7 September 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 28 August to 3 September

1.1. Wholesale spot prices this week appeared to be consistent with market conditions.

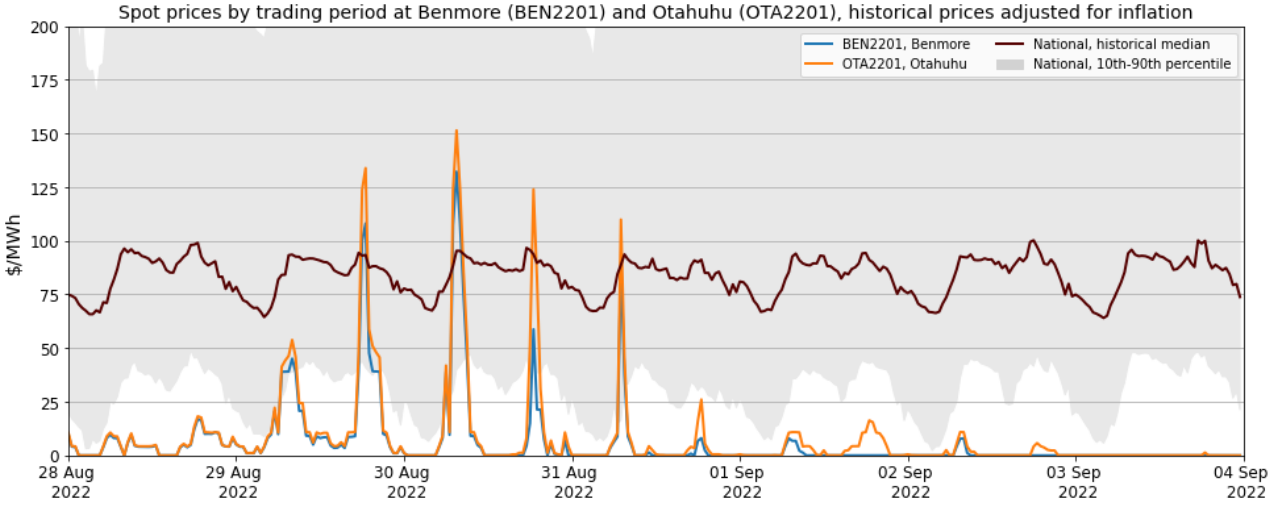
2. Spot Prices

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 spot prices across all nodes between 28 August and 3 September averaged a low $7.31/MWh this week with 95 per cent of prices spread between $0.01/MWh and $66.36/MWh. The highest spot price this week was $161.40/MWh which occurred on trading period 16 on 30 August at Wellsford.

2.3. Figure 1 shows spot prices between 28 August and 3 September at Benmore and Otahuhu alongside their historic median and historic 10th-90th percentiles adjusted for inflation. Figure 1 is a good visual of how low prices were for the majority of the week with prices outside of peak morning and evening demand periods falling well below the historic 10th percentile of prices adjusted for inflation. 93 per cent of trading periods fell below $25/MWh, something we would only usually see during the December holiday period.

