6 July 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 26 June to 2 July

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

2. Spot Prices

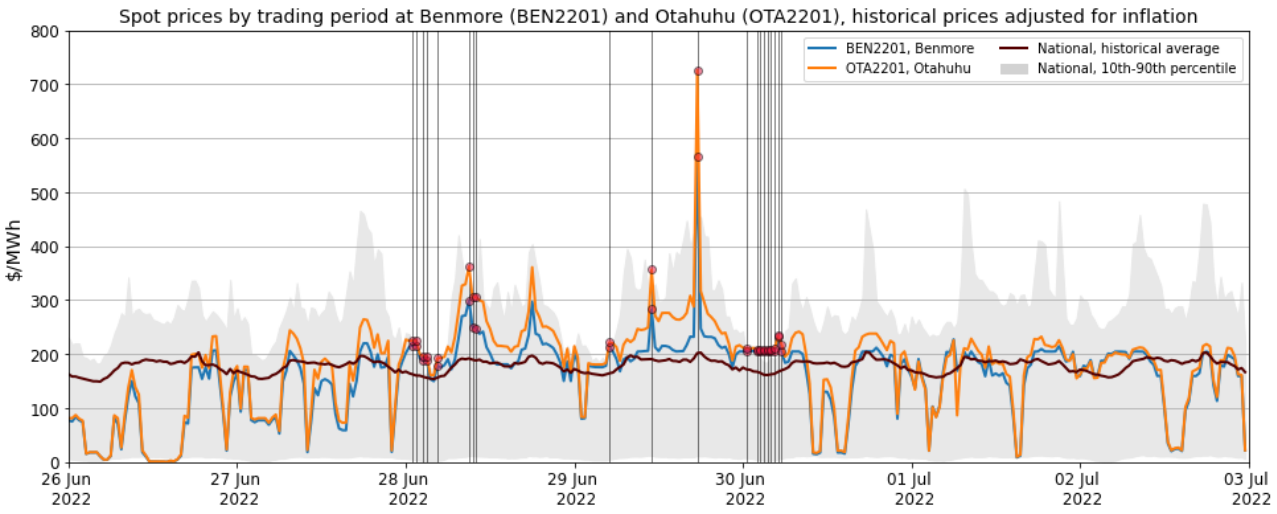
2.1. This report monitors underlying wholesale price drivers to assess whether there are trading periods that require further analysis for the purpose of considering potential non-compliance with the trading conduct rule. In addition to general monitoring, we also single out unusually high-priced individual 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 26 June and 2 July averaged $165.06/MWh with 95 per cent of prices falling between $4.54/MWh and $281.65/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. Prices remained mostly below $200/MWh at the beginning and end of the week, increasing to between $200/MWh and $400/MWh between 28 and 29 June. As with previous weeks, spot prices most commonly tended to rise above their 90th historical percentiles during off peak periods.

2.4. An unusually high price spike which exceeded $700/MWh at trading period 36 on 29 June was a result of a steep offer curve coinciding with high demand and low wind generation.

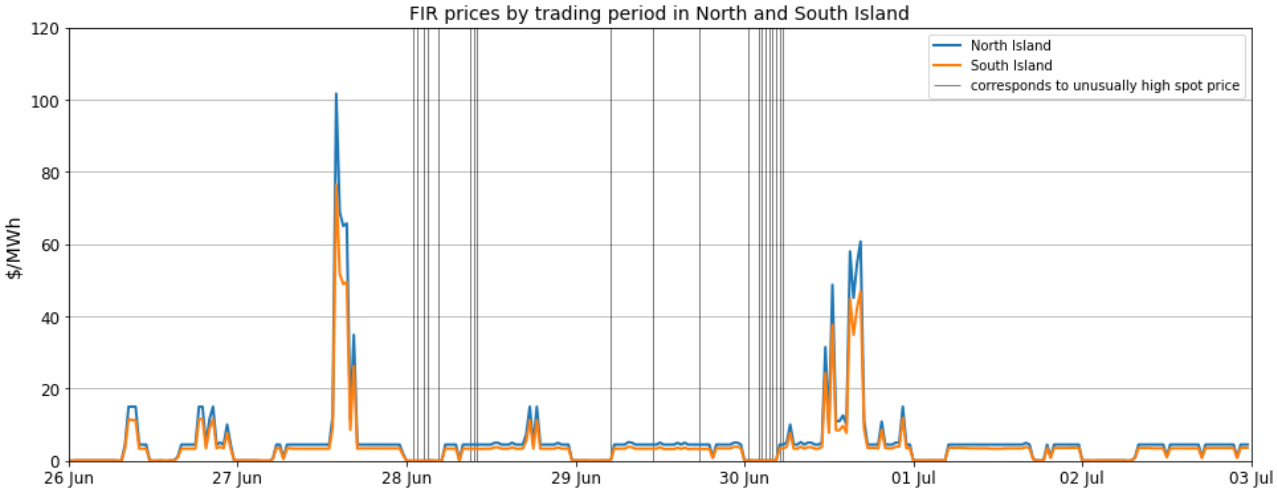
Figure 1: Wholesale Spot Prices



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 ~$100/MWh with remaining prices falling within historical bounds at below $20/MWh. These price spikes may be due to restrictions at the HVDC that prevented reserve sharing[1] as well as possible co-optimisation by the system operator.

