22 June 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 12 to 18 June

1.1. Wholesale spot prices this week appear to be consistent with supply and demand conditions.

2. Spot Prices

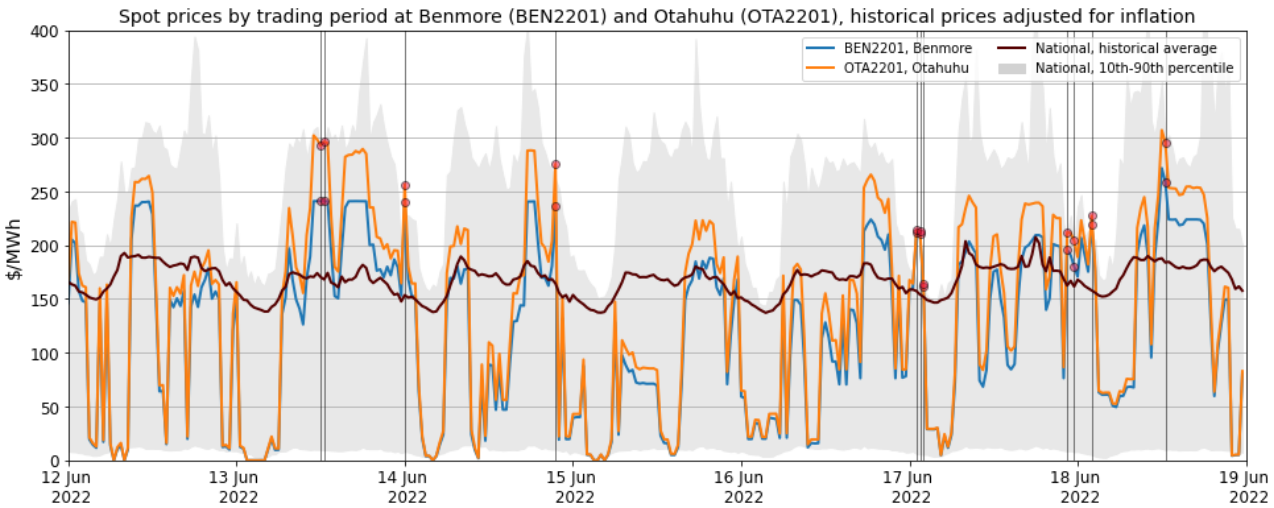
2.1. This report monitors underlying wholesale price drivers to assess whether there are trading periods that require further analysis for the purpose of considering potential non-compliance with the trading conduct rule. To do this, we assess whether spot prices are behaving in line with market conditions. 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 at Benmore and/or Otahuhu nodes exceed their historical 90th percentiles. These historically high-priced trading periods are marked out by vertical lines in the majority of figures in this report.

2.2. Wholesale electricity spot prices across all nodes between 12 and 18 June averaged $128.22/MWh, around ~$30/MWh less than the previous week's average. 95 per cent of prices fell between $0.03/MWh and $266.9/MWh.

2.3. Figure 1 shows spot prices from the past week at Benmore and Otahuhu alongside their historic mean and historic 10th-90th percentiles adjusted for inflation.

2.4. Spot prices were relatively more volatile this week with prices regularly falling below $50/MWh. Prices most commonly rose above their 90th historical percentiles during off peak periods.

