20 May 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 12-18 May

Prices were above the historical median this week and were mostly between $200-$300/MWh. Between Sunday and Tuesday, there were six price spikes over $500/MWh. Temperatures were low on these days, and low wind generation required the use of more expensive thermal and hydro generation to meet increased demand. TCC, Huntly 5 and two rankines were running simultaneously to provide baseload generation for most of the week, with their combined output often over 1,000MW. Later in the week as wind generation increased and temperatures were milder, spot prices remained steady between $200-300/MWh.

2. Spot prices

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.

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.

Between 12-18 May:

(a) the average wholesale spot price across all nodes was $293/MWh

(b) 95 percent of prices fell between $212/MWh and $591/MWh.

Prices remained high this week and were consistently above the national historical median, though the average price decreased by $63/MWh compared to the previous week. A combination of low wind generation and high demand due to low temperatures saw prices spike above $500/MWh on multiple occasions between Sunday and Tuesday. From Wednesday onwards, prices were less volatile, remaining below the 90th percentile, as wind generation and temperatures increased.

The first price spike occurred at 8:00am on Sunday, when the Ōtāhuhu price reached $592/MWh. Demand was high and wind generation was below 200MW at the time, requiring higher priced thermal and hydro generation to be dispatched.

Prices spiked again on Monday, with the Ōtāhuhu price reaching $506/MWh at 10:00am and $679/MWh at 6:00pm. Wind generation was below 100MW, and demand was high.

On Tuesday, the Ōtāhuhu price spiked to $2,123/MWh at 8:00am, $593/MWh at 10:00am and $802/MWh at 5:30pm. At the time of the highest price, wind generation was below 100MW and demand was at its peak for the week. Wind generation was also low and demand was also high at

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[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.

the time of the later price spikes, but to a lesser extent. The monitoring team will be conducting further analysis on trading periods 16 and 17 on May 14.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 12-18 May

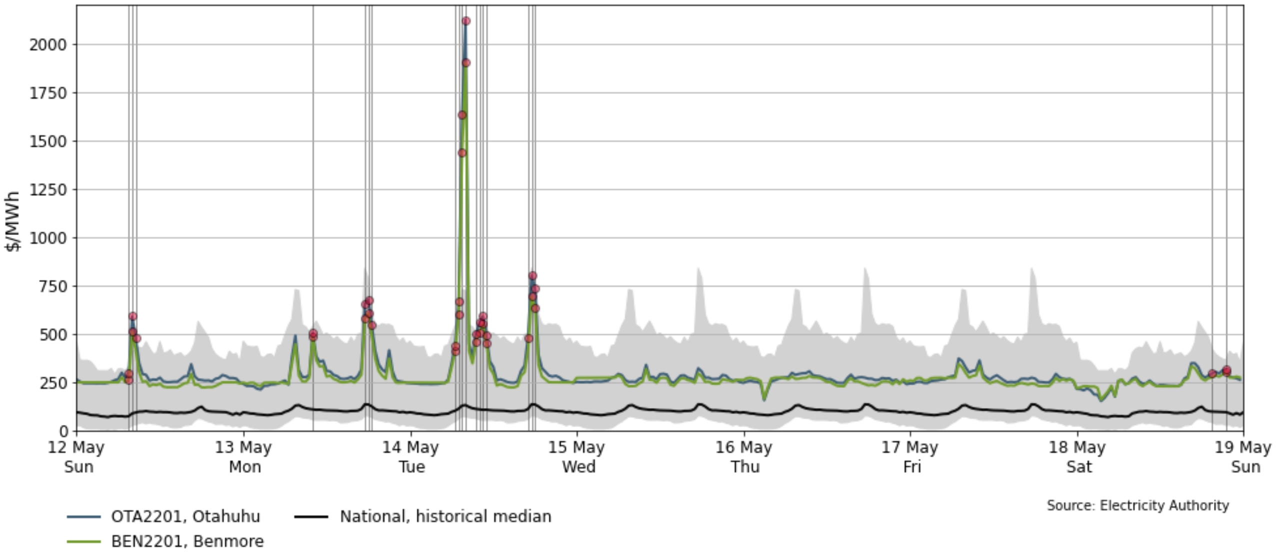
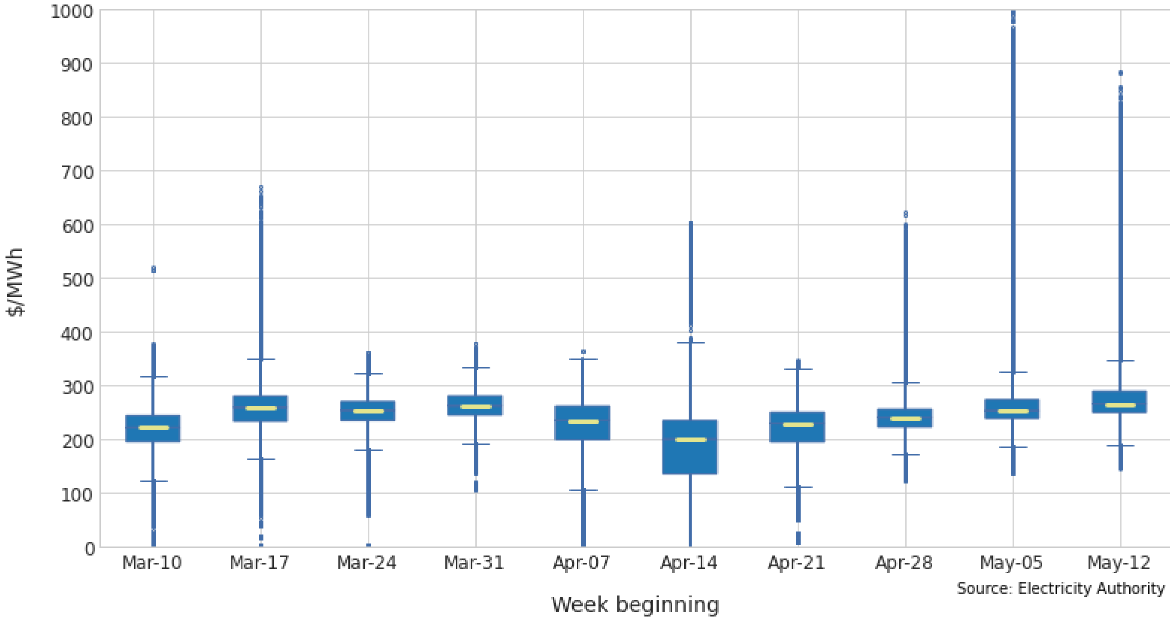


Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The green line shows each week's median price, while the box part shows the lower and upper quartiles (where 50 percent of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

The spot price distribution this week shows a slight increase in prices but with less high outliers compared to last week. This week's median price was $265/MWh, an increase of $12/MWh from the previous week. The middle 50% of prices were between $249/MWh and $289/MWh.

