22 November 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 13-19 November

1.1. Most wholesale spot prices between13-19 November appear to be consistent with market conditions. Further analysis of four trading periods is underway.

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 Ōtāhuhu nodes exceed their historical 90th percentiles.

2.2. Between 13-19 November wholesale spot prices across all nodes averaged \$78/MWh, with 95 per cent of prices falling between \$0.14/MWh and \$214/MWh.

2.3. Figure 1 shows spot prices at Benmore and Ōtāhuhu alongside their historic median and historic 10th- 90th percentiles adjusted for inflation.

2.4. Spot prices increased again this week, with high midweek off-peak prices, especially in the North Island. Spot prices were also volatile.

2.5. Multiple instances of spot prices over \$200/MWh occurred this week, mostly in the North, with two price spikes over the 90th historic percentile. These occurred on:

I. Tuesday at 8:00 am, with Benmore reaching \$348/MWh and Ōtāhuhu reaching \$470/MWh.

II. Thursday at 3:00 pm, where price separation meant Benmore stayed at \$129/MWh, while Ōtāhuhu reached \$344/MWh.

2.6. Price separation continued this week, occurring between Monday – Friday. Tuesday had the longest stint of price separation, while the largest difference in price occurred on Thursday at 3:00 pm.

2.7. Other high spot prices[1], which didn't reach the 90th percentile, occurred on:

I. Wednesday at 6:00 pm, with Benmore reaching \$286/MWh and Ōtāhuhu reaching \$358/MWh.

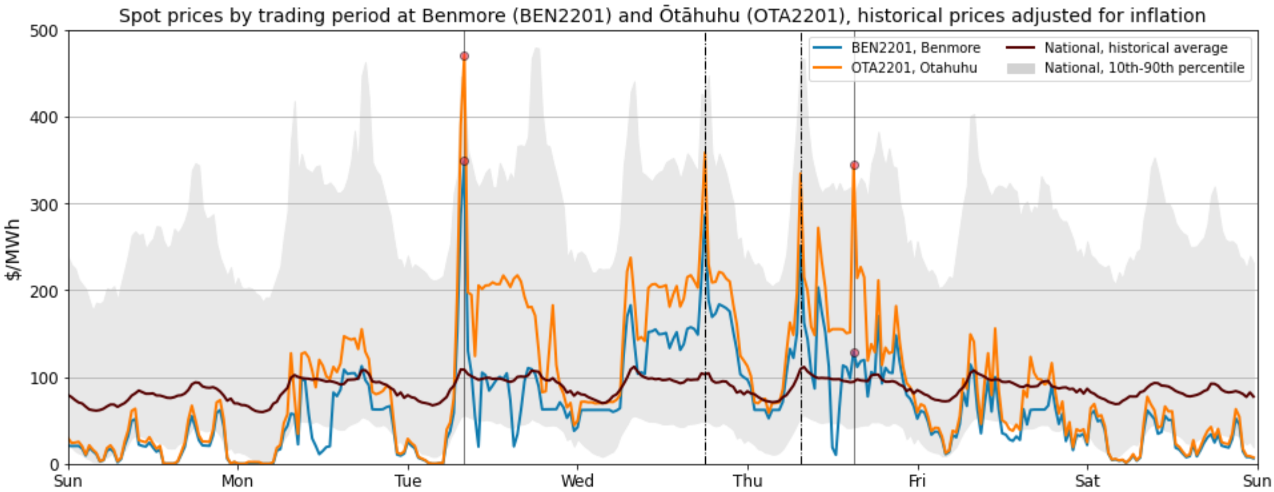
II. Thursday morning at 7:30am, with Benmore reaching \$251/MWh and Ōtāhuhu reaching \$334/MWh.

2.8. This increase in average price and the price separation was due to tighter energy market in the North Island, especially when wind generation was below 300 MW and HVDC was

[1] Note these are denoted by the dotted lines in the figures

transferring high volumes northwards. This was especially acute as live line work on the HVDC means that round power was disabled from Monday to Thursday during the day which prevents reserve sharing. This increased the reserve requirement, and while this work has been going on for some time, it seems to have had a greater impact this week. This tight North Island market is likely being exacerbated by the E3P and geothermal outages.

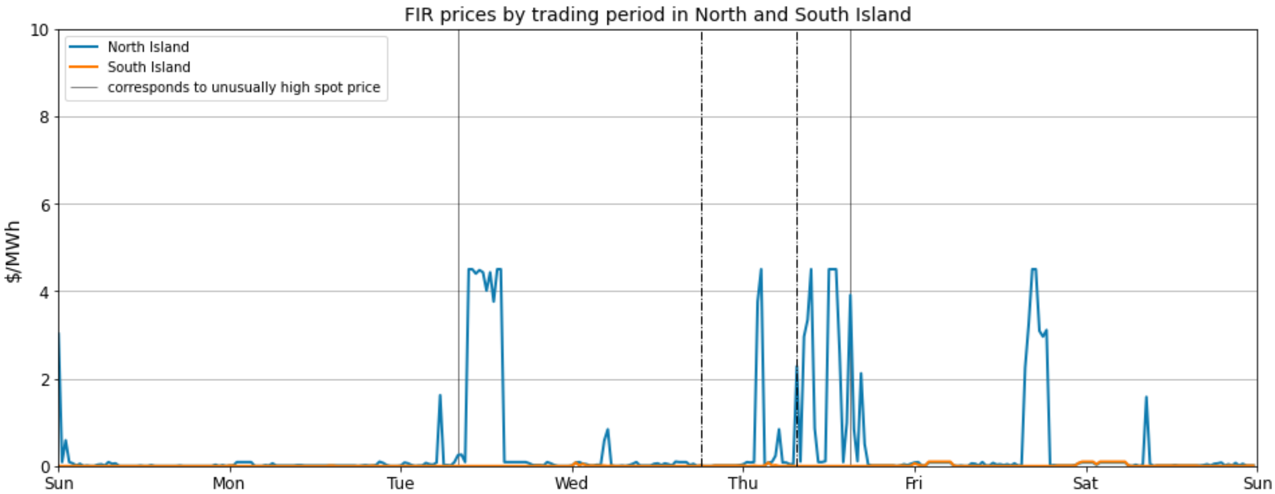
Figure 1: Wholesale Spot Prices



3. Reserve Prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Island are shown below in Figure 2. All FIR prices were $5/MWh this week.