Figure 2: FIR prices by trading period and Island

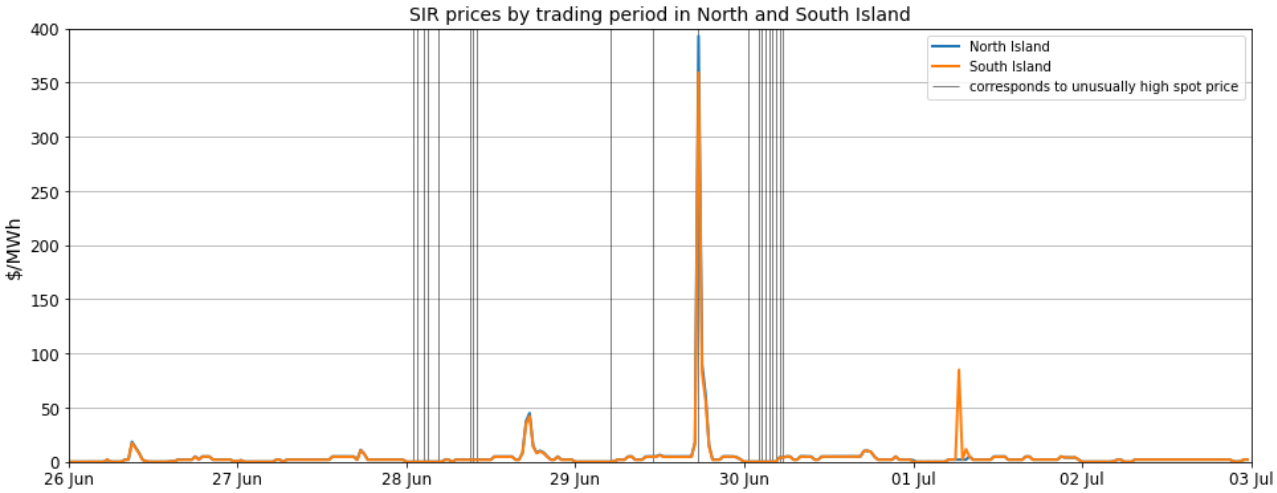


3.2. Sustained instantaneous reserves (SIR) prices for the North and South Island are shown below in Figure 3. SIR reserve prices this week saw spikes of up to $400/MWh with remaining prices falling within historical bounds at below $20/MWh.

3.3. The ~$400/MWh reserve price spike at trading period 36 on 29 June may be related to the ~$700/MWh spot price spike seen at the same time. It is possible constraints were applied to the risk setter at the time, Huntly 5, to make sure there were enough reserves to cover the potential loss of generation, resulting in higher prices for that period.

3.4. Overall, these price spikes to do not appear to be a result of any deliberate changes in offers and so do not show signs of trading misconduct.

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



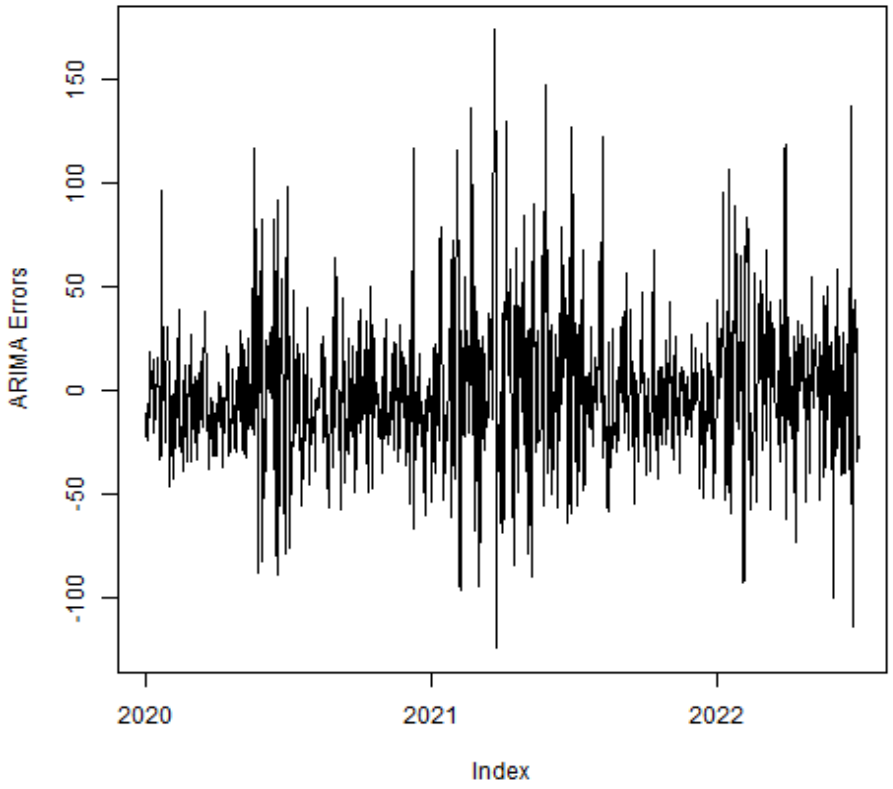
[1]https://www.transpower.co.nz/sites/default/files/interfaces/can/CAN%20Round%20power%20status%20change%204385383848.pdf