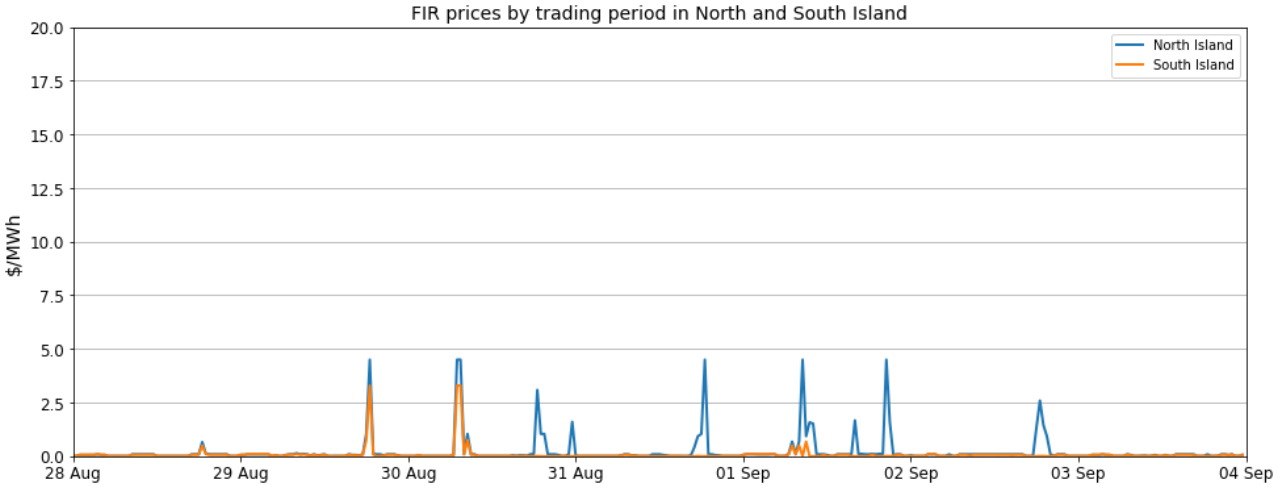
Figure 1: Wholesale Spot Prices



3. Reserve Prices

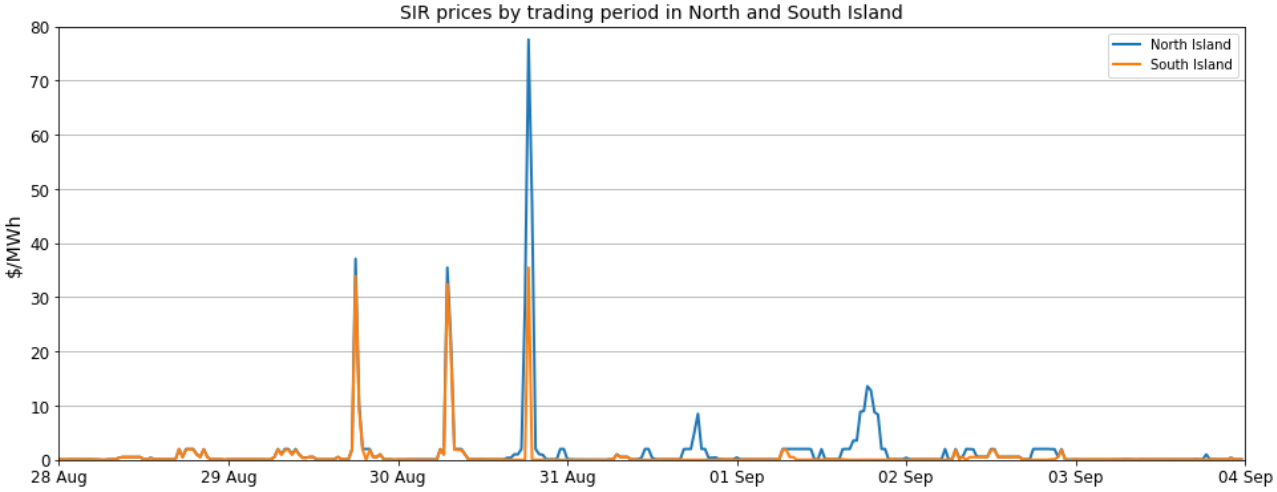
3.1. Fast instantaneous reserves (FIR) prices for the North and South Island are shown below in Figure 2. All FIR prices fell within historical bounds this week with all trading periods below $5/MWh.

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. Outside of three price peaks reaching between $30/MWh and $80/MWh on 29 and 30 August all SIR prices this week were below $20/MWh - well within historical bounds. The spikes in SIR prices corresponded with the spikes in wholesale spot prices meaning that the increase in SIR prices were likely a result of co-optimisation by the system operator with reserves being dispatched instead of higher priced energy offers.

Figure 3: SIR prices by trading period and Island



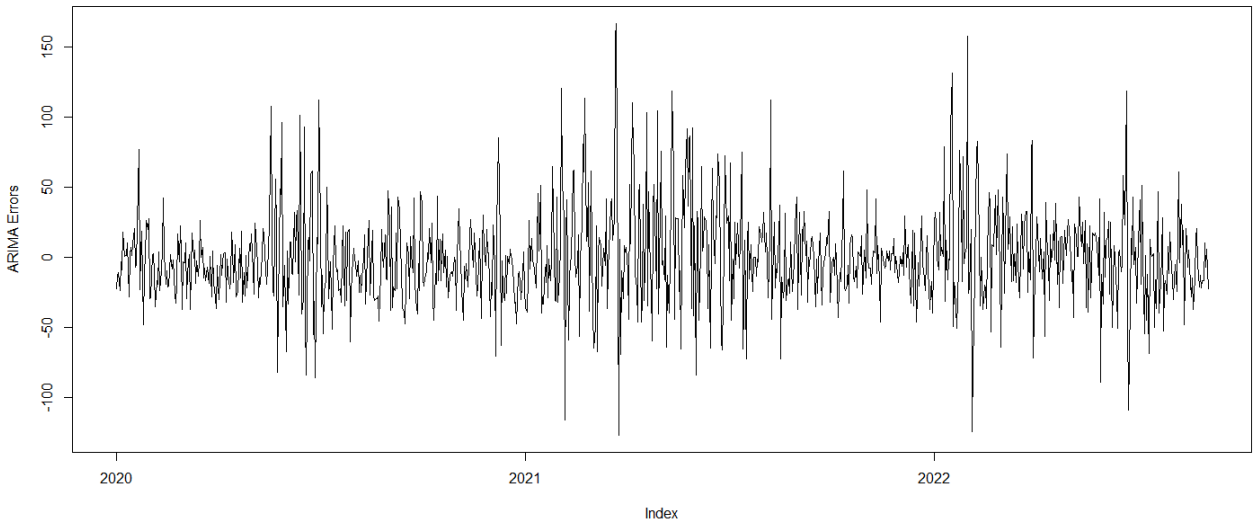
4. Regression Residuals

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 with residuals remaining relatively small.