Figure 2: FIR prices by trading period and Island

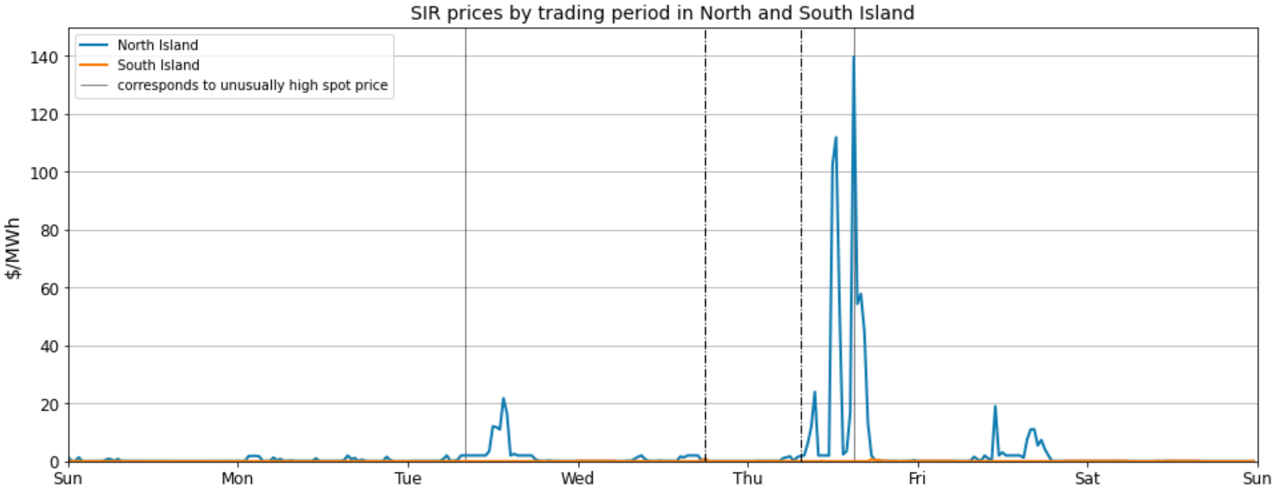


3.2. Sustained instantaneous reserve (SIR) prices for the North and South Island are shown below in Figure 3. All South Island SIR prices this week remained below $5/MWh. North Island SIR prices spiked on Tuesday and Thursday, with the largest spike at over ~$140/MWh. This price spike coincided with the $344/MWh North Island spot price, North-South Island price separation, low wind generation, and while the HVDC was transferring high load northward.

3.3. These SIR price spikes were likely due to a tight supply of reserves, resulting from thermal outages, high HVDC transfer and absence of reserve sharing increasing reserve demand,

and SPD co-optimisation, with North Island reserves being dispatched instead of higher priced energy offers.

Figure 3: SIR prices by trading period and Island

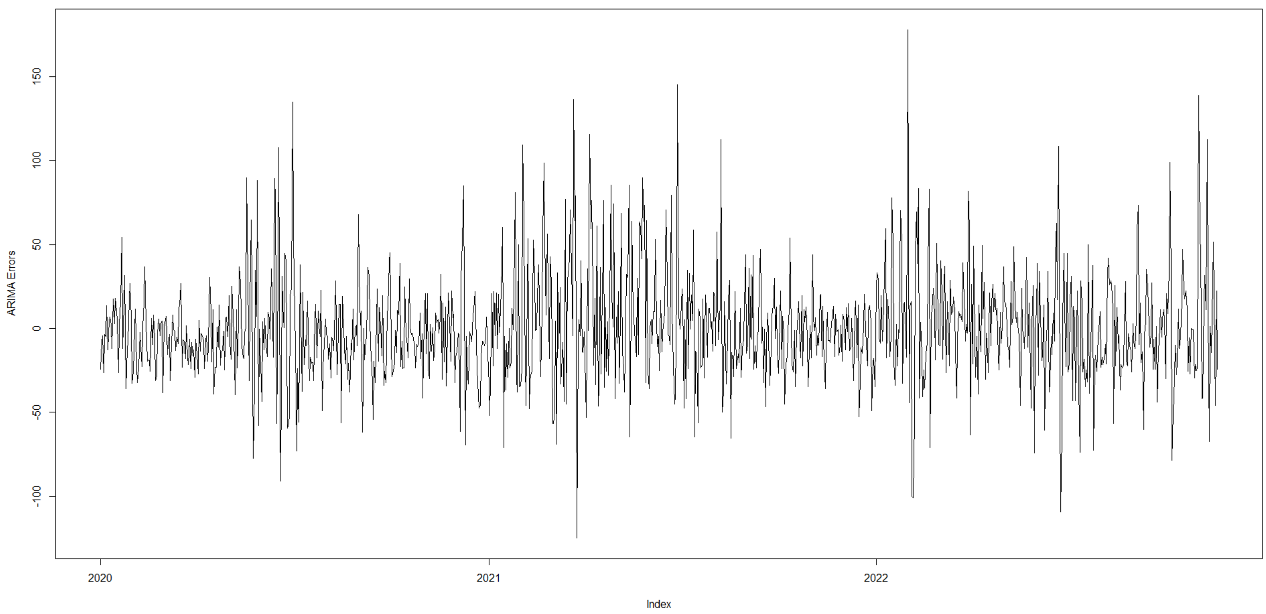


4. Regression Residuals

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[2] on the trading conduct webpage.

4.2. Figure 4 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Residuals for 13-19 November were generally small, suggesting that prices on those dates appear to be aligned with market conditions.

Figure 4: Residual plot of estimated daily average spot prices

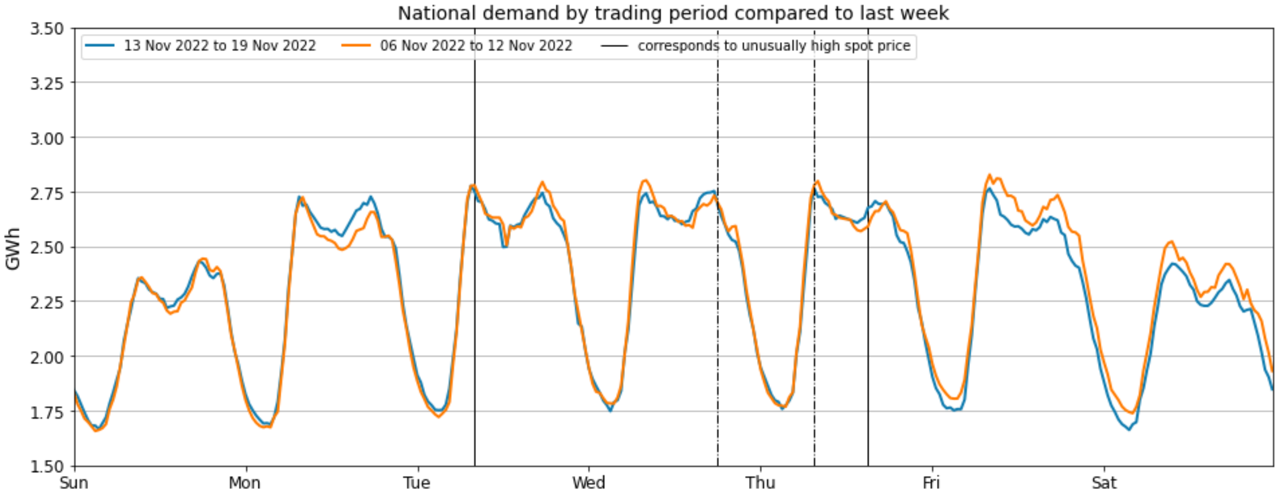


[2] https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Regression-Analysis.pdf

5. Demand

5.1. Figure 5 shows this week's national grid demand compared to the previous week. Demand between 13-19 November was similar to, or slightly less than, the previous week, due to the continued warmer temperatures, which generally reduces demand.

