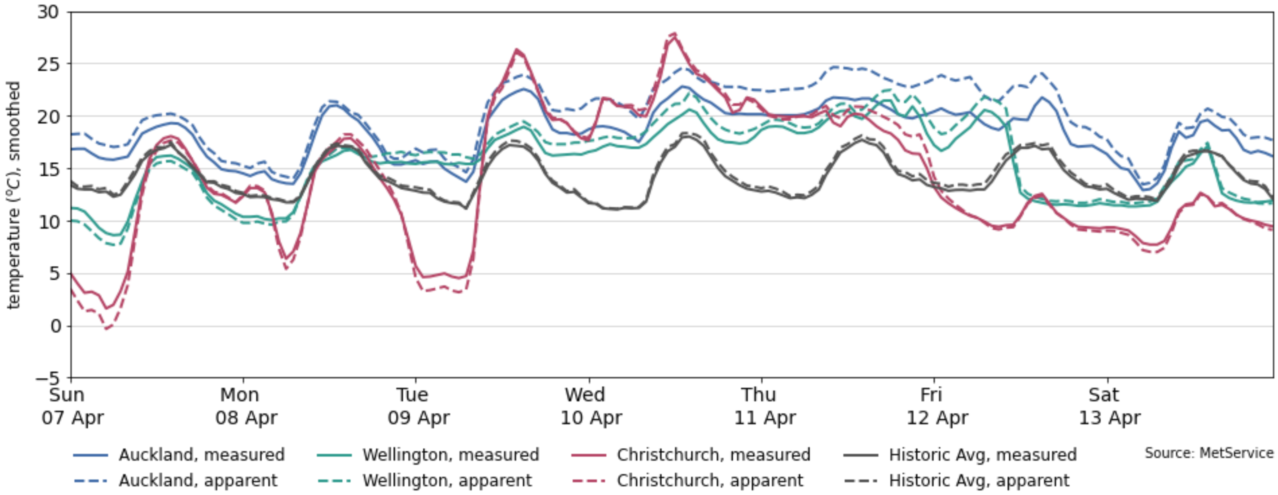


6.2. Figure 8 shows the hourly temperature at main population centres from 7-13 April. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures were mostly at or above the historical average throughout the country this week between Sunday and Friday. Temperatures were high from Tuesday until Friday when all the main centres registered temperatures considerably above the historical average. The temperatures dropped on Friday, with Christchurch and Wellington registering temperatures below the historical average.

6.4. Apparent temperatures in Auckland varied between 13ºC and 25ºC. In Wellington, the apparent temperatures fluctuated between 8ºC and 23ºC. Apparent temperatures in Christchurch were between -1ºC and 28ºC this week.

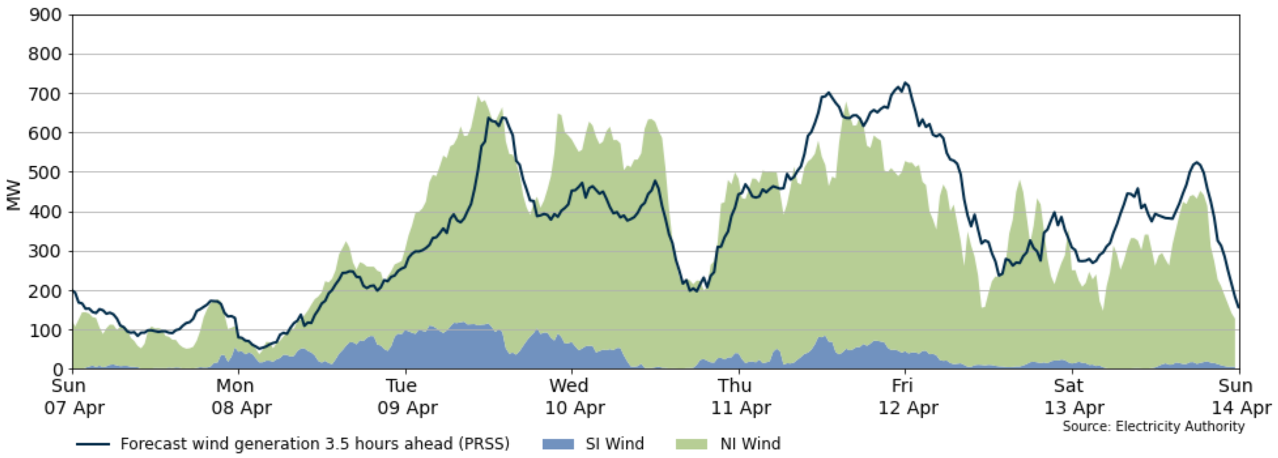
Figure 8: Temperatures across main centres between 7-13 April