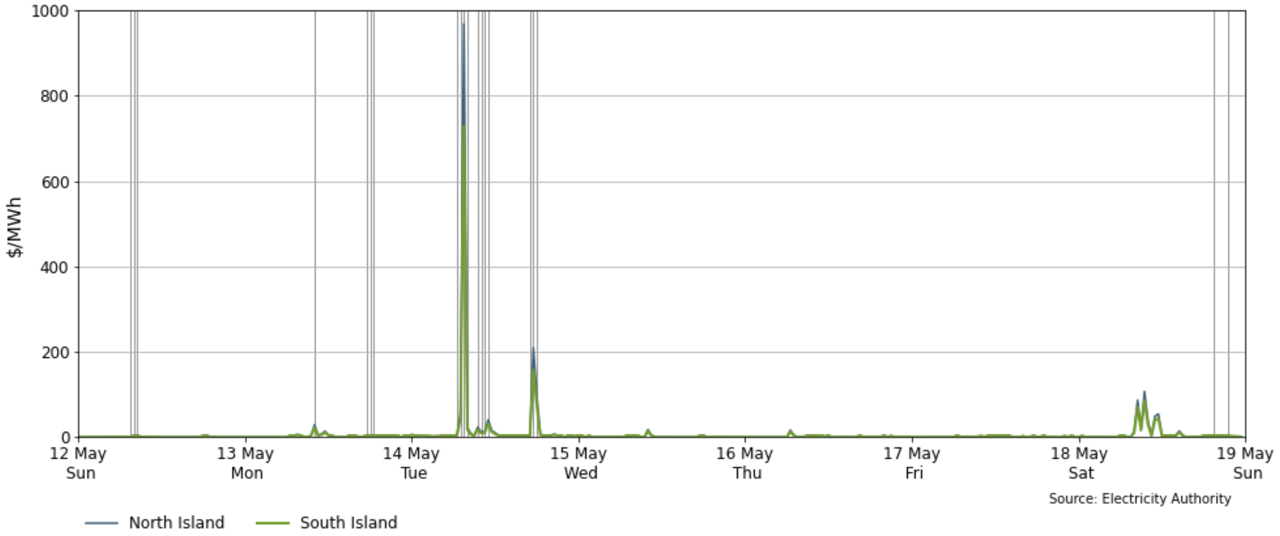
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

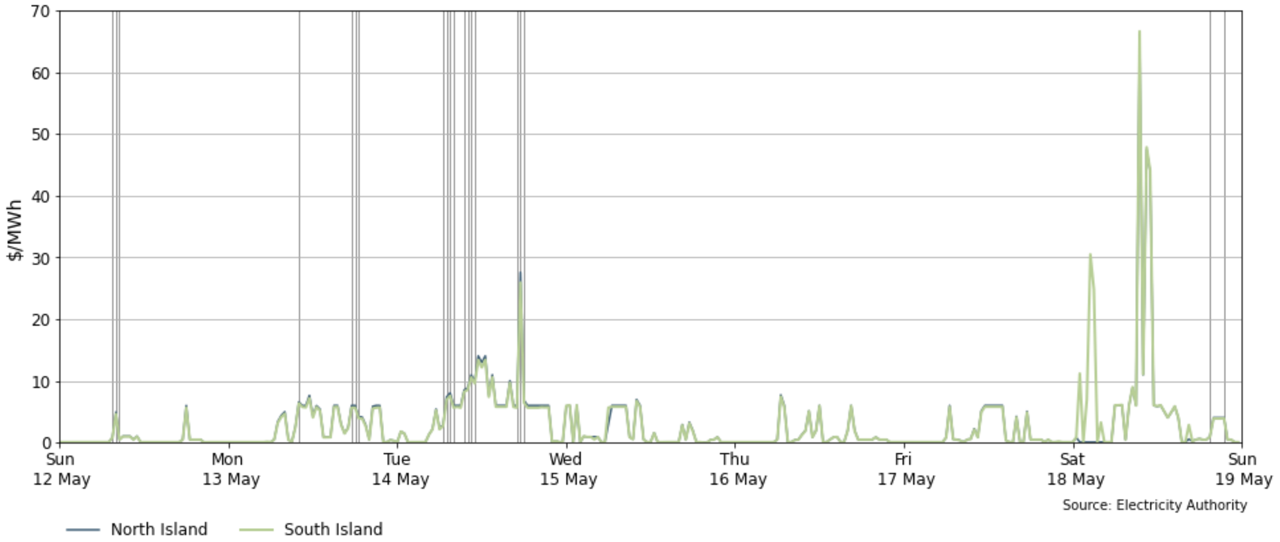
Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh this week, but spikes occurred on Tuesday at 7:30am and 5:30pm and Saturday at 9:30am. The Tuesday morning spikes will be analysed further.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 12-18 May



Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh, but spikes occurred on Tuesday at 5:30pm, which was when spot prices also spiked. South Island SIR prices also spiked several trading periods on Saturday, when the HVDC was transferring southward.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 12-18 May



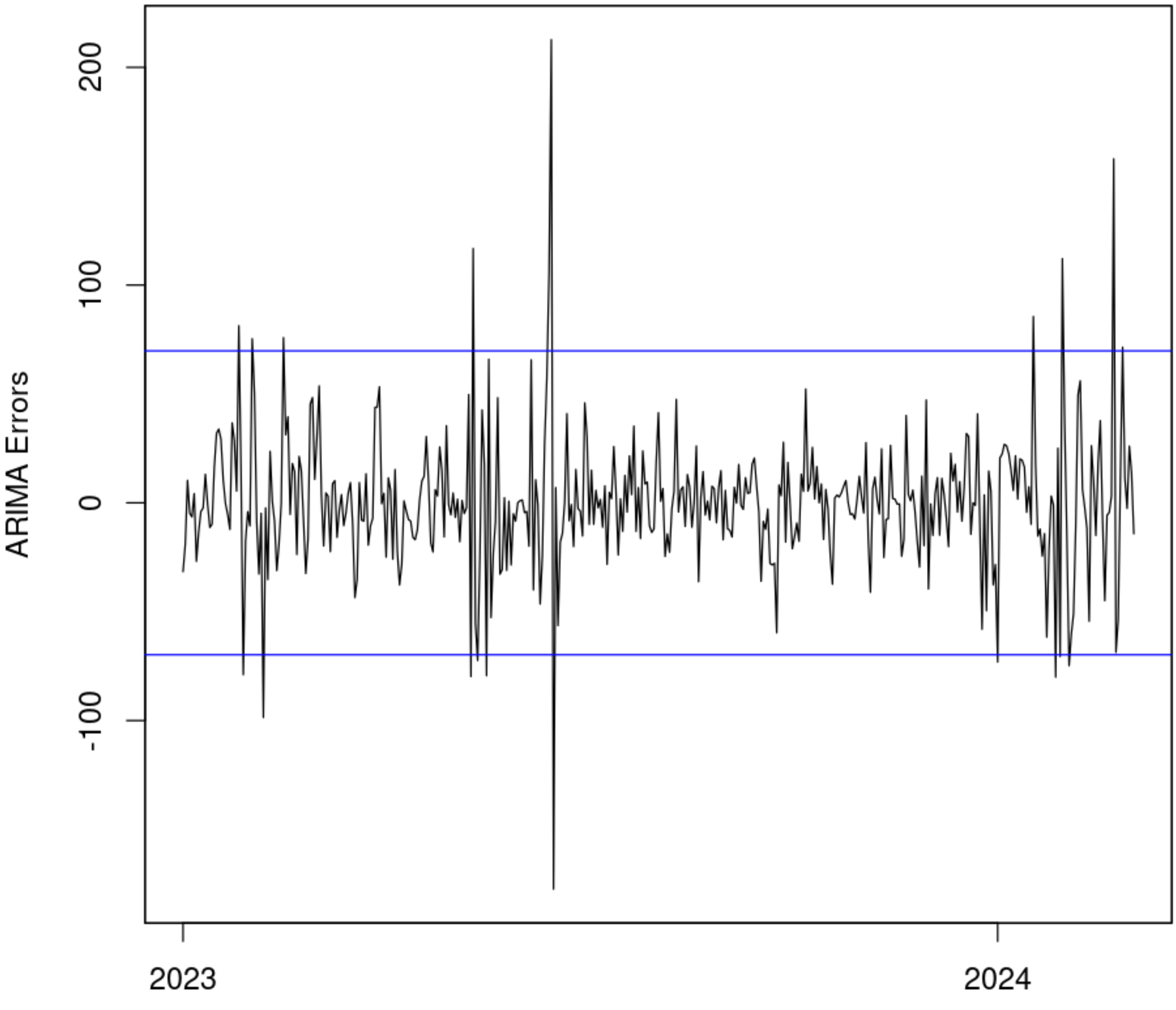
4. Regression residuals

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.

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.

