13 May 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 5-11 May

1.1. Prices were high this week, with all prices above the historical median for this time of the year. This week several price spikes occurred, most notably on Wednesday, Thursday, and Friday, related to high demand due to cold temperatures across the country during those days. Electricity supply reached levels below 200MW of residuals, prompting the system operator to release low-residual notices for Wednesday and Friday – the latter escalating to a formal warning notice. Reserve prices also spiked this week, usually following the spikes in spot prices. Thermal generation saw Huntly units 4, 5, 2 and then 1 providing baseload during the week. Junction Road and Stratford 1 ran continuously during most of the week, also contributing to the baseload. Whirinaki ran during the large price spikes seen between Wednesday and Friday. Hydro storage decreased this week and is currently at ~94% of the mean as of 11 May. Further analysis is being conducted on several high-priced trading periods from this week.

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. Between 5-11 May:

(a) the average wholesale spot price across all nodes was $356/MWh

(b) 95% of prices fell between $181/MWh and $2,166/MWh.

2.3. Prices increased substantially compared to the previous week with multiple instances of prices over $1,000/MWh. The average price this week increased by $115/MWh compared to the previous week. High prices this week occurred due to a combination of increased demand, caused by a cold snap, periods of low wind and several planned generation outages making both the energy and reserve markets tight during multiple trading periods. Further analysis is being conducted on several high-priced trading periods from this week.

2.4. The first two large price spikes occurred on Wednesday, one at 7:30am and the other at 6:00pm. During both spikes, the national generation residuals were less than 200MW and wind generation was low. On 7 May at 9:04am, the system operator, released a low-residual customer advice notice (CAN) for 8 May between 7:30am and 8:00am.

2.5. The third price spike occurred on Thursday at 7:00pm, coinciding with the highest demand on record this week (and the year so far) and declining wind generation. National generation residuals were slightly below 200MW during the spike; however, no low-residual CAN notice was issued. Wind forecast inaccuracies greater than 100MW[1] might have also contributed to the spike.

[1] Between final and PRSS 3.5 hour ahead schedules

2.6. On 9 May at 7:28am, The system operator released a low-residual CAN for 10 May between 7:30am and 8:30am, which later escalated to a formal warning notice (WRN), released at 10:51 am on Thursday. Participant reaction to the WRN, as well as demand response, ensured these morning prices did not reach initial forecasts. Prices spiked again late morning, to $646/MWh at Ōtāhuhu and $595/MWh at Benmore. This coincided with the trading periods directly after TCC tripped.

2.7. Finally, the last large price spike occurred on Friday at 5:30pm. Again, demand was high and wind generation was low.

2.8. Over-forecast demand at the times when prices peaked might have contributed to the prices seen on the highlighted days. Also, Whirinaki was running during the times when the large price spikes occurred.

2.9. Finally, on Saturday, extreme solar activity resulted in several coronal mass ejections, a phenomenon known often as a ‘solar storm’, and which can cause damage to power grids, required the grid operator to preventively remove several transmission lines from operation.[2] The system operator released several grid emergency notices (GENs), describing the affected lines and how long the assets would be offline. In the end, 8 South Island lines were removed during the whole of Saturday, which might have contributed to the high prices seen on that day.[3]

2.10. 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[4] of historic prices are highlighted with a vertical black line. Other notable prices are marked with black dashed lines. The figure is displayed twice, with vertical axis in the bottom figure limited to $1,000/MWh, to enhance the visibility of the data points.

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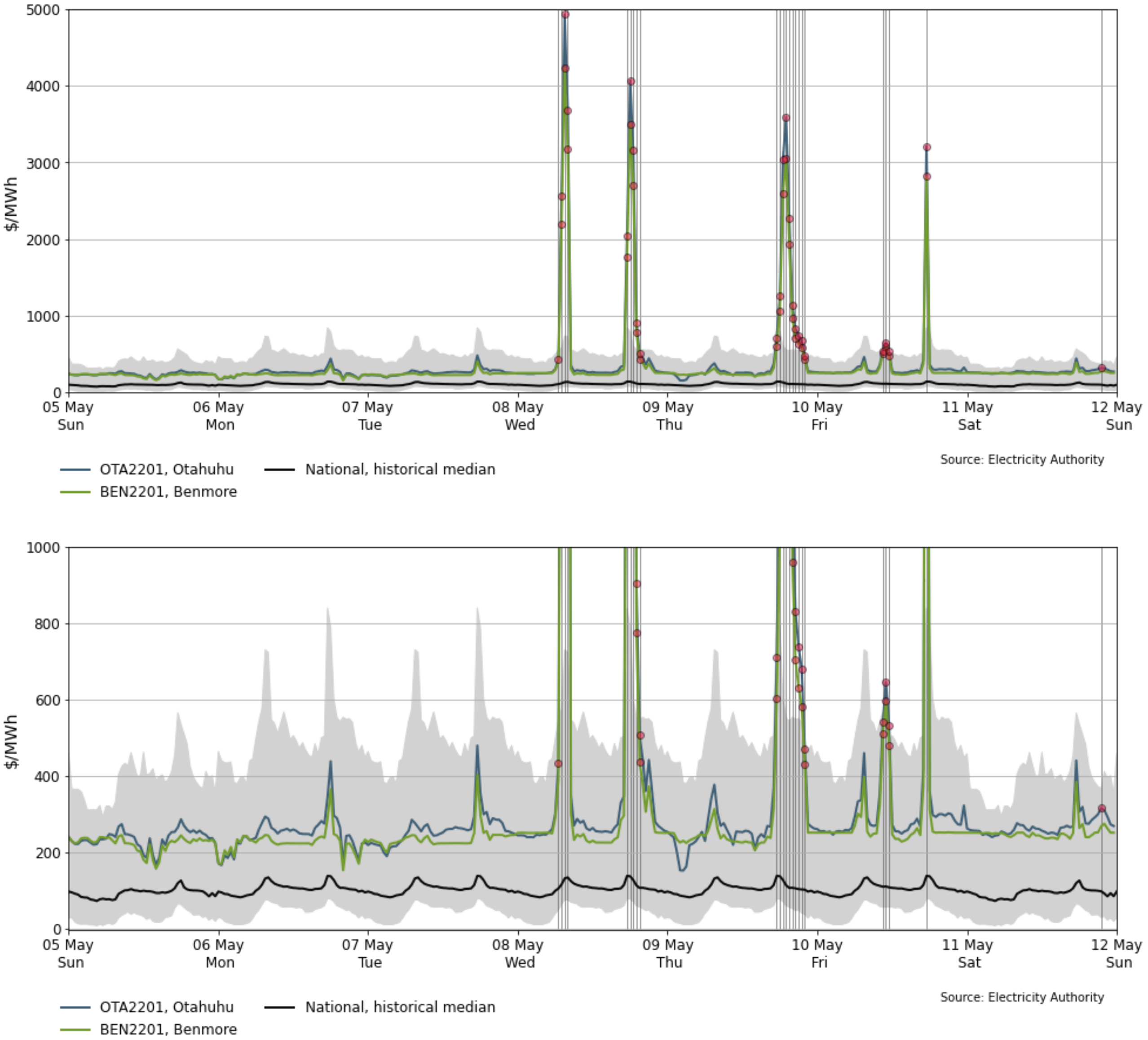
[2] See: https://www.energynews.co.nz/news/electricity-transmission/158793/solar-flares-see-transpower-remove-circuits-nationwide

[3] See: https://static.transpower.co.nz/public/interfaces/gen/GEN%20G5%20Extreme%20Geomagnetic%20Induced%20Current%20event%20South%205380954216.pdf?VersionId=UtxiRNw9VbByyz79BicnNzHDXY06K2N6

[4] 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.