7. Generation

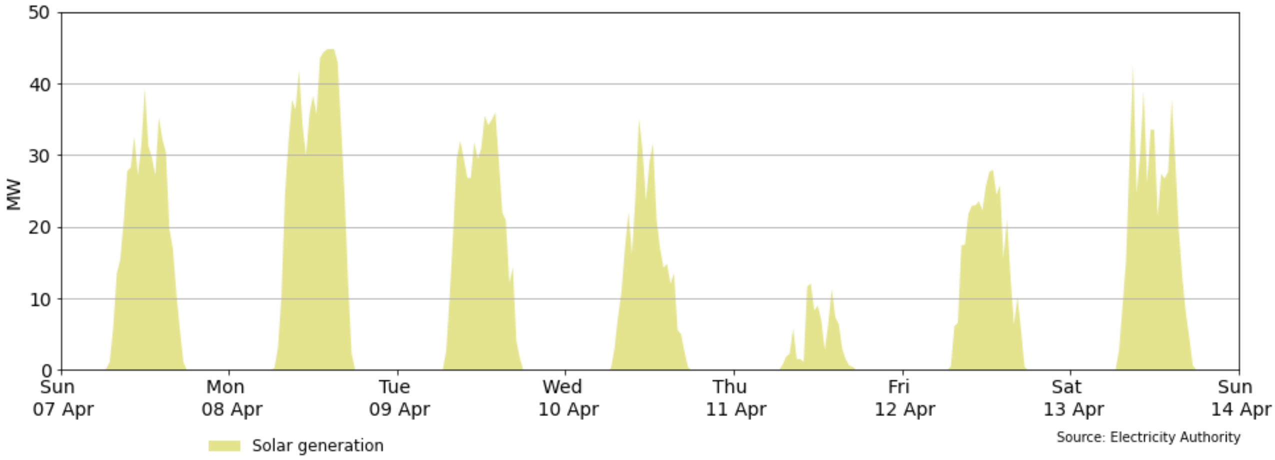
7.1. Figure 9 shows wind generation and forecast from 7-13 April. This week wind generation varied between 37MW and 694MW, with an average of 345MW. Wind generation was below 200MW until Monday. From Tuesday until Friday, wind was between 200MW and around 600MW. From Friday onwards, wind generation decreased, reaching below 200MW on a few occasions but mostly remaining between 200MW and 400MW. Wind was significantly under and over forecast at several points this week, often by more than 200MW. However, the one-hour ahead forecasting was much closer to actual wind generation.

Figure 9: Wind generation and forecast between 7-13 April



7.2. Figure 10 shows solar generation from 7-13 April. Solar generation was higher between Sunday and Tuesday, decreasing between Tuesday and Friday, due to overcast events, including rainfall.

Figure 10: Solar generation between 7-13 April



7.3. 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.

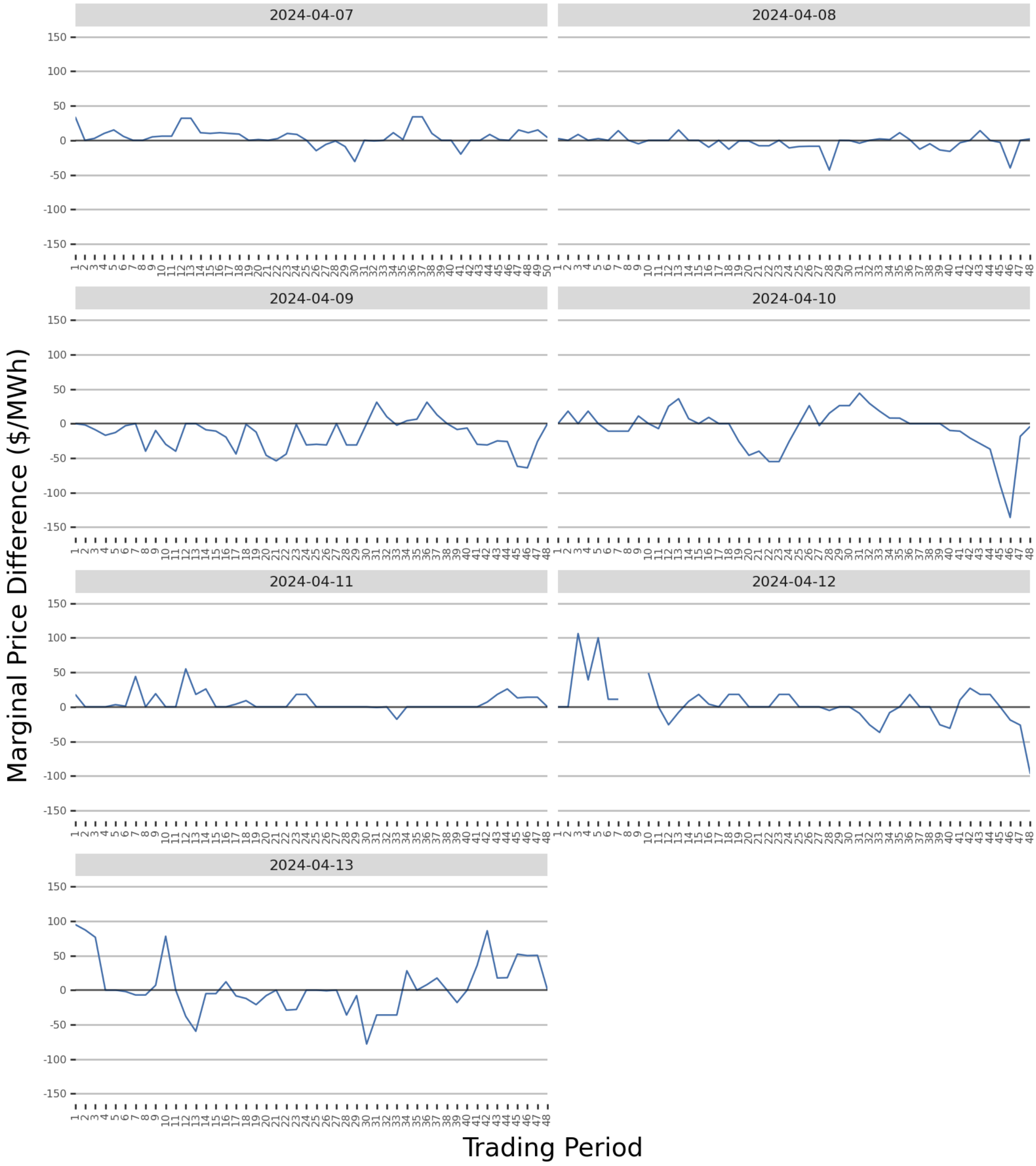
7.4. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD price will rarely be the same, but trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.5. This week the differences between the RTD and PRSS prices were mostly between negative $50/MWh and positive $50/MWh, except for a few occasions on Wednesday, Friday, and Saturday.