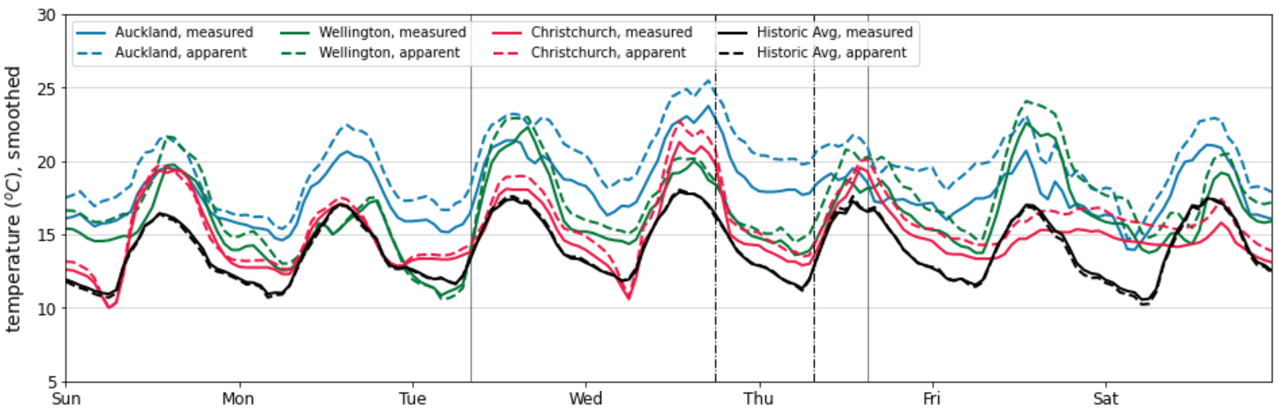
Figure 5: National demand by trading period compared to the previous week



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. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

5.3. Temperatures were mostly above average this week across Auckland, and Wellington and Christchurch, with between 10 and 24 degrees throughout the week.

Figure 6: Temperatures across main centres



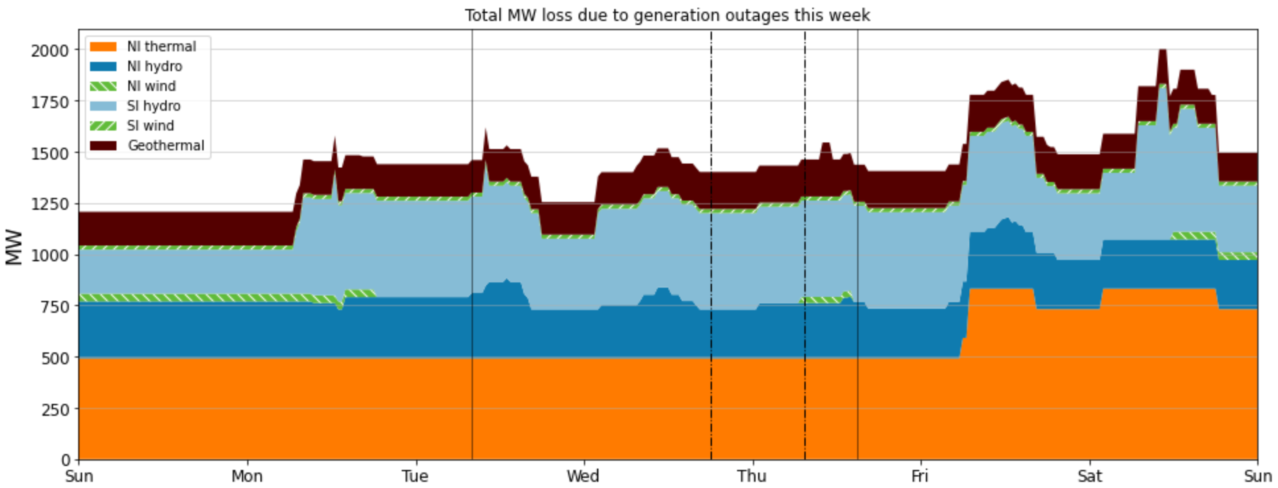
6. Outages

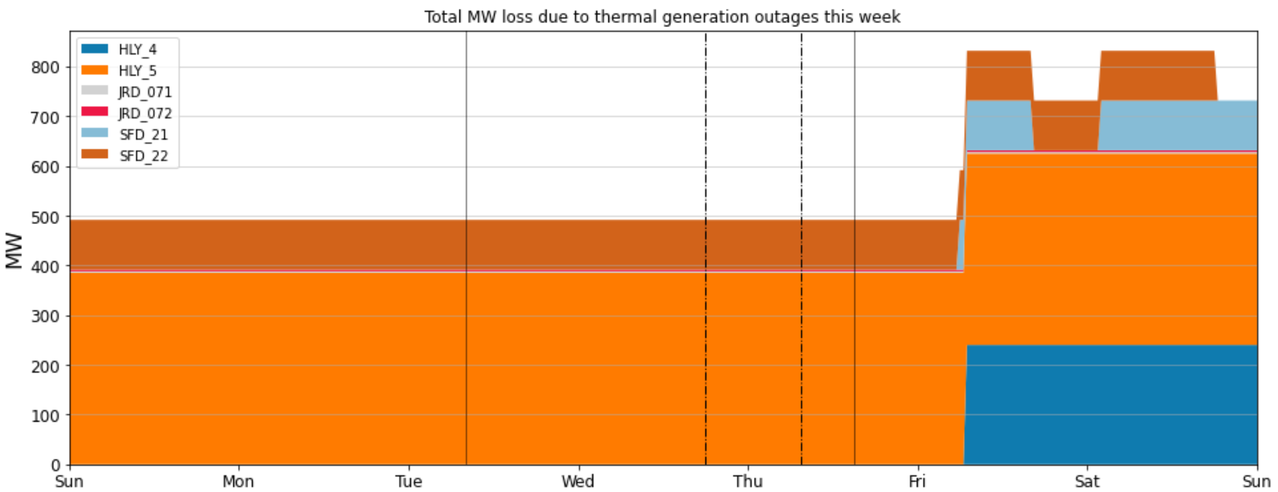
6.1. Figure 7 shows generation capacity on outage. Total capacity on outage ranged between ~1,250 – 1,750 MW over the week. Outages increased to over 1,750MW on Friday as more thermal generation went on outage. Outages stepped up to 2,000 on Saturday as more South Island hydro went on outage.

6.2. Outages of note include:

- The second Stratford peaker remained on outage.
- The first Stratford peaker had an outage on Friday and Saturday.
- Huntly 5 remained on outage.
- Huntly 4 went outage on Friday.
- Over 100 MW of geothermal generation was on outage throughout the week.