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[2] 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. Residuals were mostly flat, appearing largest on the day when spot prices spiked to $700/MWh.

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



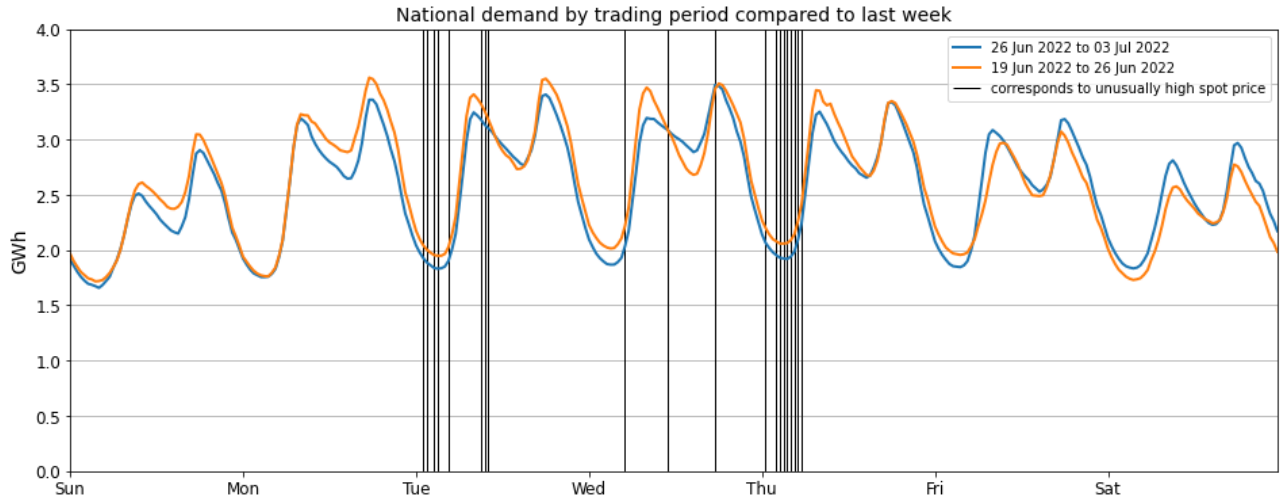
5. Demand

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 hit its highest point for the week on the evening of Wednesday 29 June, when spot prices also reached $700/MWh. Wednesday evening demand when compared to the evening demand from the other days of the week was likely higher due to lower temperatures at the time as can be seen in Figure 6.

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

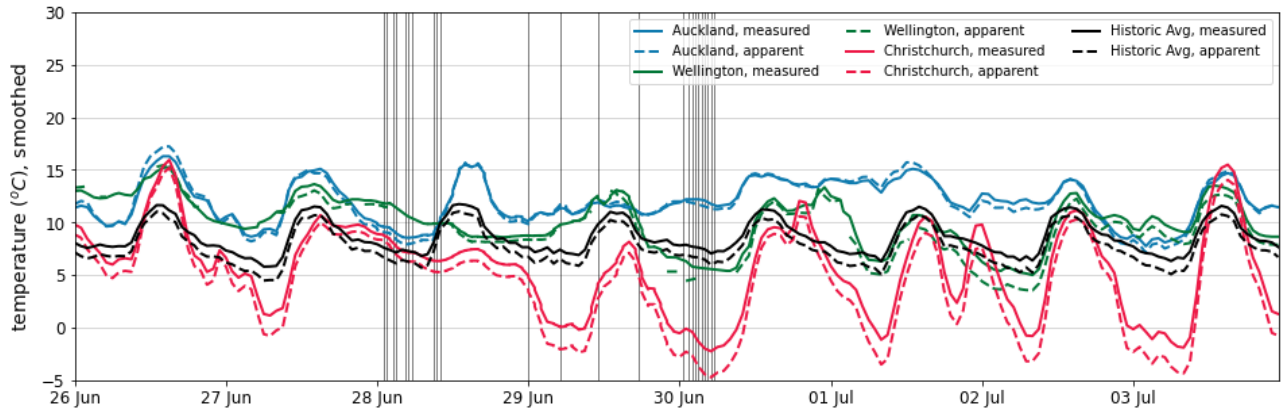
Figure 5: National demand by trading period compared to the previous week