7.6. On Wednesday, the RTD price was almost $150/MWh lower than the PRSS forecast during the trading period 46 at 10:30pm. Friday saw a few under-forecast prices between trading periods 2 and 5 (early morning), and one over-forecast price late at night during trading period 48. Finally, Saturday saw a few prices higher than forecast in the morning and at night.

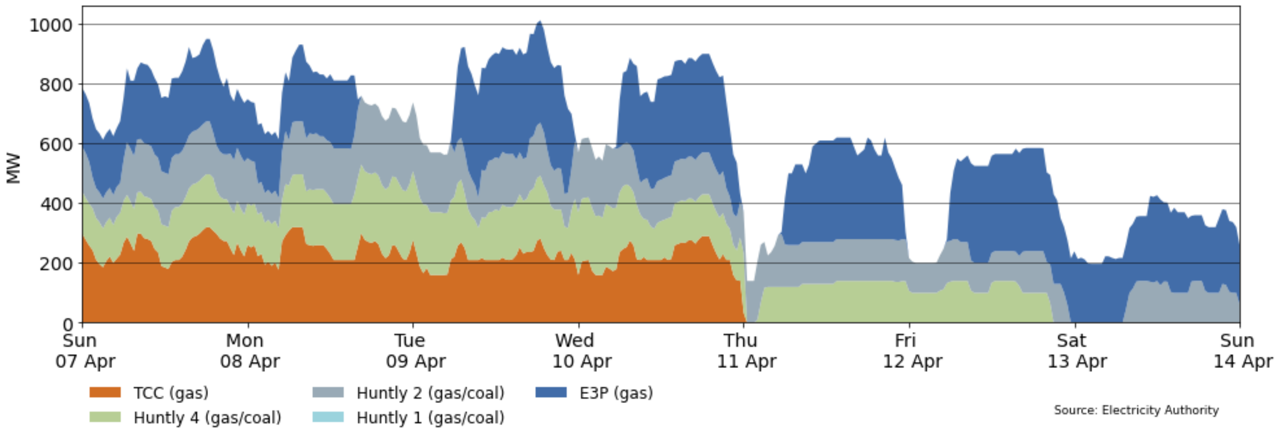
7.7. Regarding accuracy, compared to the previous week, PRSS prices were slightly less accurate this week, as there were a few price differences above $100/MWh.

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 7-13 April



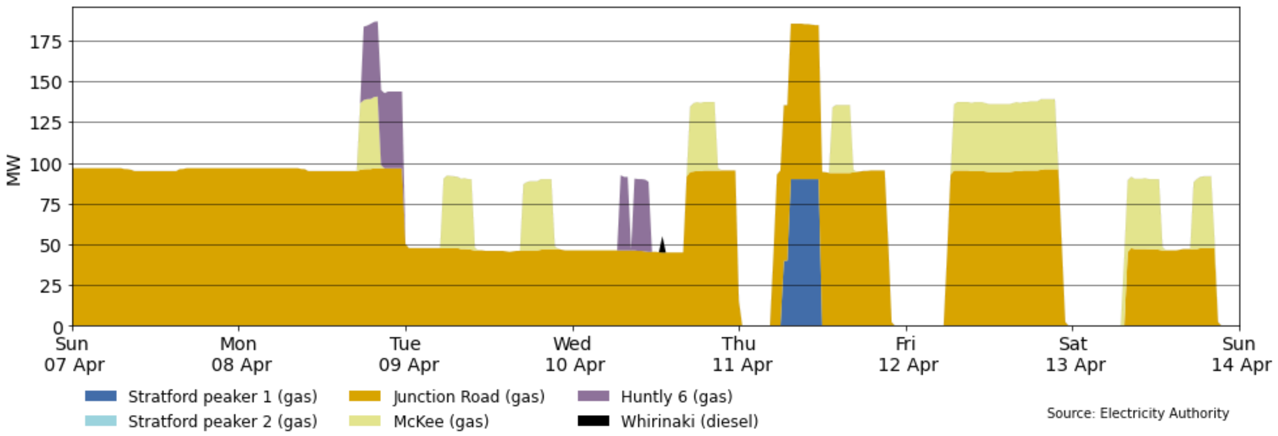
7.8. Figure 12 shows the generation of thermal baseload between 7-13 April. This week TCC, Huntly 2 and Huntly 4 ran continuously between Sunday and Thursday. From Thursday onwards, TCC turned off, likely related to the increase in hydro storage and as an opportunity to save gas. From Thursday onwards, the baseload thermal generation was provided by Huntly units 2, 4, and 5 (E3P). Finally, Huntly 4 tripped during trading period 1 on Thursday, causing the generator to re-submit the offers for that unit.