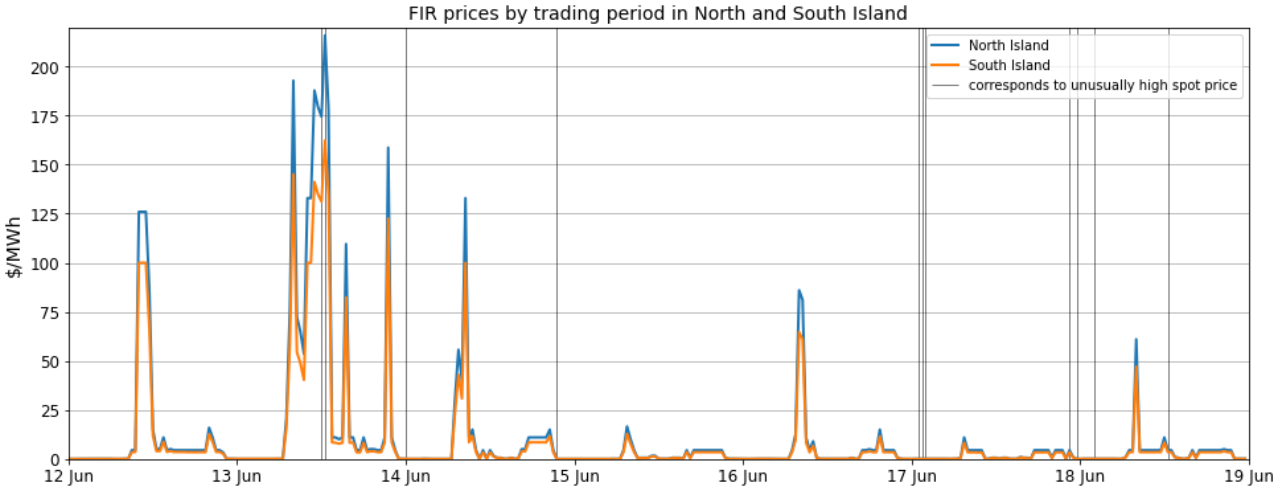
Figure 1: Wholesale Spot Prices



3. Reserve Prices

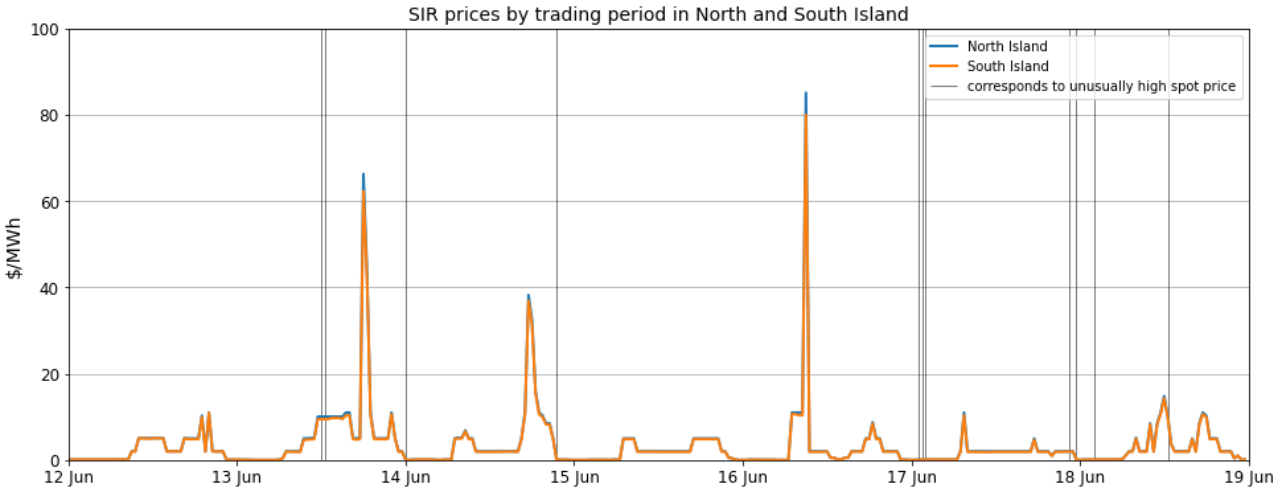
3.1. Fast instantaneous reserves (FIR) prices for the North and South Island are shown below in Figure 2. FIR prices this week saw spikes of up to $225/MWh with remaining prices falling within historical bounds at below $20/MWh. These spikes may be due to a mixture of factors including fewer reserve offers due to some thermal stations not running and possible co-optimisation by the system operator.

Figure 2: FIR prices by trading period and Island



3.2. Sustained instantaneous reserves (SIR) prices for the North and South Island are shown below in Figure 3. SIR reserve prices this week saw spikes of up to $85/MWh with remaining prices falling within historical bounds at below $20/MWh. Similarly to FIR prices these spikes may be due to a mixture of factors including fewer reserve offers due to some thermal stations not running and possible co-optimisation by the system operator.

