13 July 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 3 to 9 July

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

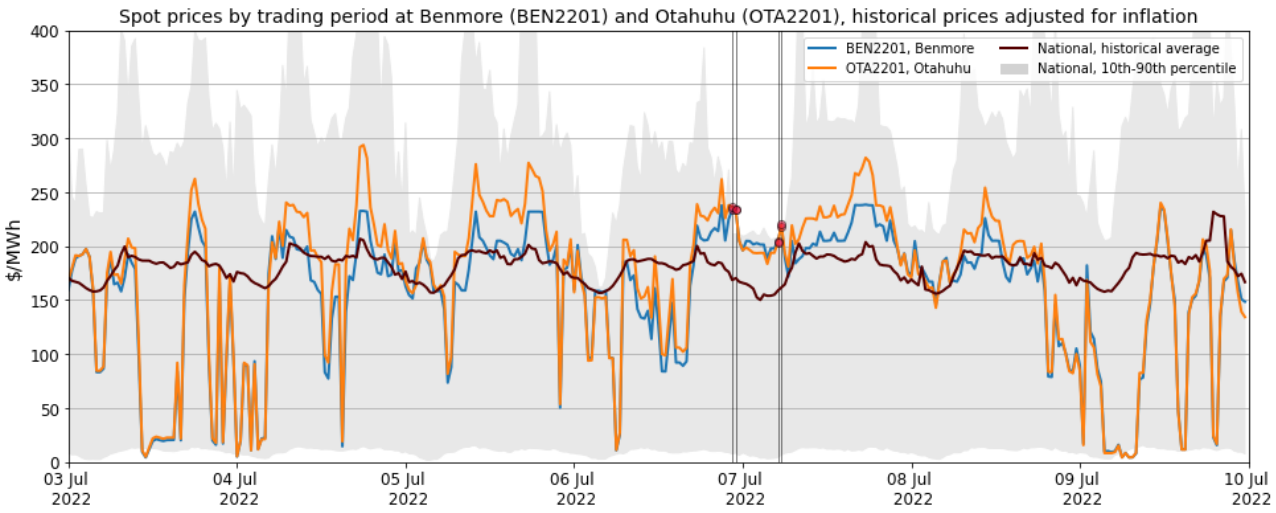
2. Spot Prices

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. 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 2 and 9 July averaged $166.59/MWh with 95 per cent of prices falling between $8.56/MWh and $253.42/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. Spot prices were reasonably close to mean for the majority of the week with only four trading periods which exceeded their historical 90th percentiles. A number of low priced trading periods occurred at the beginning and end of the week on 3 and 9 July.

