10 August 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 30 July to 6 August

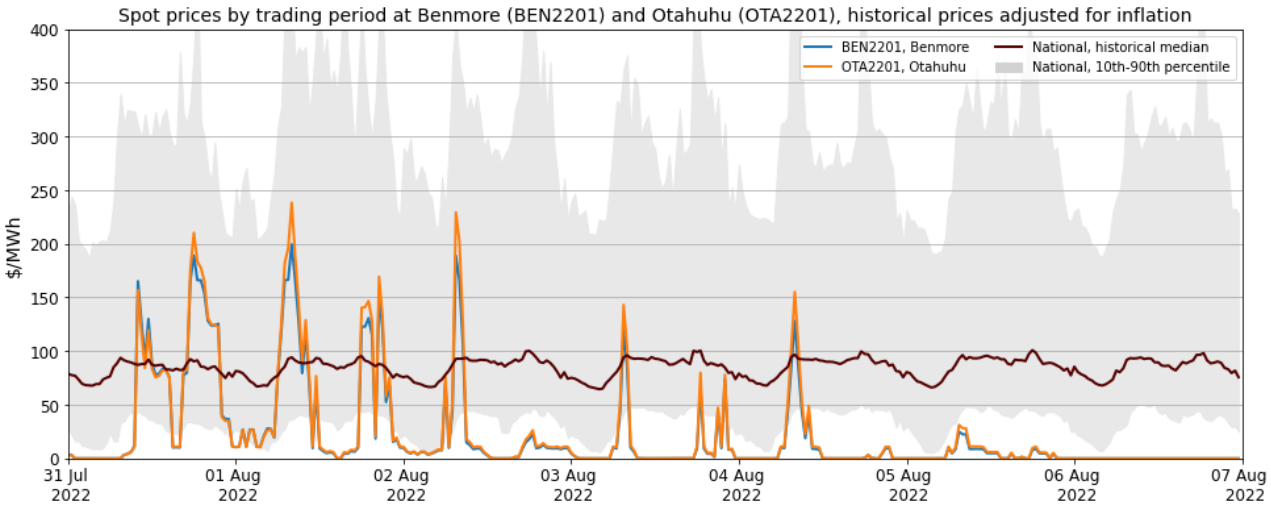
1.1. Overall wholesale spot prices appear to align with market conditions this week.

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. 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 95th percentiles. These historically high-priced trading periods are marked out by vertical lines in the majority of figures in this report.

2.2. Figure 1 shows spot prices between 30 July and 6 August at Benmore and Otahuhu alongside their historic median and historic 10th-90th percentiles adjusted for inflation. Otahuhu and Benmore spot prices were relatively low this week, falling regularly below their historic median and fluctuating between $0.01/MWh and $238.20/MWh.