Figure 12: Thermal baseload generation between 7-13 April



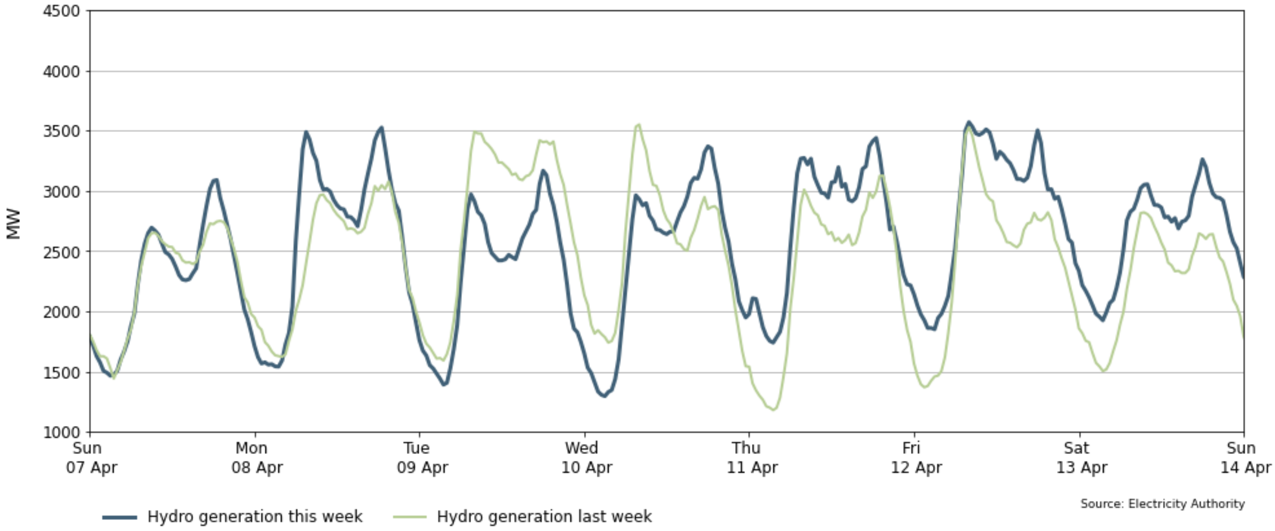
7.9. Figure 13 shows the generation of thermal peaker plants between 7-13 April. This week, Junction Road supported the baseload from Sunday to Thursday, generating between 45MW-100MW continuously during those days. Junction Road ran during the remaining days of the week, for several hours each day. McKee, Huntly 6, and Stratford 1 also ran this week during times of high demand. On Wednesday, Whirinaki was dispatched for energy at 1:00pm during trading period 27.

Figure 13: Thermal peaker generation between 7-13 April



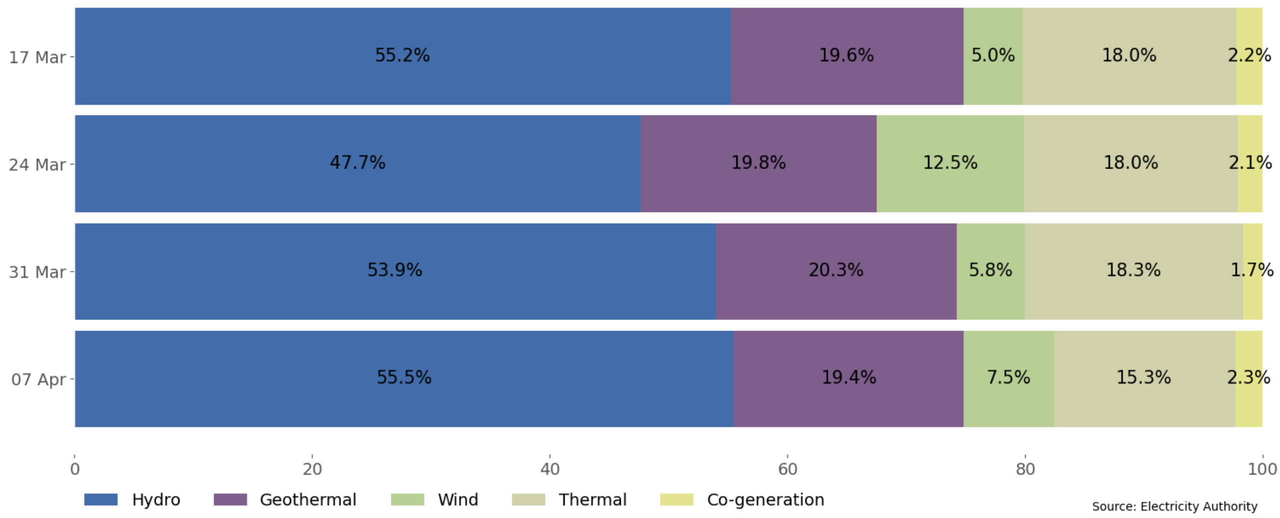
7.10. Figure 14 shows hydro generation between 7-13 April. Hydro generation was high this week on Sunday and Monday due to low wind generation during these days. On Tuesday, hydro generation decreased as hydro storage was low and wind generation increased. From Wednesday onwards, hydro generation increased above the levels seen in the previous week due to an increase in hydro storage.

Figure 14: Hydro generation between 7-13 April



7.11. As a percentage of total generation, between 7-13 April, total weekly hydro generation was 55.5%, geothermal 19.4%, wind 7.5%, thermal 15.3%, and co-generation 2.3%, as shown in Figure 15. The proportion of thermal generation decreased this week due to increases in hydro and wind.