Figure 7: Total MW loss due to generation outages

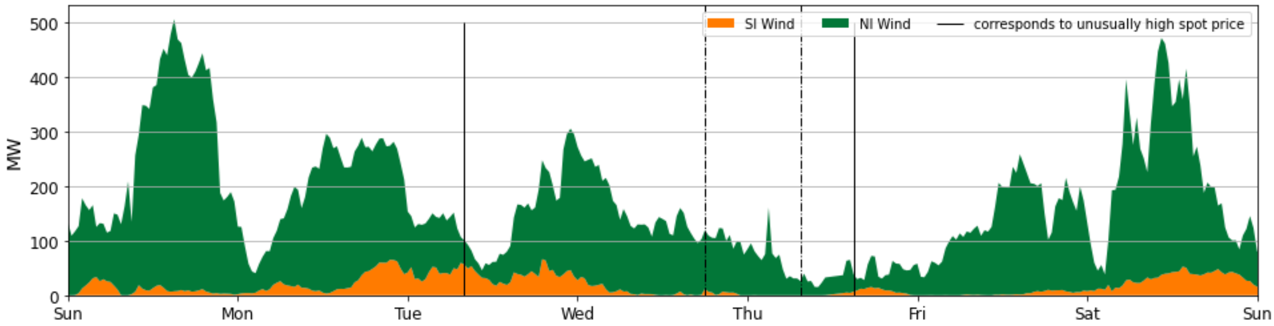




7. Generation

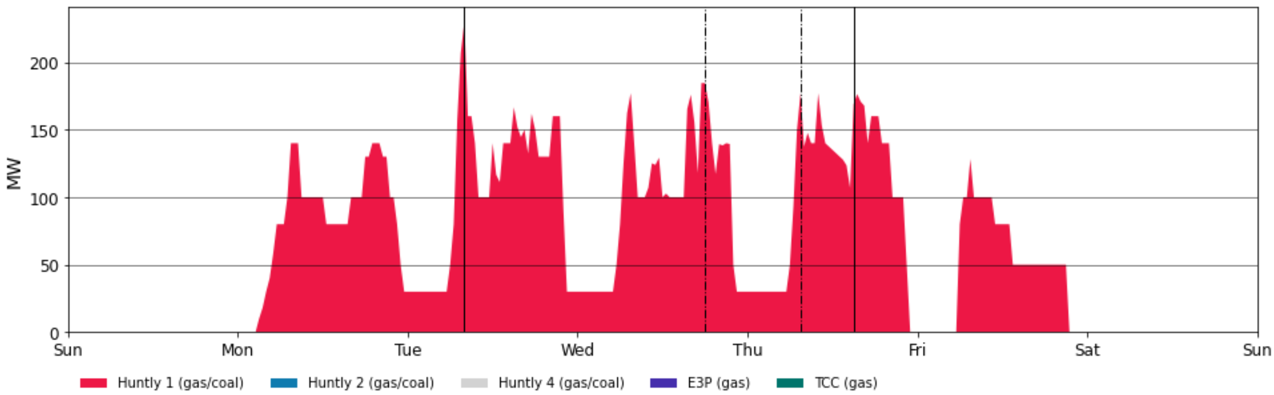
7.1. This week wind generation varied between ~20 and 500 MW, as seen in Figure 8 – a large reduction on previous weeks. Wind generation was mostly below 300 MW all week, with only a few hours on Sunday and Saturday seeing wind above 300MW. Wind generation was roughly 100 MW during the Tuesday morning price spike and less than 50 MW during the Thursday afternoon price spike. Low wind in general this week contributed to increased price volatility and increased price, both during peak and off-peak periods.

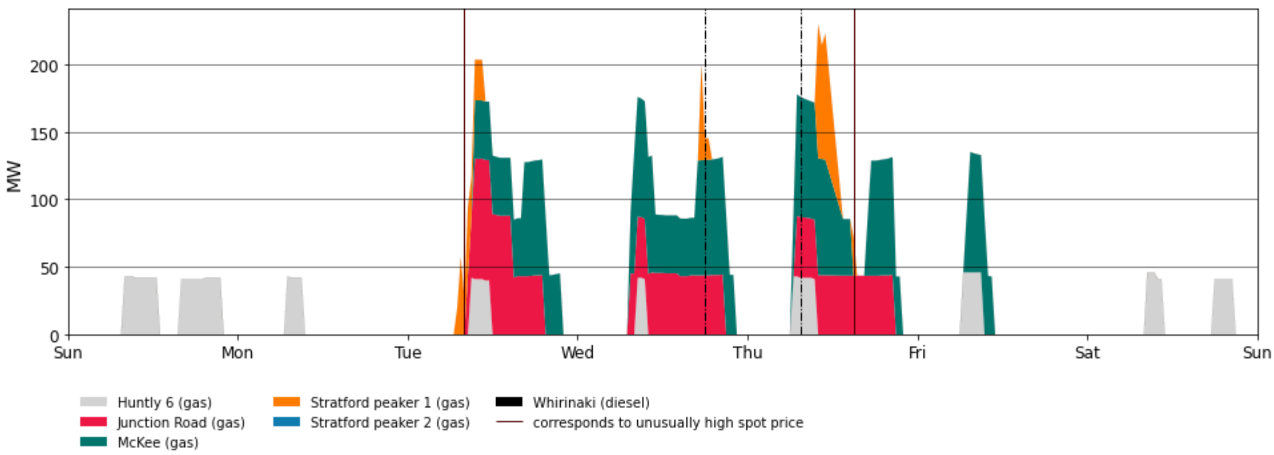
Figure 8: Wind Generation



7.2. Figure 9 shows generation of thermal baseload and thermal peaker plants between 13-19 November. Huntly 1 ran during the day as baseload, and increased output during peak times, between Monday and Friday after which it was switched off, likely due to higher wind and low demand.

Figure 9: Thermal Generation





7.3. Huntly 6 ran during the day on Sunday, likely to cover baseload while no other Huntly units were running. Huntly 6 then ran during the morning peaks on Monday to Friday, however, Huntly 6 was priced high during the Tuesday morning price spike. Junction Road and McKee ran long stints on Tuesday to Friday, ramping up to meet the peaks. Stratford 1 ran on Tuesday, Wednesday and Thursday.

7.4. As a percentage of total generation, between 14-20 November, hydro totalled 78.6 percent, geothermal 14.6 percent, thermal 2.0 percent and wind 2.9 percent.