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. Low temperatures and high demand therefore were likely contributors to high spot prices this week.

Figure 6: Temperatures across main centres

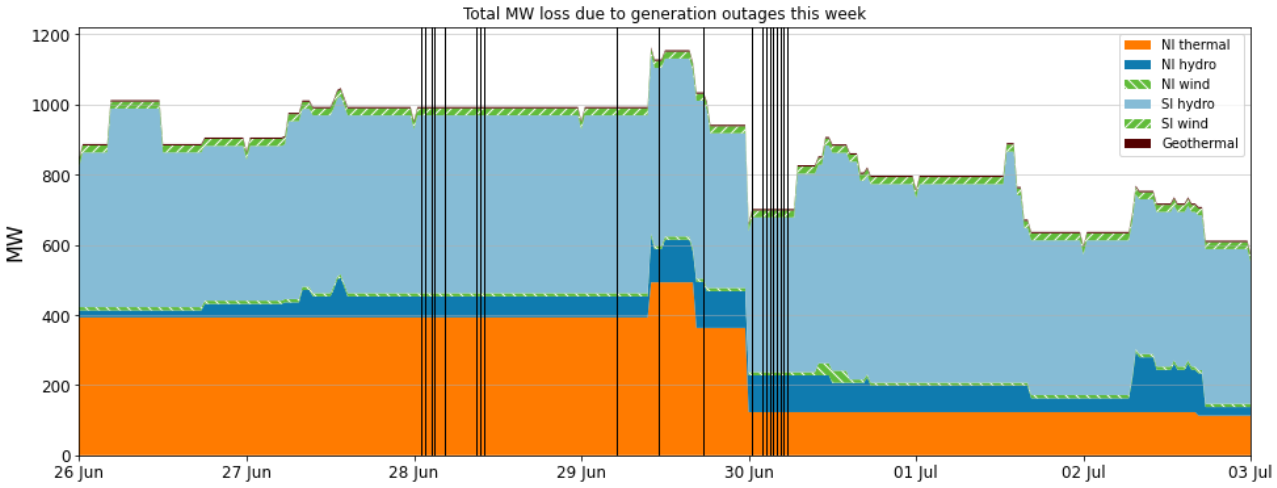


6. Outages

6.1. Figure 7 shows total generation capacity lost due to outages between 26 July and 2 June. The majority of outages continues to come from a loss of thermal and South Island hydro generation.

6.2. Total generation capacity lost due to outages averaged around 1,000 MW between 26 and 29 June before decreasing to around ~600 MW by 2 July.

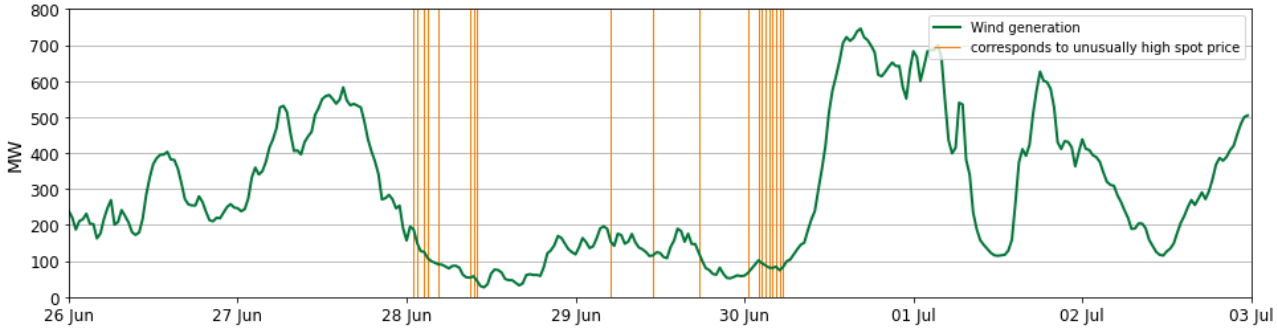
Figure 7: Total MW loss due to generation outages