Figure 3: SIR prices by trading period and Island



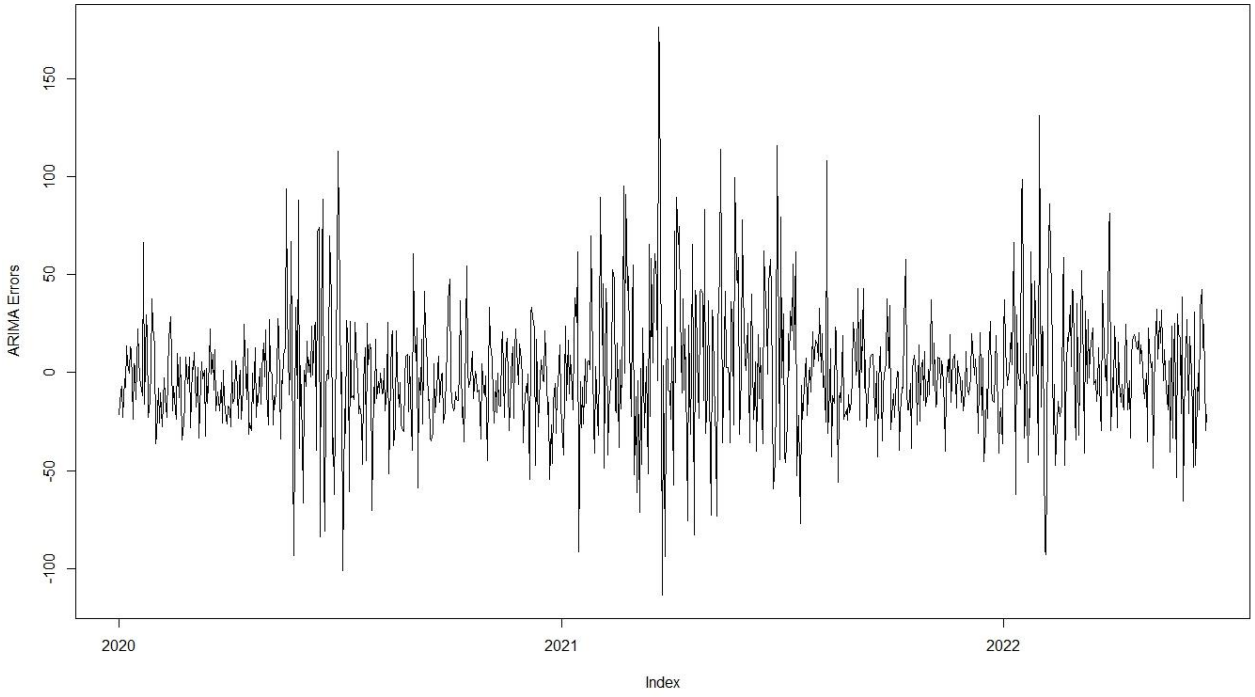
4. Regression Residuals

4.1. The Authority's monitoring team has developed two regression models of the 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[1] on the trading conduct webpage.

[1] https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Regression-Analysis.pdf

4.2. Figure 4 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Daily residuals this week suggest that prices appear to be largely aligned with market conditions.

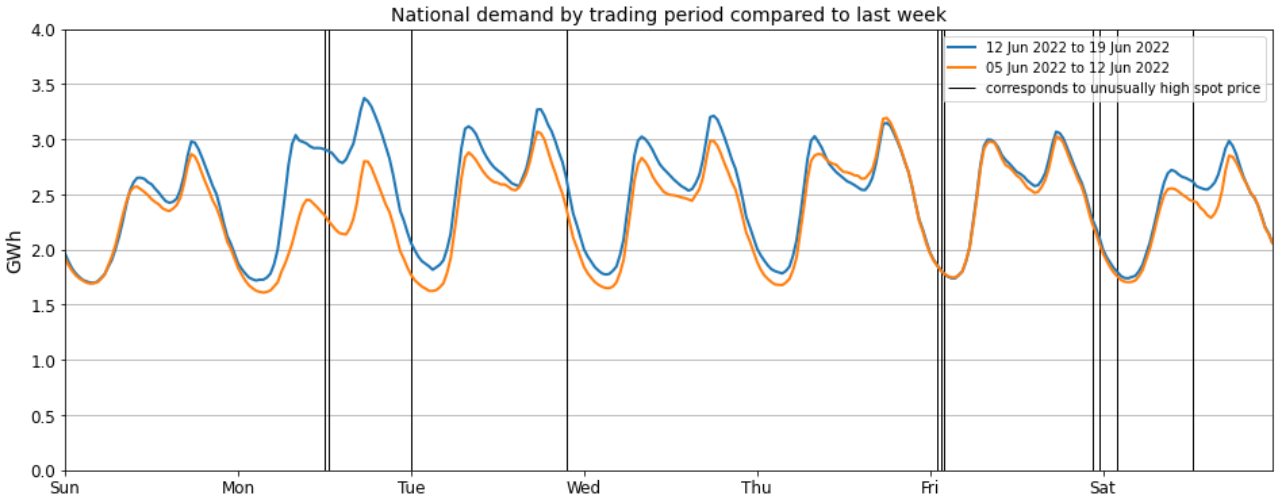
Figure 4: Residual plot of estimated daily average spot price YTD



5. Demand

5.1. Figure 5 shows this week's (12-18 June) national grid demand against national grid demand from the previous week (5-11 June). Weekday grid demand this week has increased compared to the previous week. Demand peaked on Monday reaching 6,544 MW (in contrast demand last week was at its lowest on Monday due to it being the Queen's Birthday holiday). The overall increase in demand follows seasonal trends, conforming to what we would expect from consumer demand behaviour at the beginning of winter.

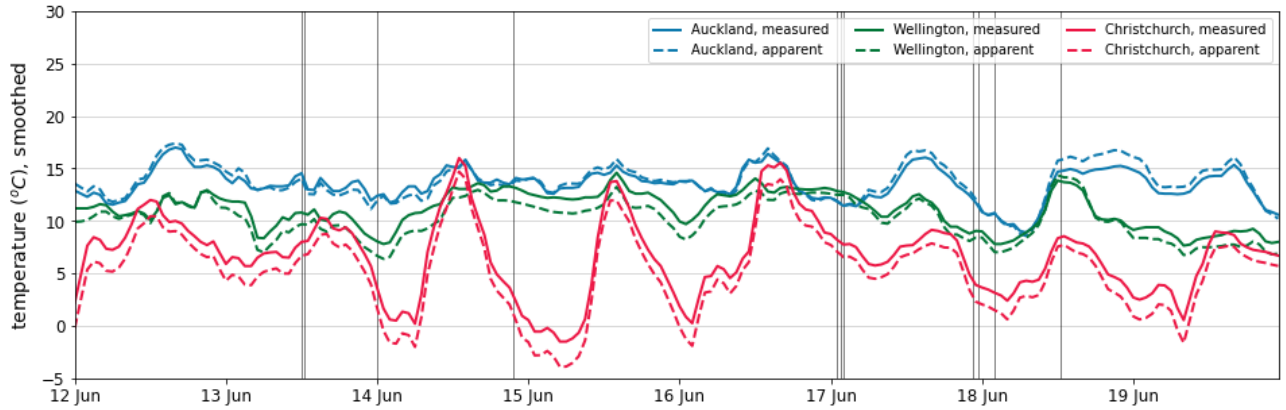
Figure 5: National demand by trading period compared to the previous week



5.2. Figure 6 shows hourly temperature at main population centres. 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.