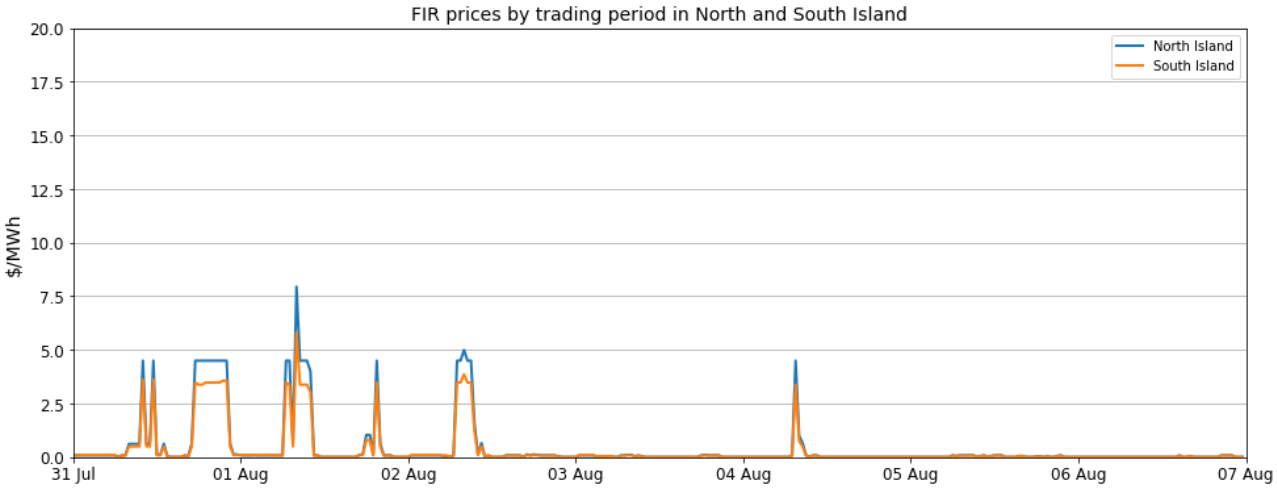
Figure 1: Wholesale Spot Prices



3. Reserve Prices

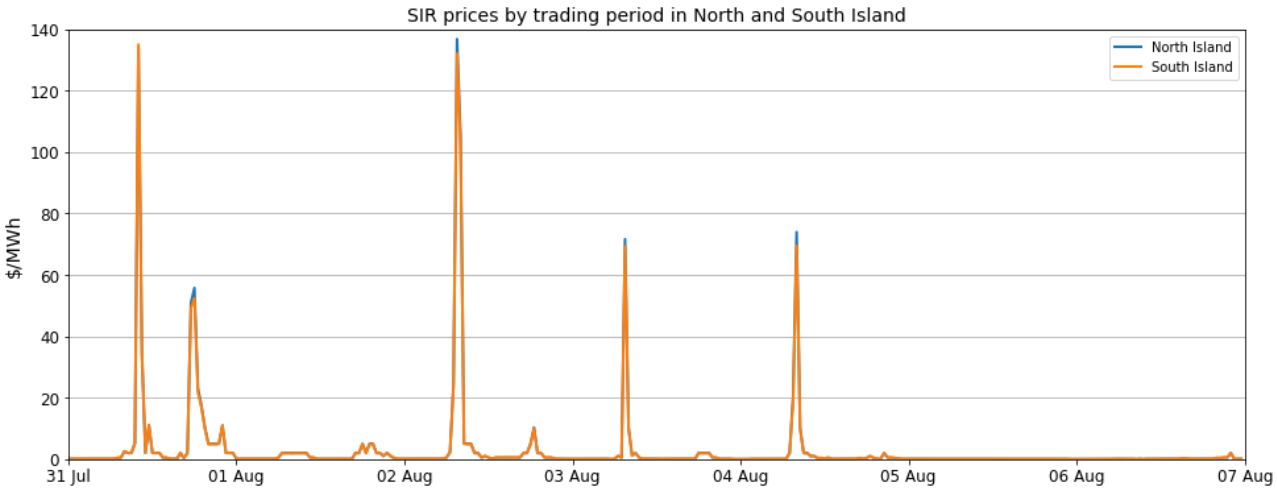
3.1. Fast instantaneous reserves (FIR) prices for the North and South Island are shown below in Figure 2. FIR prices were within historical bounds this week with prices all below $10/MWh.

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 prices also fell mainly within historical bounds this week with the exception of some price spikes which reached almost $140/MWh. The price spikes were likely due to reserves being dispatched instead of higher priced energy offers in an effort to reduce the overall spot price.

Figure 3: SIR prices by trading period and Island



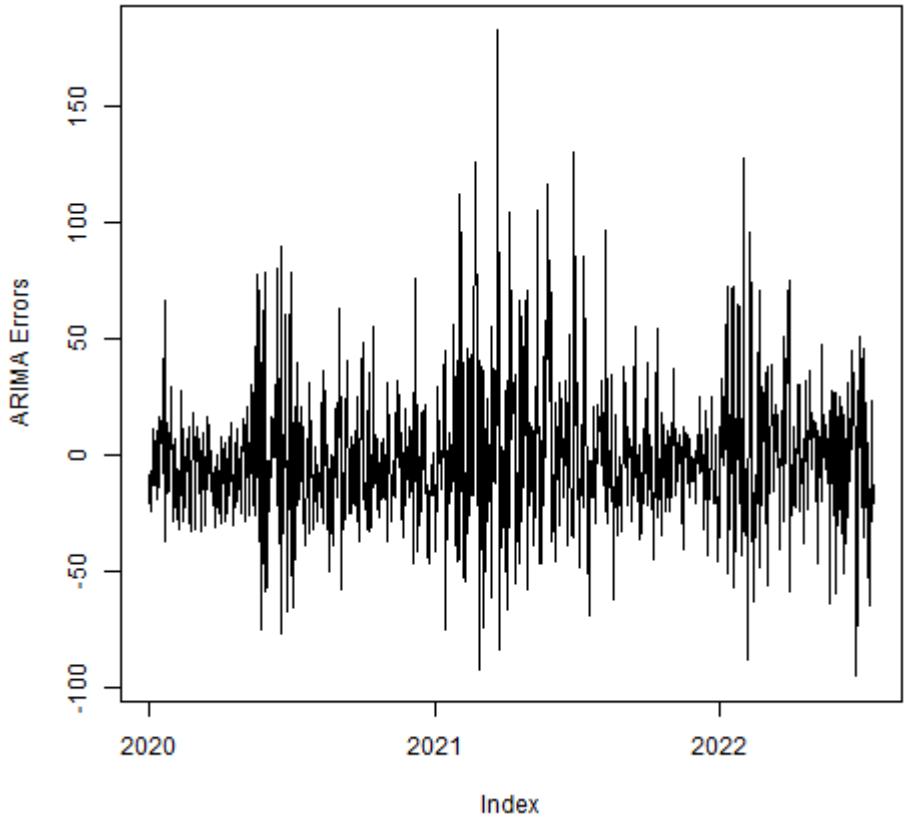
4. Regression Residuals

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[1] on the trading conduct webpage.