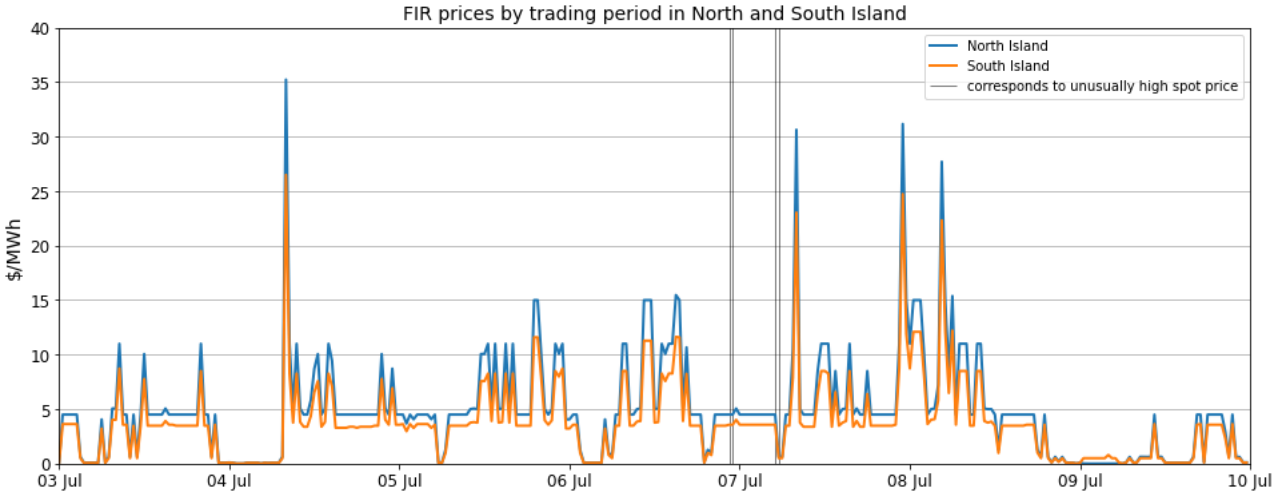
Figure 1: Wholesale Spot Prices



3. Reserve Prices

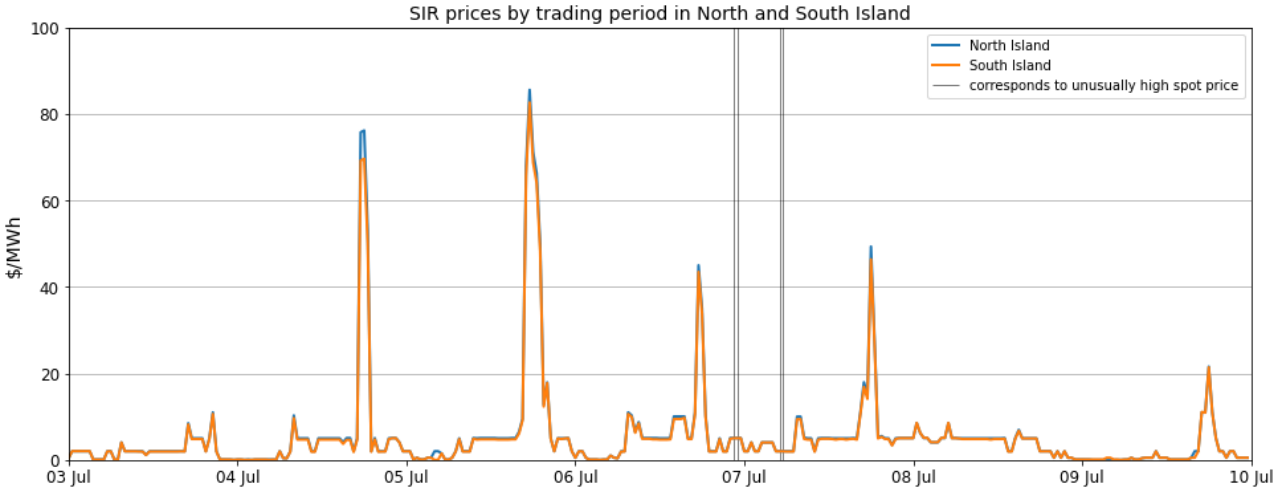
3.1. Fast instantaneous reserves (FIR) prices for the North and South Island are shown below in Figure 2. FIR prices were within historical bounds this week with some spikes reaching up to $35/MWh but most prices remaining below $15/MWh.

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 reserve prices saw some price spikes rising just above $80/MWh this week with remaining prices falling within historical bounds at below $20/MWh. The price spikes were likely due to reserves being dispatched instead of higher priced energy offers to reduce the overall spot price.

3.3. Figure 3: SIR prices by trading period and Island



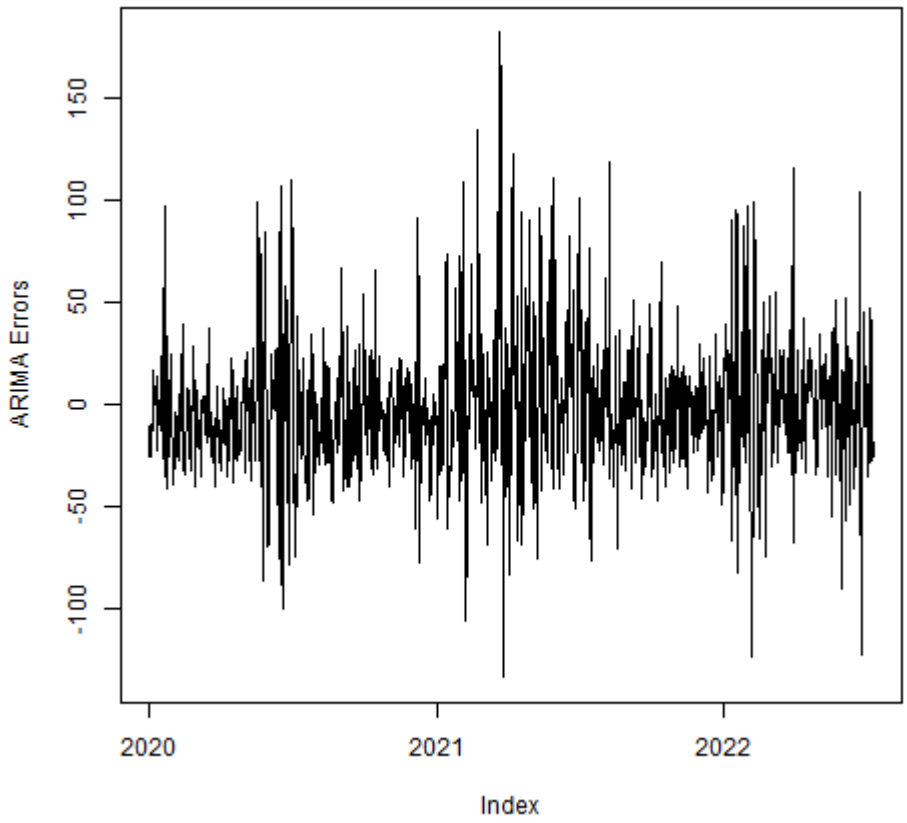
4. Regression Residuals

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.