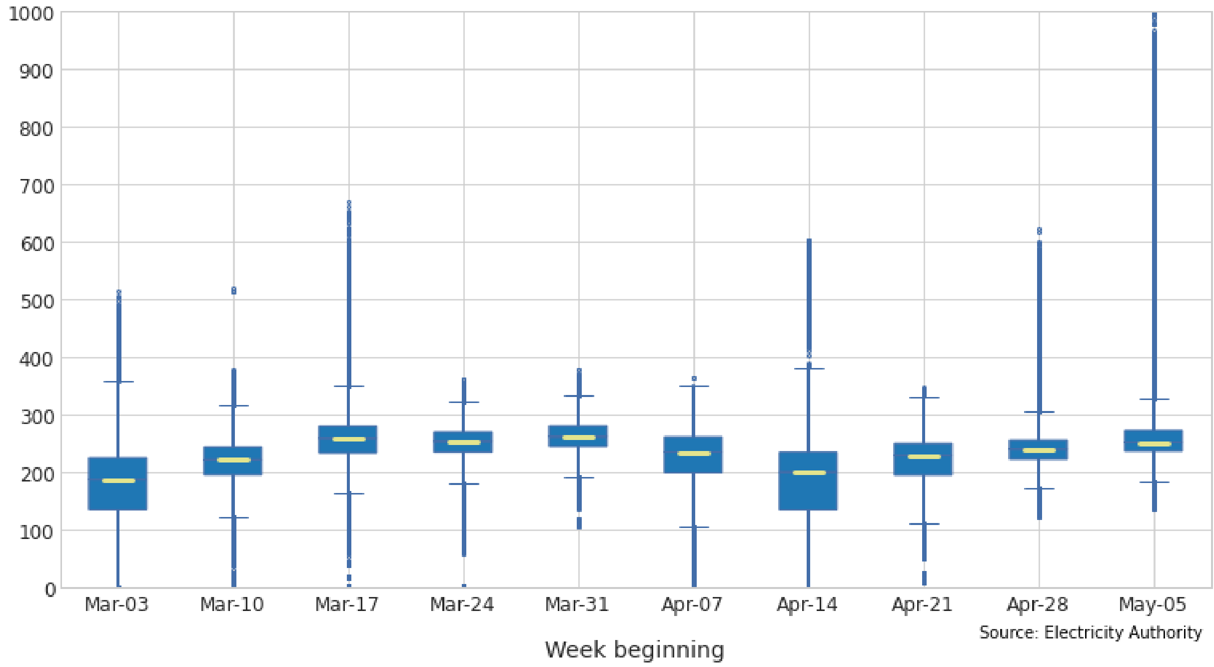
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 5-11 May



2.11. 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.

2.12. The spot price distribution this week shows an increase in prices and several price outliers. This week's median price was $253/MWh, compared to $241/MWh in the previous week, a $12/MWh increase. The middle 50% of the prices were between $236-$272/MWh. Note that Figure 2 is capped at $1,000/MWh but price outliers this week went as high as $5,000/MWh.

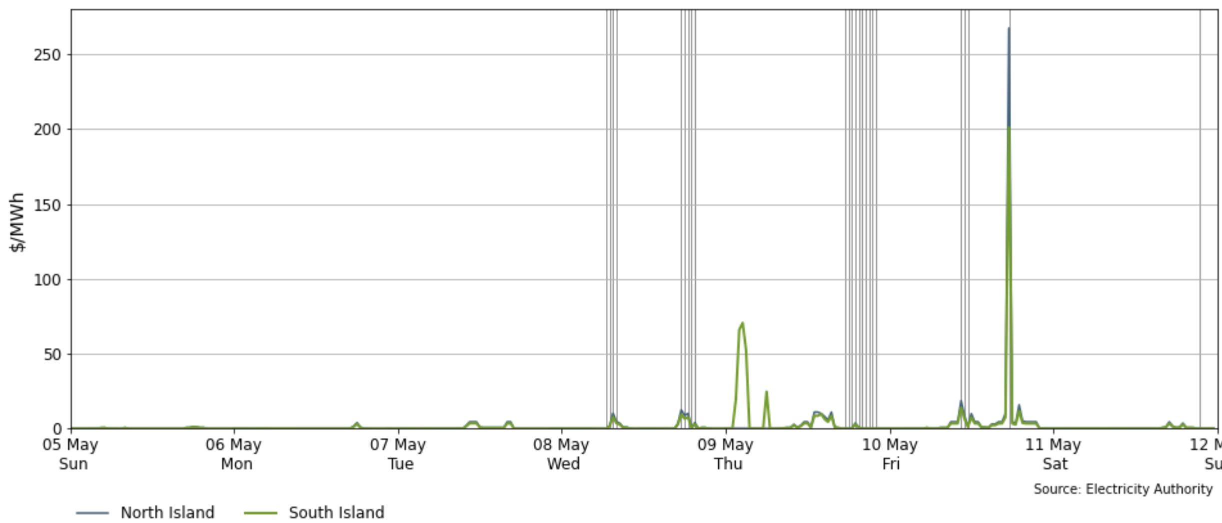
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



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 $10/MWh this week. On Thursday, the first FIR price spike is likely related to high HVDC southward transfers while the second occurred close to the time when the HVDC was reversing its flow. The Friday spike might be related to a decrease in reserve offers during the time of peak demand.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 5-11 May

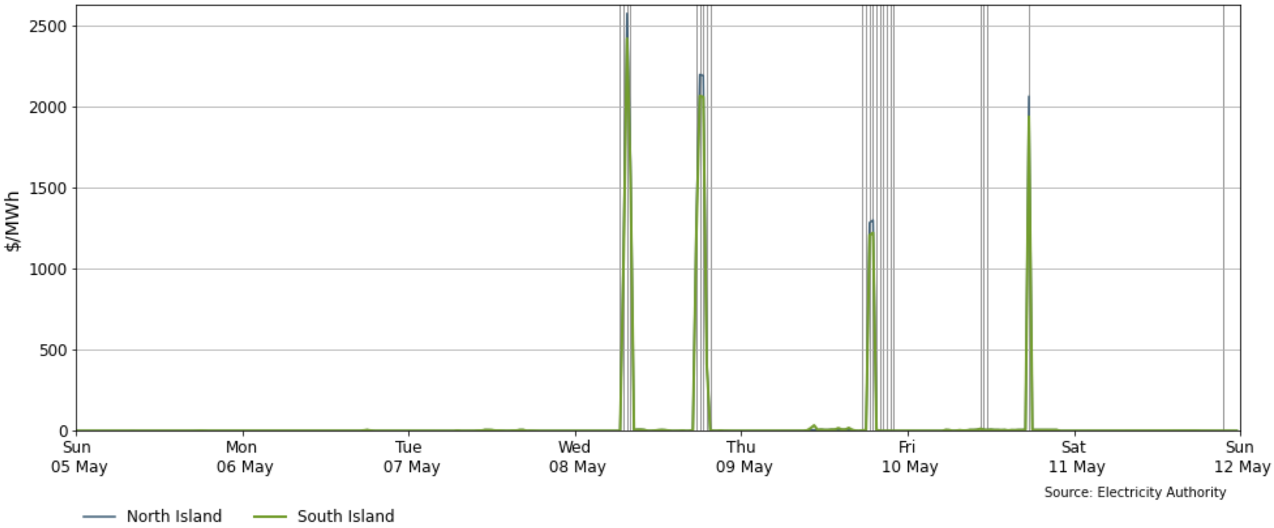


3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh, but several spikes occurred this week. There were several 5-minute trading periods on Wednesday morning and Friday evening where SIR reserve scarcity pricing [5]applied. Other high SIR prices were likely related to

[5] Scarcity pricing | Electricity Authority (ea.govt.nz)

energy and reserve co-optimisation during times of tightness in both the energy and reserve markets.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 5-11 May