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.

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

Figure 4: Residual plot of estimated daily average spot price

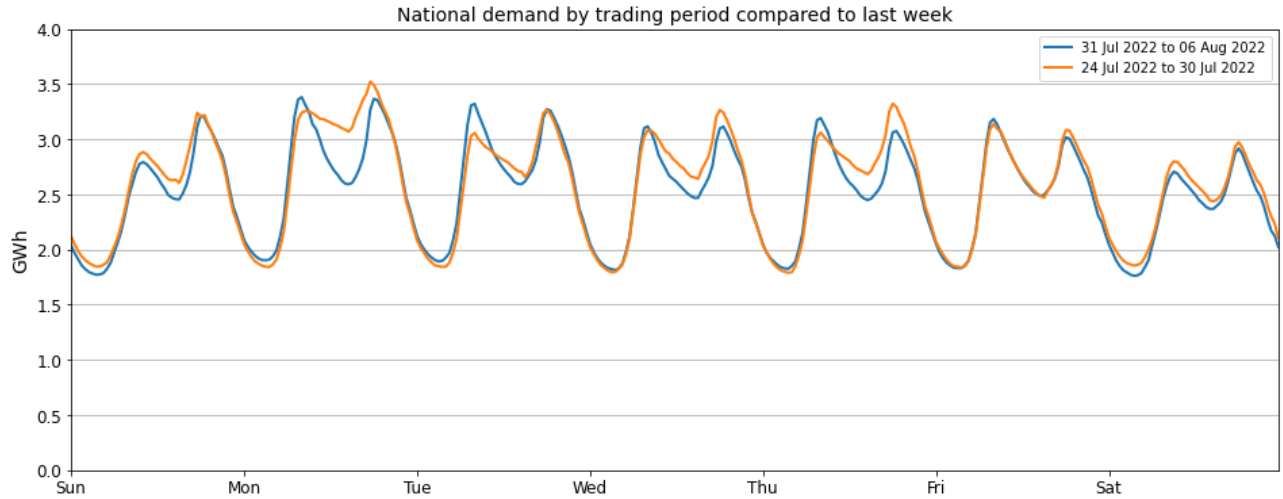


5. Demand

5.1. Figure 5 shows this week's national grid demand against national grid demand from the previous week.

5.2. Daily demand this week (31 July to 6 August) was on average lower than daily demand last week (17 and 23 July), likely due to warmer weather as seen in Figure 6. Monday continues to exhibit the highest peak demand of all the weekdays.

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

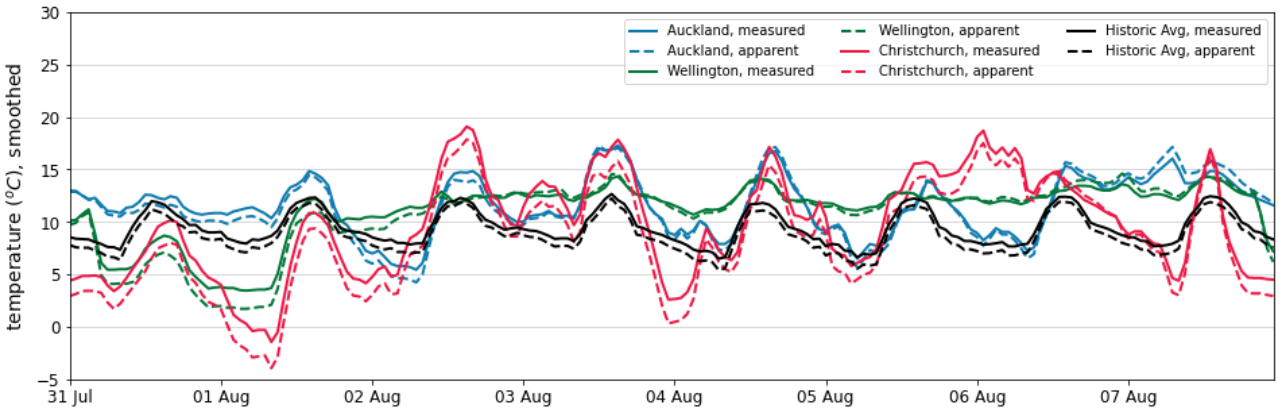


5.3. Figure 6 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks from previous years averaged across the three main population centres.

5.4. Apparent temperatures this week were clustered more closely than usual with major areas sharing in similar conditions with increased Christchurch temperatures meeting decreased Auckland temperatures during the middle of the week. Overall temperatures were relatively mild for this time of year with grid demand continuing to follow seasonal trends by decreasing when temperatures increase.