Figure 4: Residual plot of estimated daily average spot prices



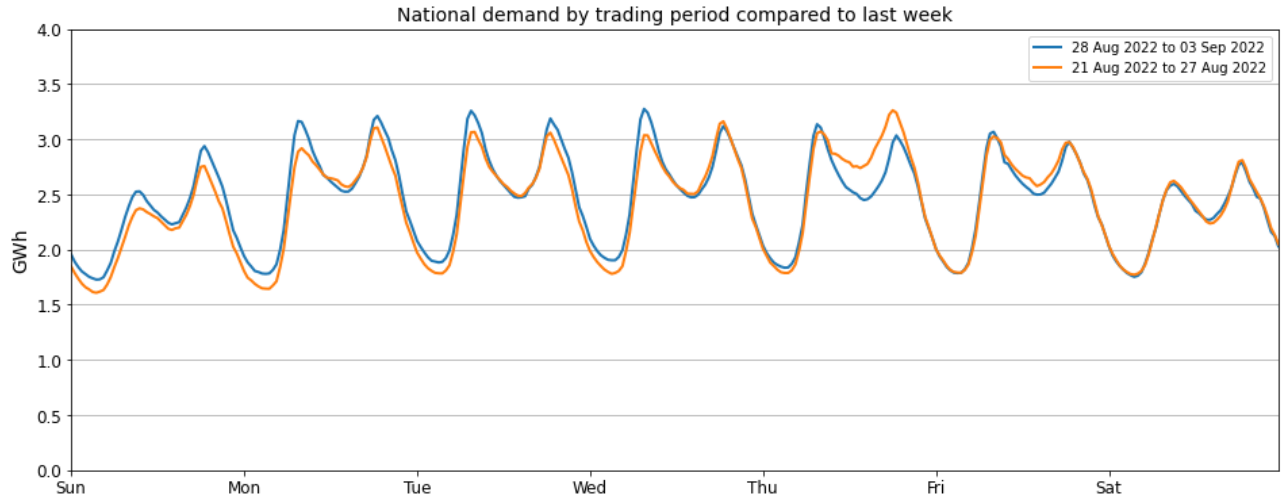
5. Demand

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, 28 August to 3 September, was fairly similar to the previous week, 21 to 27 August, with higher peak demand between Sunday and Wednesday. Peak demand reached its highest point for the week on trading period 16 on 31 August at 6,326MW. Usually morning peak demand tends to be less than evening peak demand so when morning demand exceeds evening demand this tends to be a signal of higher than usual morning demand which likely contributed to some of the price spikes seen in Figure 1.

5.3. Overall national grid demand levels this week were consistent with historical grid demand levels for this time of year.

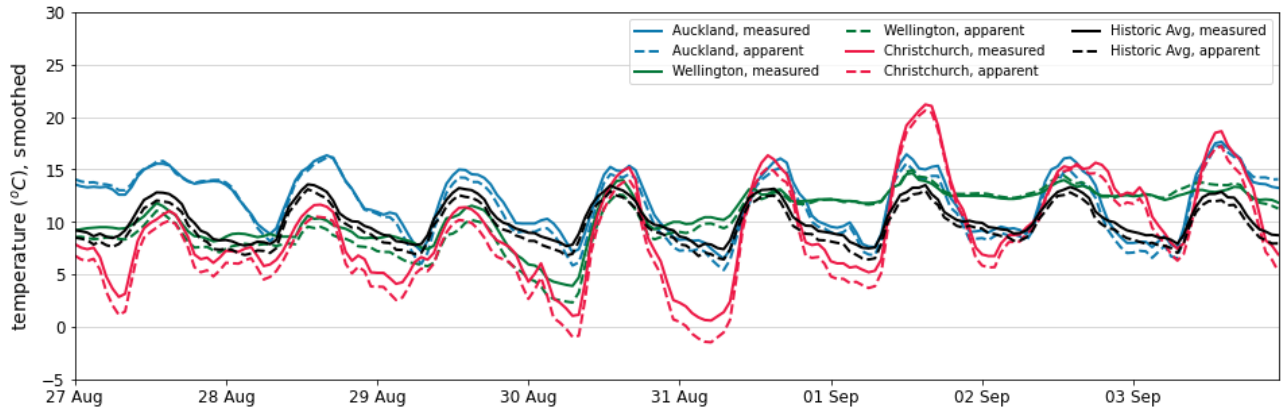
Figure 5: National demand by trading period compared to the previous week



5.4. 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.

5.5. Temperatures were close to historic average for this time of year with North Island temperatures a bit lower than usual and South Island temperatures a bit higher than usual. Temperatures were lowest between 28 and 31 August, likely being the reason behind higher Monday to Wednesday demand compared to the previous week.