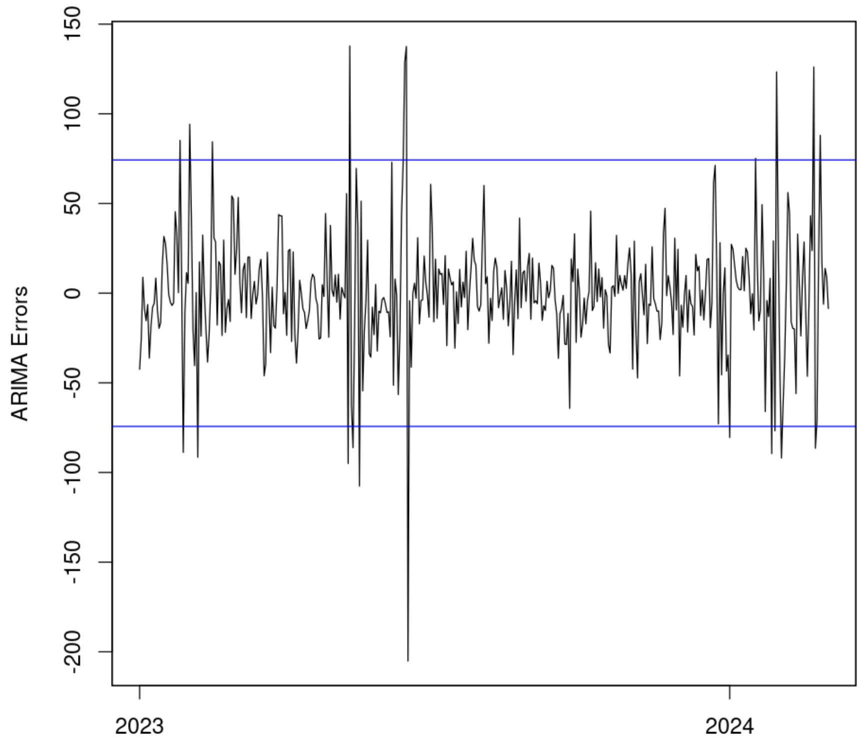
4. Regression residuals

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 prices were above the two standard deviation threshold, indicating that prices were above the expected values. Since the prices were above by a significant margin, it influenced the results for the following days, due to the nature of the autoregressive model. For this reason, although the model captured lower-than-expected prices on Friday, the result is likely not as relevant.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 11 May 2024

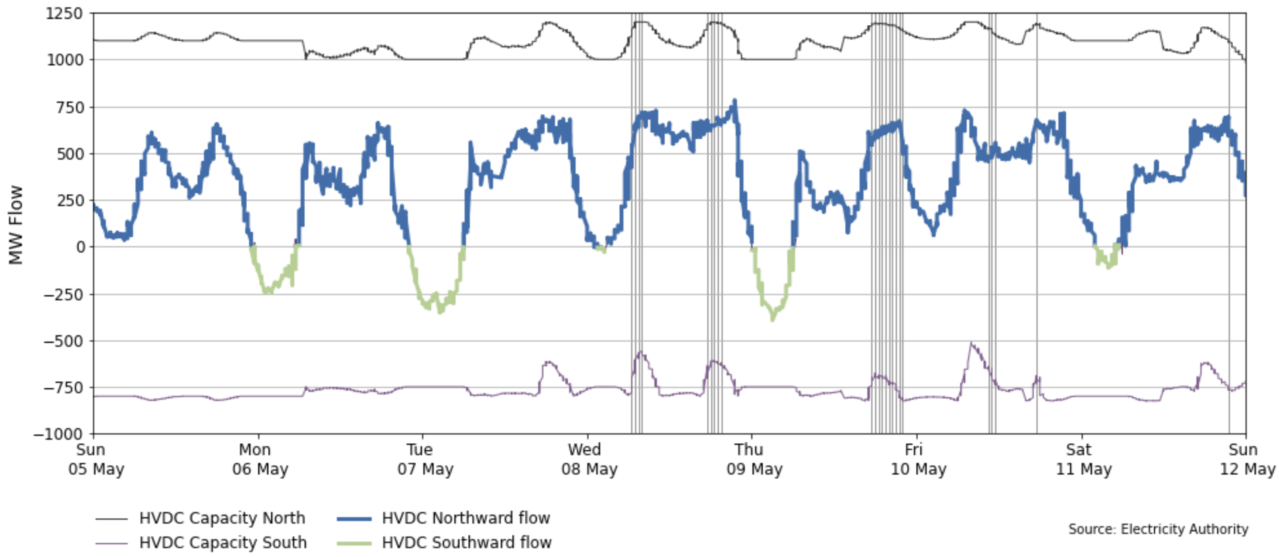


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 5-11 May. HVDC was mostly flowing northward this week due to relatively low wind generation and high North Island demand. Overnight southward flow occurred from Sunday to Monday, Monday to Tuesday, and then during the early hours of Thursday and Saturday, matching the times of increased wind generation.

Figure 6: HVDC flow and capacity between 5-11 May

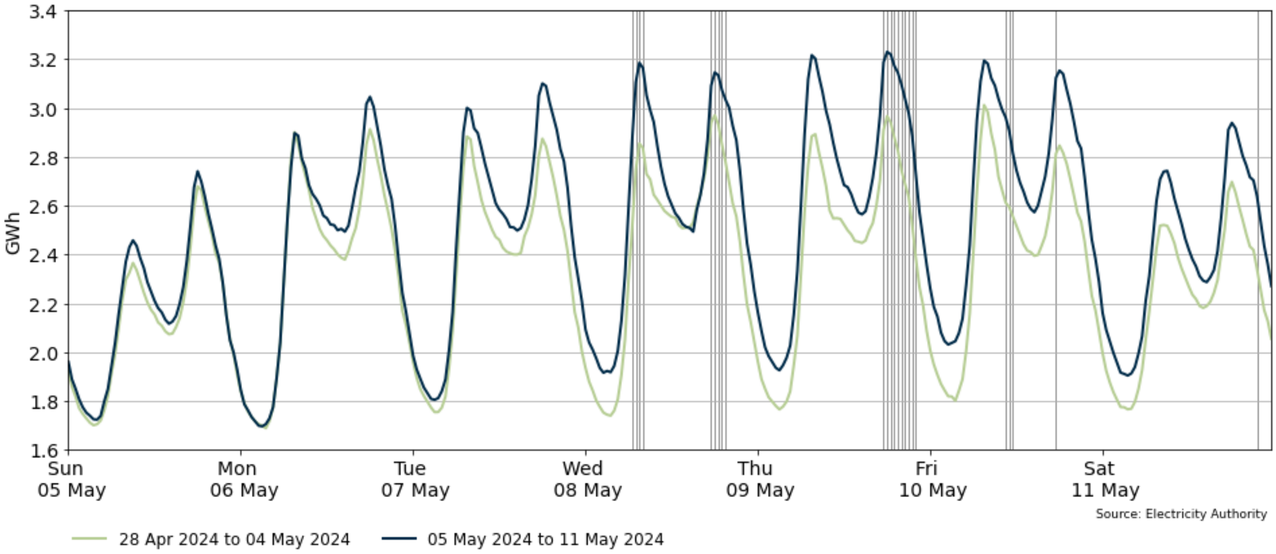


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 5-11 May, compared to the previous week. Demand was significantly higher than the previous week, especially from Tuesday afternoon onwards due to a cold snap driving temperatures down across the country. The maximum demand, 3.23GWh, occurred on Thursday at 6:00pm. This is also the highest demand of the year until now.

Figure 7: National demand between 5-11 May compared to the previous week

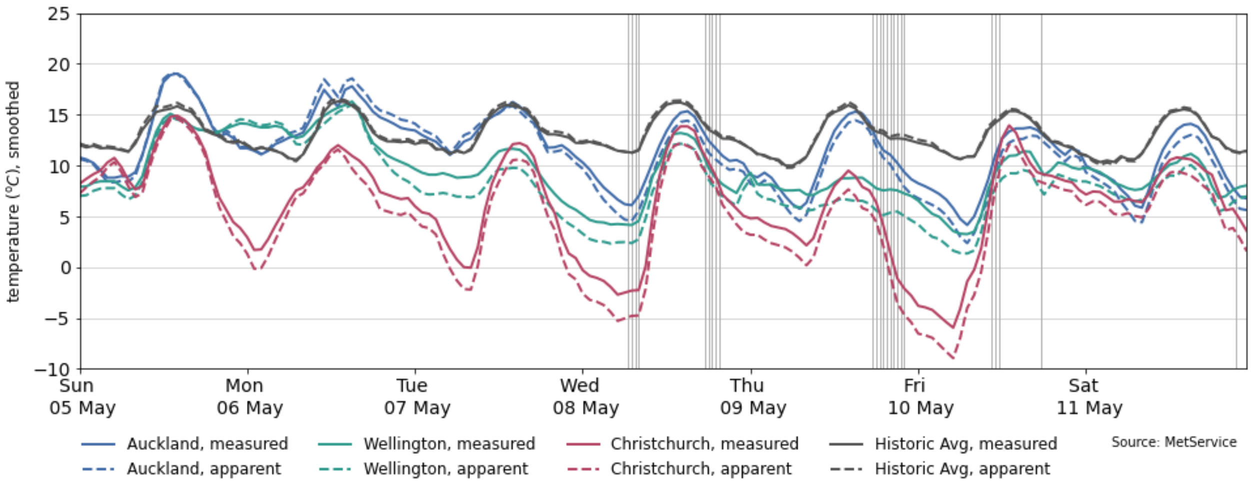


6.2. Figure 8 shows the hourly temperature at main population centres from 5-11 May. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures this week were mostly below the historical average with low temperatures seen in all major cities due to a polar jet stream bringing a cold snap to the country starting on Tuesday.[6] Apparent temperatures in Auckland were as low as 2ºC on Friday, varying between 2ºC and 19ºC this week. Temperatures in Wellington reached around 1ºC on Friday and varied between around 1ºC and 16ºC. Apparent temperatures in Christchurch reached a low of around -8ºC on Friday, with the city seeing its temperature varying between -8ºC and 15ºC this week.