5.5. Milder temperatures likely contributed to lower demand and lower average spot prices this week.

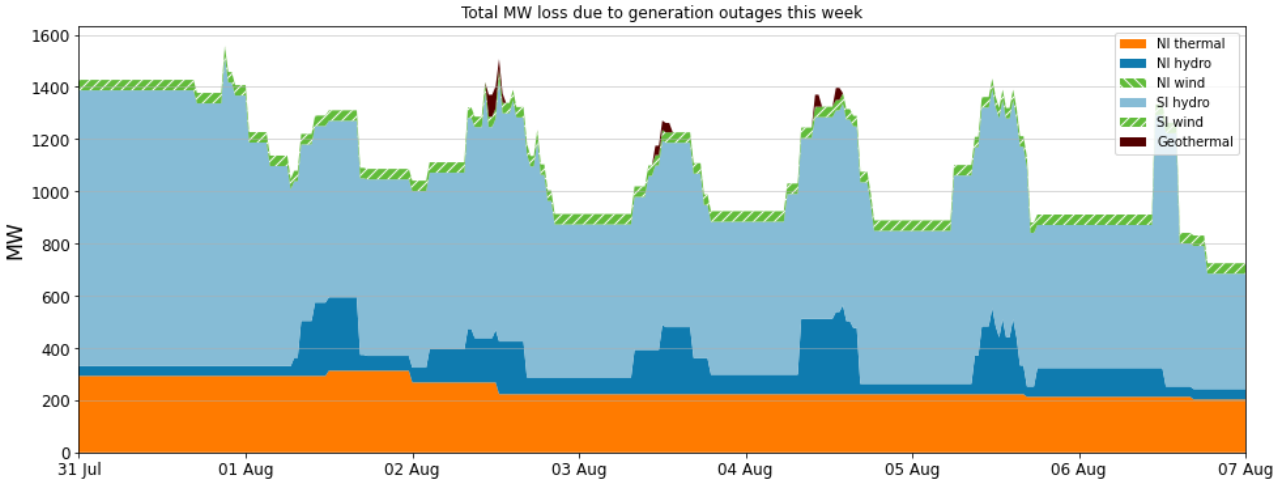
Figure 6: Temperatures across main centres



6. Outages

6.1. Figure 7 shows generation capacity lost due to outages between 31 July and 6 August. Total capacity lost due to outages was high at 1400 MW at the beginning of the week before dropping to around 800 MW by the end of the week. The reduction in capacity lost would have helped reduce spot prices as the week progressed.

Figure 7: Total MW loss due to generation outages



7. Generation

7.1. Wind generation from the past week as seen below in Figure 8 was high for the majority of week, generating between 300 MW and 700 MW consistently with the exception of 31 July and 1 August when wind generation fell to below 100 MW.

7.2. High wind generation likely contributed to low spot prices this week with spot prices falling close to $0/MWh during periods of high wind generation. Spot prices peaked during periods of low wind generation (less than 200 MW) on 31 July and 1 August.

Figure 8: Wind Generation

7.3. Figure 9 shows generation at thermal and thermal peaker plants from the past week. Thermal generation was the inverse of wind generation, with higher thermal generation during periods of low wind generation.

7.4. Thermal generation fell mostly between 200 MW and 1000 MW between 31 July and 2 August before falling to between 50 MW and 500 MW from 3 August onwards. The drop in thermal generation corresponded with a drop in average spot price so decreasing thermals likely contributed to decreasing prices. TCC stopped running from 3 August onwards due to an abundance of wind and hydro generation offers with Figure 10 showing the rise in renewable generation from 3 August.

7.5. Thermal peaker generation was similarly low for the week, only running during peak demand periods and mostly remaining below 150 MW when running. The only exception to this was a rise in peaker generation on 4 August with almost all available peakers running, this was likely due to a sudden drop in wind generation and generators expecting high demand.