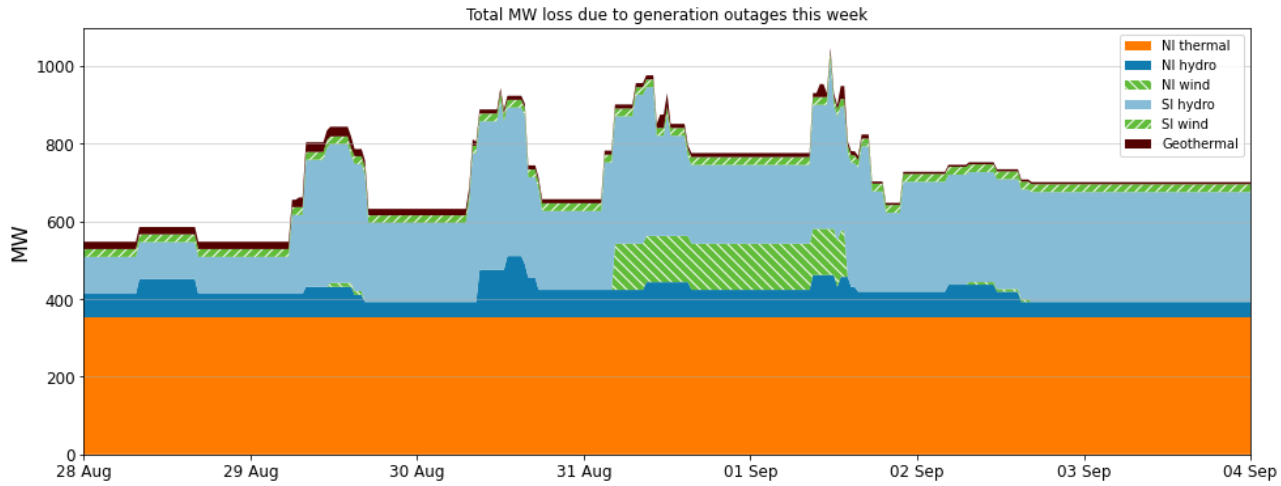
Figure 6: Temperatures across main centres



6. Outages

6.1. Figure 7 shows generation capacity lost due to outages between 28 August and 3 September. Total capacity lost due to outages was a little lower than average with lost capacity largely falling between 500MW and 800MW for most of the week. Any reduction in lost generation capacity would have helped contribute to lower spot prices.

Figure 7: Total MW loss due to generation outages



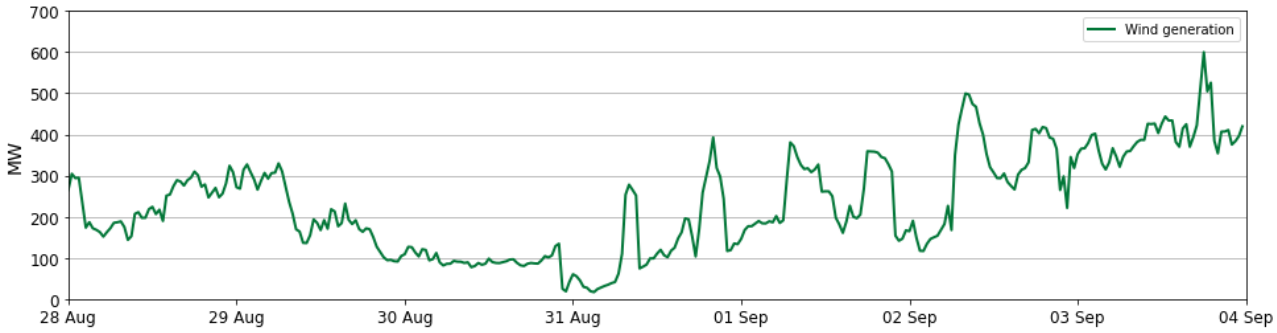
7. Generation

7.1. Wind generation as seen in Figure 8 was relatively low at the beginning of the week with total wind generation below 300MW between 28 August and 31 August. Average wind generation gradually increased to 400MW by the end of the week from 31 August onwards, fluctuating between 100MW and 600MW at times. The period of low wind generation between 28 August and mid 31 August was when prices spiked during peak demand

periods. In comparison from late 31 August onwards, when wind generation increased, there were no price spikes suggesting that low wind generation contributed partially to the higher prices seen between 29 and 31 August.

7.2. Usually we would expect to see much higher wind generation (between 300MW and 700MW) with prices as low as those seen this week. As demand is fairly average for this time of year with wind generation this low this indicates that a sizeable amount of another type of generation is being priced much lower than usual.