[6] https://www.newshub.co.nz/home/new-zealand/2024/05/weather-polar-jet-stream-to-unleash-big-chill-on-new-zealand.html

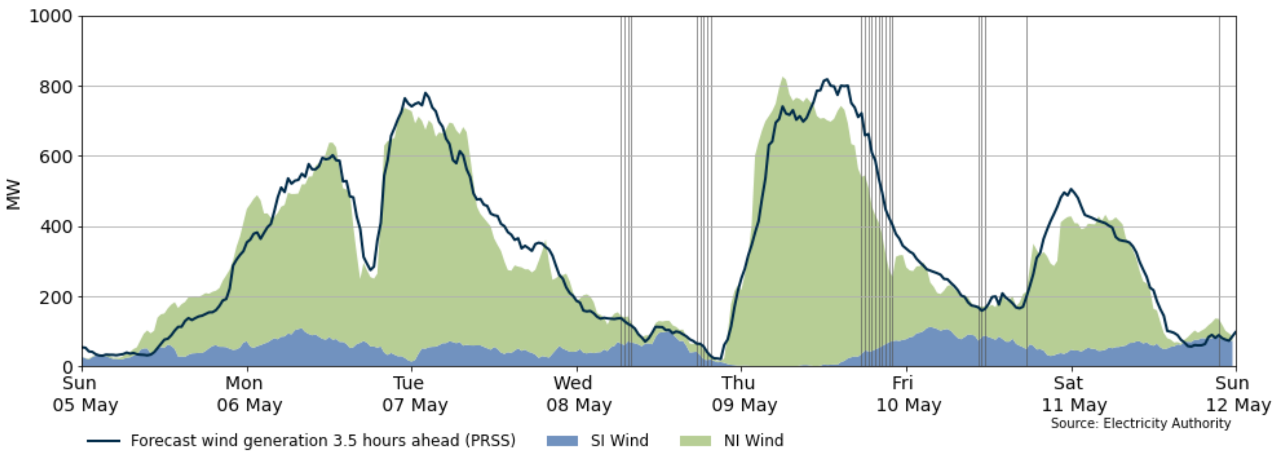
Figure 8: Temperatures across main centres between 5-11 May



7. Generation

7.1. Figure 9 shows wind generation and forecast from 5-11 May. This week wind generation varied between 16MW and 826MW, with an average of 326MW. Wind generation was above 200MW only between Monday afternoon and Tuesday night, also between Thursday and Friday morning, and for a few hours on Saturday. Wind generation was below 200MW during three out of the four highlighted price spikes this week. On Thursday afternoon during the price spike, the wind generation was decreasing quickly, and was often over-forecast[7] by more than 100MW.

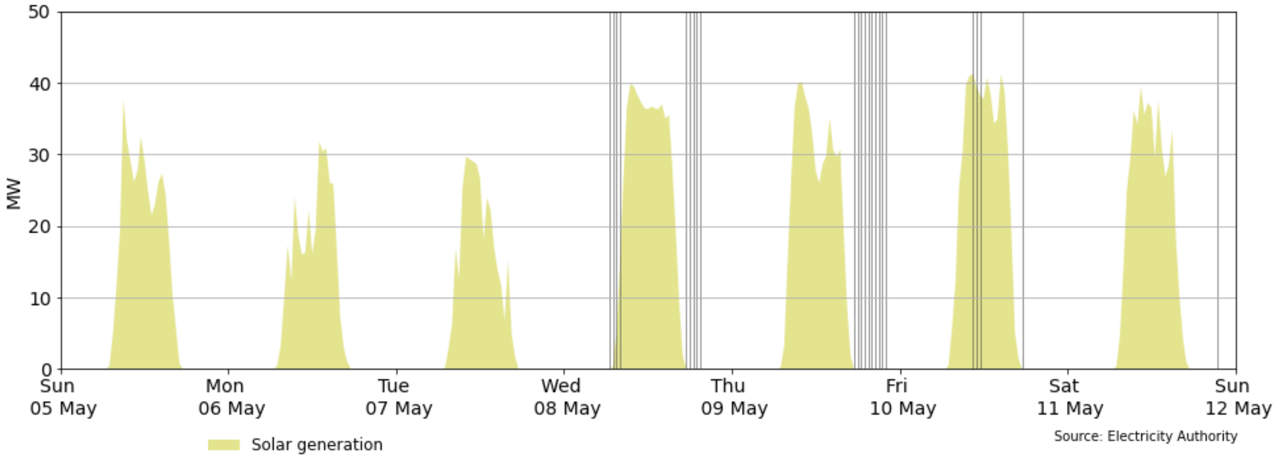
Figure 9: Wind generation and forecast between 5-11 May



7.2. Figure 10 shows solar generation from 5-11 May. Solar generation was between 32MW and 41MW this week. This week, solar was lower between Sunday and Tuesday, likely due to overcast situations, and increased from Wednesday onwards. Solar generation is expected to decrease due to shorter days and higher declination angles limiting the availability of the resource, as we approach the winter solstice.

[7] Difference between RTD and 3.5 hour ahead PRSS schedules

Figure 10: Solar generation between 5-11 May



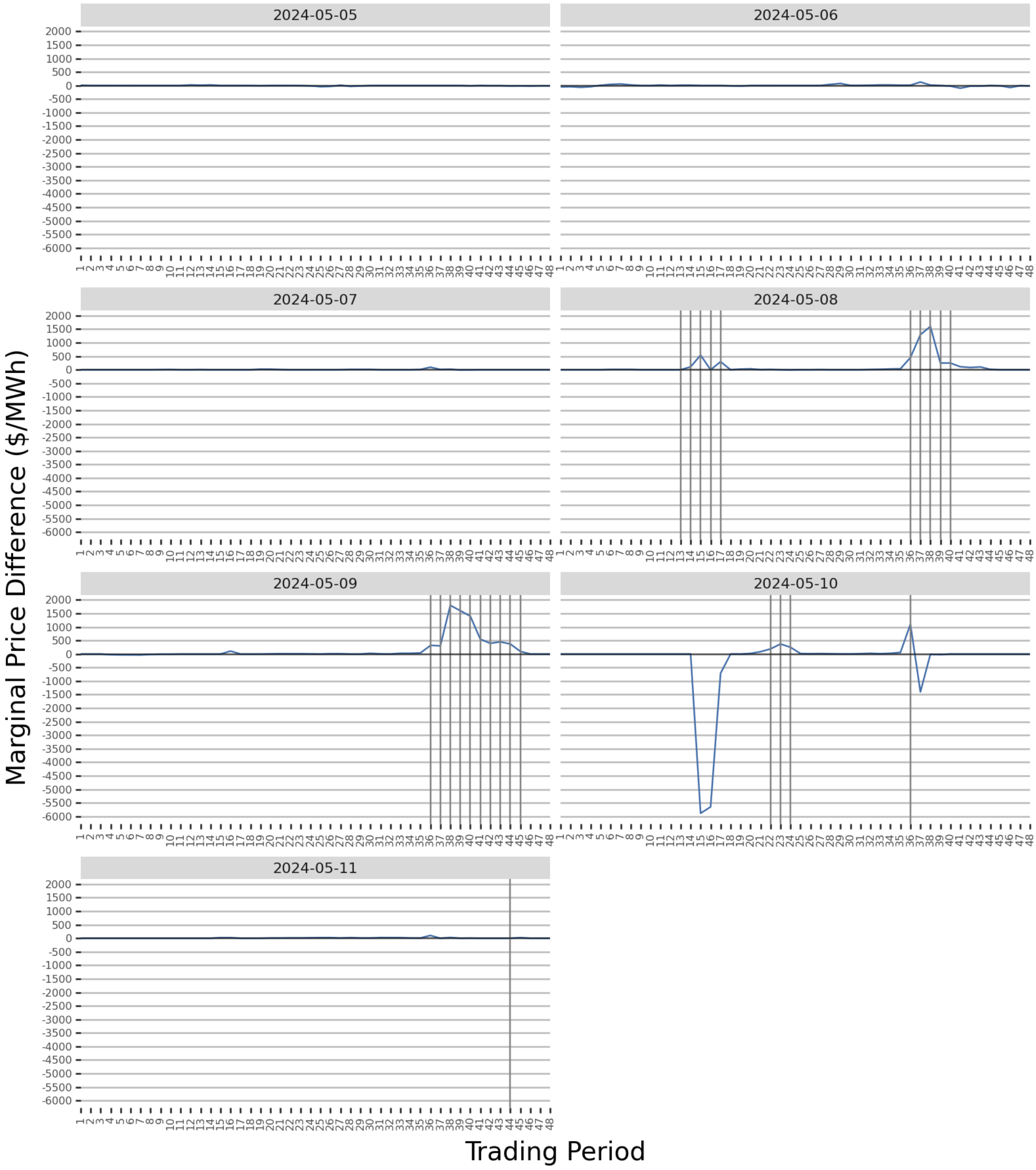
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS) projections. The figure highlights when forecasting inaccuracies are causing large differences in final prices. When the difference is positive this means that the 1-hour ahead 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 wind and demand forecasts 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.