The residual on Thursday was above two standard deviations of the data indicating that prices were higher than the model expected. This is likely due to high wind generation displacing hydro generation rather than thermal generation, and prices remaining between $200-$300/MWh as a result.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 18 May 2024

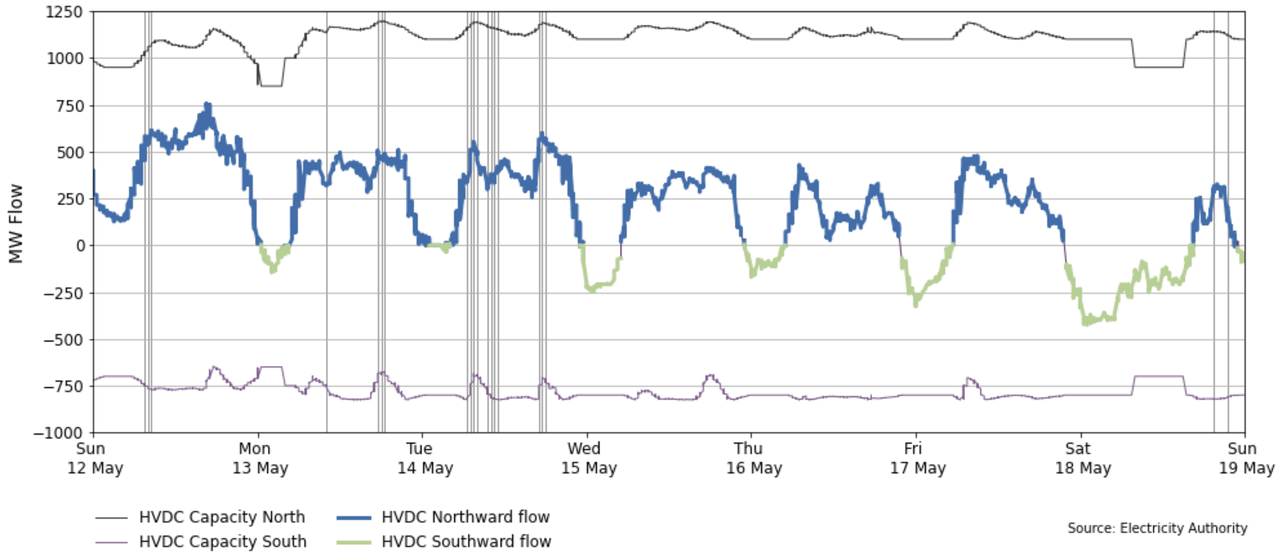


Source: Electricity Authority/see Appendix A

5. HVDC

Figure 5 shows HVDC flow between 12-18 May. Due to very low wind generation, HVDC flow was almost entirely northward at the start of the week with some southward flow overnight. There was more southward flow from Wednesday as wind generation increased.

Figure 6: HVDC flow and capacity between 12-18 May



6. Demand

Figure 7 shows national demand between 12-18 May compared to the previous week. Demand was significantly higher than the previous week between Sunday and Tuesday when temperatures were low, reaching a maximum of 3.22GWh on Tuesday morning. From Wednesday onwards, temperatures in the North Island increased and demand was generally lower than the previous week.

Figure 7: National demand between 12-18 May compared to the previous week

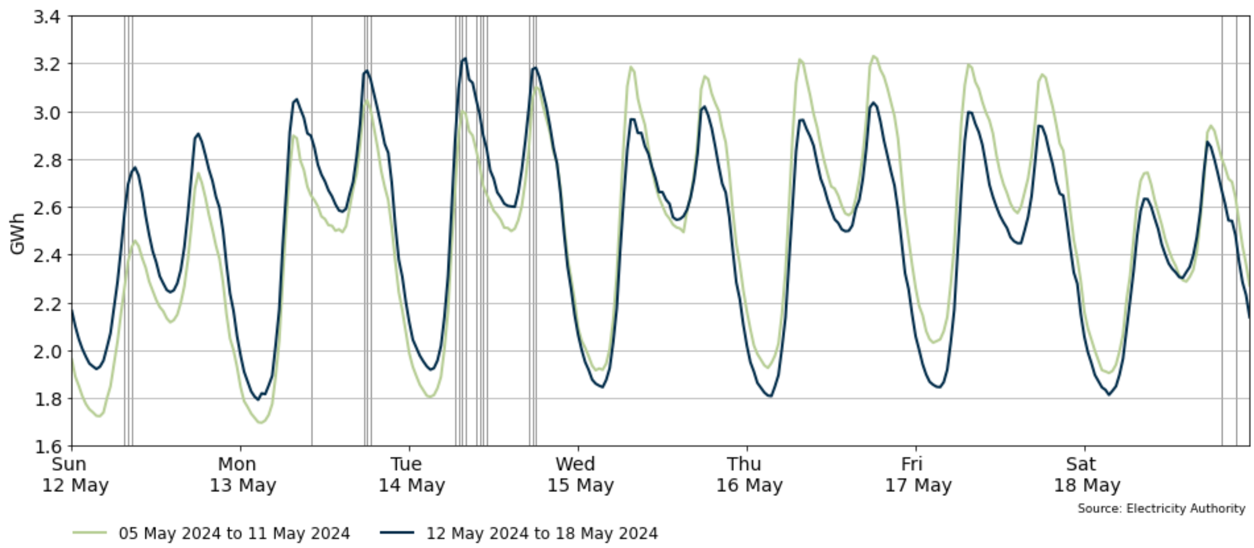
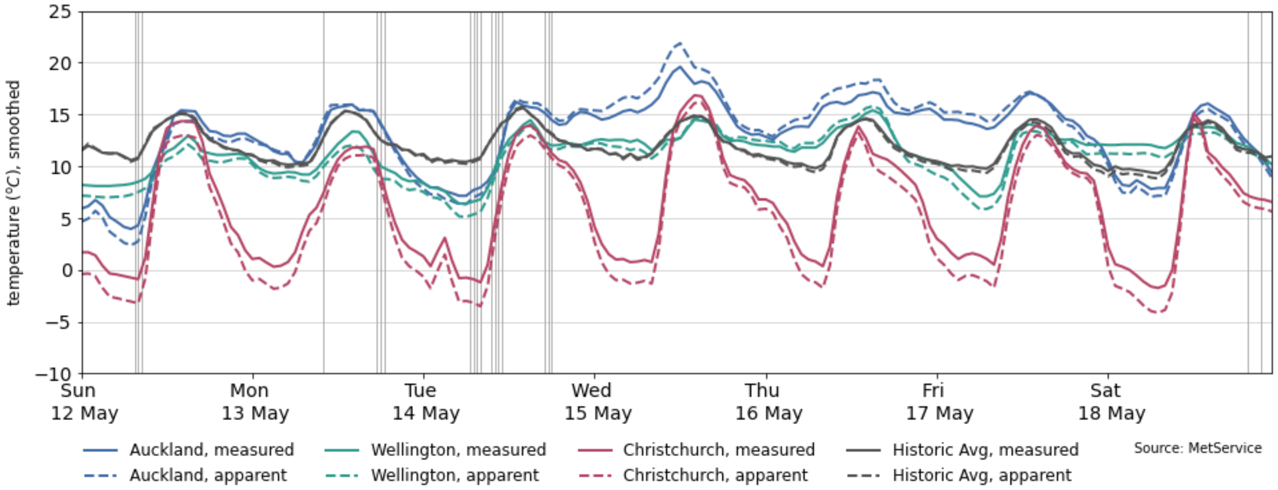


Figure 8 shows the hourly temperature at main population centres from 12-18 May. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

Temperatures were generally below average until Wednesday this week, then increased in the North Island. Christchurch temperatures were low throughout the week, ranging from -4ºC to 16ºC. Temperatures ranged from 2ºC to 22ºC in Auckland and 5ºC to 16ºC in Wellington.

Figure 8: Temperatures across main centres between 12-18 May



7. Generation

Figure 9 shows wind generation, from 12-18 May. Wind generation ranged from 26MW-810MW this week, with an average of 288MW. Until Tuesday afternoon and at the time of this week's price spikes, wind generation was mostly below 200MW.