Figure 15: Total generation by type as a percentage each week between 17 March and 7 April



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 7-13 April ranged between ~1500MW and ~2300MW. Figure 17 shows the thermal generation capacity outages. This week there was an extension of the Stratford 2 outage, from 1 May 2024 to 30 June 2024.

8.2. Notable outages include:

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

(b) Stratford 2 is on outage until 30 June 2024

(c) McKee is on partial outage until 15 April 2024

(d) Junction Road is on partial outage until 16 April 2024

(e) Stratford 1 was on outage on 7 April and between 11-12 April

(f) Huntly 4 was on outage on 13 April

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

Figure 16: Total MW loss due to generation outages between 7-13 April

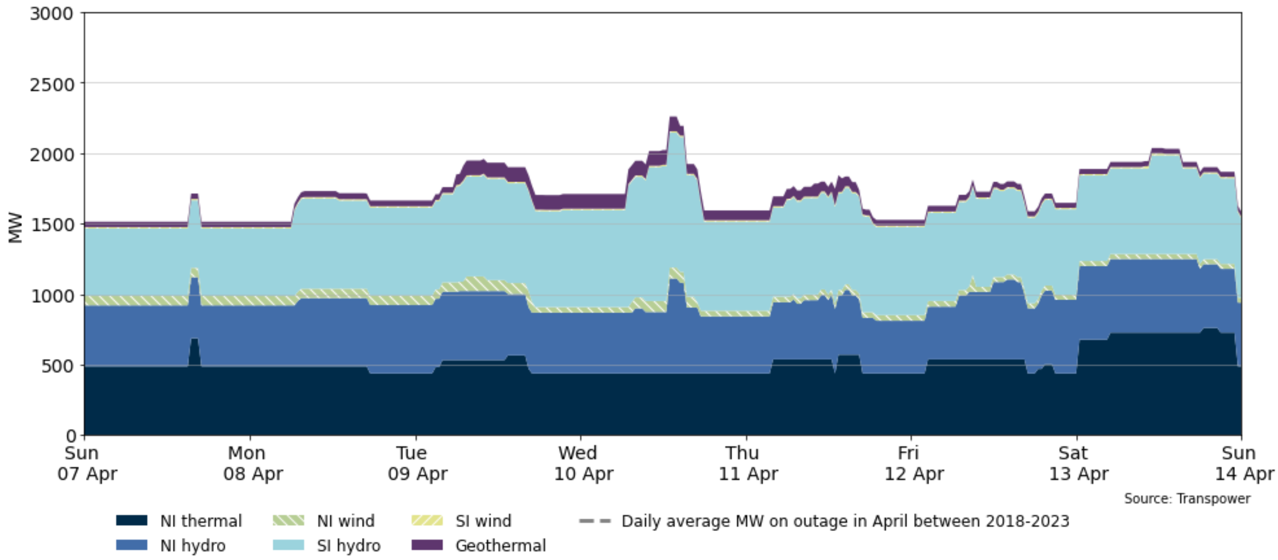
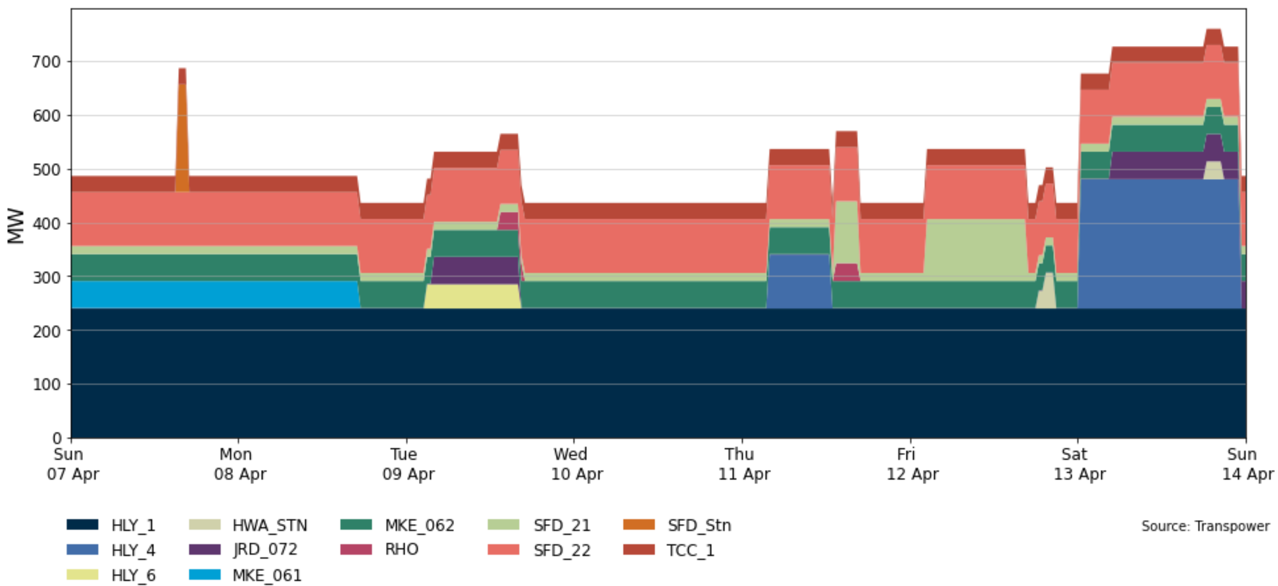