7.4. This week the most notable positive differences (marginal prices higher than simulation) occurred on Wednesday, Thursday, and Friday. On Wednesday the high differences occurred on trading periods 13-17 (6:30am-8:30am) and on trading periods 36-40 (5:30pm-7:30pm). The high differences on Thursday occurred on trading periods 36-45 (5:30pm-10:00pm). On Friday the highest differences occurred on trading period 22-24 (10:30am-11:30am) and on trading period 36 (5:30pm). These differences in marginal prices, which were over $300/MWh, were related to demand being under-forecast, wind generation being over-forecast, or a combination of both.

7.5. The most relevant negative difference this week occurred on Friday between trading periods 14 and 17 (6:30am-8:00am) when interruptible load was used to constrain demand thus decreasing the prices.

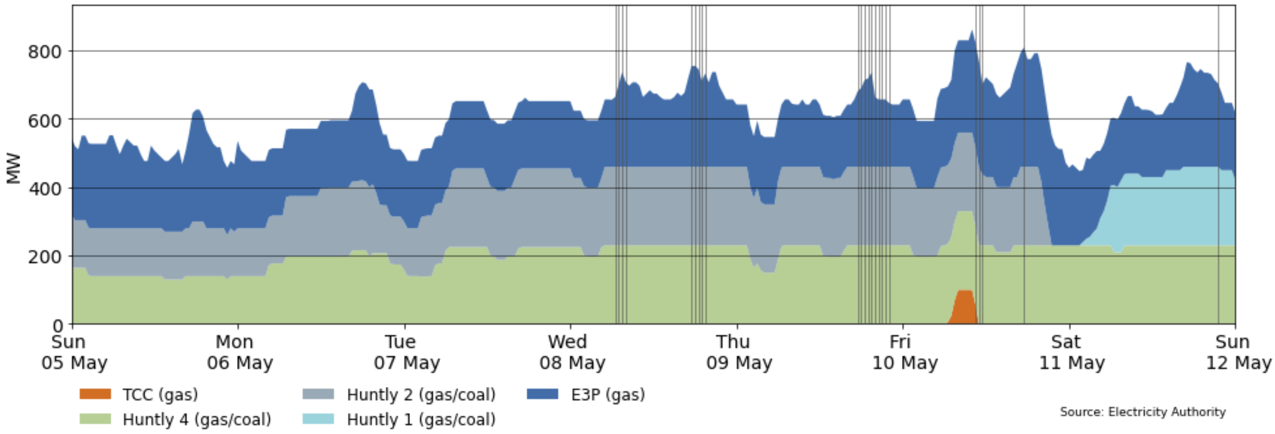
7.6.

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 5-11 May



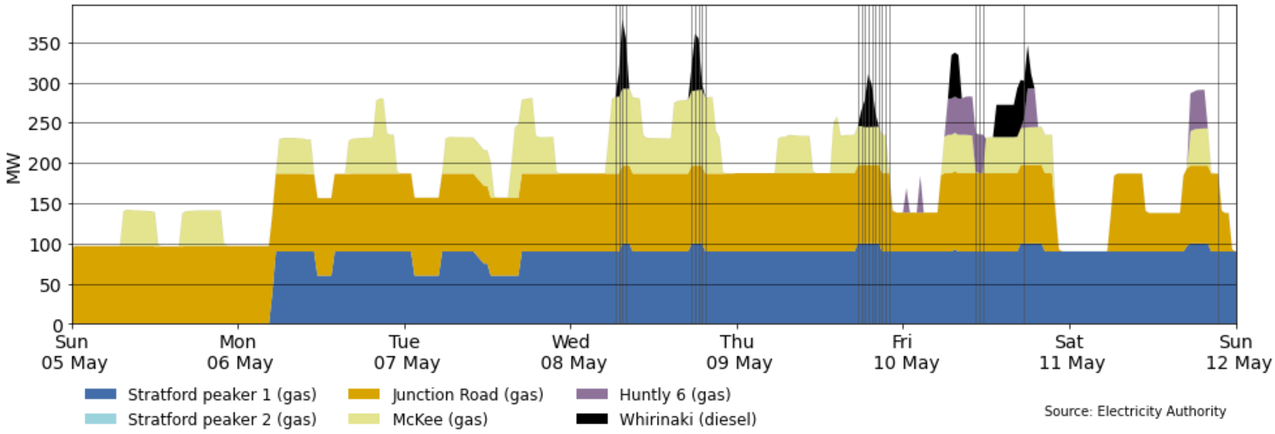
7.7. Figure 12 shows the generation of thermal baseload between 5-11 May. This week, Huntly units 4 and 5 (E3P) ran continuously to support baseload. Huntly 2 ran from Sunday until late Friday when it was switched off. On Saturday Huntly 1 came back from an outage, also contributing to the baseload. Finally, TCC ran for a few hours on Friday, close to the afternoon demand peak times.

Figure 12: Thermal baseload generation between 5-11 May



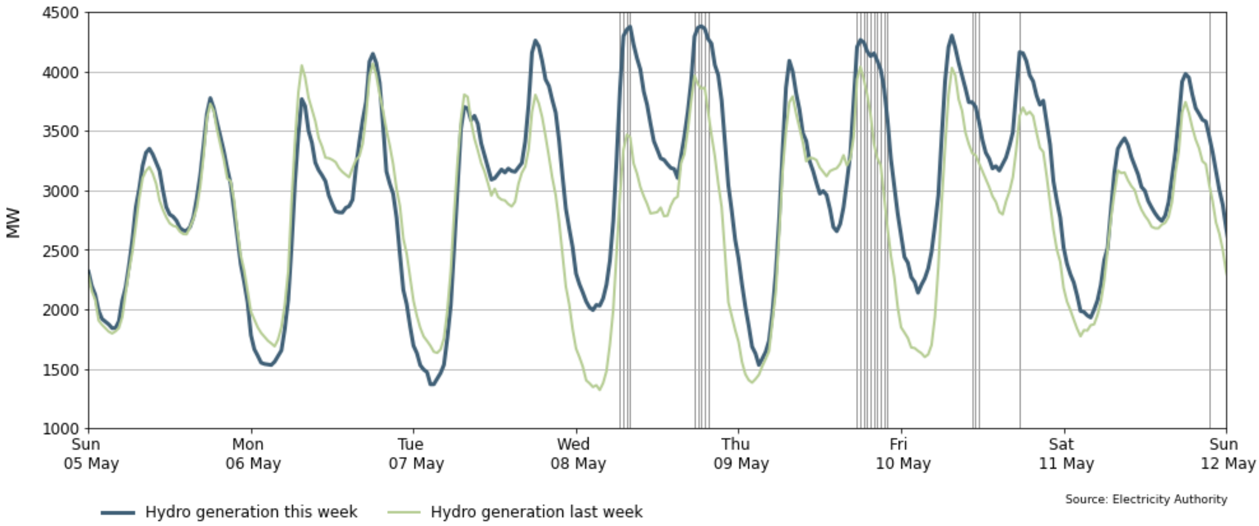
7.8. Figure 13 shows the generation of thermal peaker plants between 5-11 May. Peaker generation this week was provided by Junction Road, Stratford 1, McKee, Huntly 6 and Whirinaki. Junction Road ran continuously between Sunday and late Friday, contributing to the baseload. The unit also ran for most of Saturday. Stratford 1 ran continuously from Monday morning onwards, also providing baseload generation. McKee ran during times of high demand. Huntly 6 ran during peak demand times on Friday and Saturday afternoon, after being on outage until 9 May. Finally, Whirinaki ran during the peaks in demand between Wednesday and Friday.