Figure 9: Wind generation and forecast between 12-18 May

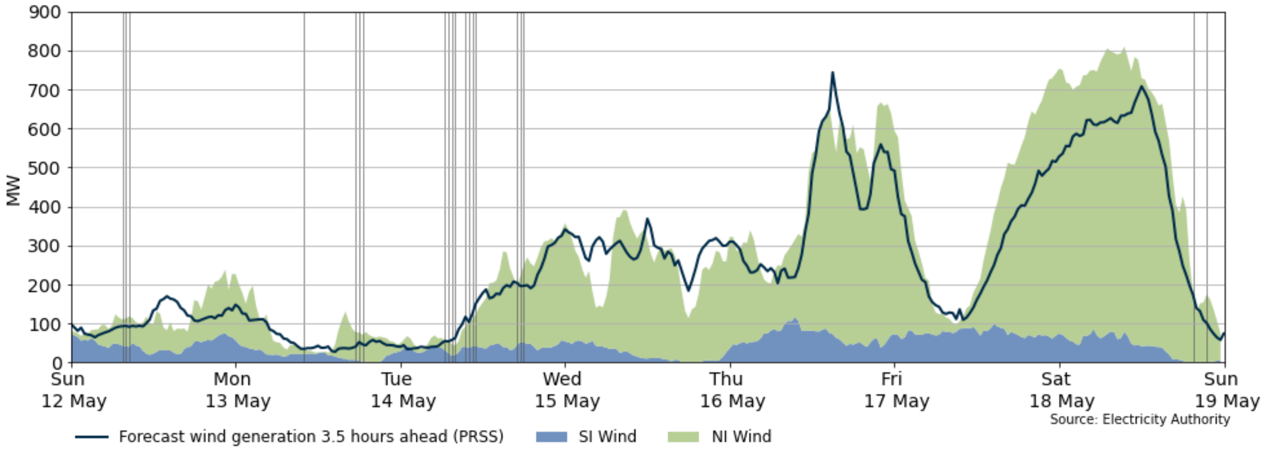


Figure 10 shows solar generation from 12-18 May. Solar generation varied between 22-39MW this week. It was below 30MW from Tuesday to Thursday due to overcast conditions.

Figure 10: Solar generation between 12-18 May

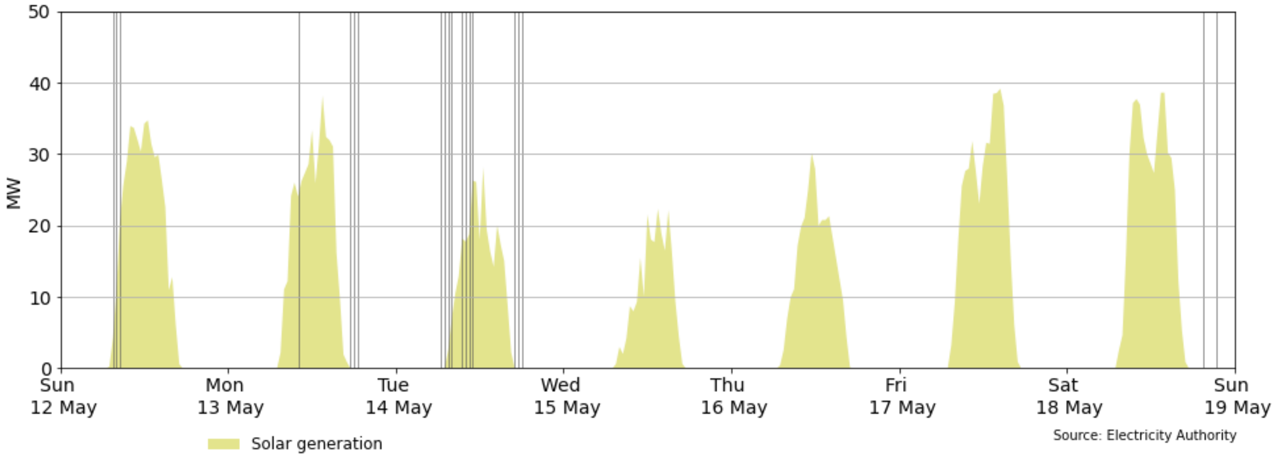


Figure 11 shows the difference between the real time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1 hour ahead (PRSS) demand and wind forecasts. This plot highlights when forecasting inaccuracies are causing large differences between pre-dispatch and final prices.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

This week the most notable positive differences (marginal prices higher than simulation) occurred on Sunday, Monday and Tuesday. On Sunday the high price differences occurred on trading period 17 (8:00am). The high differences on Monday occurred on trading periods 21 (10:00am) and 38 (6:30pm). On Friday the highest differences occurred on trading periods 16 (7:30am), 18 (8:30am) and 20-22 (9:30-10:30am). These differences in marginal prices, which were over $200/MWh, were related to demand being under-forecast, wind generation being over-forecast, or a combination of both.

The most relevant negative difference this week occurred on Tuesday during trading period 38 (6:30pm).

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 12-18 May

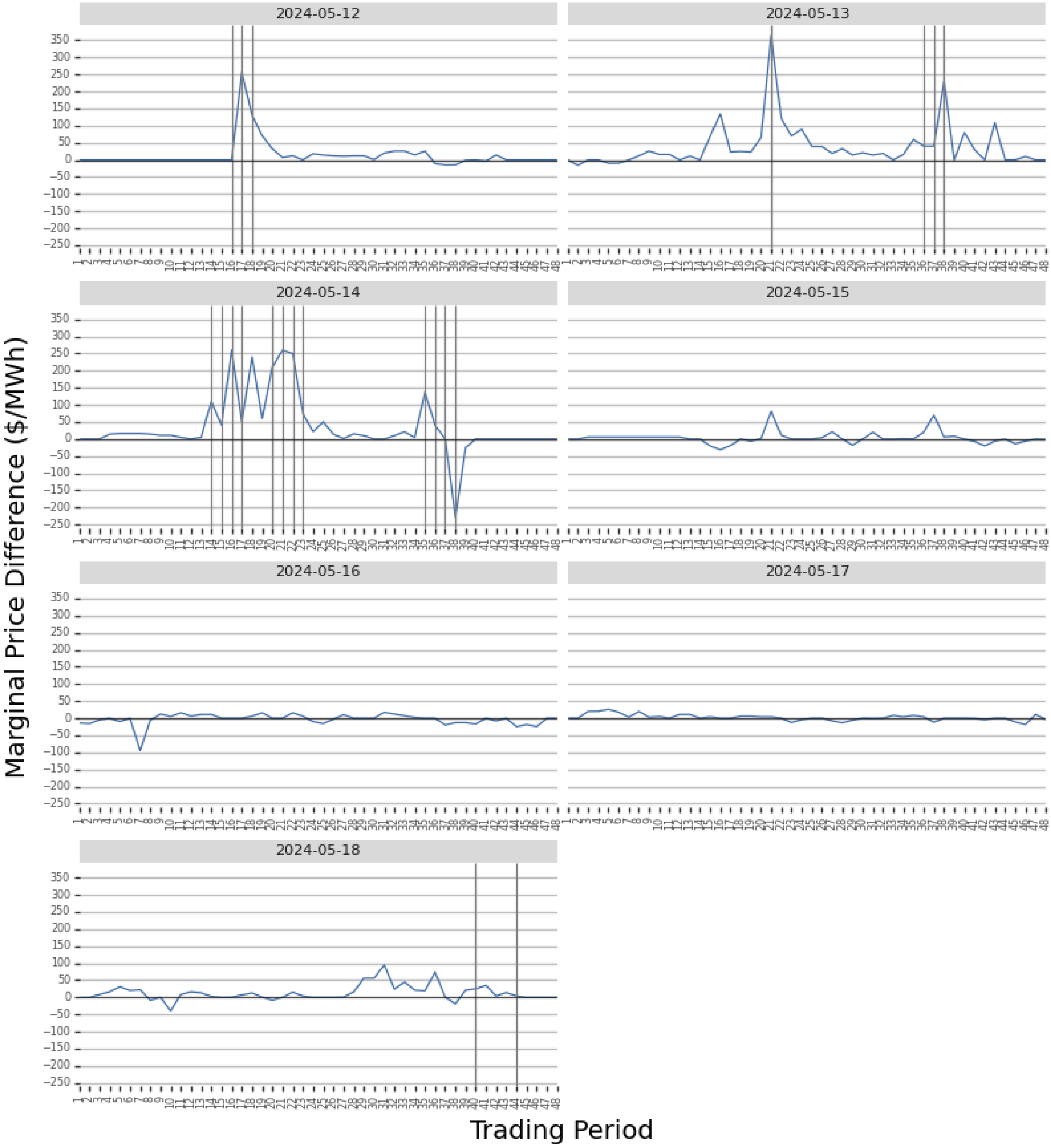


Figure 12 shows the generation of thermal baseload plants between 12-18 May. Thermal generation was high this week, often over 1,000MW. Huntly 1 ran for the entire week. TCC ran continuously after returning from outage on Sunday afternoon. Huntly 4 ran until Friday night, when it went on outage and Huntly 2 switched on. Huntly 5 (E3P) ran for the entire week but switched off overnight on Friday.