5.3. Low temperatures were likely the reason for increased demand this week with temperatures at main population centres averaging between 5° and 15° degrees.

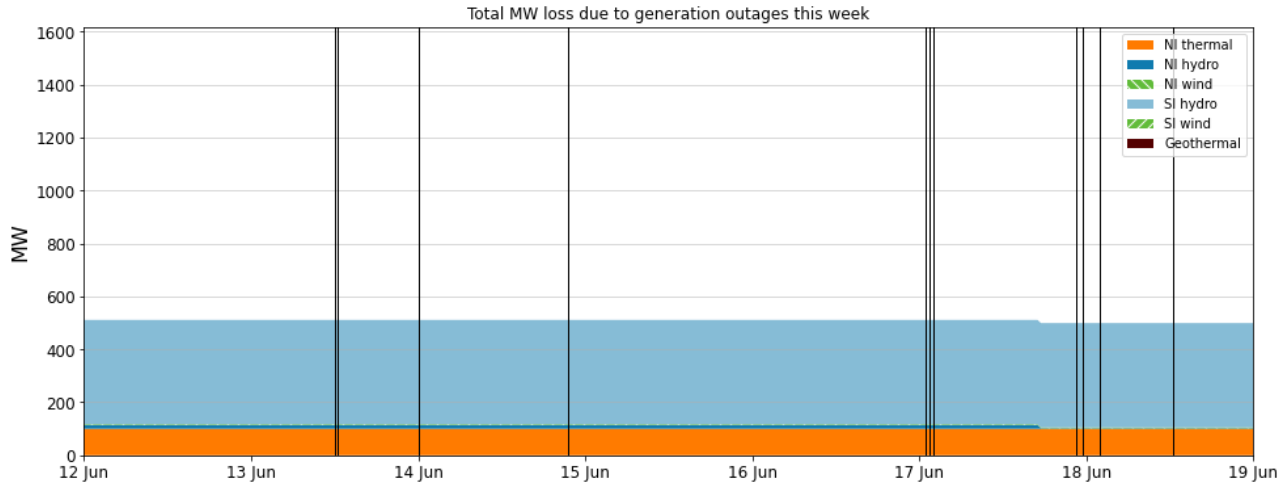
Figure 6: Temperatures across main centres



6. Outages

6.1. Figure 7 shows total generation capacity lost due to outages. Outages continue to be significantly lower than previous weeks with total capacity lost this week just above 500 MW. Current outages compose of one thermal outage at Stratford Peaker 2 and hydro outages. Generally, fewer outages help to keep spot prices within historical bounds.

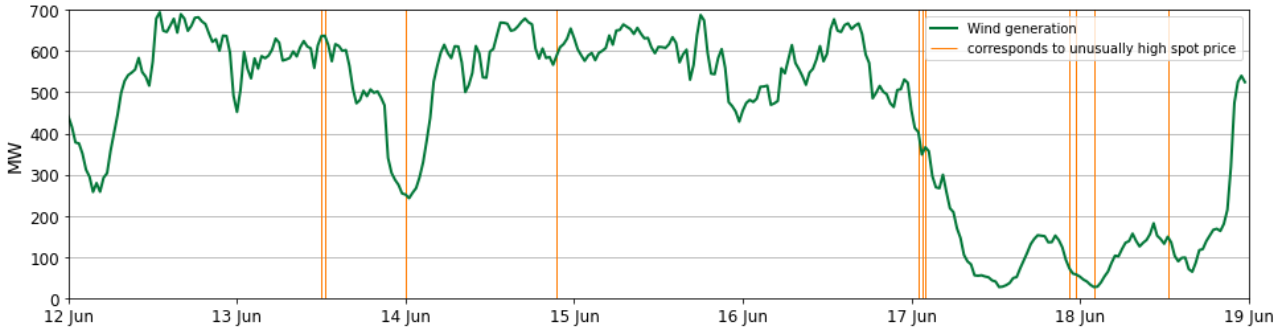
Figure 7: Total MW loss due to generation outages



7. Generation

7.1. Figure 8 shows wind generation between 12 and 18 June. Wind generation was high for the majority of the week, regularly generating at ~600 MW and reaching up to 700 MW between 12 and 16 June. As wind generation is usually offered in at a few cents per MW the high amount of wind generation would have been the largest contributor towards low spot prices this week.