[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

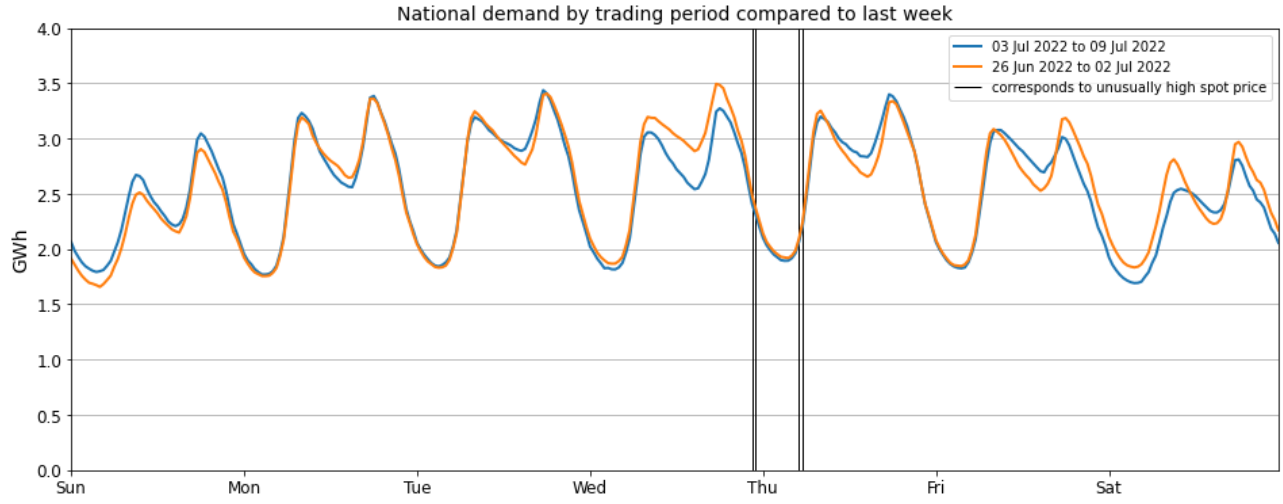


5. Demand

5.1. Grid demand continues to follow seasonal trends, increasing when temperatures decrease. Figure 5 shows this week's national grid demand against national grid demand from the previous week.

5.2. Demand between 3 and 9 July was similar to demand between 26 June and 2 July. Historically high priced trading periods coincided with when off peak demand was at its highest point for the week on Thursday morning. Relatively high off peak demand therefore likely increased off peak spot prices.

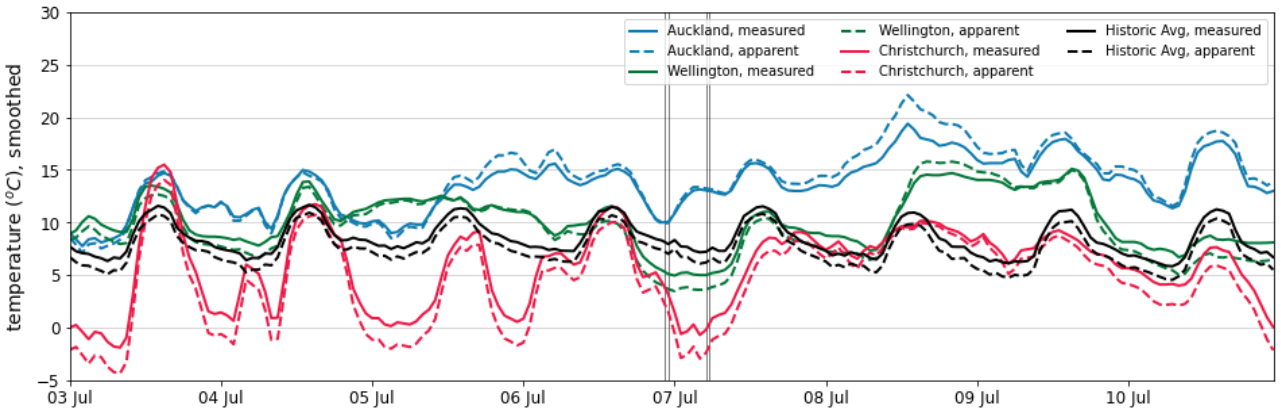
Figure 5: National demand by trading period compared to the previous week



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. Falling temperatures continue to coincide with increases in demand.