Figure 12: Thermal baseload generation between 12-18 May

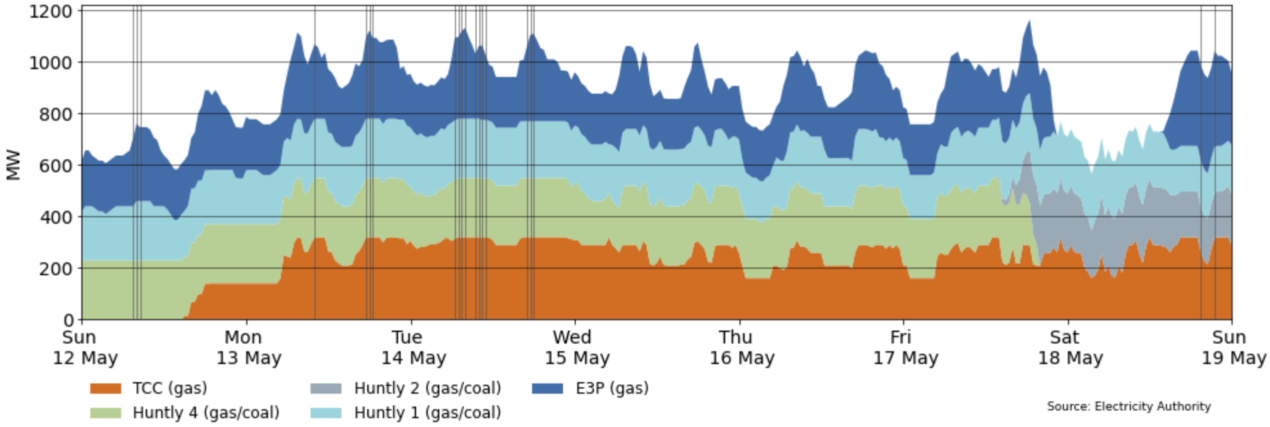


Figure 13 shows the generation of thermal peaker plants between 12-18 May. Stratford 1 turned off to begin an outage on Sunday night, having run continuously since early last week. Junction Road ran during peak and shoulder periods every day and provided baseload support from Thursday onwards. McKee and Huntly 6 also ran during peak periods throughout the week. Whirinaki ran during peak and shoulder periods on Monday, Tuesday, Wednesday and Thursday.

Figure 13: Thermal peaker generation between 12-18 May

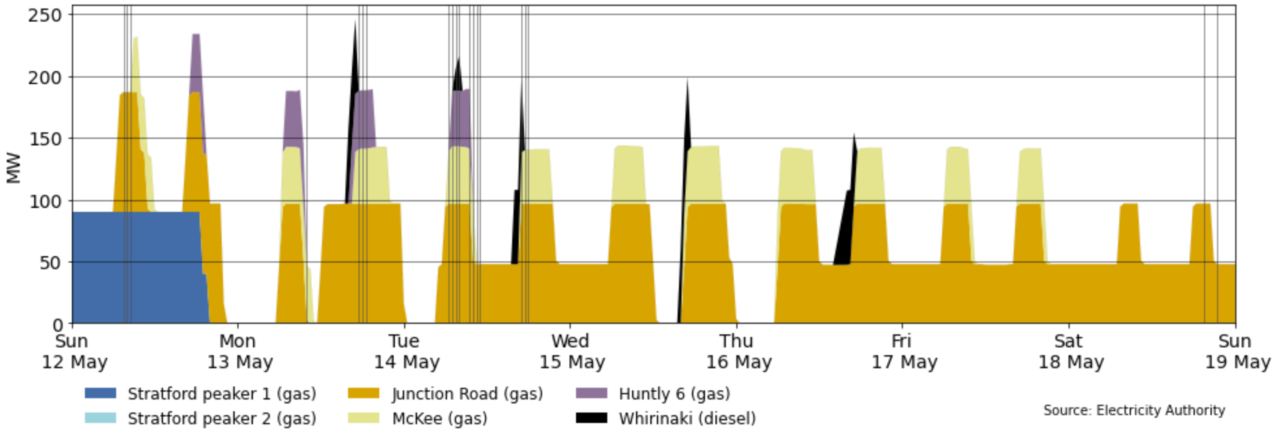
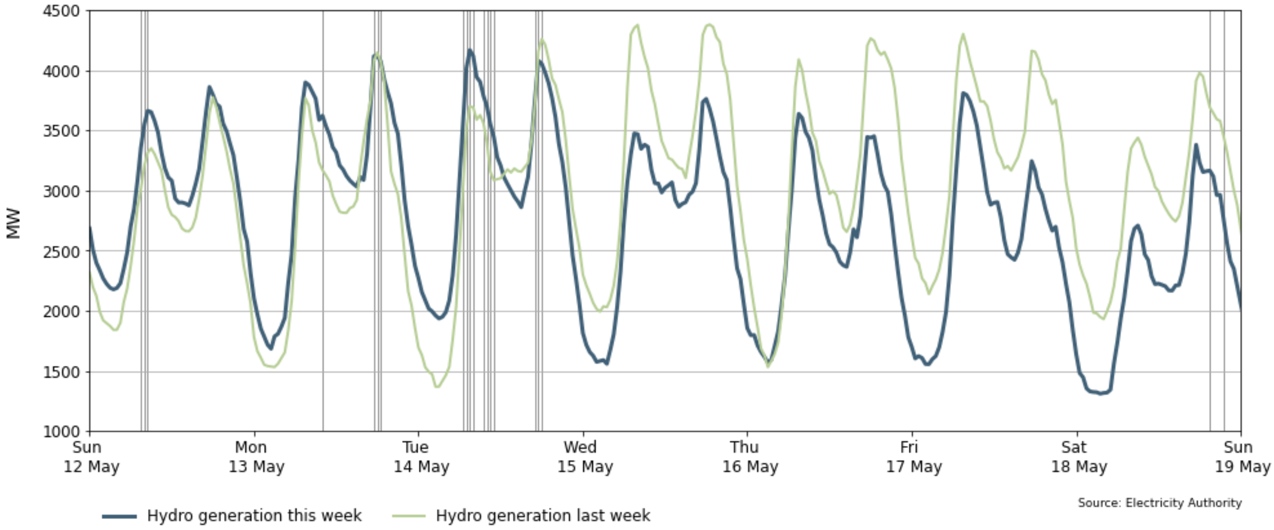