Figure 9: Thermal Generation

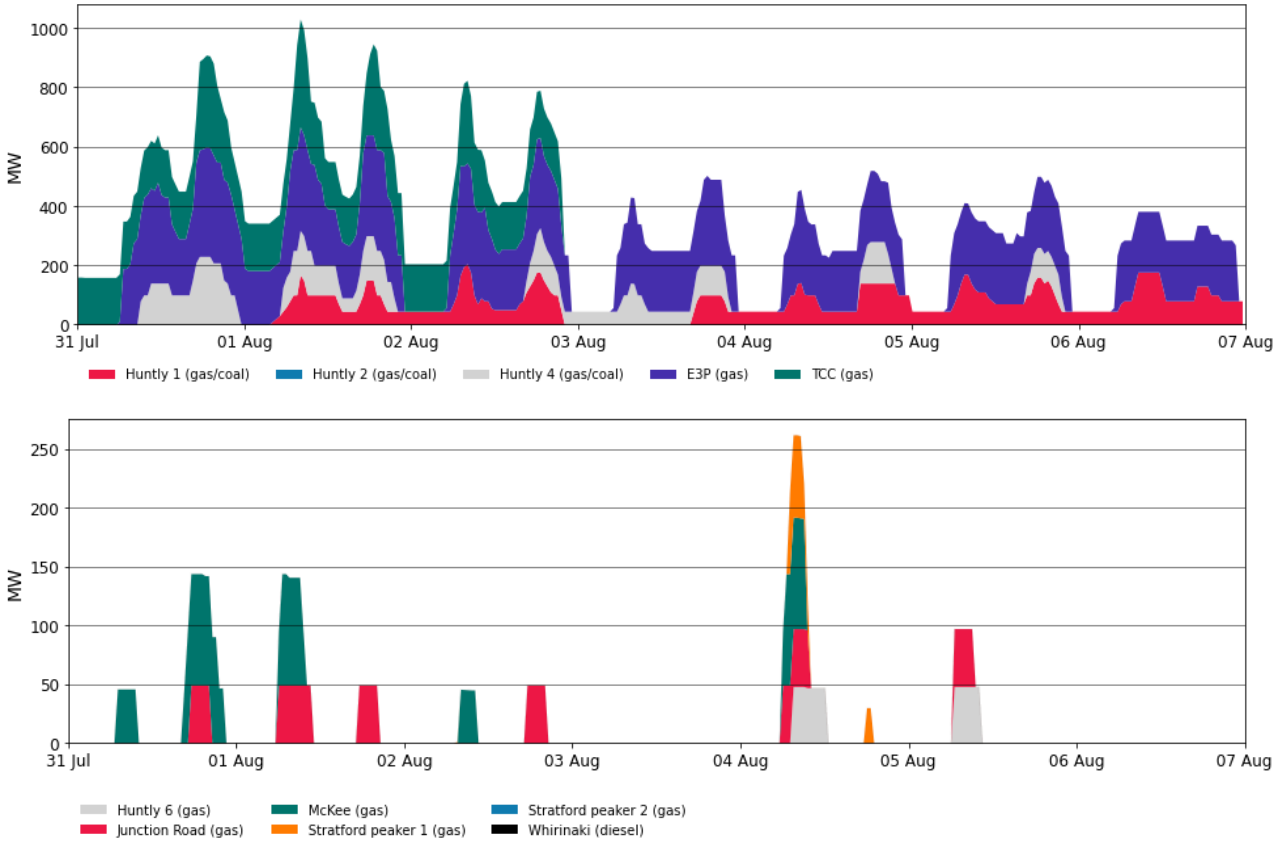
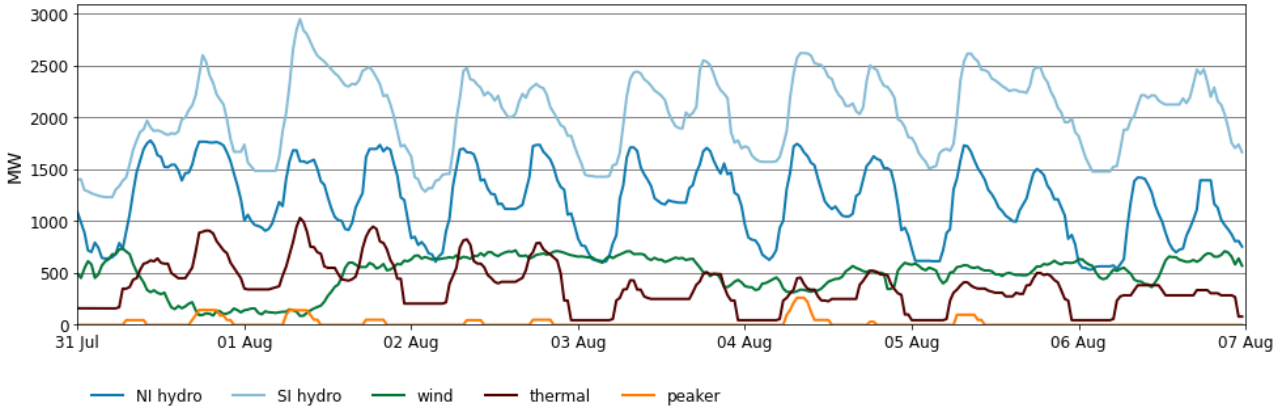