Figure 13: Thermal peaker generation between 5-11 May



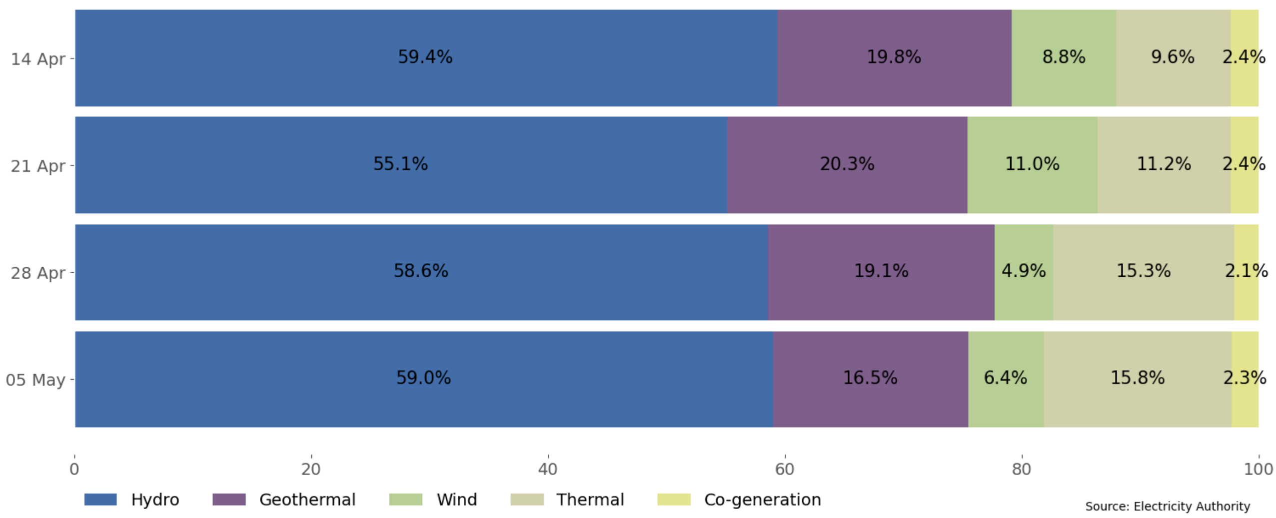
7.9. Figure 14 shows hydro generation between 5-11 May. Hydro generation was mostly higher than the previous week and mainly followed demand. Low wind generation this week also contributed to the high hydro generation.

Figure 14: Hydro generation between 5-11 May



7.10. As a percentage of total generation, between 5-11 May, total weekly hydro generation was 59%, geothermal 16.5%, wind 6.4%, thermal 15.8%, and co-generation 2.3%, as shown in Figure 15. Low wind generation and high demand contributed to the increase in hydro generation in the electricity mix this week.

Figure 15: Total generation by type as a percentage each week between 14 April and 11 May



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 5-11 May ranged between ~1380MW and ~2260MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

(b) Huntly 1 was on outage from 30 April until 11 May

(c) Huntly 6 was on outage from 1 May until 9 May

(d) TCC was on outage from 3 May until 12 May

(e) Kawerau geothermal plant was on outage between 5-11 May

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

Figure 16: Total MW loss due to generation outages between 5-11 May

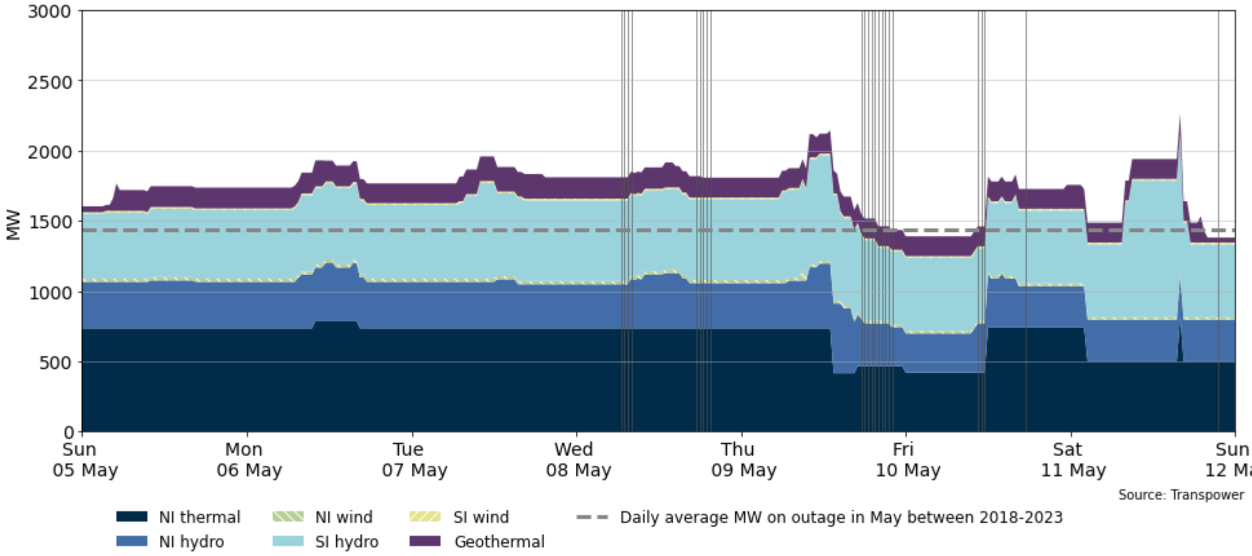
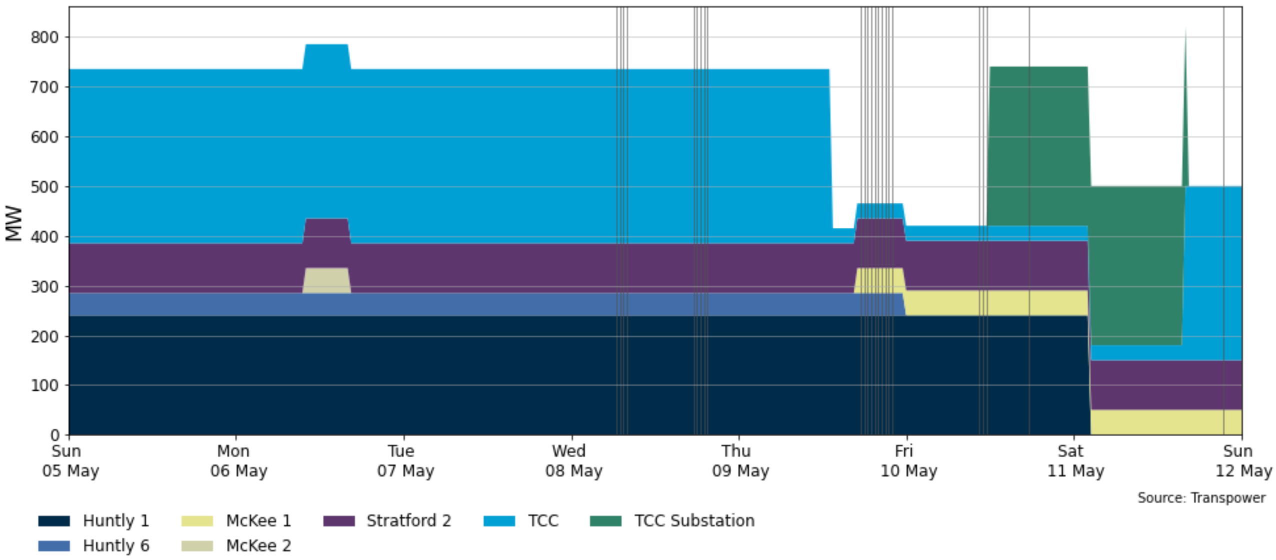