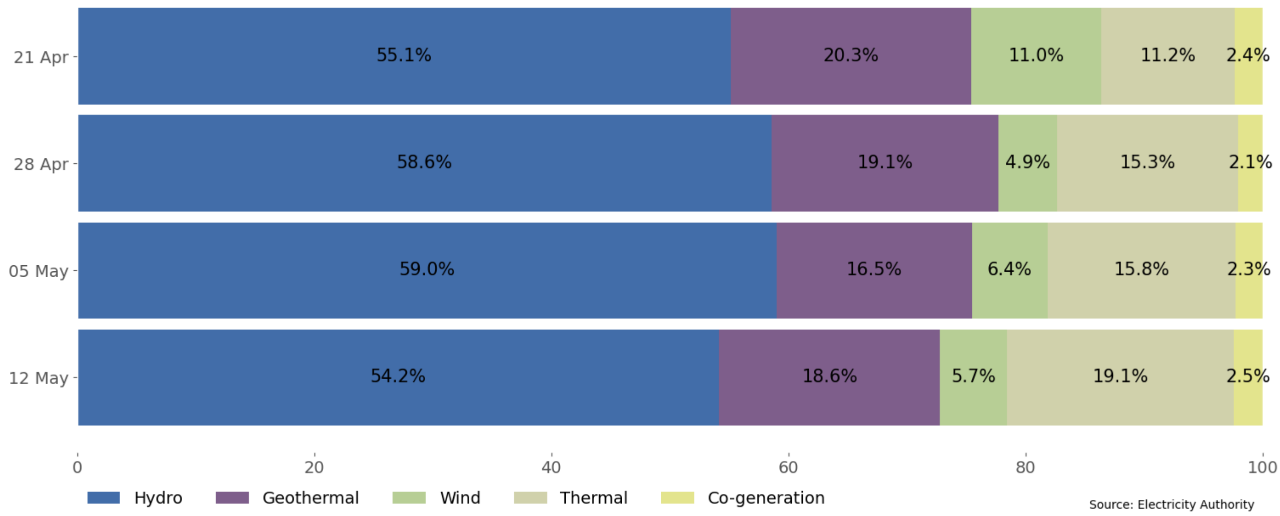
Figure 14 shows hydro generation between 12-18 May. Hydro generation was generally higher than the previous week until Wednesday, due to high demand and low wind generation. From Wednesday onwards, it was significantly lower than the previous week.

Figure 14: Hydro generation between 12-18 May



As a percentage of total generation between 12-18 May, total weekly hydro generation was 54.2%, geothermal 18.6%, wind 5.7%, thermal 19.1%, and co-generation 2.5%. Thermal generation increased this week, compensating for a decrease in the proportion of hydro and wind generation.

Figure 15: Total generation by type as a percentage each week between 21 April and 18 May



8. Outages

Figure 16 shows generation capacity on outage, and Figure 17 shows the thermal generation capacity outages. Total capacity on outage between 12-18 May ranged from 1,000-1,600MW, generally below average for May.

Notable outages include:

(a) TCC was on outage from 11-12 May.

(b) Huntly 4 is on outage from 17-27 May.

(c) Huntly 2 was on outage from 15-16 May.

(d) Stratford 1 is on outage from 12-26 May.

(e) Stratford 2 is on outage until 30 June.

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

Figure 16: Total MW loss due to generation outages between 12-18 May

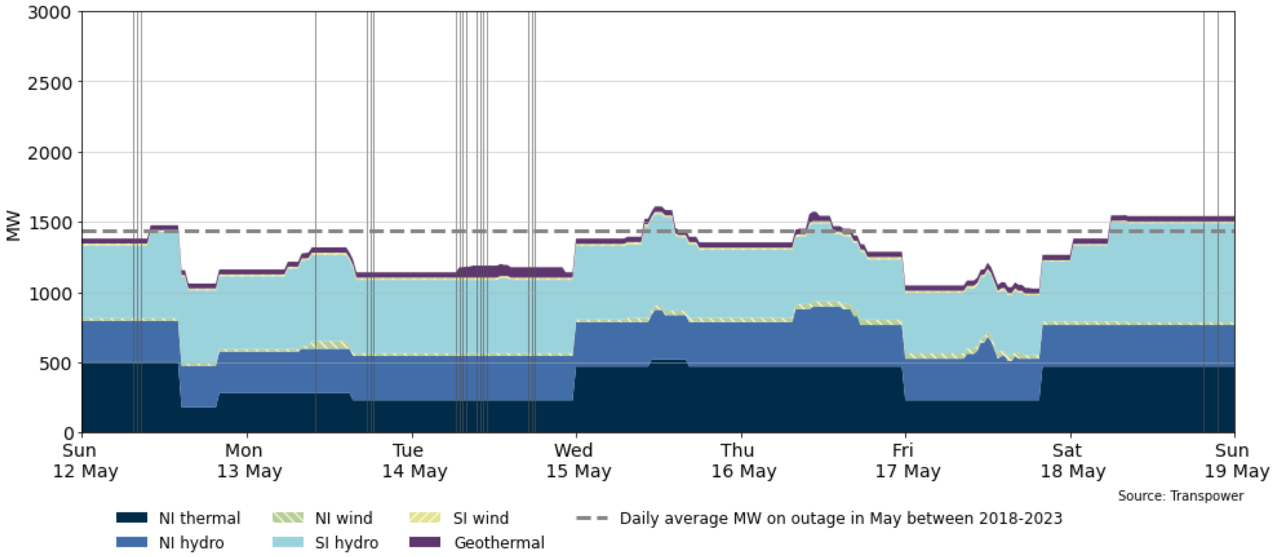
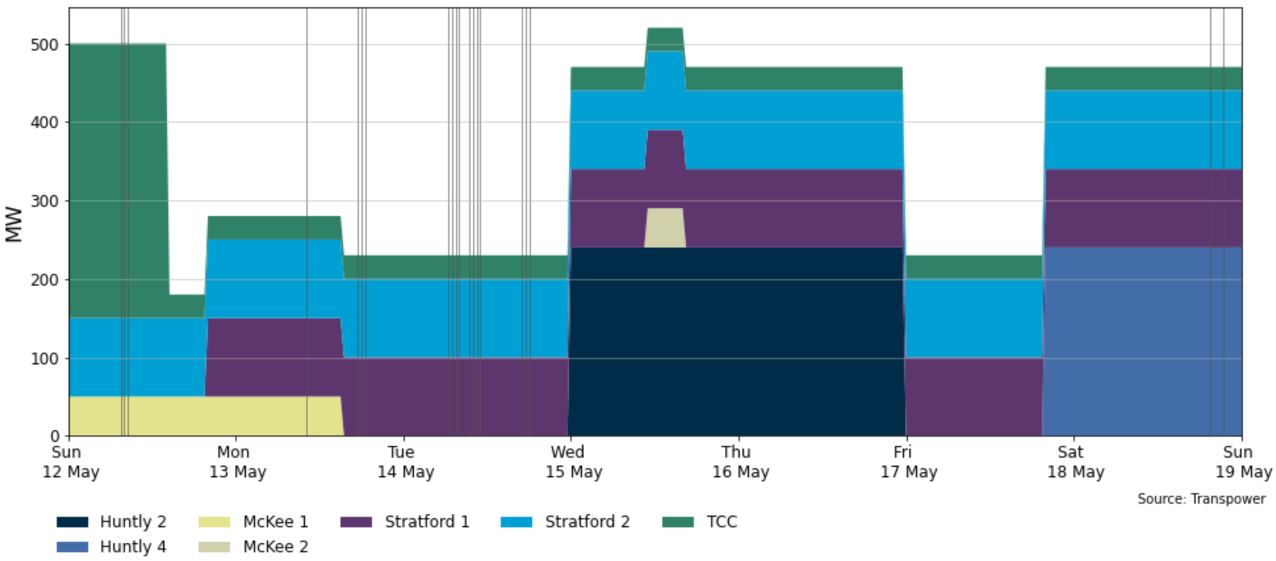