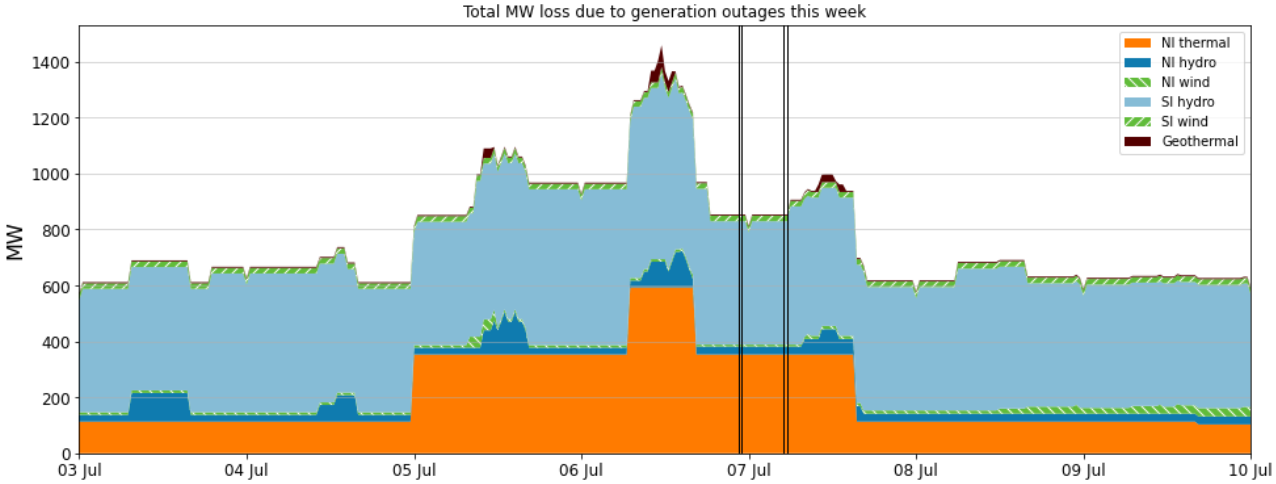
Figure 6: Temperatures across main centres

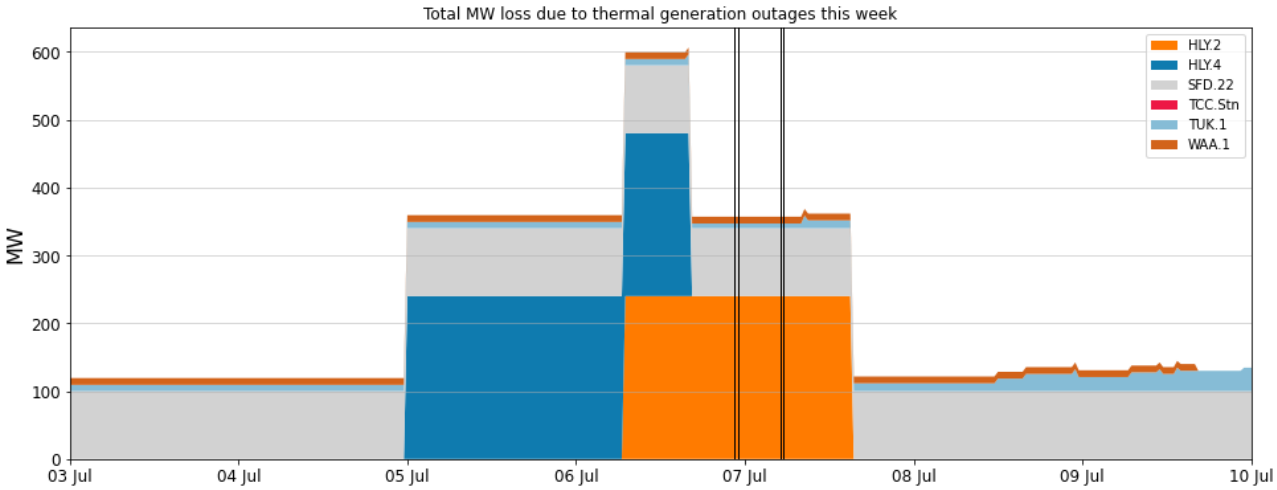


6. Outages

6.1. Figure 7 shows total generation capacity lost due to outages between 3 and 10 July across all fuel types as well as generation capacity lost due to thermal outages. The majority of outages continues to come from a loss of thermal and South Island hydro generation. Total generation capacity lost due to outages was around 600 MW at the beginning and end of the week, peaking during the middle of the week to 1,400 MW when Huntly units 2 and 4 went on outage.