7. Generation

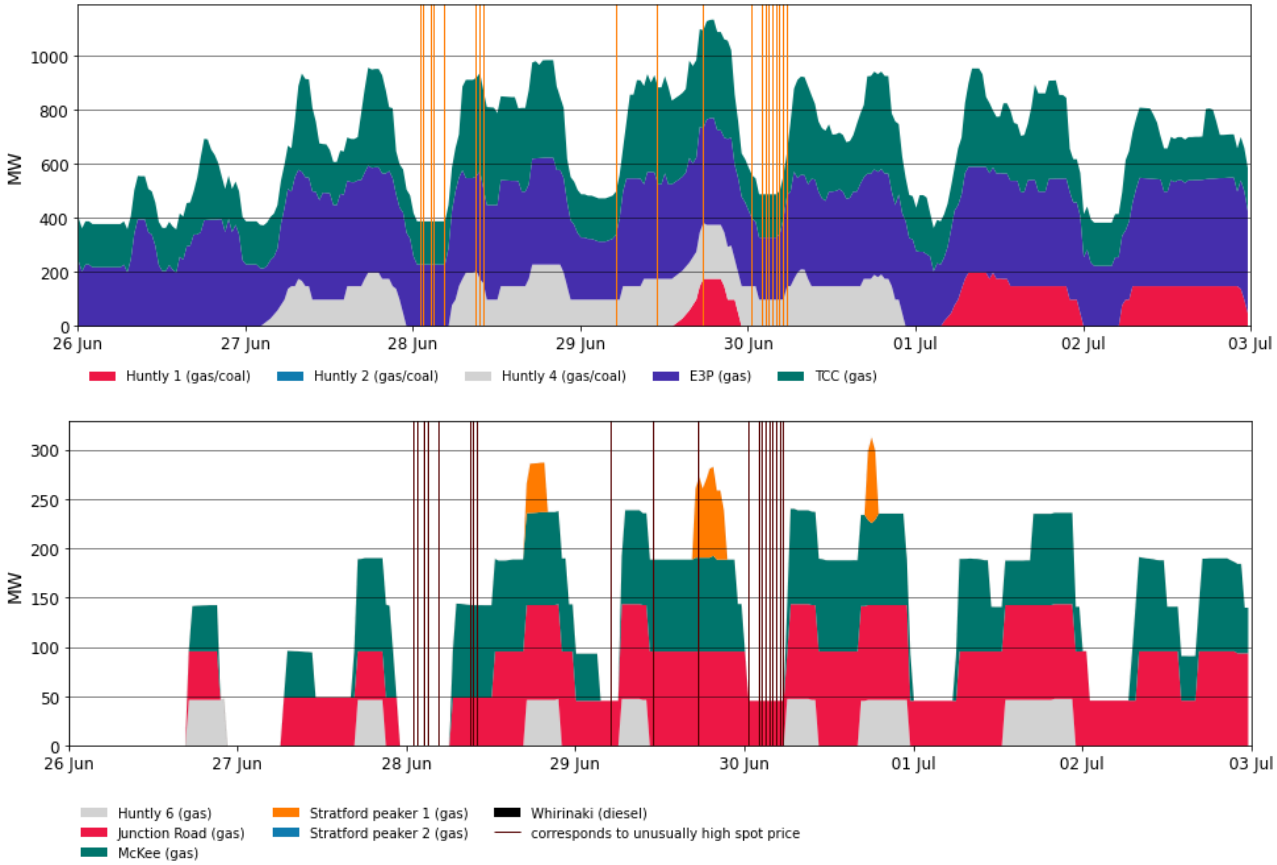
7.1. Figure 8 shows wind generation from the past week. Wind generation was reasonably strong at the beginning and end of the week, generating between 200 MW and 600 MW between 26 and 27 June and generating between 100 MW and 750 MW between 30 June and 2 July. Wind generation was consistently low during the middle of the week, with generation staying below 200 MW between 28 and 29 June. Low wind generation coincided with when spot prices were high, totalling 100 MW when prices reached $700/MWh on 29 June. 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. When wind generation was low thermal generation was high. Thermal generation reached its peak on the evening of 29 June with Huntly units 1, 3, and 4 dispatched and Stratford Peaker 1 dispatched. Thermal generation was over 1,100 MW when prices peaked at $700/MWh on 29 June. High thermal generation would therefore have been one of the main contributors to high spot prices this week.