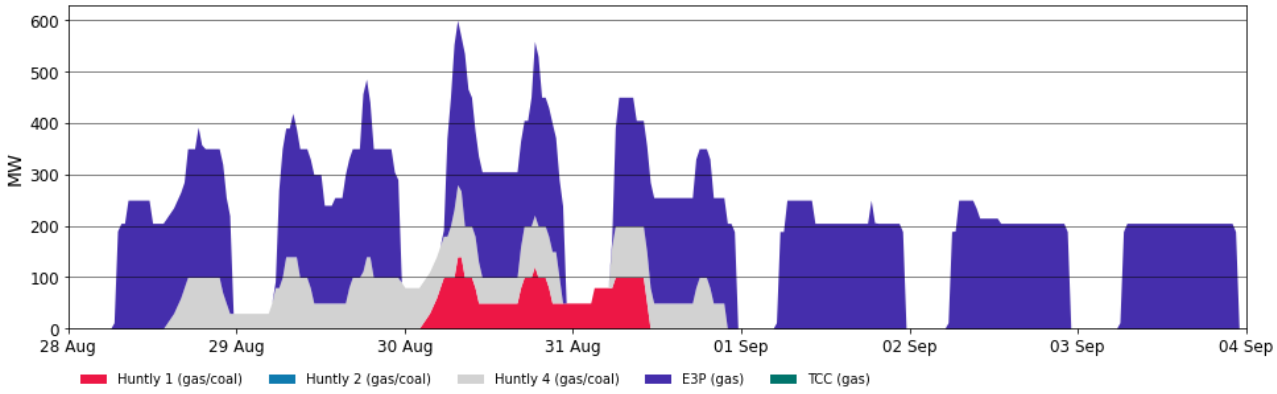
Figure 8: Wind Generation

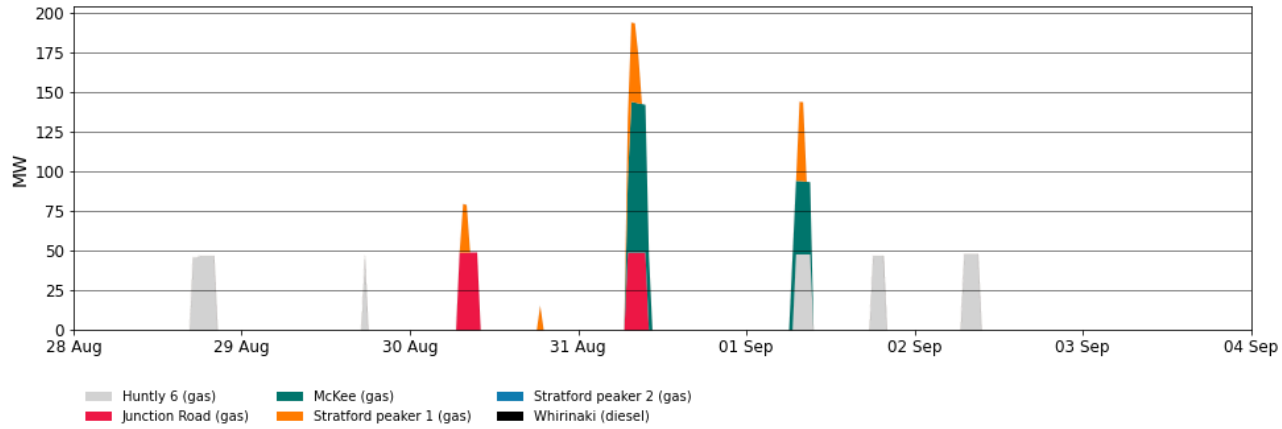


7.3. Figure 9 shows generation at thermal and thermal peaker plants between 28 August and 3 September. Thermal generation was highest between 28 August and 31 August corresponding to when wind generation was lowest (below 200MW). Thermal generation decreased from 1 September on once wind generation increased, with only E3P generating around 200MW during the day.

7.4. Overall total thermal and thermal peaker generation was quite low for this time of year, with peak thermal generation remaining below 600MW and thermal peaker generation peaking over 100MW only twice. The low overall thermal generation would have contributed to keeping spot prices below $25/MWh for most of the week. Peaks in thermal generation for peak demand periods from 29 August to 31 August likely contributed to the spikes in prices seen in those periods.