8. Storage/Fuel Supply

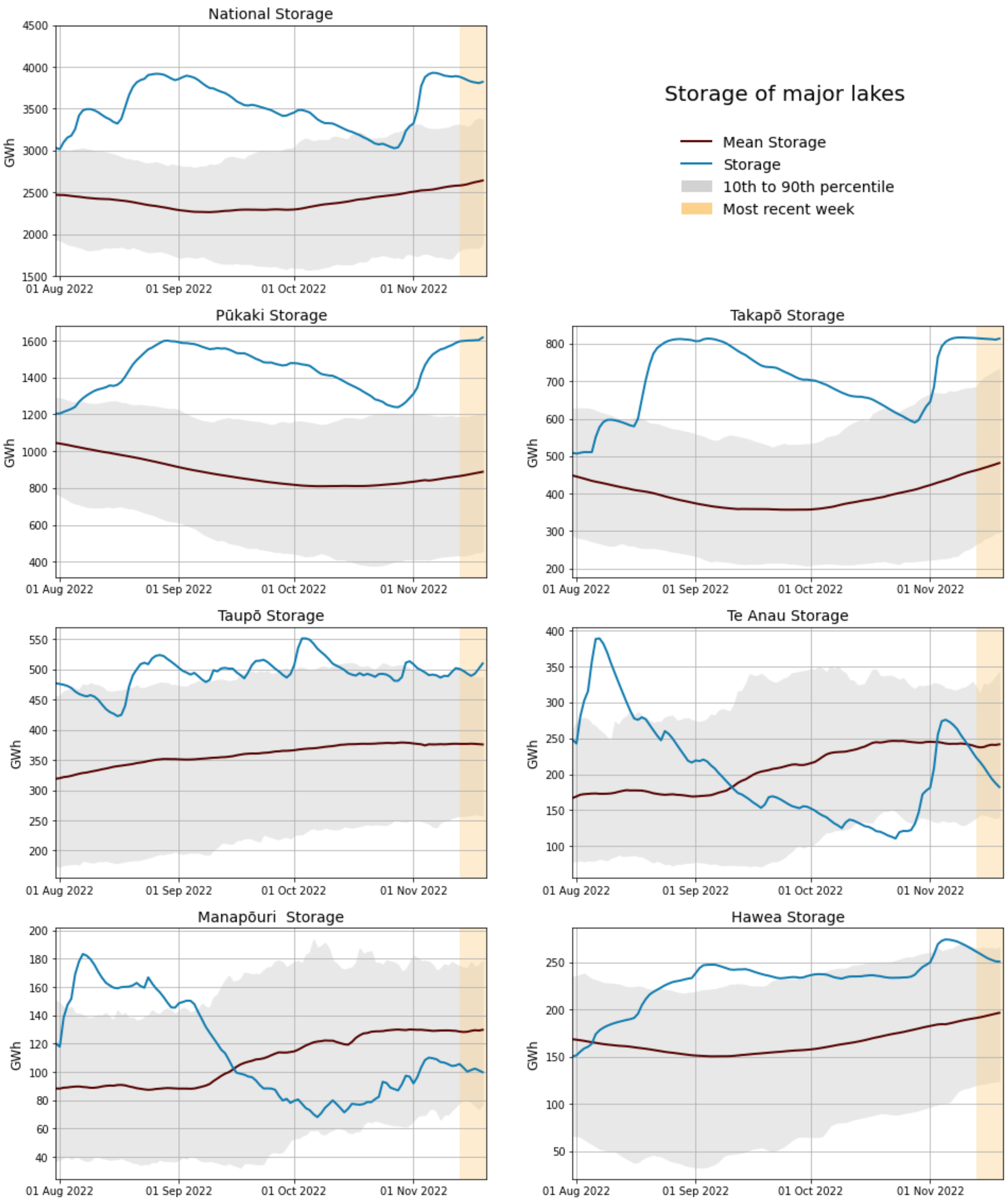
8.1. Figure 10 shows total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

8.2. National hydro storage levels increased slightly due to rainfall last week, and is now around 92 per cent of nominal full.

8.3. Lakes Hawea, Takapō and Pūkaki all remain well above their 90th percentiles this week. Storage at Lake Te Anau continued to fall below its historic mean, while Manapōuri remains more steady below its historic mean. Storage at Lake Taupō increased this week.

8.4. The flow of the HVDC was northward all week.

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 is 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.

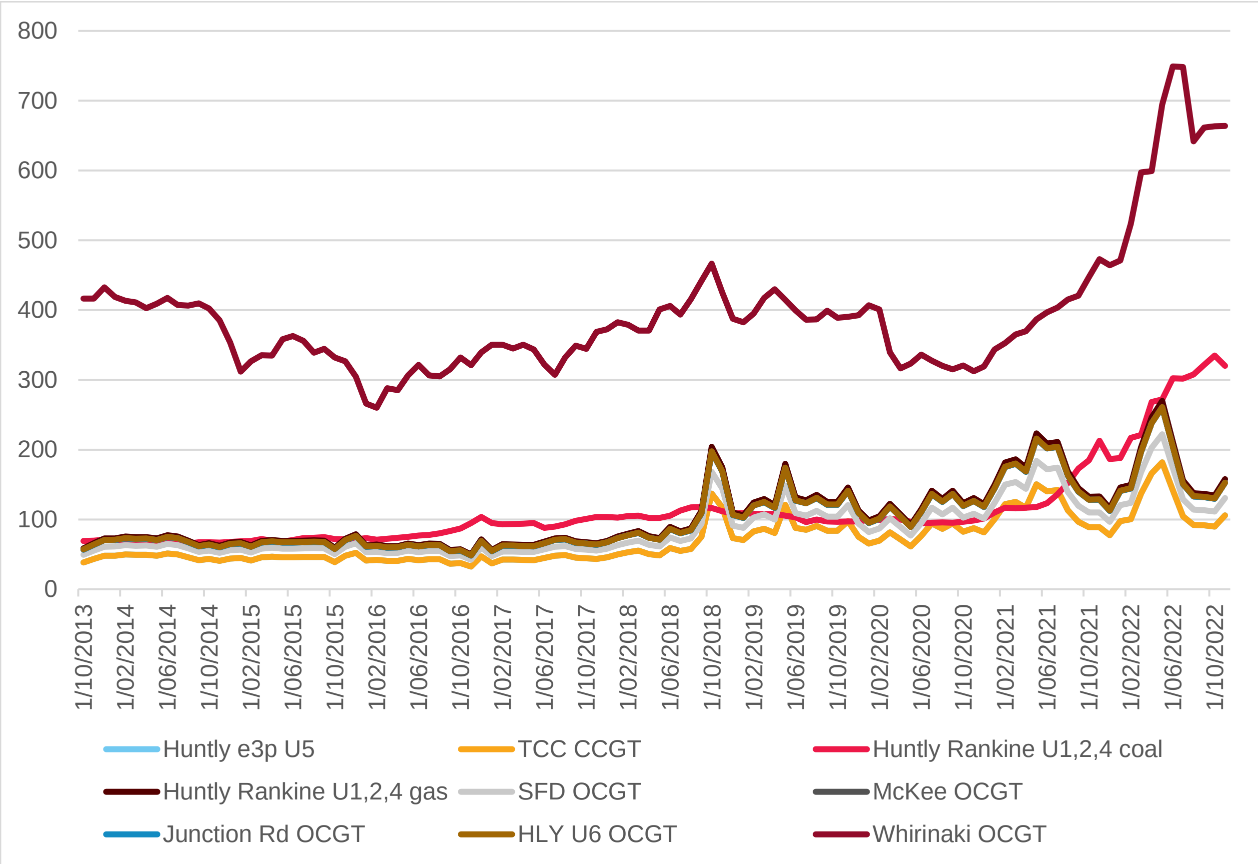
9.3. Figure 11 shows an estimate of thermal SRMCs as a monthly average up to 1 November 2022. The SRMC of gas fuelled plants has increased, the SRMC of diesel remains below its June peak, while the SRMC of coal has fallen.