Figure 9: Thermal Generation



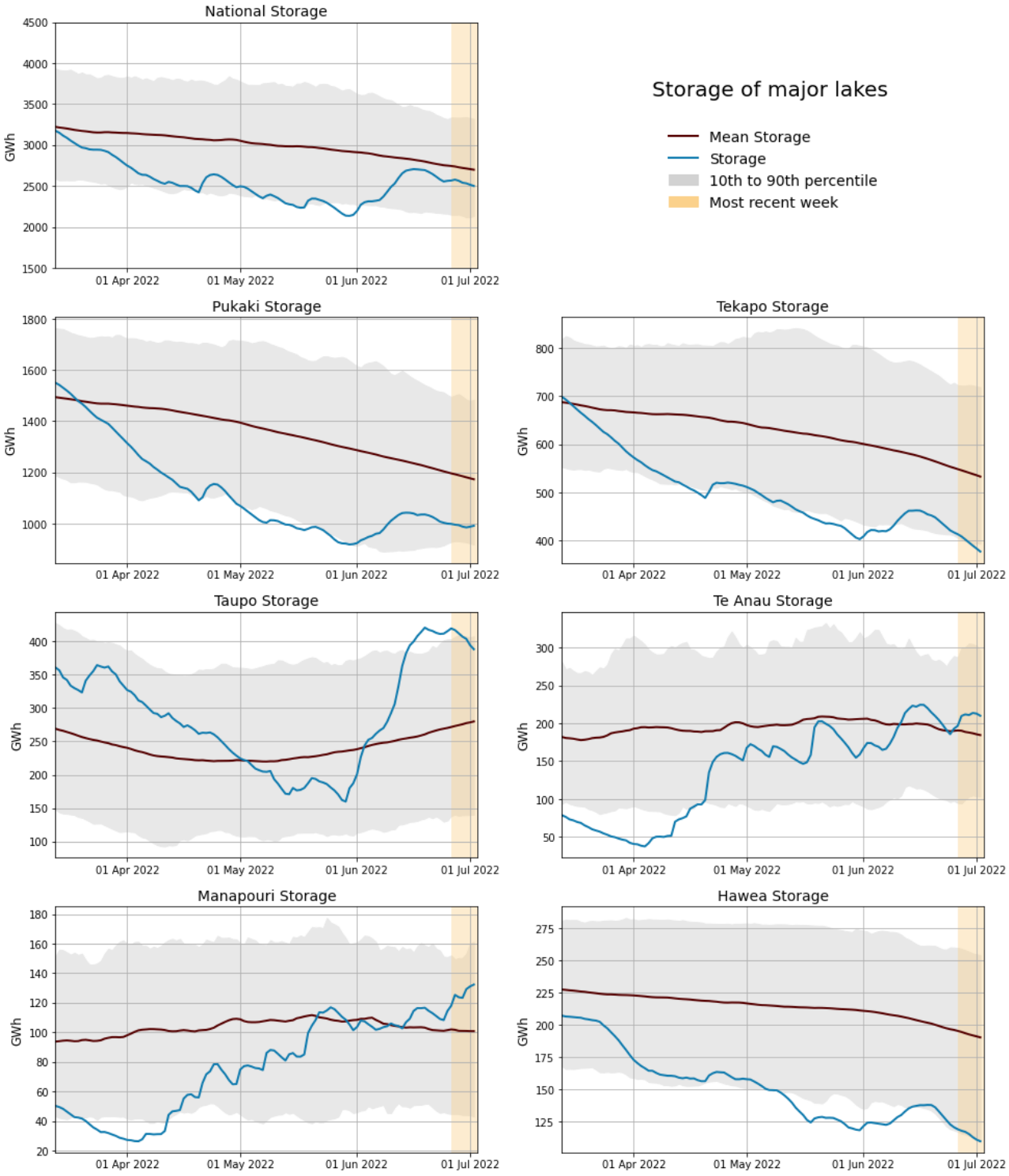
8. Storage/Fuel Supply

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.

8.2. A lack of inflows has meant hydro storage across most major lakes has declined. 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. 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