Figure 10: Generation by Type



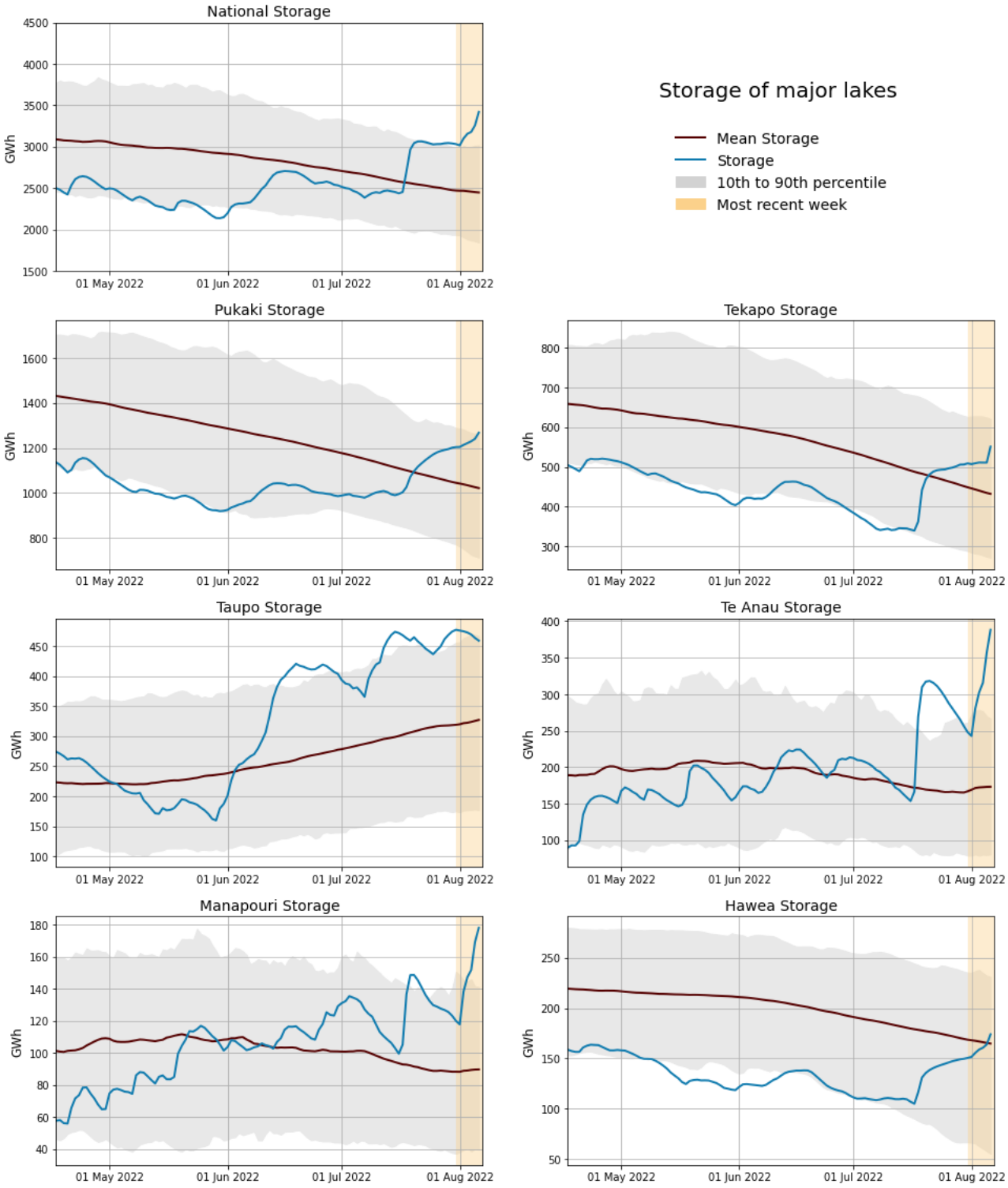
8. Storage/Fuel Supply

8.1. Figure 11 shows total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

8.2. High amounts of rainfall increasing hydro inflows continues to result in hydro storage levels increasing at major lakes. At the time of writing the storage levels of all major catchements were above their historical mean with Lakes Pukaki, Taupo, Te Anau and Manapouri close to their historic 90th percentiles.

8.3. The increase in inflows likely contributed to below average spot prices this week with the lowered opportunity cost of hydro generation increasing the amount of low priced hydro generation offers.

Figure 11: 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.

9.3. Figure 12 shows an estimate of thermal SRMCs as a monthly average up to 1 August 2022. The SRMC of gas fuelled plants has fallen from its peak in May 2022 while the SRMC of diesel and coal fuelled plants continues to remain high.