Figure 17: MW loss from thermal outages between 5-11 May

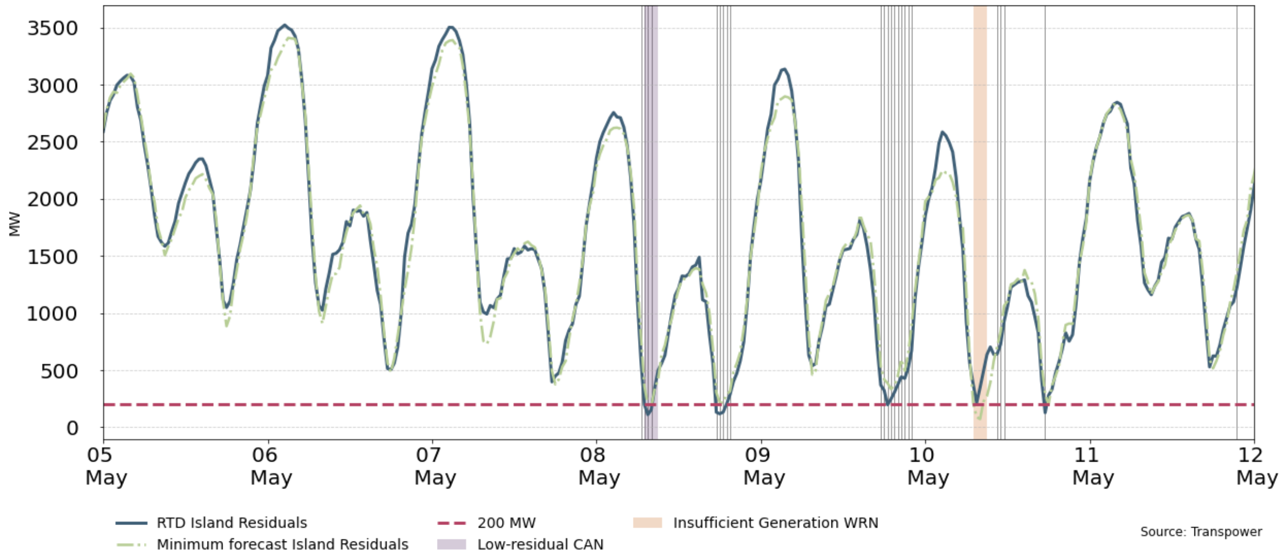


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 5-11 May. 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 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 reached low levels between Wednesday and Friday this week. The minimum national residual was 109MW on Wednesday at 7:30am. The minimum North Island residual level of 91 MW occurred on Friday afternoon when wind generation was low, and demand was high. This week the system operator issued low-residual CANs for Wednesday and Friday between 7:30am and 8:30 am due to potential tight supply situations during those days and times. The Friday low-residual CAN was updated to an insufficient Generation WRN, as shown in Figure 18. Note that the system operator does not send notices every time residuals go below the 200MW level.

Figure 18: National generation balance residuals 5-11 May



10. Storage/fuel supply

(a) Lake Taupō storage decreased this week and is now below its historical average.

(b) Lake Pūkaki is now below its historical average after another week of decrease in storage.

(c) Lake Takapō storage decreased this week, now sitting close to its 10th percentile.

(d) Lake Manapōuri and Te Anau saw a decrease in storage. Both lakes are sitting between their 90th percentile and their historical average.

(e) Lake Hawea's storage decreased this week and is now between its historical average and its 10th percentile.

10.2. 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.

10.3. National controlled storage decreased compared to the previous week, now sitting at 71% of nominally full and ~94% of the historical average for this time of the year (as of 11 May).

(a) Lake Taupō storage decreased this week and is now below its historical average.

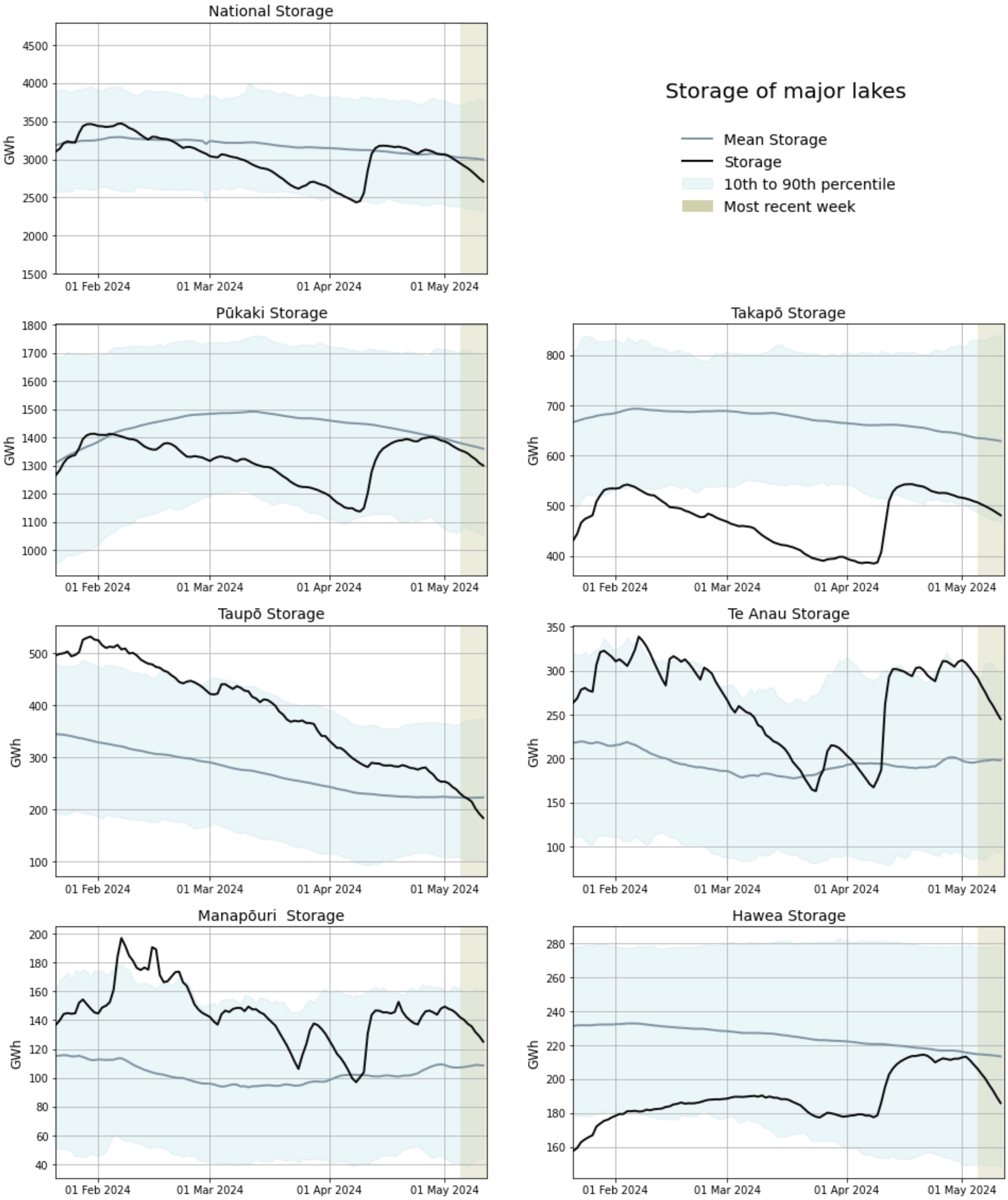
(b) Lake Pūkaki is now below its historical average after another week of decrease in storage.

(c) Lake Takapō storage decreased this week, now sitting close to its 10th percentile.

(d) Lake Manapōuri and Te Anau saw a decrease in storage. Both lakes are sitting between their 90th percentile and their historical average.

(e) Lake Hawea's storage decreased this week and is now between its historical average and its 10th percentile.