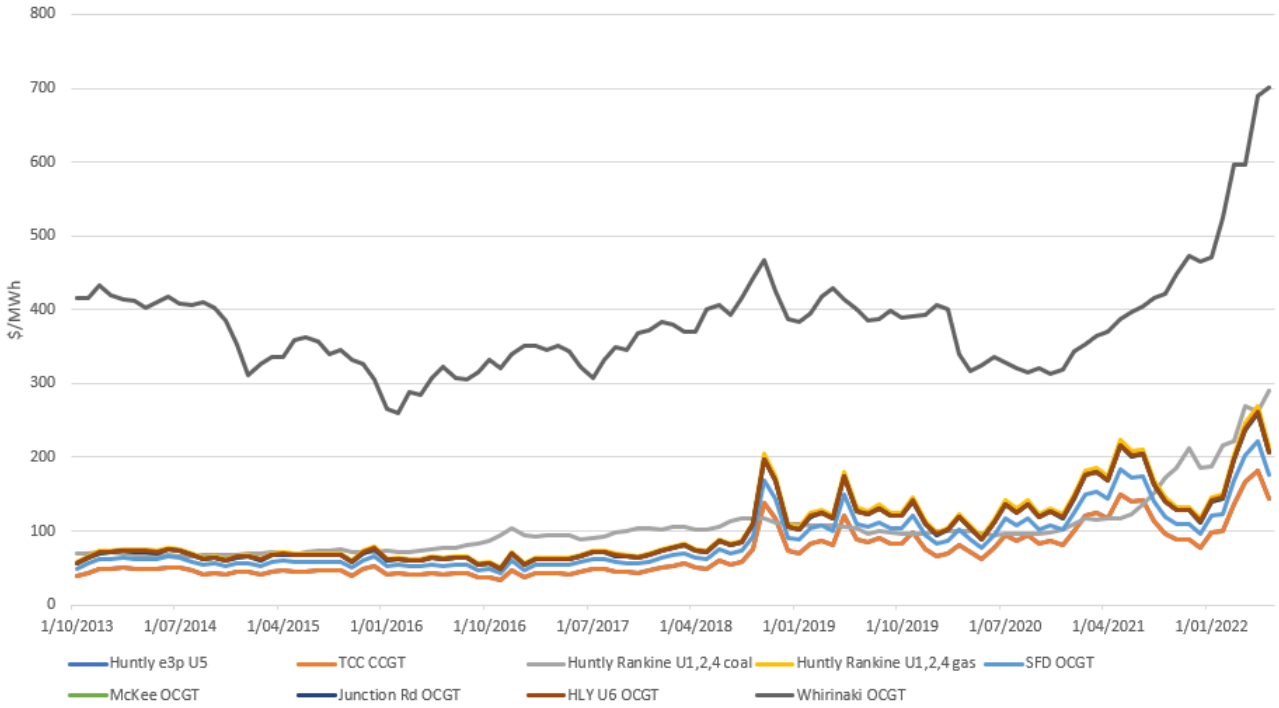
average up to 1 June 2022. The SRMC of all plants has increased sharply since the beginning of 2022.

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 $513/tonne. The increase in diesel and coal prices has put the latest SRMC of Whirinaki and coal fuelled 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[3] on the trading conduct webpage.

Figure 11: Estimated monthly SRMC for thermal fuels



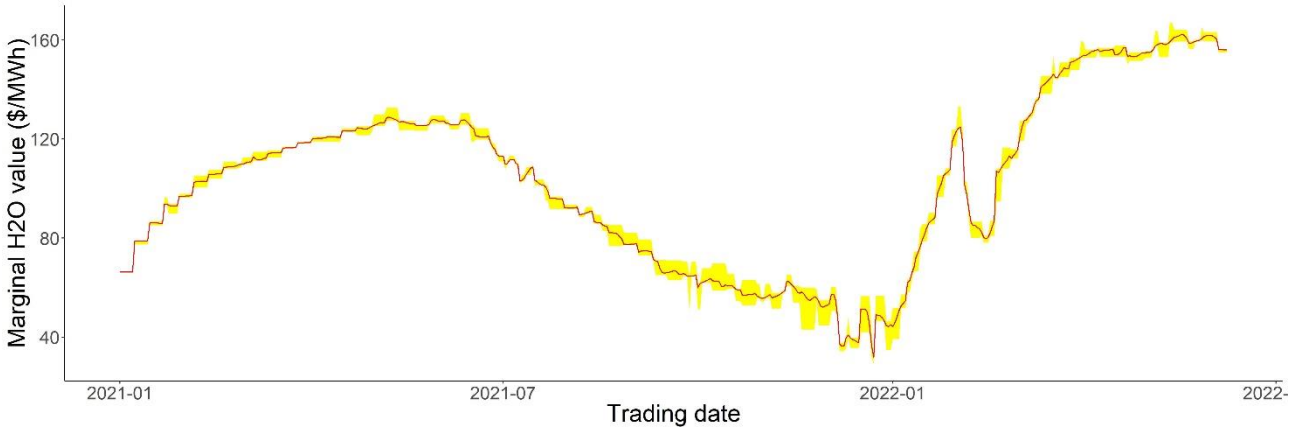
10. JADE Water values

10.1. The JADE[4] 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[5] on the trading conduct webpage.

[3] https://www.ea.govt.nz/assets/dms-assets/30/Appendix-C-Calculating-thermal-SRMCs.pdf
[4] 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.
[5] https://www.ea.govt.nz/assets/dms-assets/29/Appendix-B-JADE-water-value-model.pdf

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.[6] 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 at the beginning and end of the week remained primarily within or below the $200-300/MWh range.