Figure 17: MW loss from thermal outages between 7-13 April

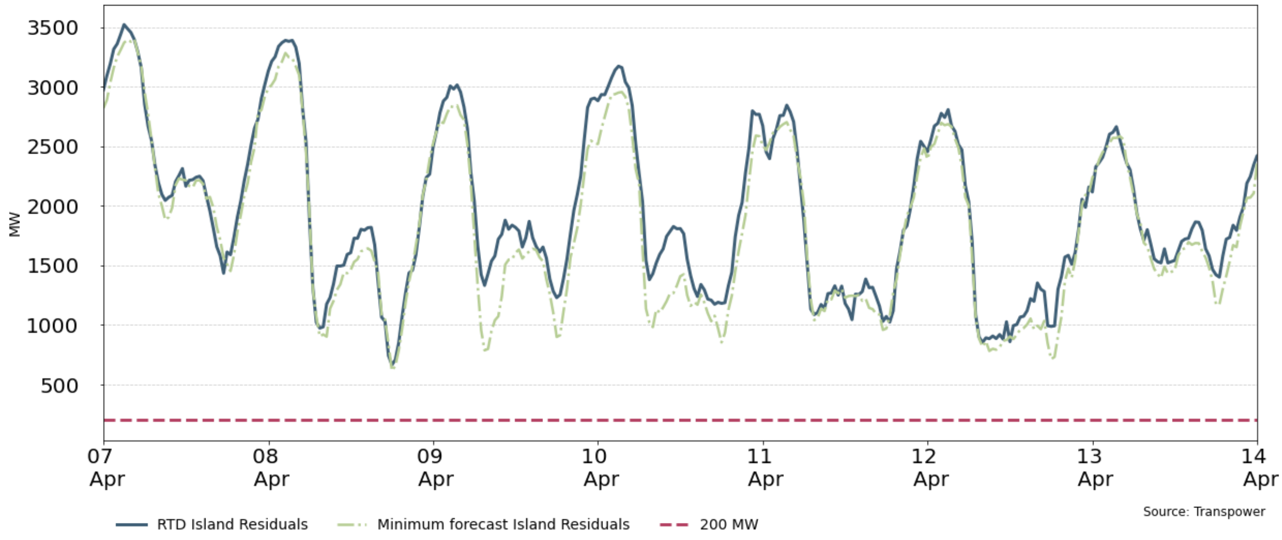


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 7-13 April. 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. Generation residuals were healthy this week, with the minimum national residual levels at around 660MW and the minimum North Island residual levels at around 390MW.

Figure 18: National generation balance residuals 7-13 April



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 increased this week and is now sitting at 76% of nominally full and ~97% of the historical average for this time of the year (as of 13 April).

(a) Lake Taupō is still sitting between its 90th percentile and its historical average after a slight decrease in storage this week.

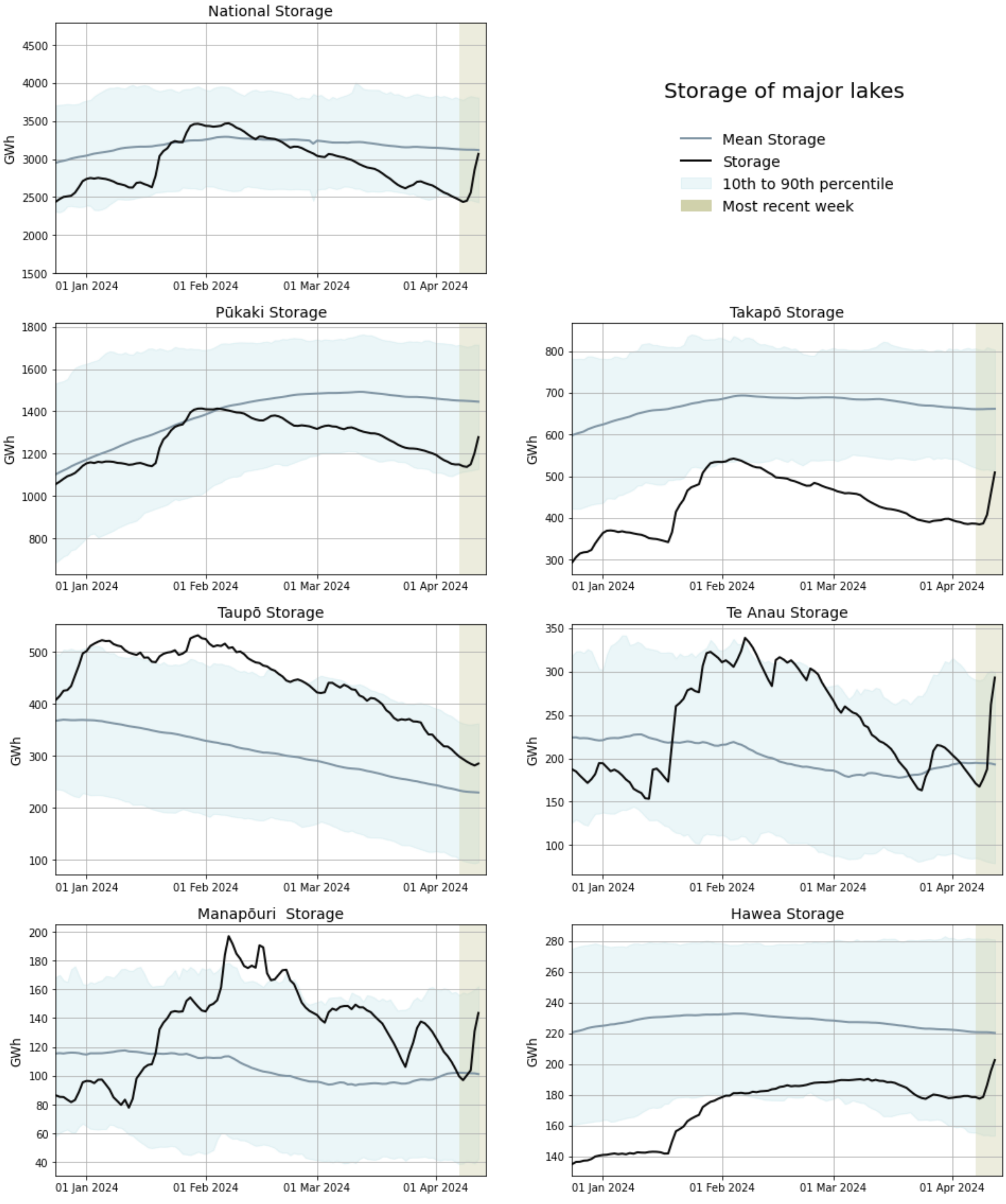
(b) Lake Pūkaki increased considerably this week, now sitting between its historical average and 10th percentile.