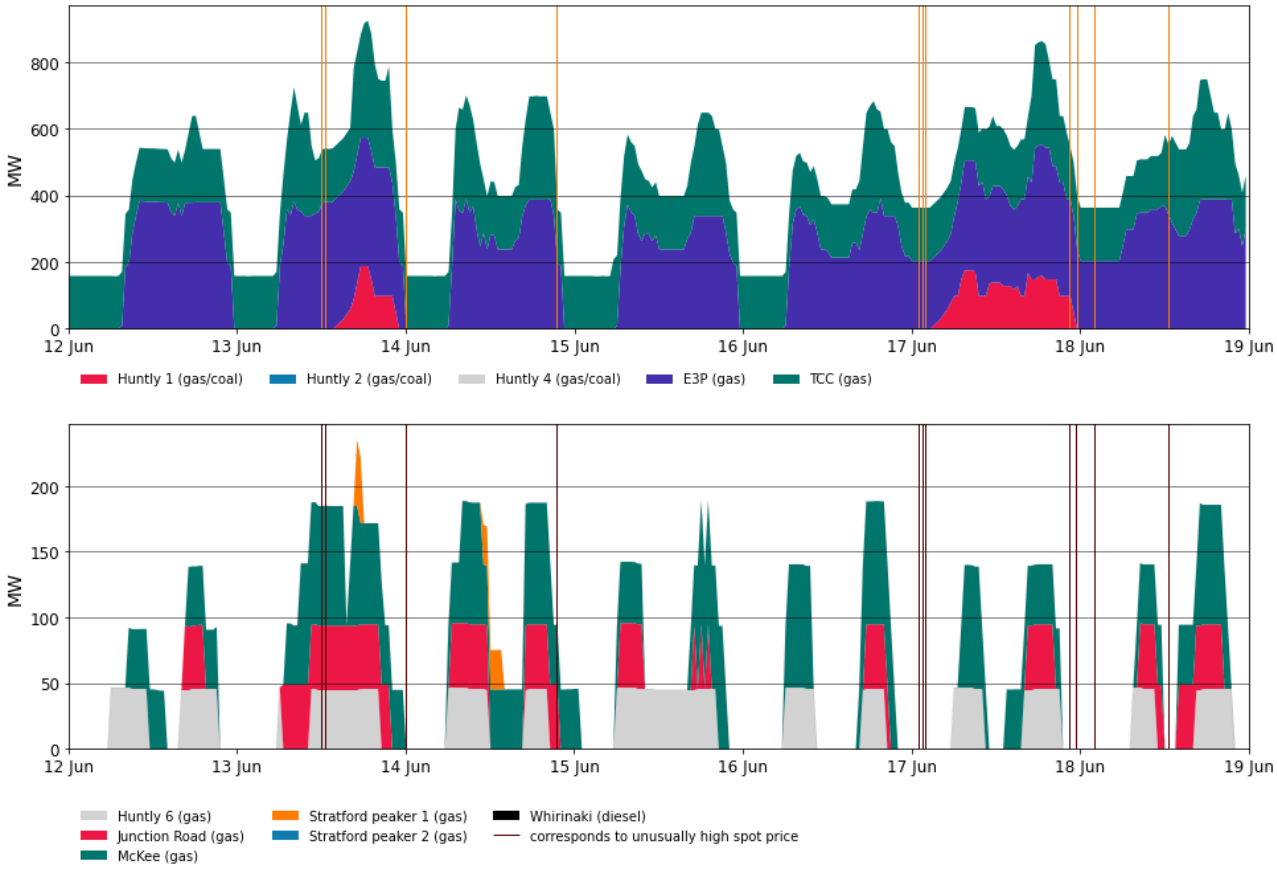
Figure 8: Wind Generation



7.2. Figure 9 shows generation at thermal and thermal peaker plants. Thermal generation was low when wind generation was high between 12 and 16 June, only increasing by around 200 MW when wind generation decreased to below 200 MW between 17 and 18 June. Thermal peakers only ran during peak periods, with total generation usually below 200 MW. As thermal generation is currently priced quite highly the reduction in total thermal generation would have helped contribute to the lower spot prices seen this week.

7.3. TCC continued to run during off peak periods this week despite high wind generation even when other thermal plants shut down (despite needing to run at a loss it was likely more efficient to keep running than to repeatedly shut down and restart) explaining some of the high price volatility seen this week.