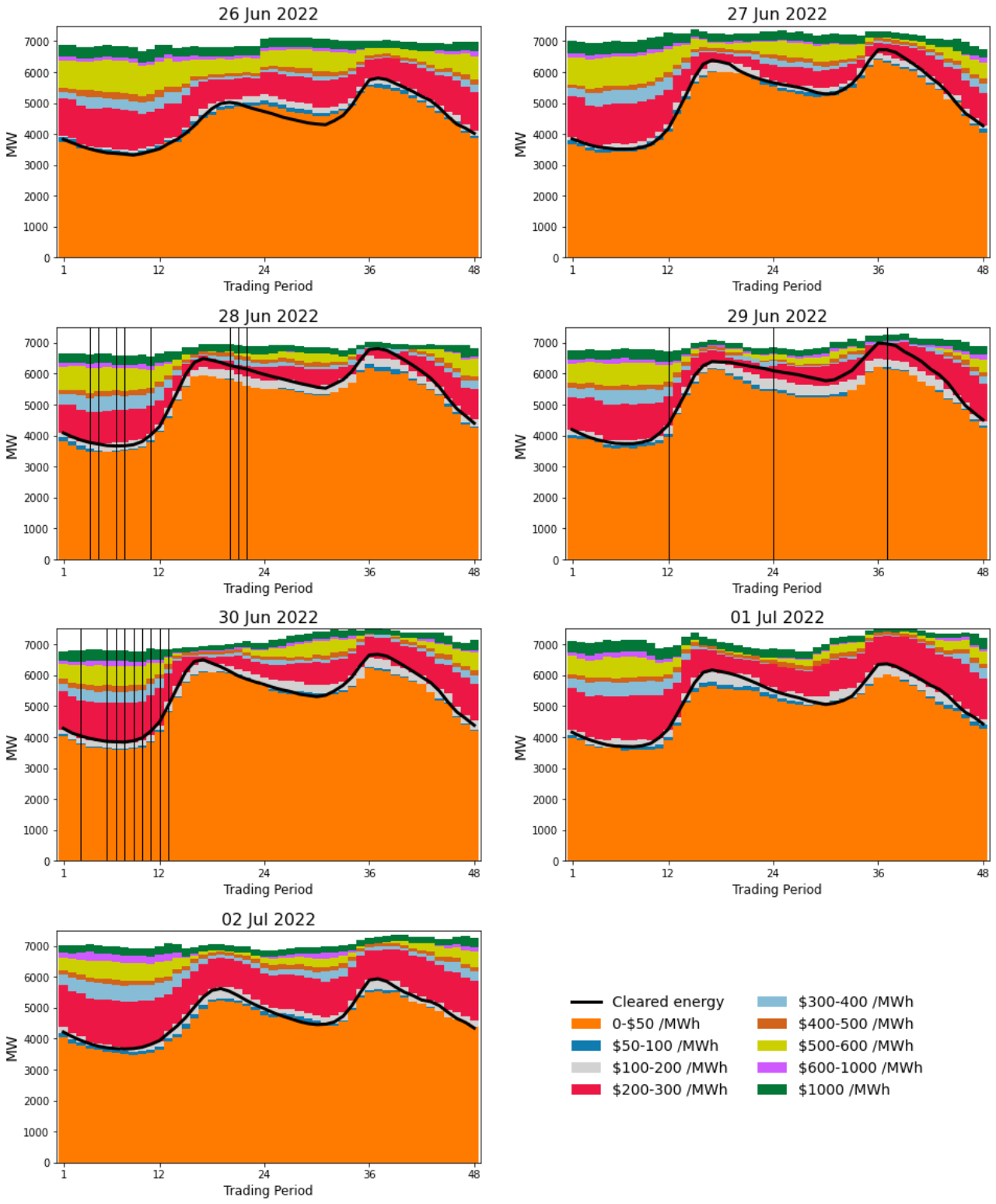
11.4. Low wind generation decreased the amount of low priced $0-50/MWh offers on 28 and 29 June resulting in a steeper offer curve on those days compared to the rest of the week. As the amount of offers between $200-300/MWh and $1,000+/MWh during evening peak demand periods is minimal compared to total available offers the increased evening demand seen on 29 June resulted in prices rapidly climbing the offer curve. 30 MW from Huntly 1 was required to be dispatched to meet demand at trading period 36, setting the marginal price of ~$700/MWh.

11.5. Low wind generation, high thermal generation and a relatively high amount of demand pushing prices up a steep offer curve can also be seen setting higher than historically expected prices during off peak periods between 28 and 30 June.

11.6. 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.

[6] 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.