(c) Lake Takapō storage increased substantially this week, enough to reach its 10th percentile.

(d) Lake Manapōuri and Te Anau saw a large increase in storage. Te Anau is now at its 90^{th} percentile, while Manapōuri is between its historical average and its 90^{th} percentile.

(e) Lake Hawea storage also increased and is now trending towards its historical average and well above its 10th percentile.

Figure 19: Hydro storage



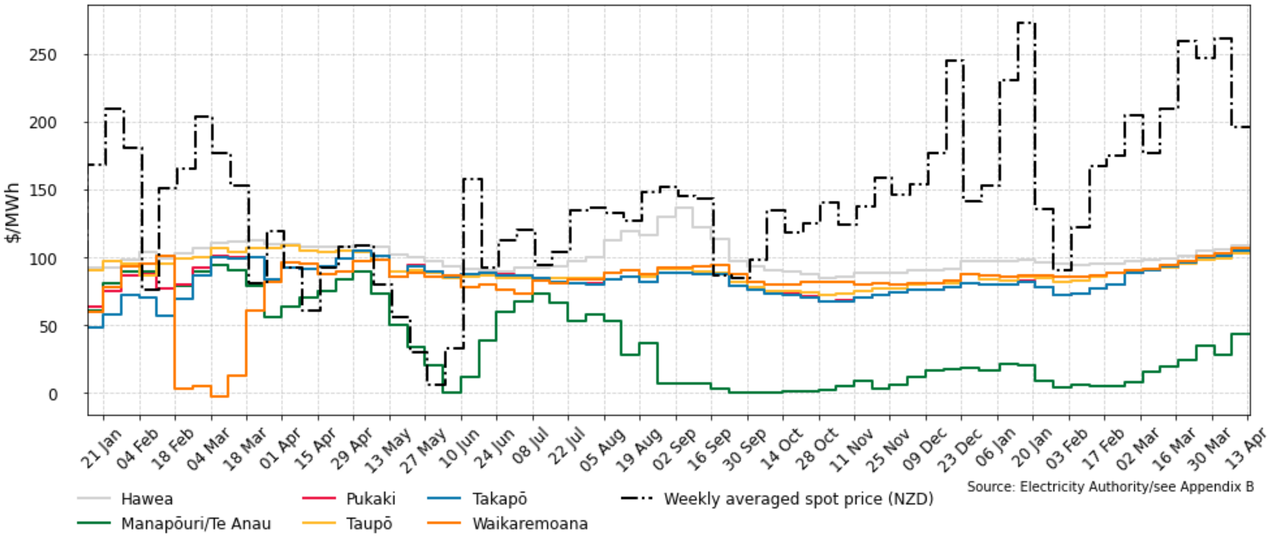
Source: Electricity Authority

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 13 April 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 lakes saw an increase in their water values. The increase was in the order of \$3-\$4/MWh at all lakes except for Manapōuri/Te Anau, which saw an increase in water values of around \$16/MWh, after a \$6/MWh decrease in the previous week.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 13 April 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-fuelled Rankine generation is ~\$156MWh. The cost of running the Rankines on gas is now more expensive at ~\$236/MWh.

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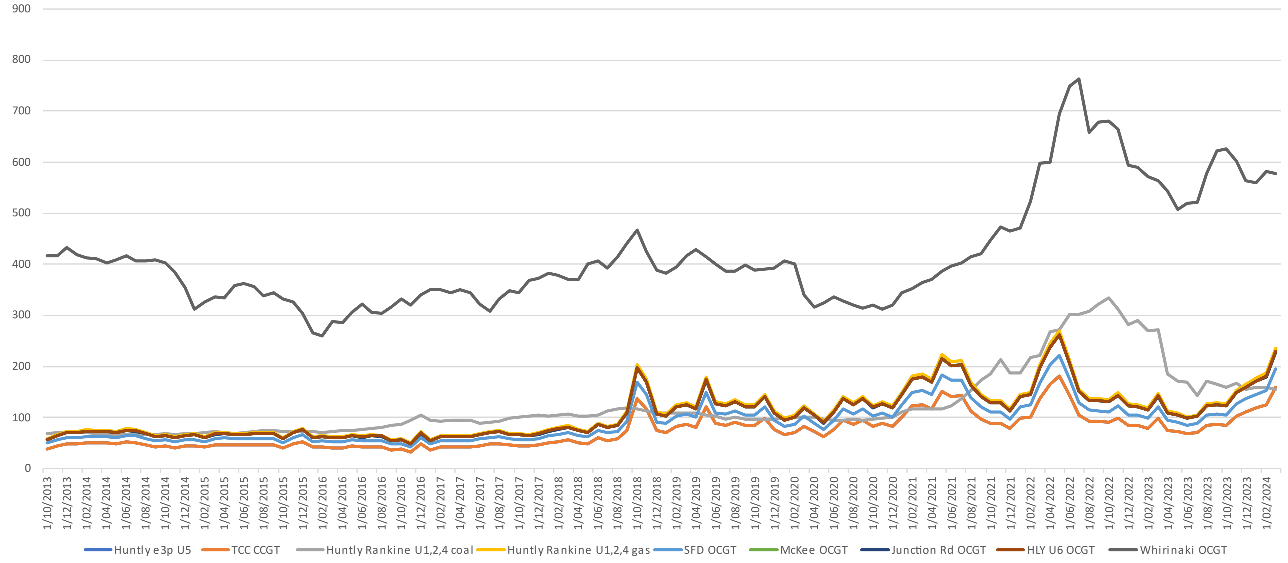
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas-fuelled 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