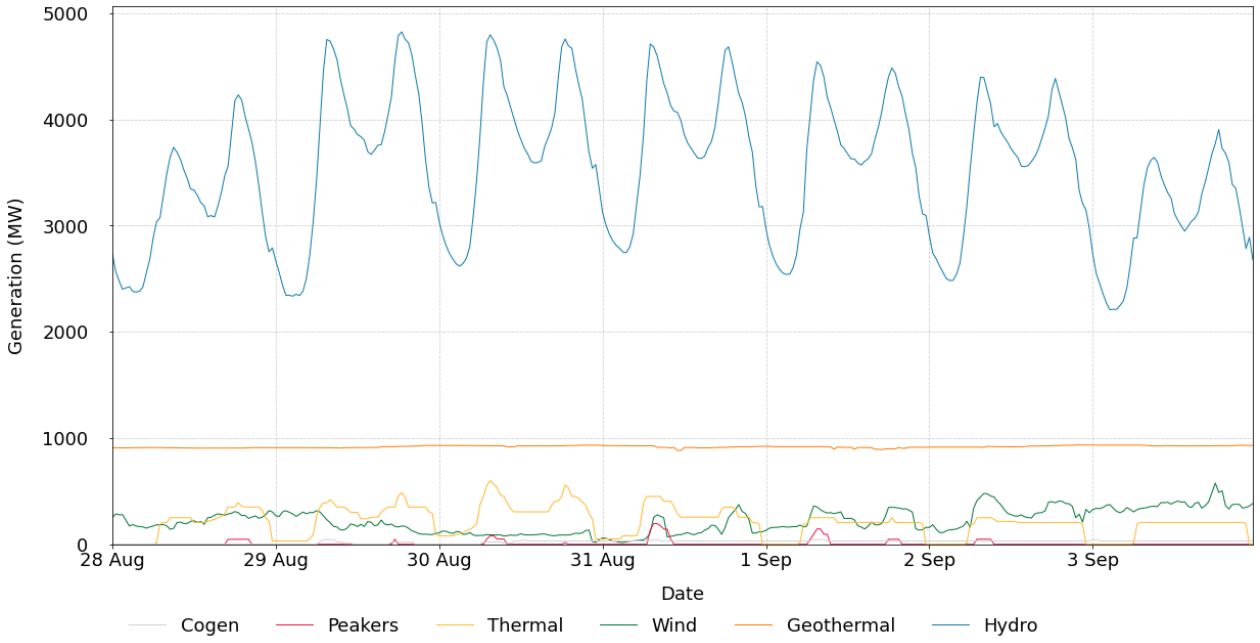
Figure 9: Thermal Generation





7.5. Figure 10 shows generation by fuel type. With relatively low wind and thermal generation hydro generation has made up an average of ~71.6 per cent of total generation between 28 August and 3 September. Usually hydro generation would be around ~60 per cent of total generation. As spot prices were quite low this week this would suggest a larger percentage of generation was made up by an increased amount of lower priced hydro generation compared to usual.

Figure 10: Generation by Fuel

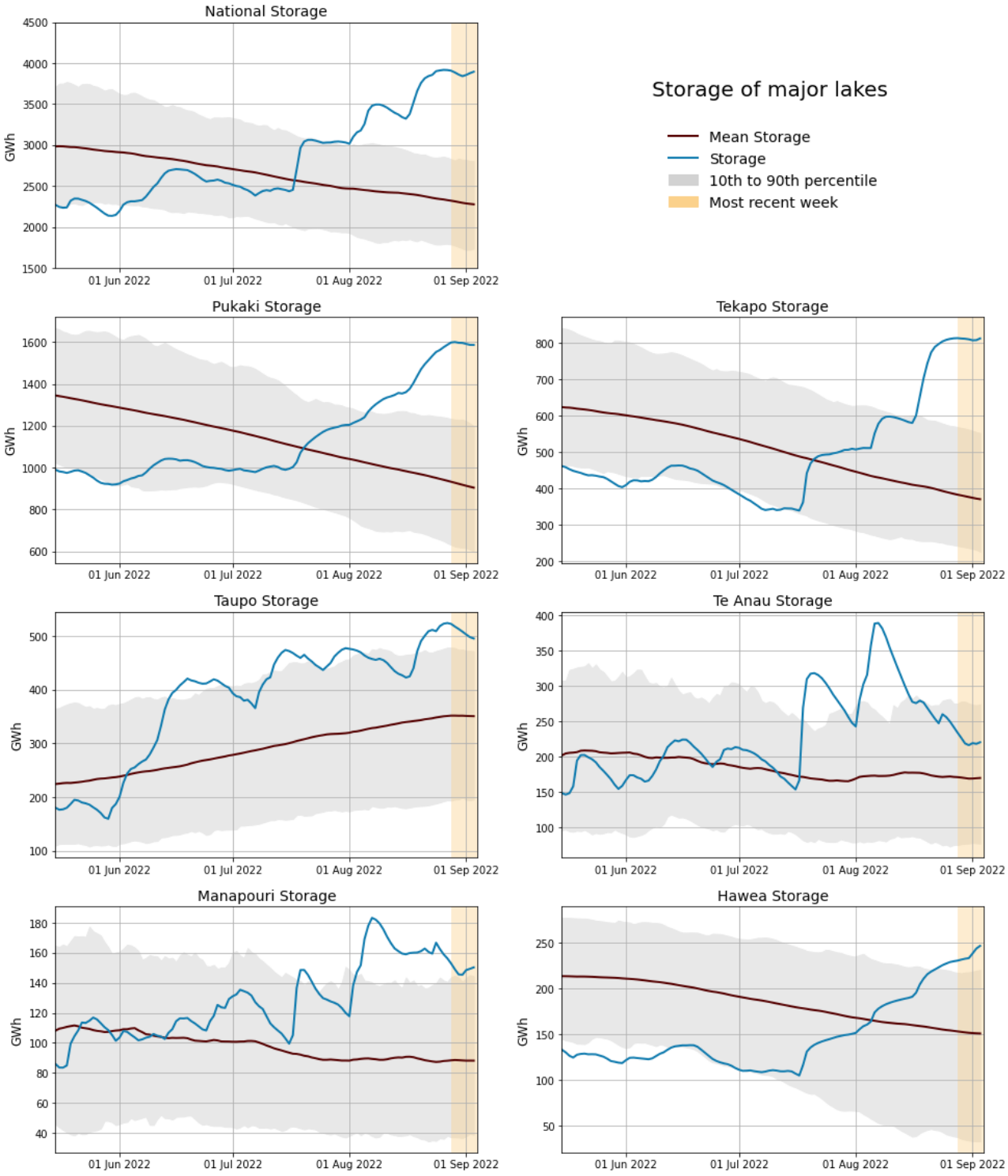


8. Storage/Fuel Supply

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. Hydro storage levels continue to remain well above usual for this time of year accompanied by an increase in lower priced hydro generation offers. Most major lakes are currently above their historic 90th storage percentiles. A combination of factors including spill gate maintenance and high lake levels even lead to Lake Pukaki spilling during the week. Usually we would only expect to see hydro storage levels this high towards the end of December which is likely why we are seeing spot prices similar to December prices currently.