Figure 9: Thermal Generation



8. Storage/Fuel Supply

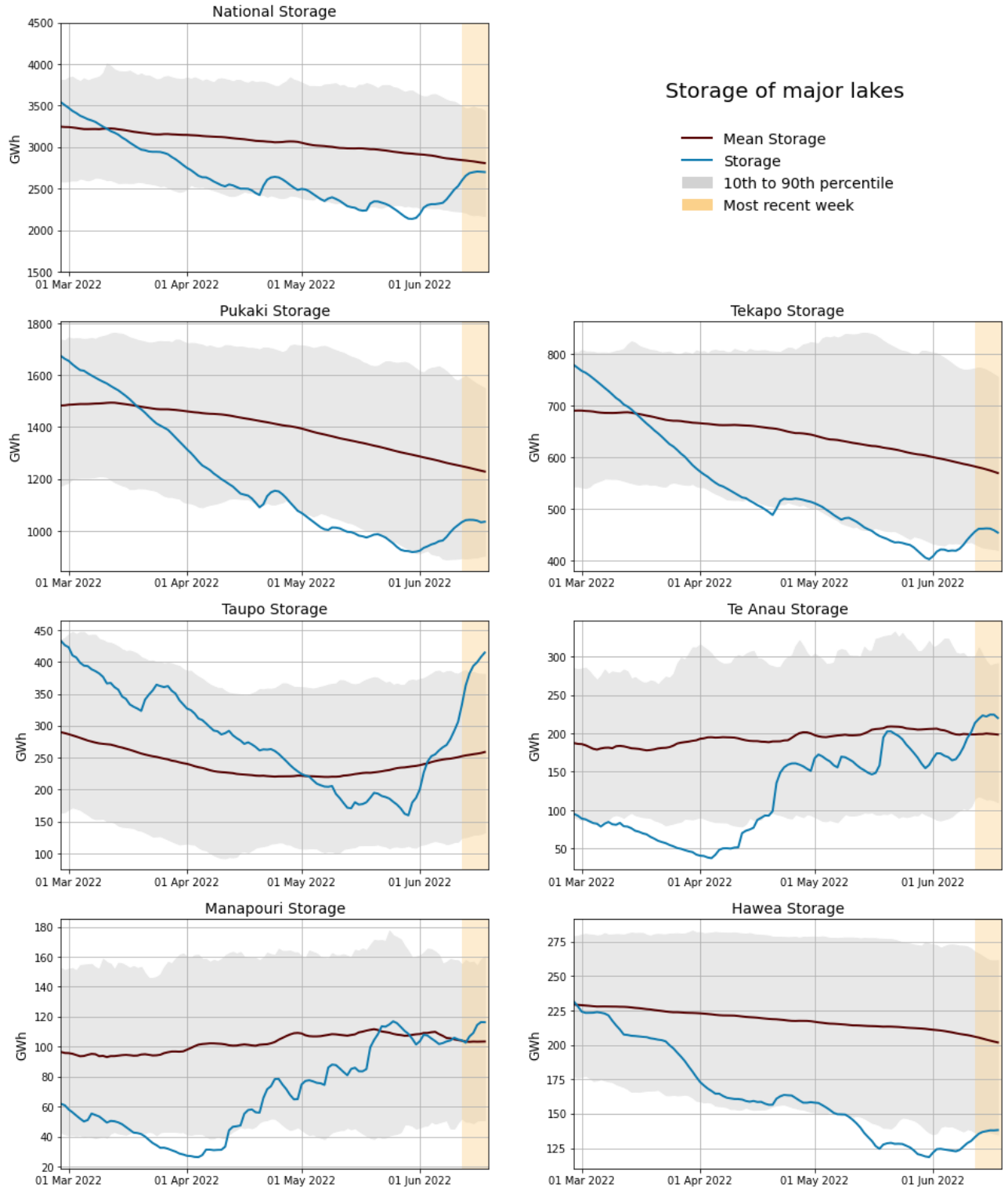
8.1. Figure 10 shows total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles. Recent rainfall

has increased total national hydro storage with all major storage lakes seeing an increase in their lake levels.

8.2. In the North Island Lake Taupo received the greatest amount of inflows with storage exceeding the lakes 90th percentile. In the South Island Lakes Manapouri and Te Anau both rose above their historical mean. Remaining South Island lakes also all rose above their 10th percentiles.

8.3. The increase in hydro storage has increased the availability of hydro generation, increasing the amount of lower priced hydro generation offers and helping to decrease spot prices as a result.

Figure 10: Hydro Storage



9. Price versus estimated costs

9.1. 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).

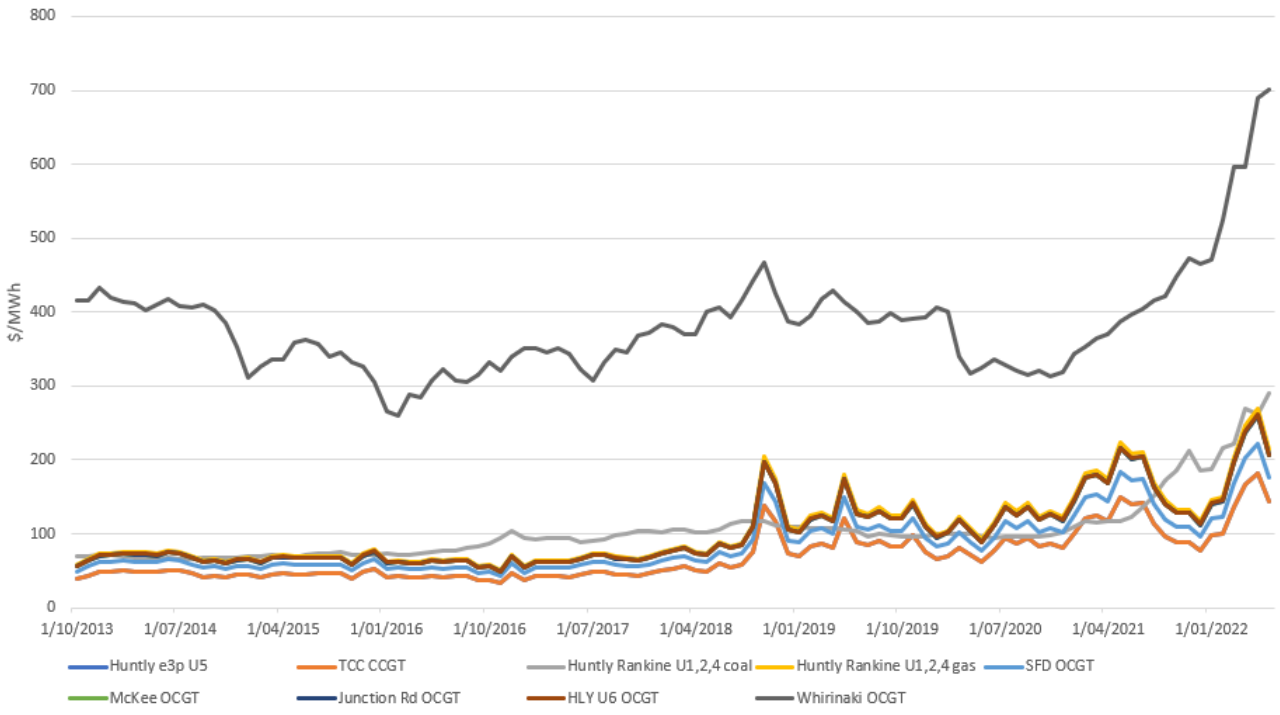
9.2. The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal. Figure 11 shows an estimate of thermal SRMCs as a monthly average up to 1 June 2022. The SRMC of all plants has increased sharply since the beginning of 2022.