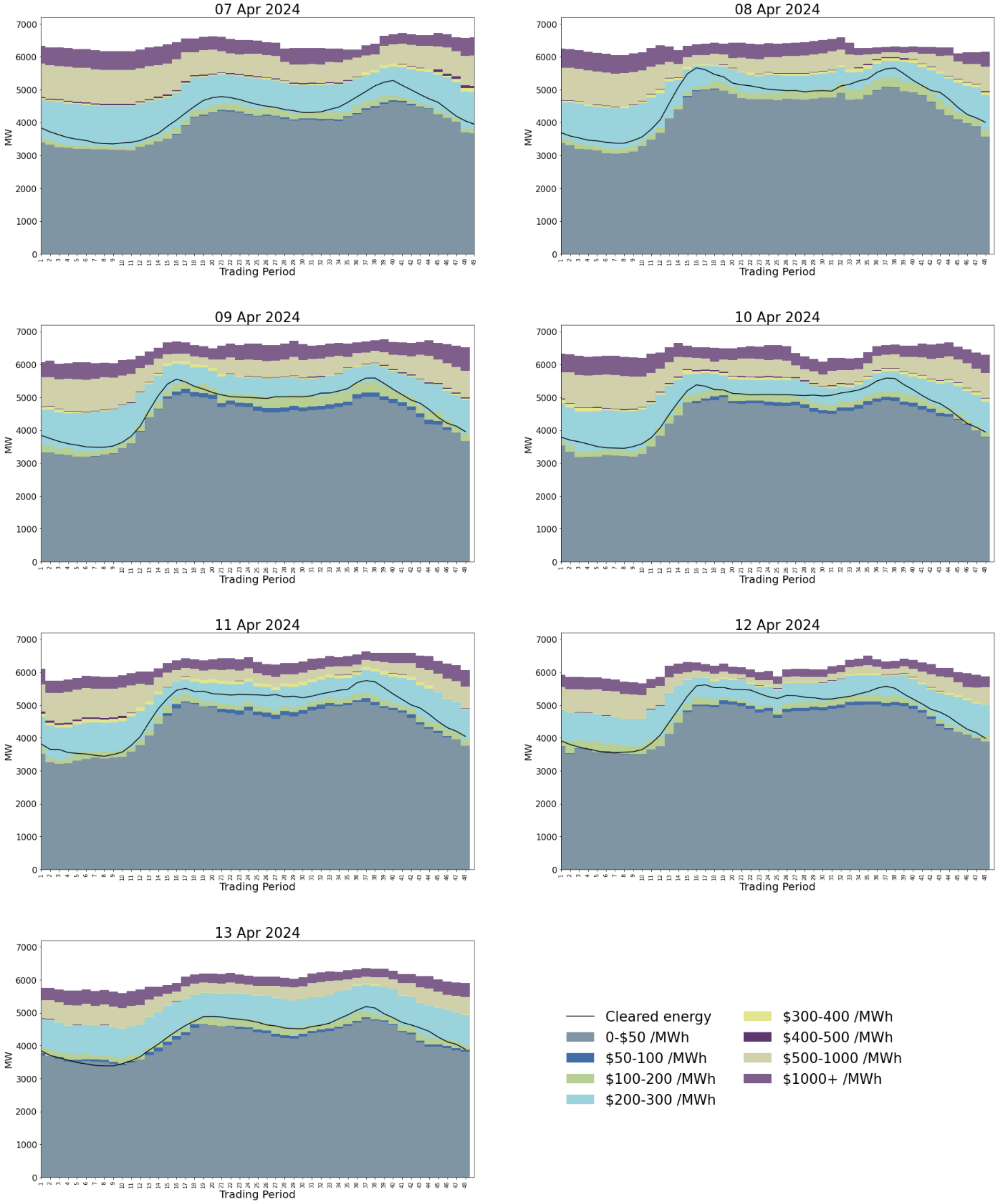
13. Offer behaviour

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 offers this week cleared in the $200-$300/MWh region. A small change in the position of the offers' clearing curve can be seen before and after Monday. On Monday the offers were cleared close to the $300-$400/MWh, decreasing slightly on the following days, likely due to the increase in hydro storage.

13.3. Despite the increase in hydro storage, the offers are reflective of current gas prices, many storage lakes remaining below average for this time of year, and the need to conserve water for winter.

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	Hydro offers
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Hydro offers