9.4. In early November Indonesian coal was around ~$560/tonne putting the latest SRMC of coal fuelled Huntly generation at ~$320/MWh. The SRMC of Whirinaki has stayed constant at ~$660/MWh. Both are likely reactions to a slight easing of international demand.

9.5. The SRMC of gas run thermal plants increased slightly to between $105/MWh and $160/MWh, likely due to the decrease in gas fuel availability in the market with Kupe on outage in November.

9.6. 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. Offer Behaviour

10.1. Figure 12 shows this week's daily offer stacks from WITS[4]. The black line shows cleared energy, indicating the range of the average final price.

10.2. The majority of cleared energy on the Saturday and Sunday was cleared in the $0-10/MWh or $10-50/MWh bands. While during the week it fell in mostly in the $50-100/MWh band, with some instances of dispatch in the $100-1000/MWh band. This jump in clearing price reflects the tighter supply of energy in the North Island this week, especially during times of low wind, and with more peakers being dispatched to cover baseload, due to the E3P outage.

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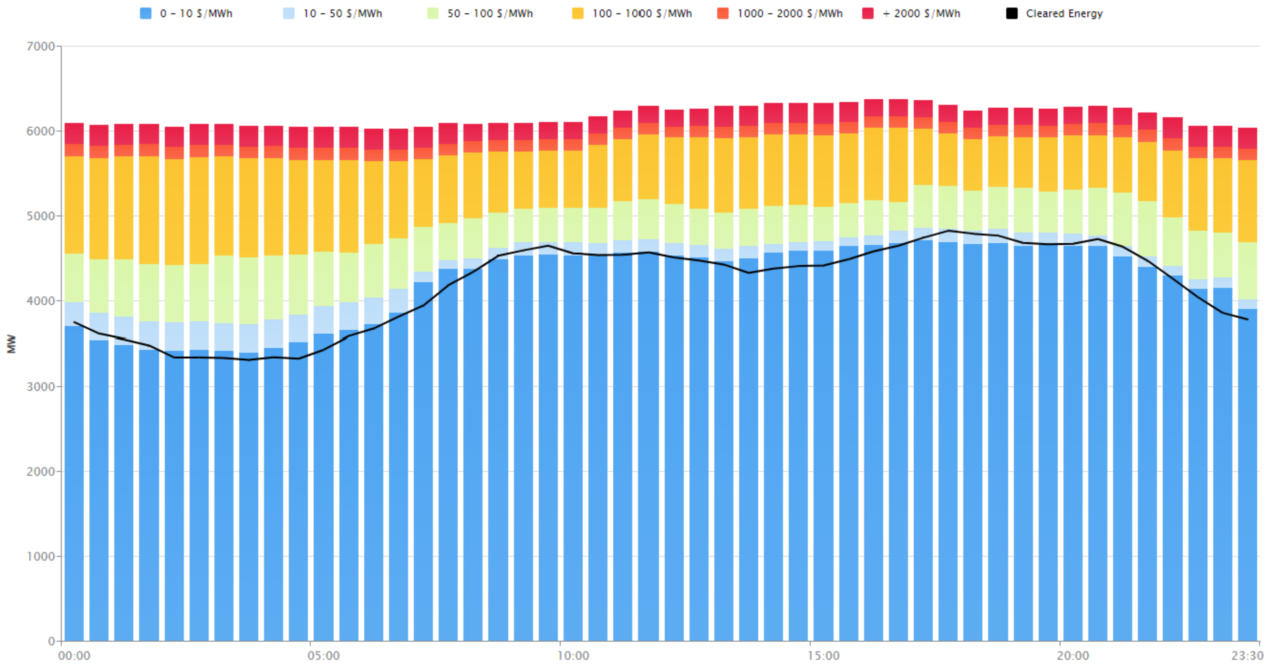
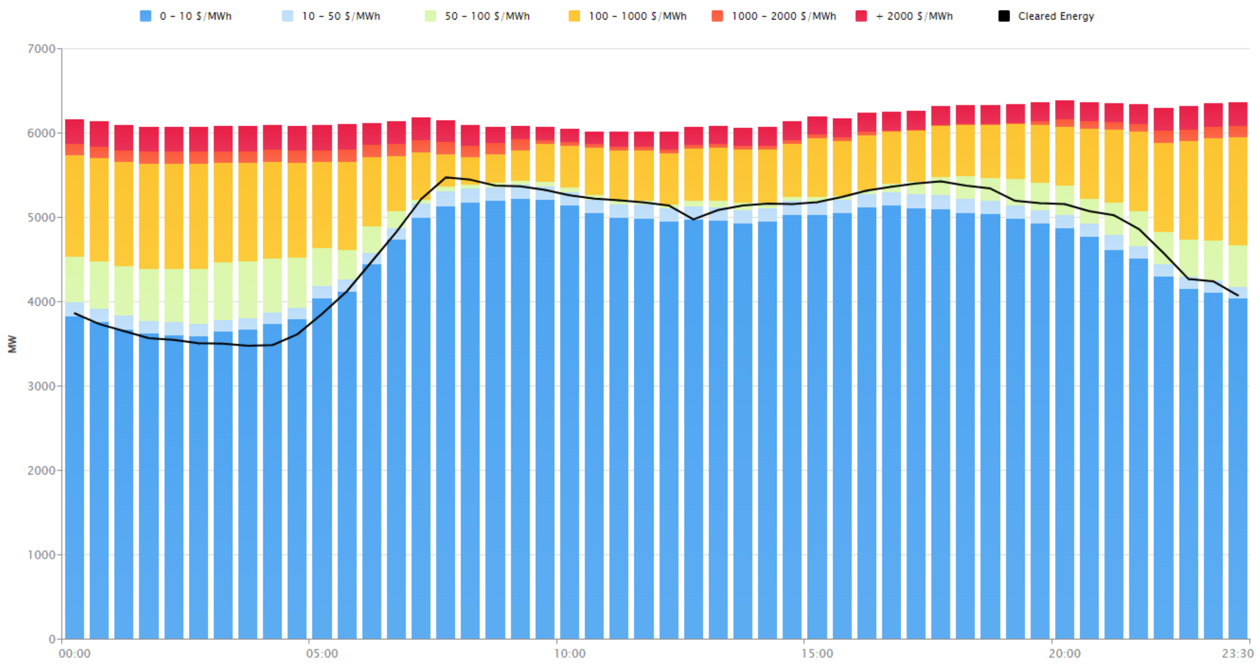
[3] https://www.ea.govt.nz/assets/dms-assets/30/Appendix-C-Calculating-thermal-SRMCs.pdf
[4] Cleared Energy Stack | WITS (electricityinfo.co.nz)