Figure 7: Total MW loss due to generation outages

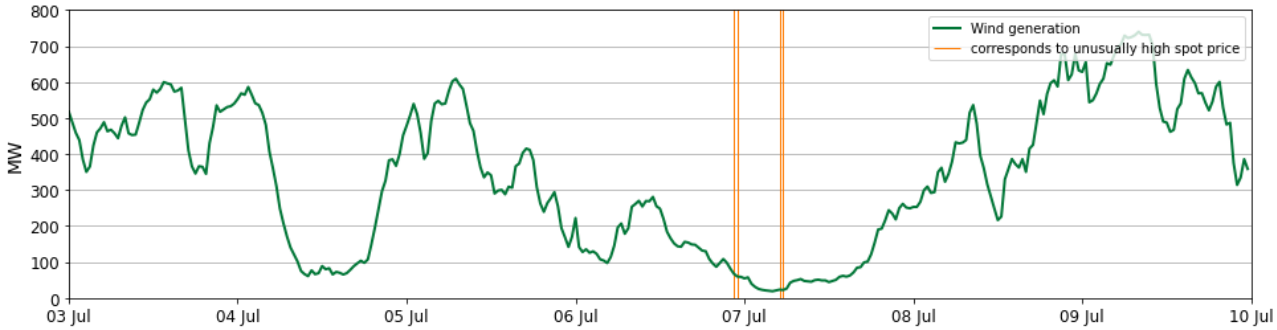




7. Generation

7.1. Figure 8 shows wind generation from the past week. Fluctuating wind generation went from ~500 MW on 3 July to ~100 MW on 4 July, increasing to ~600 MW on 5 July before falling to ~50 MW on 6 July and finally increasing to ~700 MW by 9 July. Low wind generation generally correlated with high spot prices with historically high priced trading periods coinciding with when wind generation was at its lowest point for the week. Low wind generation was therefore one of the main reasons for high spot prices this week.

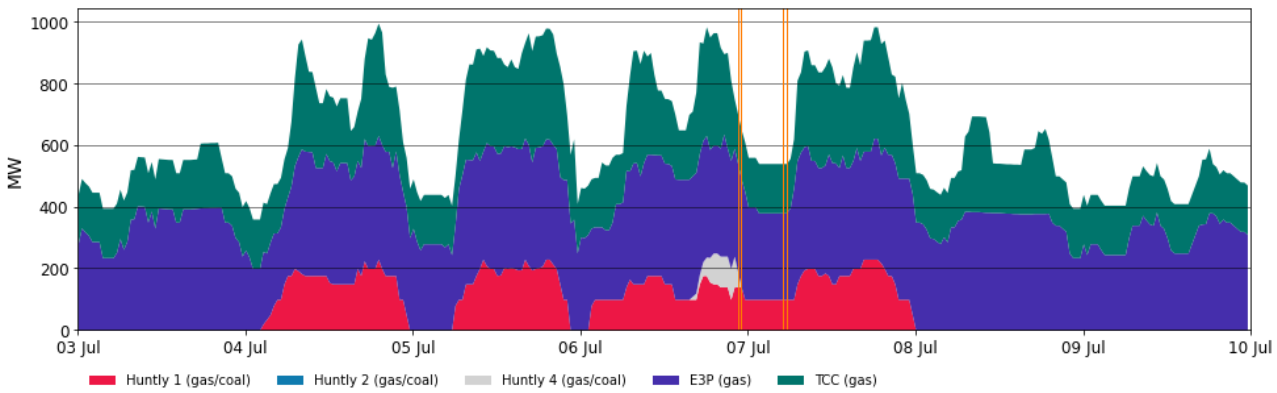
Figure 8: Wind Generation

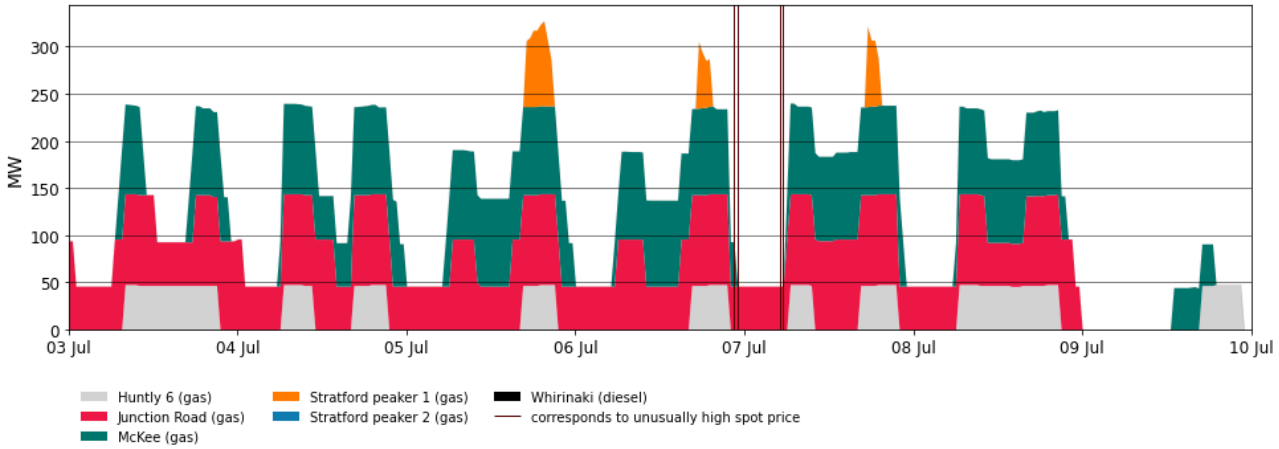


7.2. Figure 9 shows generation at thermal and thermal peaker plants from the past week. Thermal generation continues to follow the trend of increasing when wind generation decreases. High thermal generation would therefore have been a large contributor to any high spot prices this week.