Figure 17: MW loss from thermal outages between 12-18 May

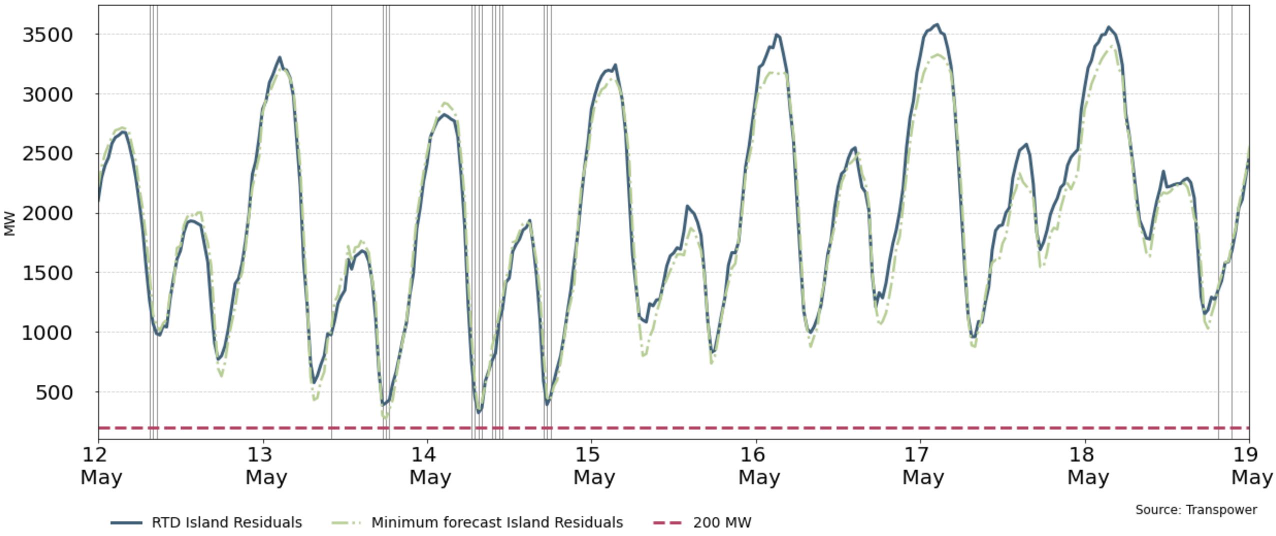


9. Generation balance residuals

Figure 18 shows the generation balance residuals between 18-24 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.

Generation residuals were lowest on Monday and Tuesday this week, dropping below 500MW. The minimum national residual was 321MW on Tuesday morning and the minimum North Island residual was 245MW on Monday evening. At both of these times, wind generation was low and demand was high.

Figure 18: National generation balance residuals 12-18 May



10. Storage/fuel supply

Figure 19 shows the total controlled national hydro storage and the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

Due to high hydro generation and low inflows, national controlled hydro storage decreased compared to the previous week. Controlled storage is 66% of nominally full and 88% of historical mean as of 18 May.

Storage decreased at all major lakes this week, with levels at all lakes now below their historical means.

(a) Lake Pūkaki is above its 10^{th} percentile.

(b) Takapō has reached its 10^{th} percentile.

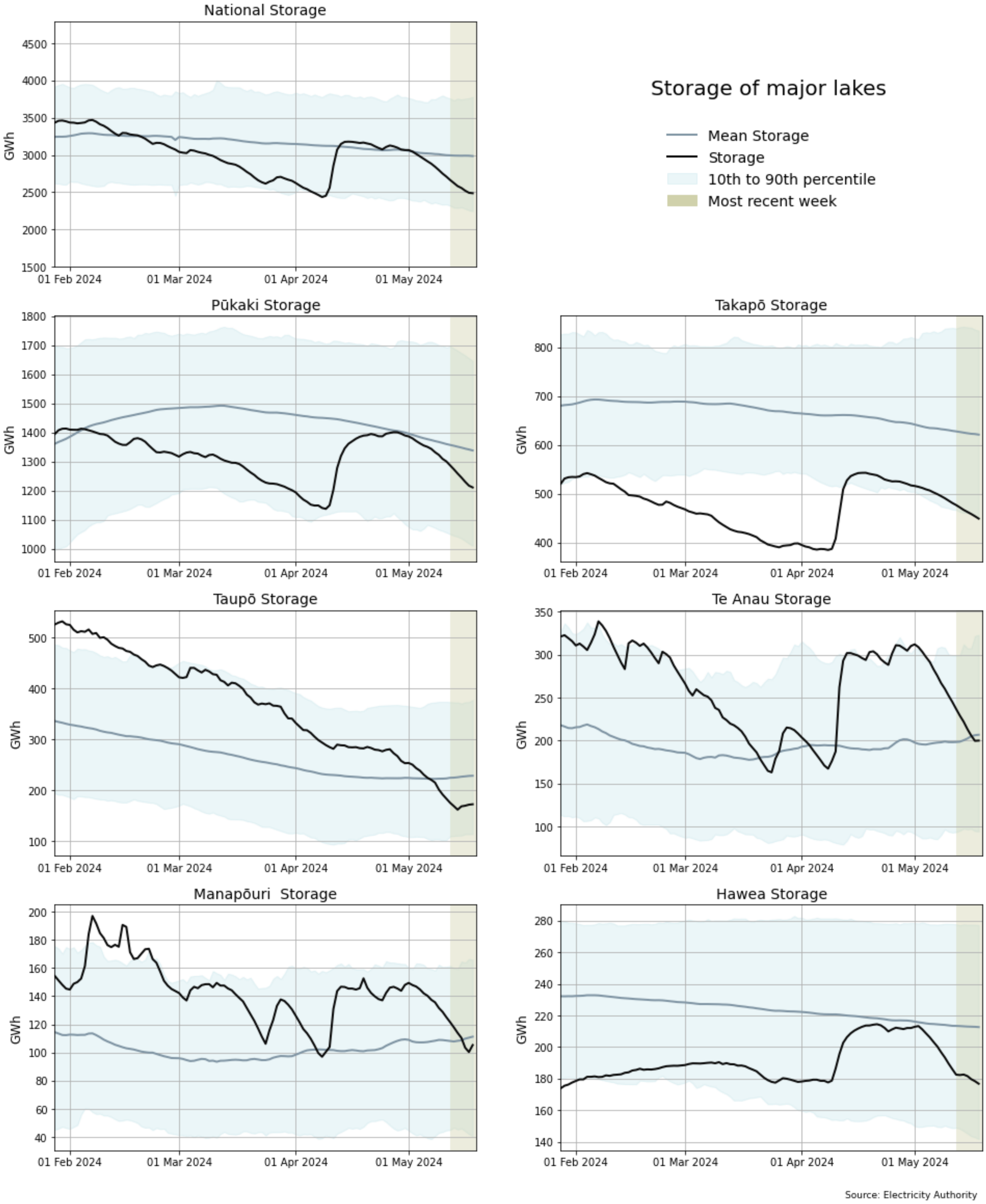
(c) Taupō is above its 10^{th} percentile and saw a slight increase in storage at the end of the week.

(d) Te Anau is just below its mean.

(e) Manapōuri is just below mean and saw an increase in storage at the end of the week.

(f) Hawea is above its 10^{th} percentile.

Figure 19: Hydro storage

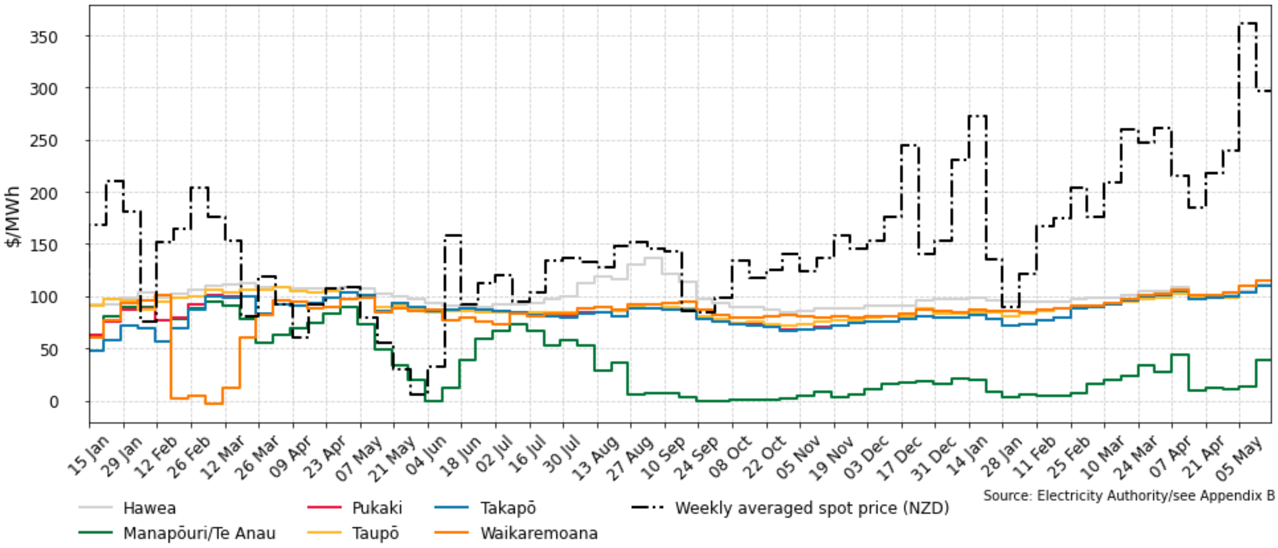


11. JADE water values

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 15 January 2023 and 18 May 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.