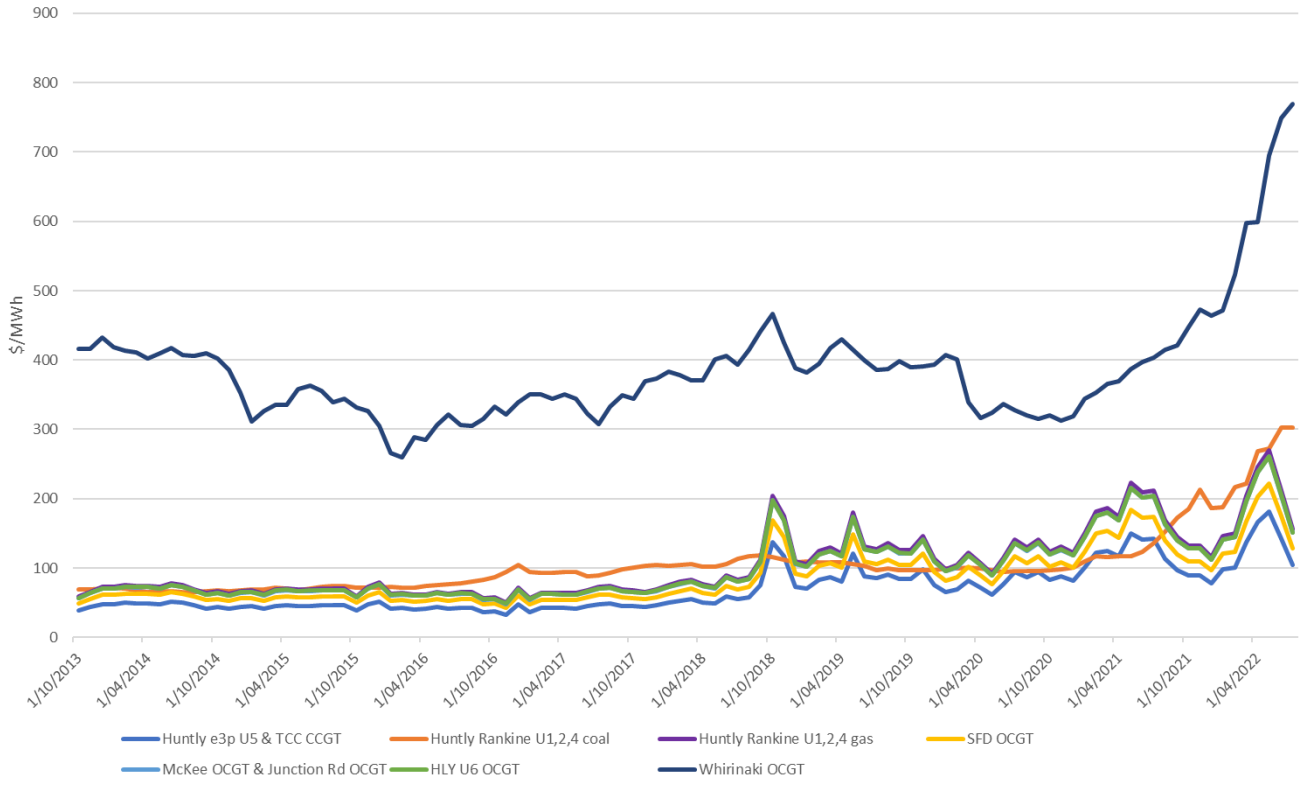
9.4. The SRMC of coal and diesel have remained largely unchanged due to global supply and demand conditions. As well as supply disruptions caused by Covid, the Russian-Ukraine conflict has increased the premium on all international coal due to sanctions placed on Russia.

9.5. The most recent price for Indonesian coal was around $511/tonne. The increase in diesel and coal prices has put the latest SRMC of Whirinaki and coal fuelled Huntly generation to $770/MWh and $302/MWh respectively.

9.6. SRMCs of gas run thermal plants have decreased to between $100/MWh and $200/MWh with the recent downturn at Methanex freeing up gas supply and successful well tie-ins at Pohokura gas field also increasing supply.

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

Figure 12: Estimated monthly SRMC for thermal fuels



10. JADE Water values

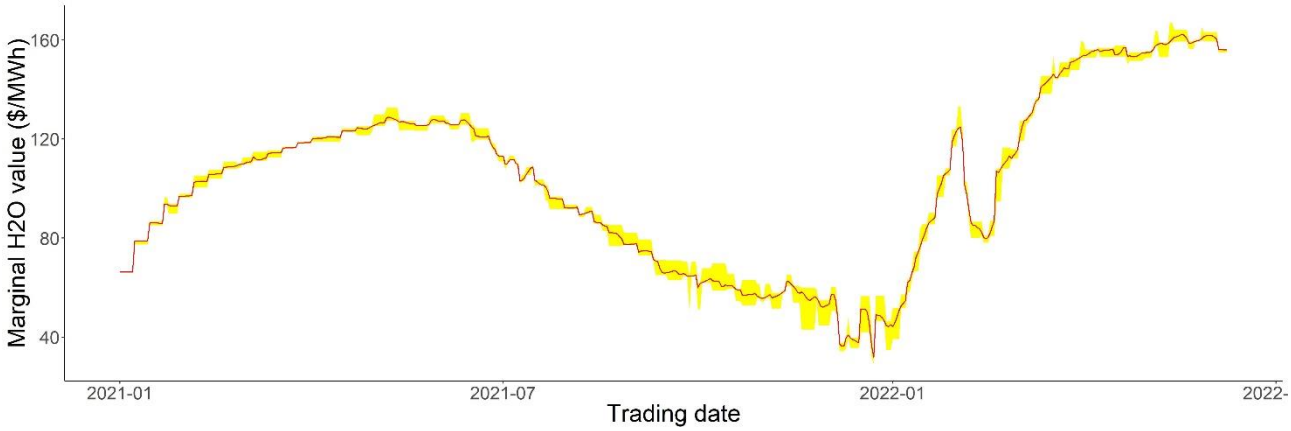
10.1. The JADE[3] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 13 shows the national water values to 8 June 2022 using values obtained from JADE. The outputs from 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

[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.