7.3. TCC and E3P thermal plants continue to support the majority of baseload generation. Stratford Peaker 1 continues to support load during high peak demand periods.

Figure 9: Thermal Generation





8. Storage/Fuel Supply

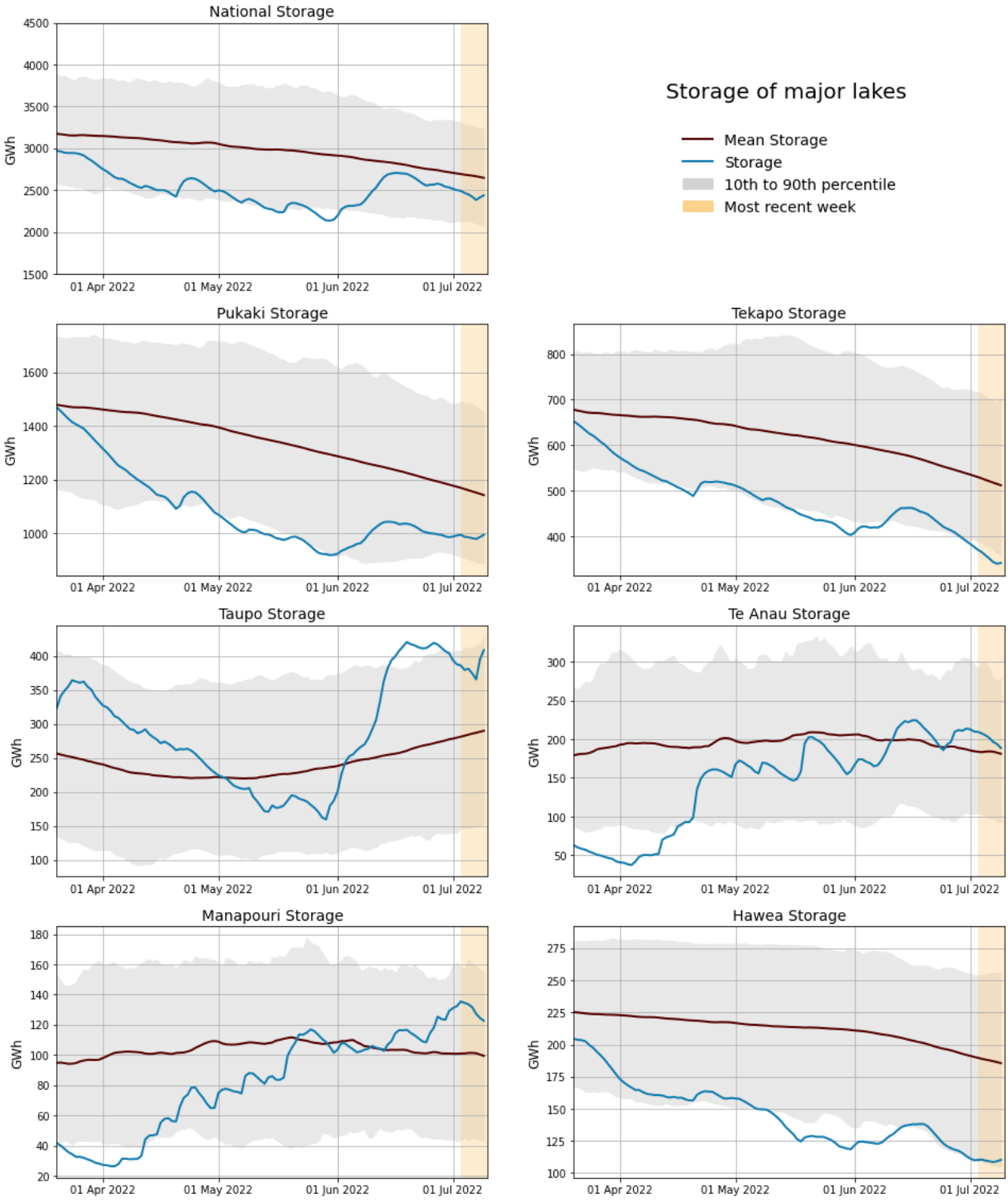
8.1. Figure 10 shows total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

8.2. A recent burst in inflows has increased hydro storage across most major lakes. Of the major catchments Lake Taupo storage is just below its historical 90th percentile, Lakes Manapouri and Te Anau are above their historical mean and remaining South Island catchments are around their historical 10th percentiles.

8.3. The large imbalance between storage gains across Islands may be due to rainfall freezing as snow around major South Island hydro catchement areas, meaning much of the incoming South Island inflows is being locked away until summer.