Figure 19: Hydro storage



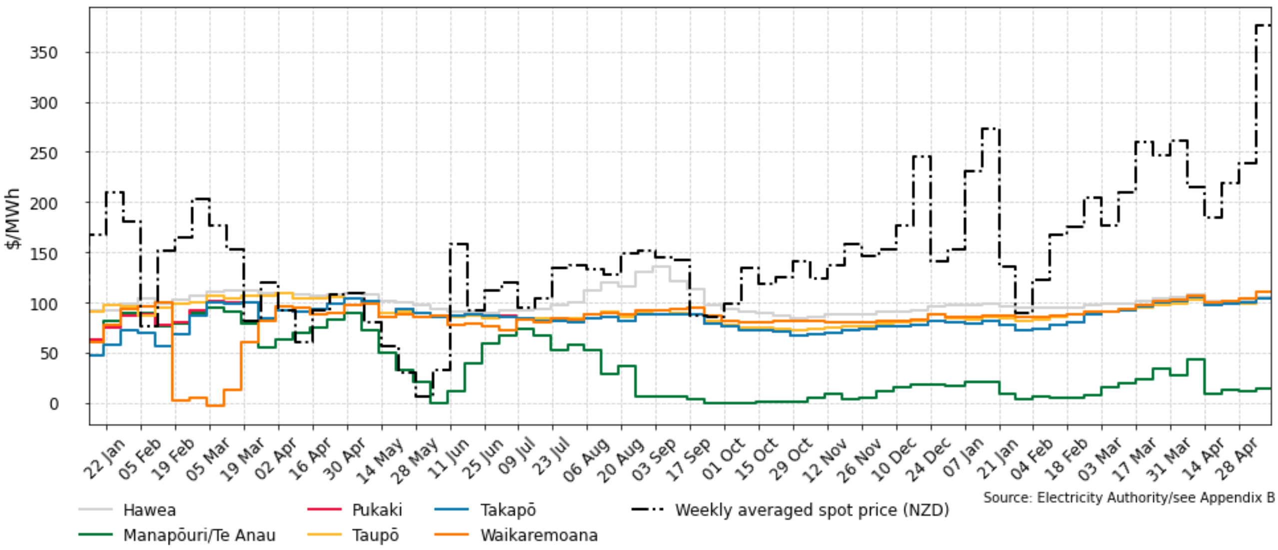
Source: Electricity Authority

11. JADE water values

11.1. The JADE[8] 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 11 May 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 between ~$2.5/MWh (Manapōuri/Te Anau) and ~$7/MWh (Waikaremoana).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 11 May 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 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.

12.4. 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.

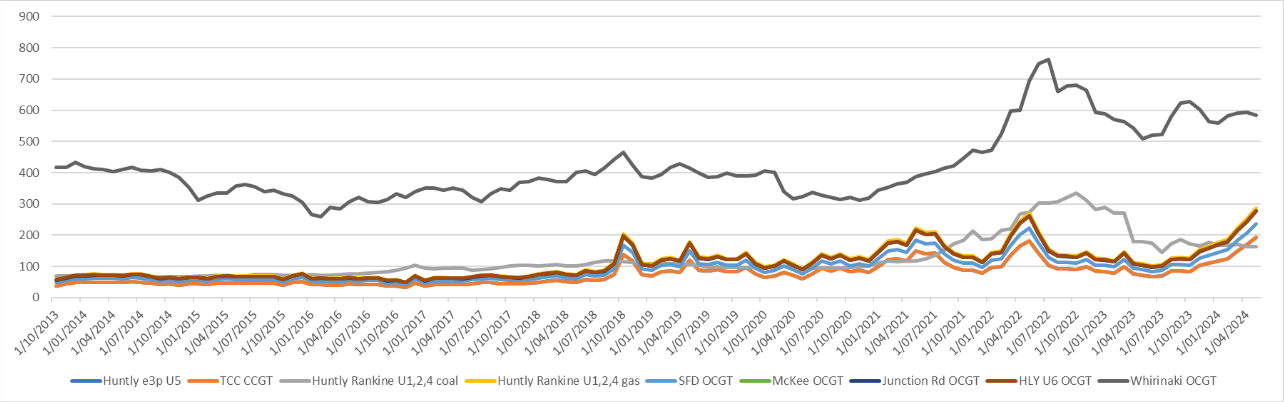
[8] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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

12.6. The SRMC of Whirinaki is ~$584/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



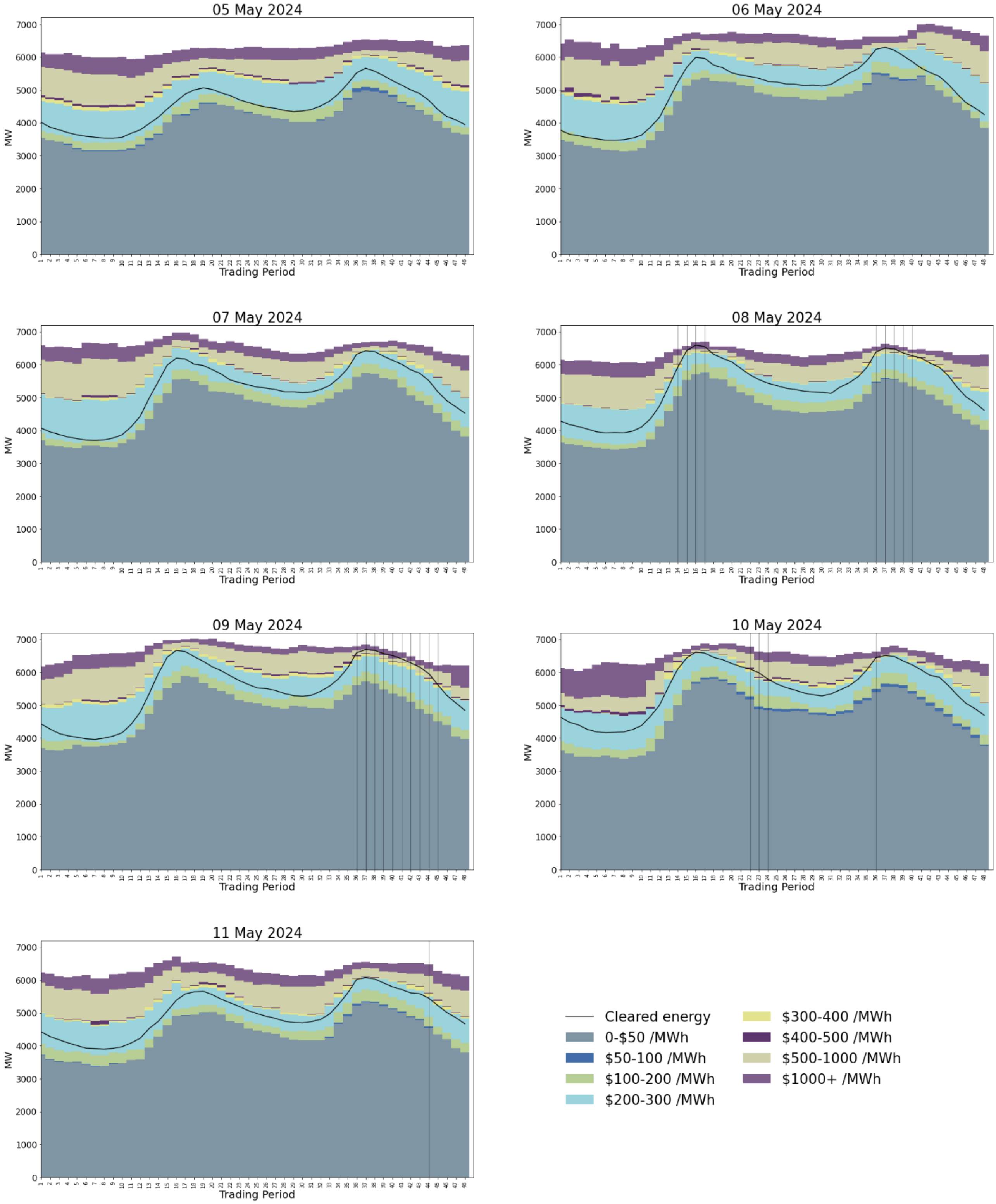
Source: Electricity Authority/see Appendix C

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. This week, most offers were cleared in the $200-$300/MWh region except for the trading periods matching the peaks in demand on Wednesday, Thursday afternoon, Friday afternoon, and Saturday afternoon. On Wednesday prices reached the $1000+/MWh band during the demand peaks related to tight supply. A similar situation occurred on Thursday and Friday in the afternoon.

Figure 22: Daily offer stacks[9]



Source: Electricity Authority

[9] 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. During analysis will be done on the trading periods this week which saw very high prices.

14.2. Further analysis is being done on the trading periods in Table 1 as indicated. Table 1 includes the trading periods this week which saw very high prices

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