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 and decreased when total national hydro storage has increased.

Figure 13: Water Values



11. Offer Behaviour

11.1. Figure 14 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.

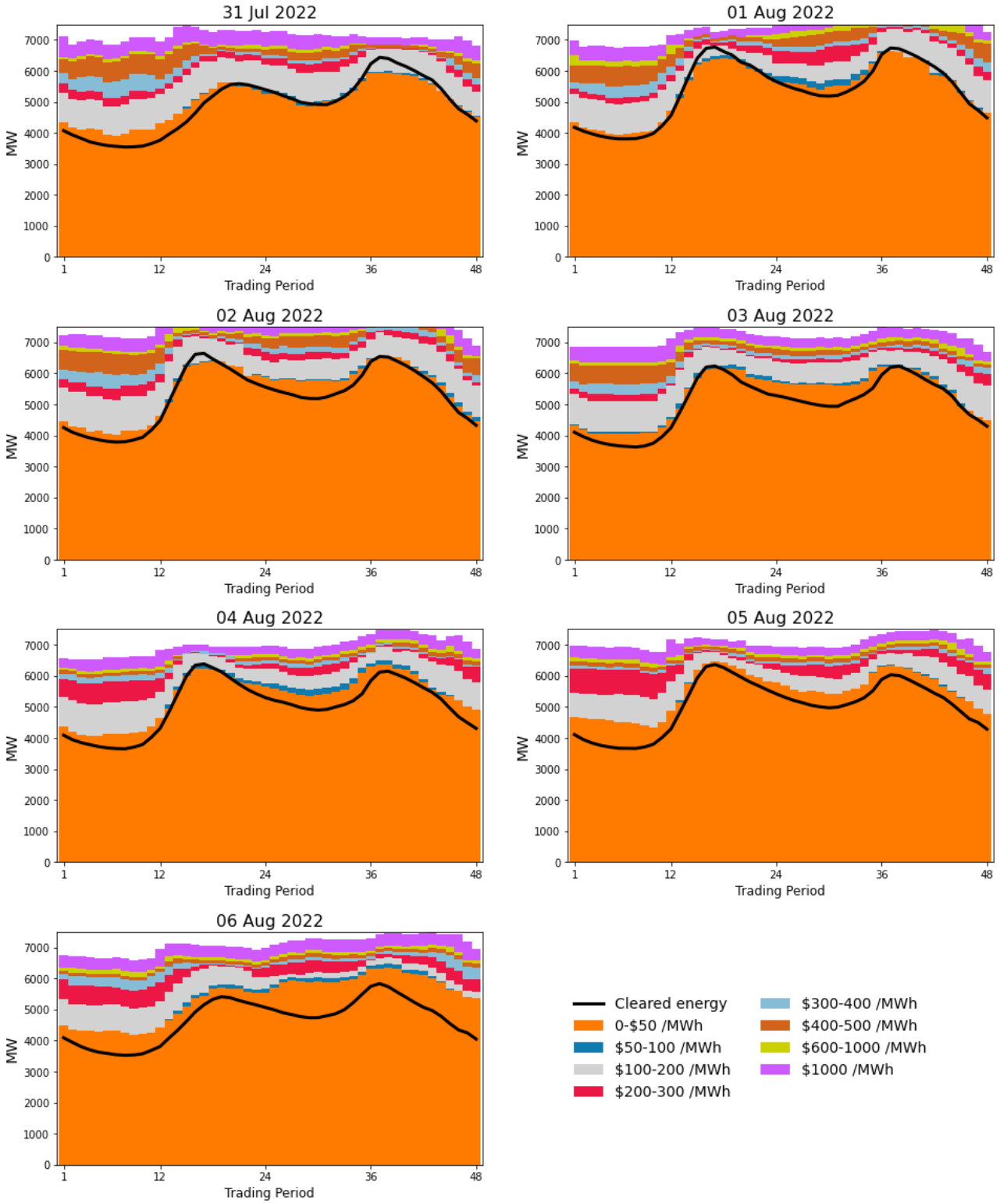
11.2. Cleared energy remained primarily within the $0-50/MWh price range due to high wind generation and high hydro inflows this week with prices only rising into the $100-200/MWh range during periods of peak demand when thermal generation reached its peak. With the SRMC of thermals at between $100-200/MWh this is consistent with what we would expect prices to be at current market conditions.

11.3. 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 14: 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
19/02/22-24/02/22	Several	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.
29/06/2022	26-48	Further analysis	The Authority is making enquires with Genesis regarding offers at both Huntly 1 and Huntly 4 - the addition of only high priced offers at Huntly 1 lead to $700/MWh+ pricing on trading period 36.