8.4. While increased hydro storage has increased the amount of offered hydro generation the imbalance in storage between islands means the ratio of offers in different price tranches for hydro generation is still relatively similar to when hydro storage was lower, preserving the steepness of current offer curves.

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

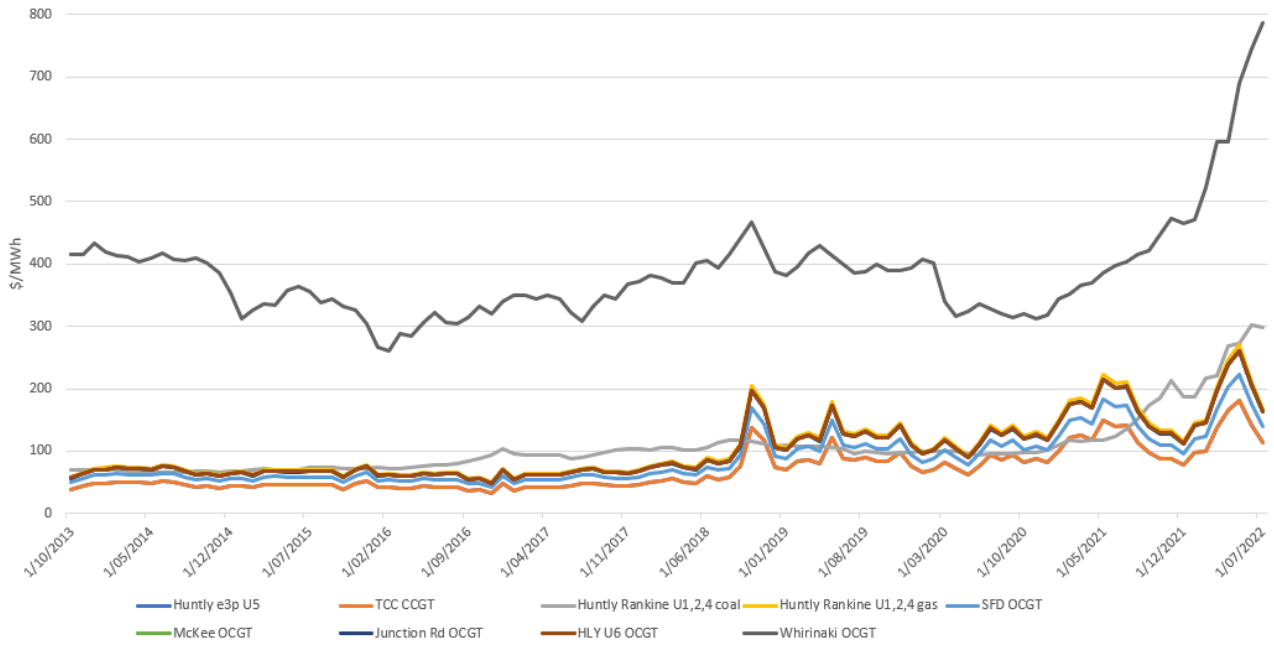
average up to 1 July 2022. The SRMC of gas fuelled plants has fallen from its peak in May 2022 while the SRMC of diesel and coal fuelled plants continues to increase.

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 most recent price for Indonesian coal was around $515/tonne. The increase in diesel and coal prices has put the latest SRMC of Whirinaki and coal fuelled Huntly generation to $786/MWh and $299/MWh respectively.

9.4. SRMCs of gas run thermal plants have decreased to between $100/MWh and $200/MWh 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 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.

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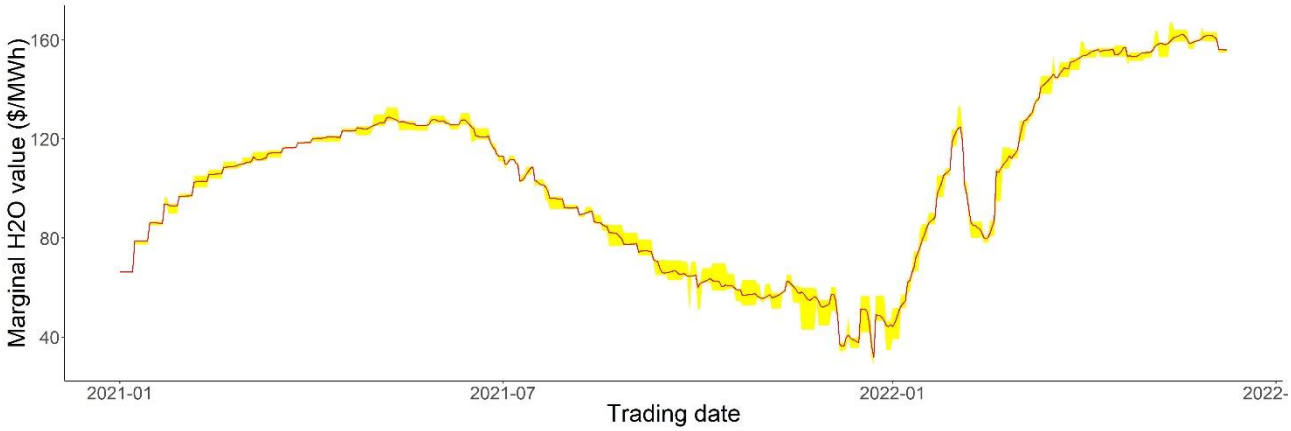
[2] https://www.ea.govt.nz/assets/dms-assets/30/Appendix-C-Calculating-thermal-SRMCs.pdf

[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.