9.3. The SRMC of coal and diesel have both increased due to global supply and demand conditions. As well as supply disruptions caused by Covid, the Russian-Ukraine conflict has increased the premium on all international coal due to sanctions placed on Russia. The conflict has pushed recent coal prices to a historic high of $510/tonne. The increase in diesel and coal prices has put the latest SRMC of Whirinaki and coal-fired Huntly generation to well above $700/MWh and $300/MWh respectively.

9.4. SRMCs of gas run thermal plants have decreased with the outlook for gas supply in the second half of 2022 looking increasingly positive.

9.5. More information on how the SRMC of thermal plants is calculated can be found in Appendix C[2] on the trading conduct webpage.

Figure 11: Estimated monthly SRMC for thermal fuels



10. JADE Water values

10.1. The JADE[3] 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 12 shows the national water values to 8 June 2022 using values obtained from JADE. The outputs from

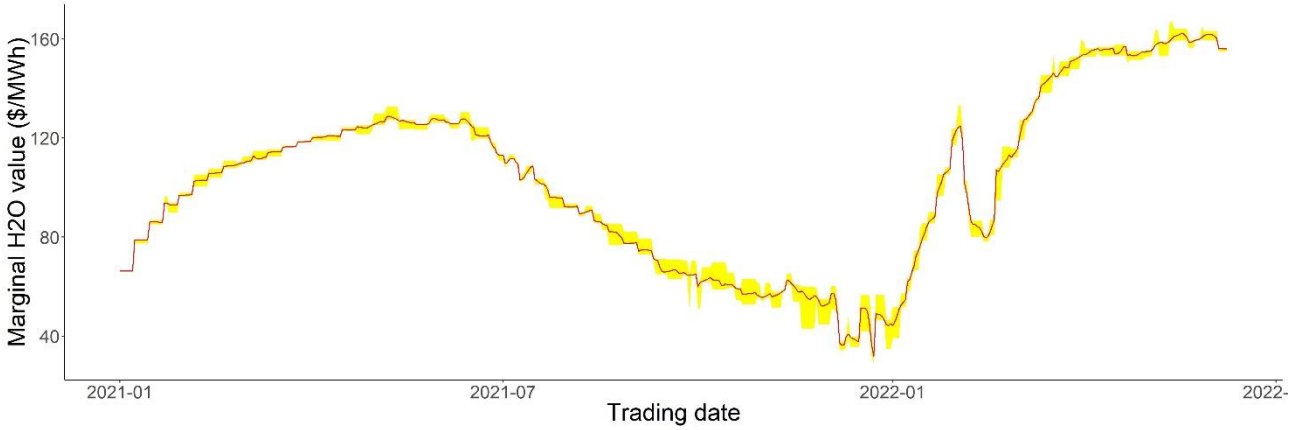
[2] https://www.ea.govt.nz/assets/dms-assets/30/Appendix-C-Calculating-thermal-SRMCs.pdf

[3] 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.

JADE closest to actual storage levels are shown as the yellow water value range. These values are used to estimate marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B[4] on the trading conduct webpage.

10.2. In general, marginal water values have increased when total national hydro storage has decreased. For the last two months water values have been gradually increasing as hydro storage has declined and despite the recent bump in hydro storage water values continue to hover around ~$150/MWh.

Figure 12: Water Values



11. Offer Behaviour

11.1. Figure 13 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[5] The black line shows cleared energy, indicating the range of the average final price.

11.2. High thermal and hydro generation opportunity costs as detailed above continue to drive a steep offer curve.

11.3. High wind generation increased the amount of low priced $0-50/MWh offers this week. Increased hydro storage and TCC running during off peak periods also helped to increase the amount of lower priced offers though the disparity in prices between offers still resulted in a steep offer curve. As a result, despite increased demand the average spot price decreased this week though price volatility did increase.