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.

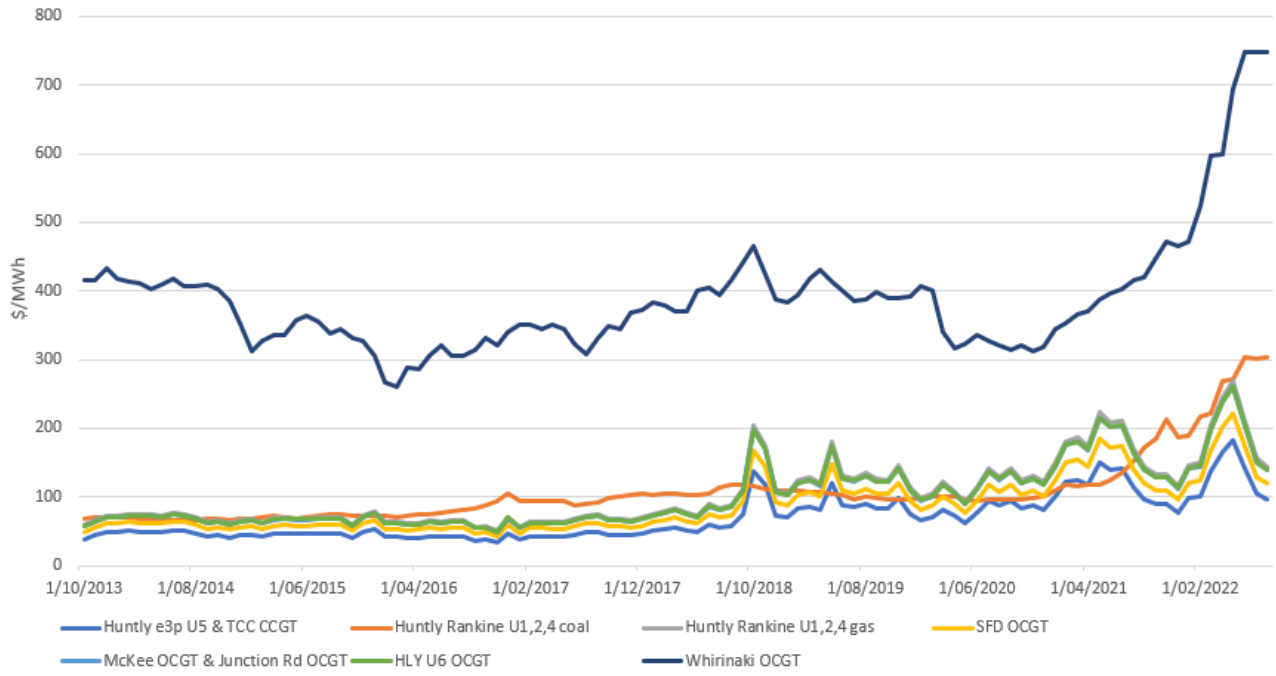
9.3. Figure 12 shows an estimate of thermal SRMCs as a monthly average up to 1 September 2022. The SRMC of gas fuelled plants continues to fall while the SRMC of diesel and coal fuelled plants appears to have plateaued.

9.4. The SRMC of coal and diesel have remained largely unchanged due to stable global supply and demand conditions. The most recent price for Indonesian coal was around ~$524/tonne putting the latest SRMC of Whirinaki and coal fuelled Huntly generation at around ~$750/MWh and ~$300/MWh respectively.

9.5. SRMCs of gas run thermal plants have decreased to between $96/MWh and $144/MWh with the increase in gas fuel availability in the market.

9.6. 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



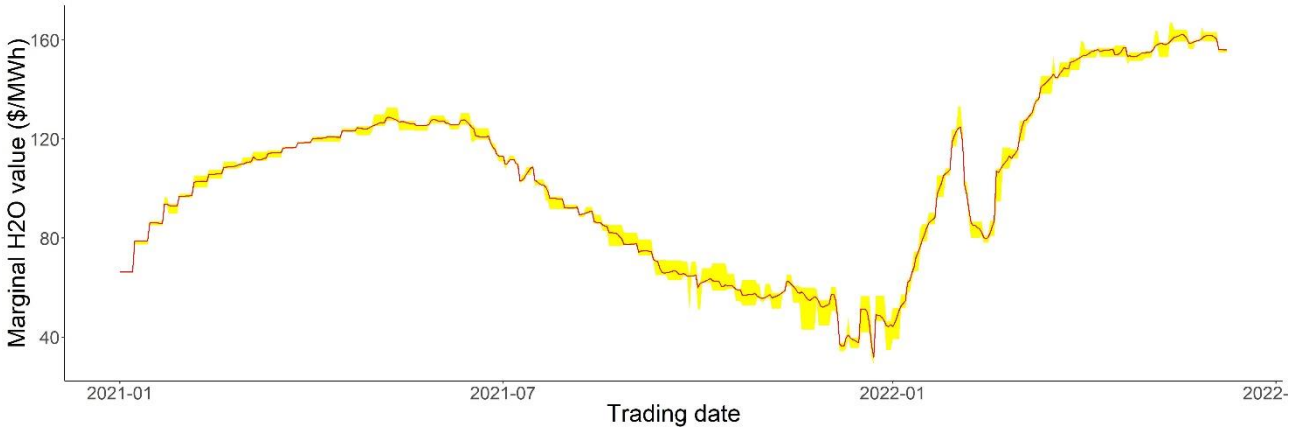
10. JADE Water values

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 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.