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

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.

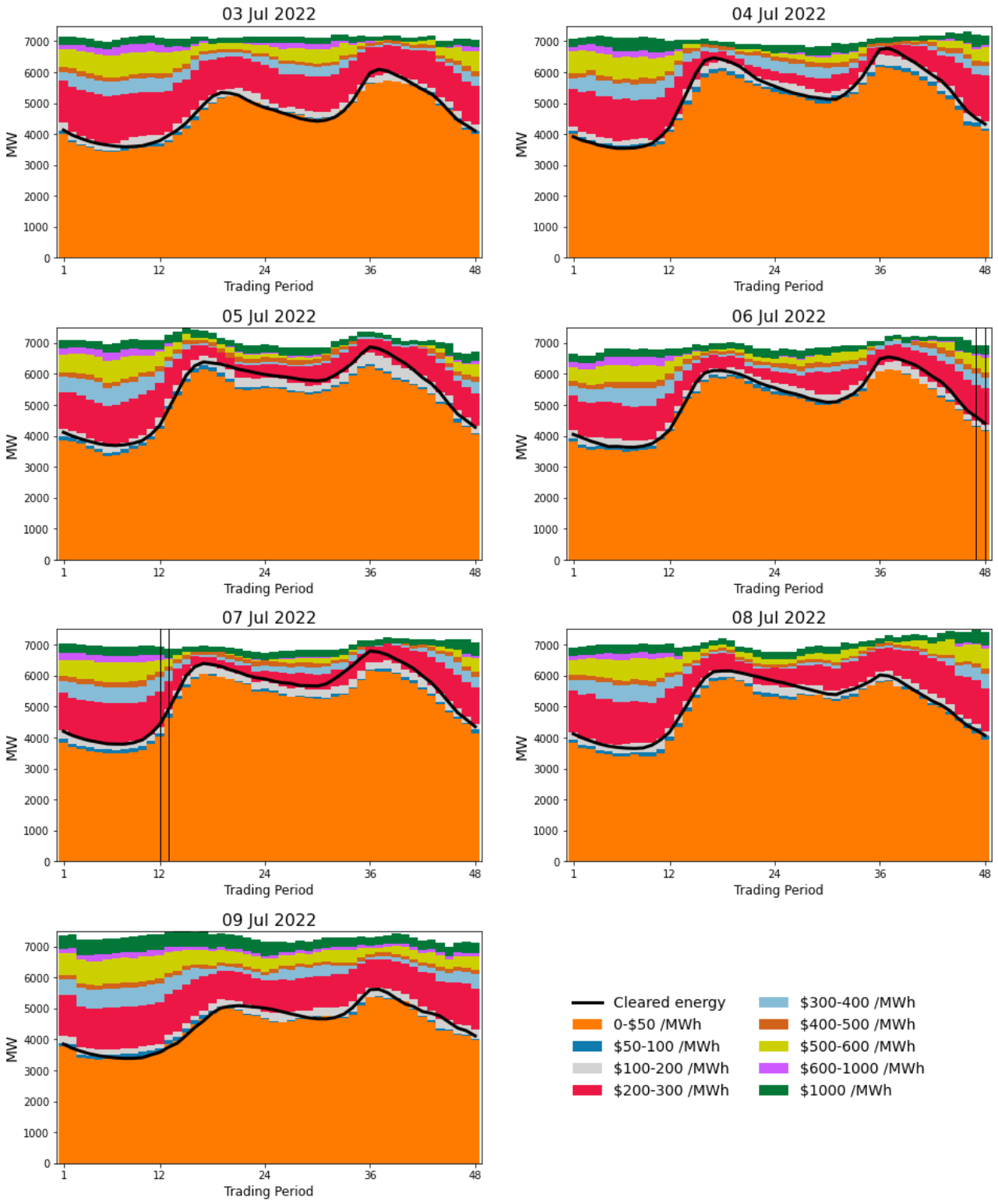
11.2. High thermal and hydro generation opportunity costs as detailed above continue to drive a steep offer curve.

11.3. Cleared energy during the week remained primarily within or below the $100-200/MWh range and $200-300/MWh range despite low wind generation reducing the amount of $0-50/MWh offers for some trading periods.

11.4. 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.

[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
19/02/22-24/02/22	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	Ongoing	Messaged Genesis about 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.