Figure 12: National daily offer stack from WITS

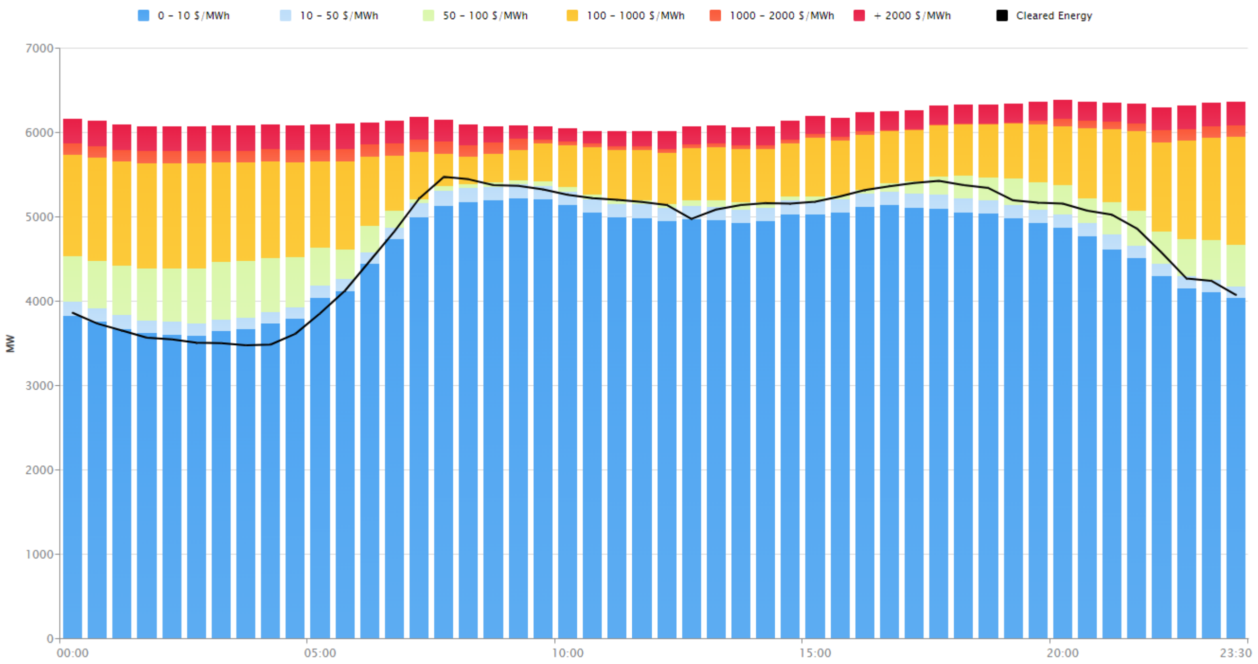
Sunday 13 November



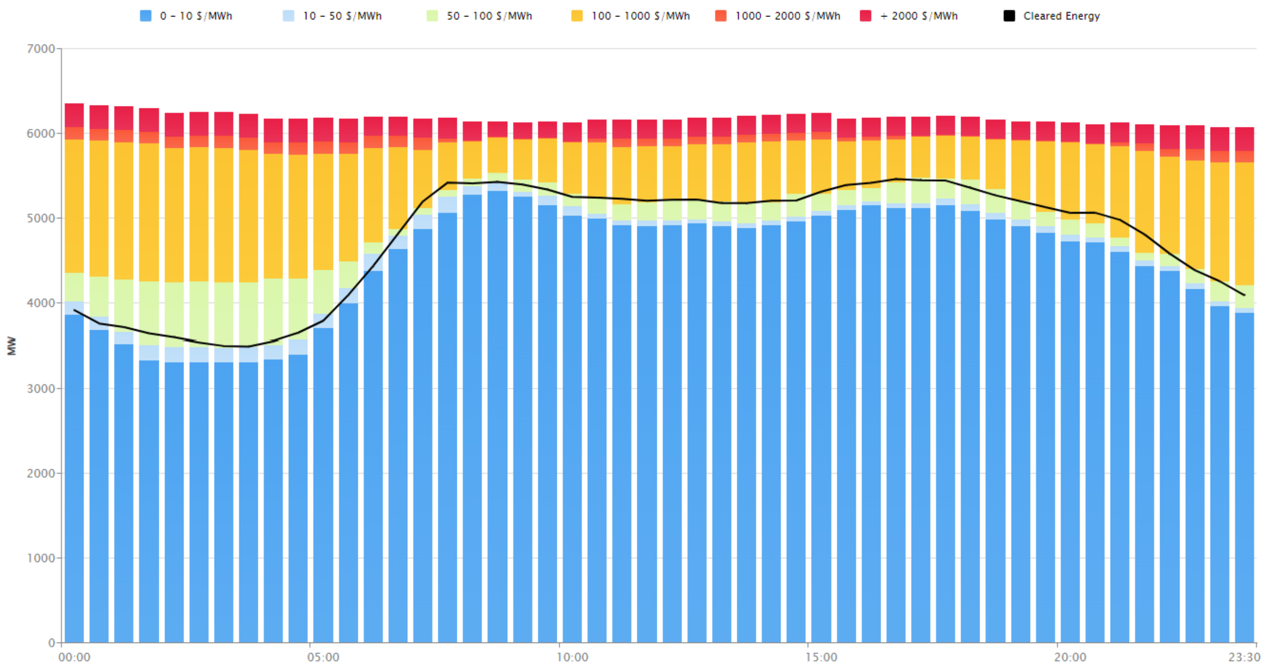
Monday 14 November



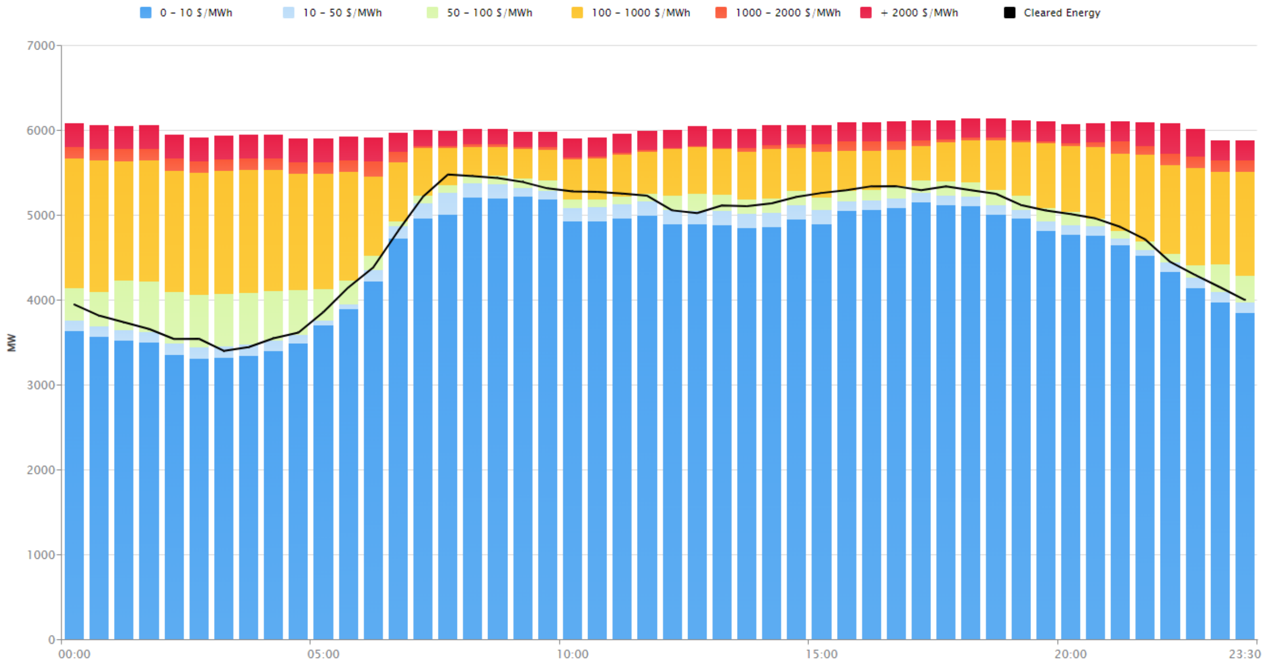
Tuesday 15 November



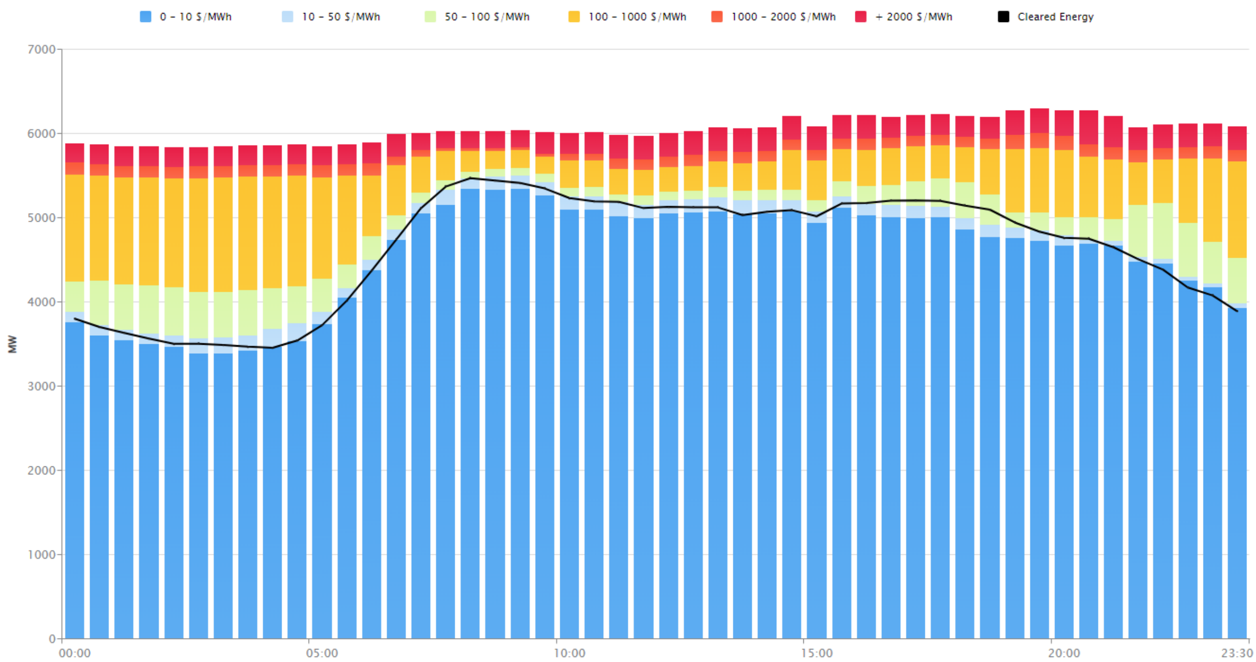
Wednesday 16 November



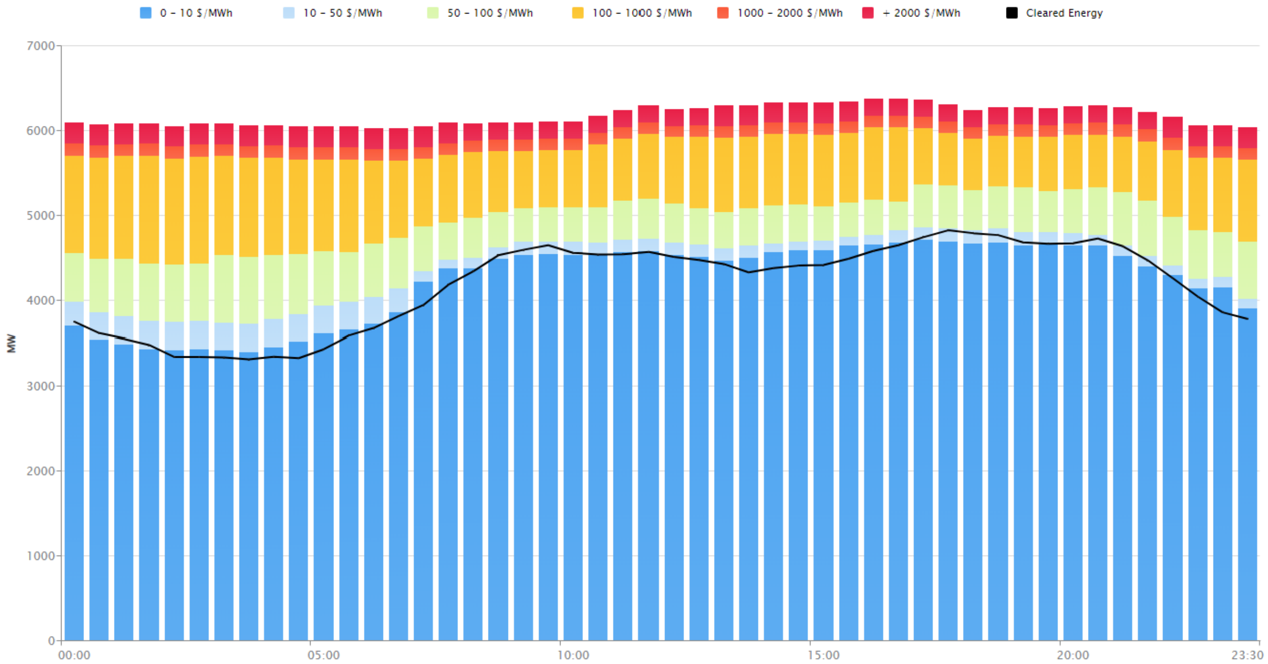
Thursday 17 November



Friday 18 November



Saturday 19 November



11. Ongoing Work in Trading Conduct

11.1. This week most prices appeared to be consistent with supply and demand conditions, however a few trading periods were identified for further analysis.

11.2. 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.
07/10/22	15-16	Further analysis	The Authority is making enquires with Genesis regarding offers changes to final tranche prices at Huntly 1,4 and 5 for trading period 15-16.
15/11/2022	17	Further analysis	The Authority will continue analysis into the high energy price.
16/11/2022	37	Further analysis	The Authority will continue analysis into the high energy price.
17/11/2022	16 & 31	Further analysis	The Authority will continue analysis into high energy prices.