[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 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. The majority of cleared energy fell below $100/MWh this week, driven by high hydro generation and low-priced hydro generation offers. Relatively high renewable generation and low thermal generation also helped to keep spot prices reasonably low during price spikes this week despite relatively low wind generation. Price spikes were likely a product of higher than usual demand and low wind generation.

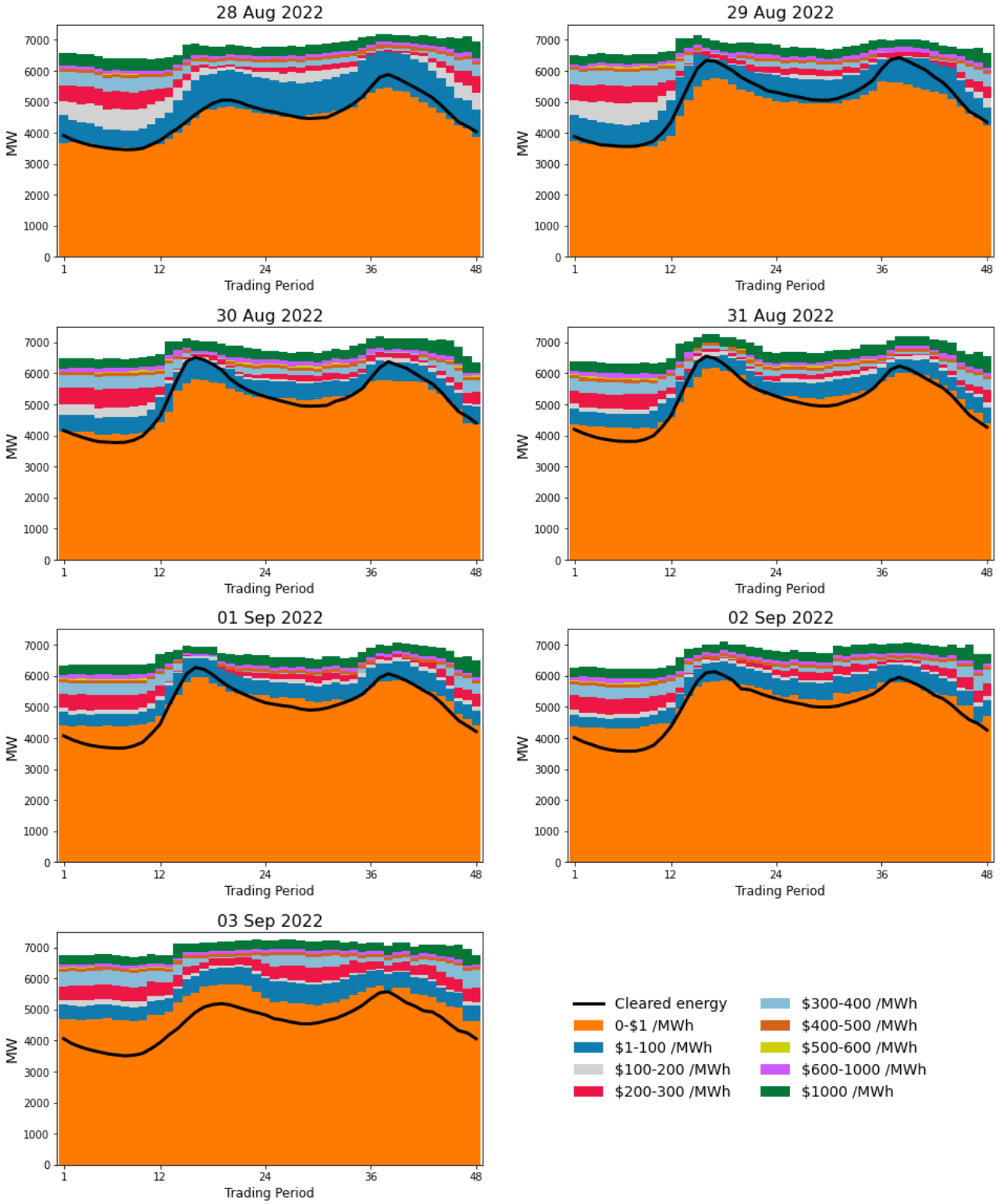
11.3. With low priced $0-100/MWh offers having increased the amount of $100-300/MWh offers have decreased in turn. As the upper end of the offer curve has continued to retain its usual steepness above average peak demand can still result in spikes in spot prices.

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.

11.5. Low prices this week were indicative of how much above average renewable generation can affect the spot market, with unusually high hydro storage for this time of year leading to unusually low prices for this time of year.

[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.