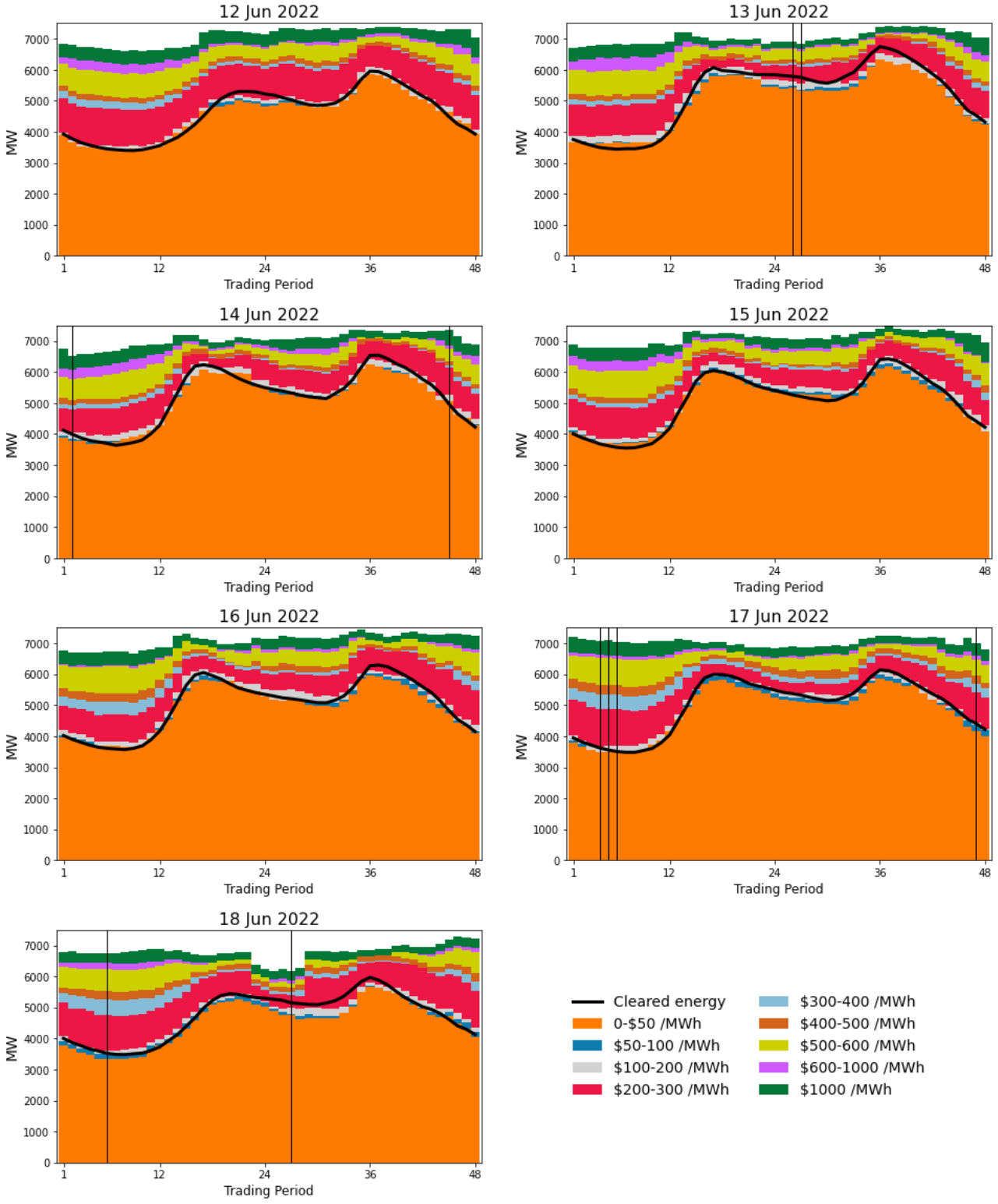
11.4. The relatively high amount of thermal generation running during off-peak periods and relatively high amount of demand pushing prices up a steep offer curve resulted in higher than historically expected prices during morning off peak periods.

11.5. The pre-dispatch offers in the short term lead up to high prices showed no changes that would suggest generators were trying to take advantage of market conditions.

[4] https://www.ea.govt.nz/assets/dms-assets/29/Appendix-B-JADE-water-value-model.pdf

[5] The offer stacks show all offers bid into the market (where wind offers are truncated at their actual generation and excluding generation capacity cleared for reserves) in price bands and plots the cleared quantity against these.

Figure 13: Daily offer stack



12. Ongoing Work in Trading Conduct

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

12.2. 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	Notes
19/02-24/02		Compliance enquiries in progress	After reviewing information received from Genesis regarding offers from Tekapo B while Lake Tekapo was spilling, this case has been passed to compliance to assess if the offers were compliant with trading conduct rules.
19/02-21/02	Several	Further Analysis	High reserve prices were due to the HVDC outage, which increased reserve requirement in South Island, combined with less reserves available in the South Island due to low lake levels at Manapouri.