Compared to the previous week, all lakes saw an increase in their water values between ~$5.30/MWh (Tekapo) and ~$25.60/MWh (Manapōuri/Te Anau).

Figure 20: JADE water values across various reservoirs between 15 January 2023 and 18 May 2024



12. Prices versus estimated costs

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).

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.

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

The latest SRMC of coal-fuelled Rankine generation is ~$163/MWh. The cost of running the Rankines on gas remains more expensive at ~$287/MWh.

The SRMC of gas-fuelled thermal plants is currently between ~$194/MWh and ~$287/MWh.

The SRMC of Whirinaki is ~$584/MWh.

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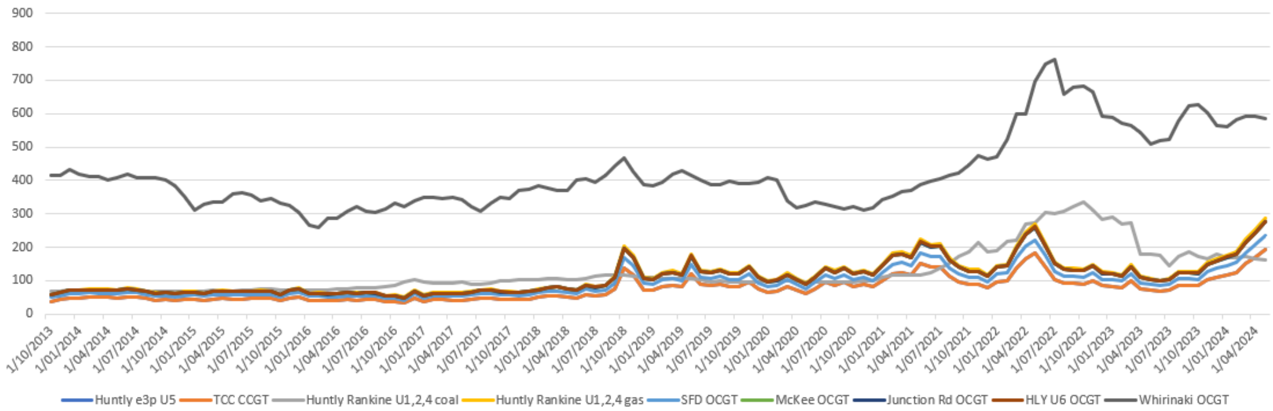
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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



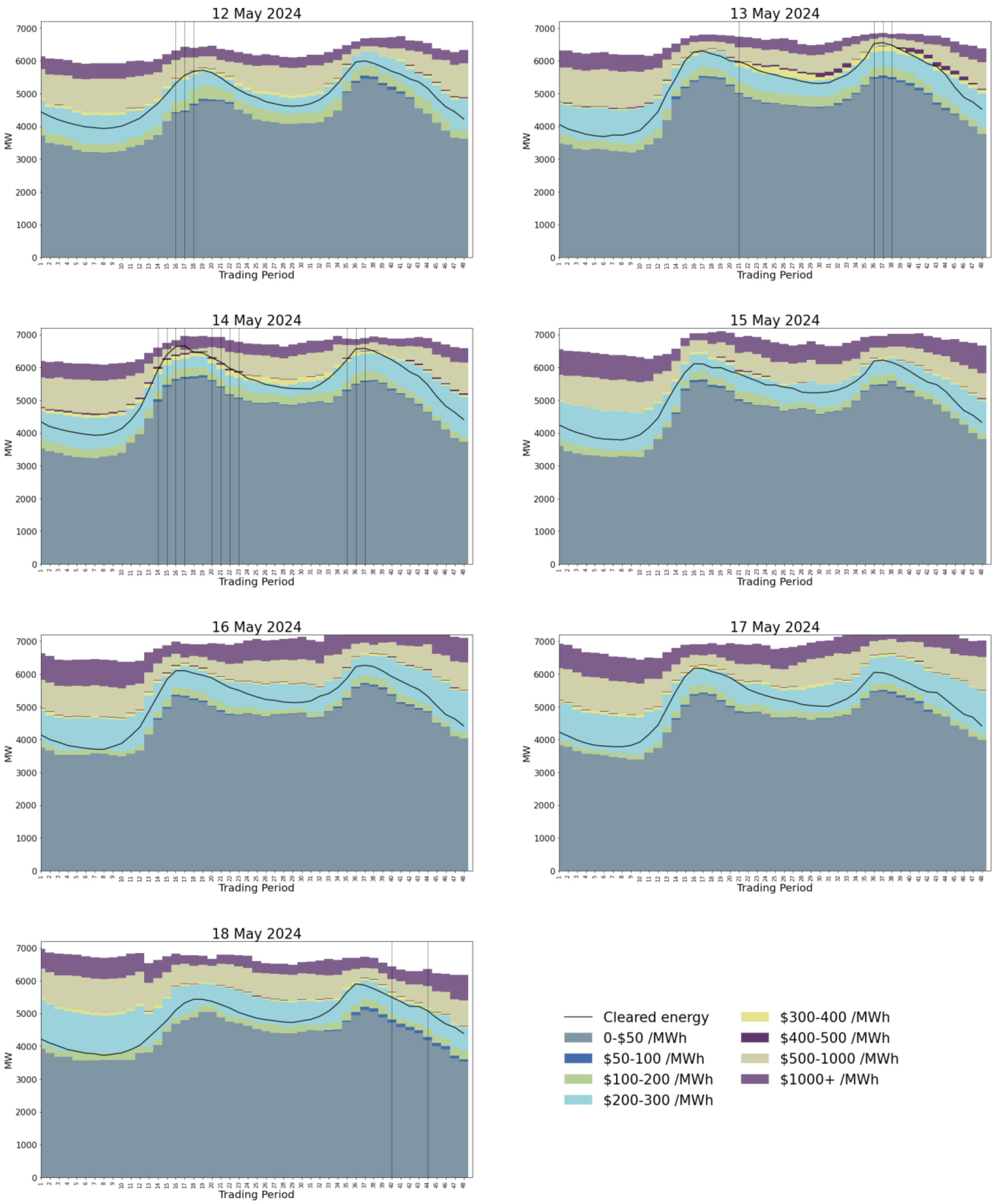
Source: Electricity Authority/see Appendix C

13. Offer behaviour

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

This week, most offers were cleared in the $200-$300/MWh region. Prices reached the $500-$1,000MWh band on Sunday and Monday, and the $1,000+/MWh band on Tuesday.

Figure 22: Daily offer stacks



Source: Electricity Authority

14. Ongoing work in trading conduct

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

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	Energy offers
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Energy offers
8/05/2024	15-17	Further analysis	Genesis	Multiple	Energy offers
8/05/2024	36-39	Further analysis	Genesis	Multiple	Energy offers
9/05/2024	36-44	Further analysis	Genesis	Multiple	Energy offers
10/05/2024	35-37	Further analysis	Genesis	Multiple	Energy offers
14/05/2024	16-17	Further analysis	N/A	N/A	Energy and reserve offers