17 November 2021

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 7 to 13 November

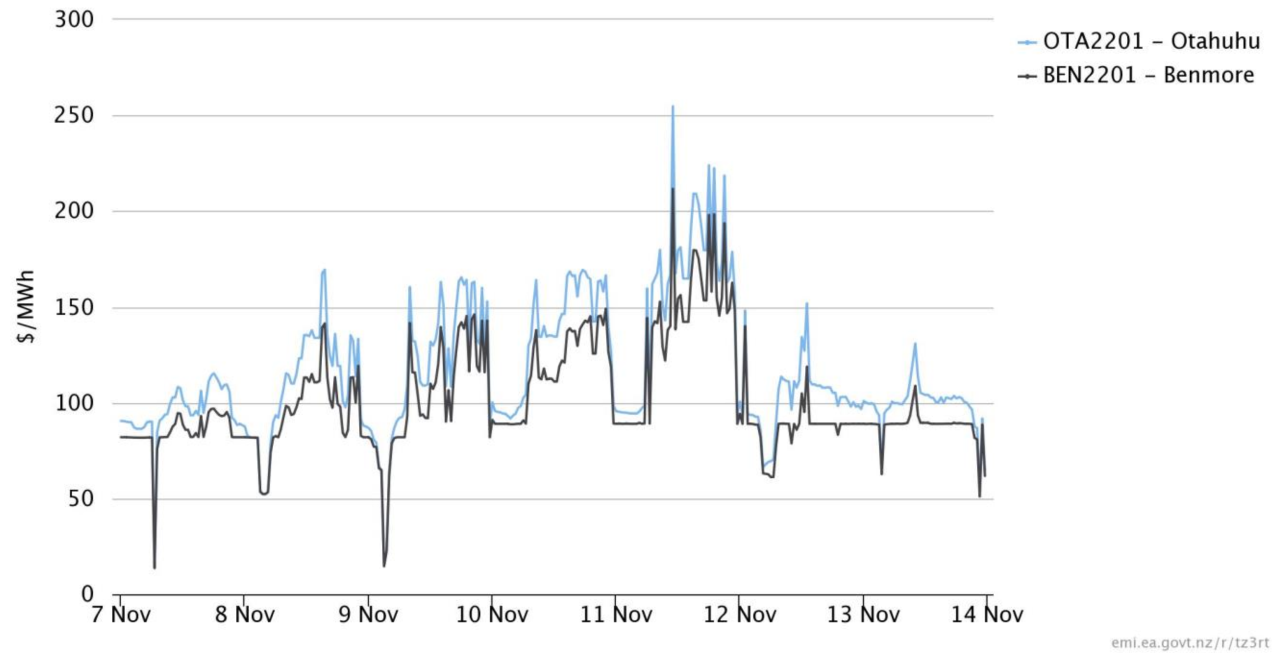
1.1. Prices this week appear to be consistent with underlying supply and demand conditions. Higher prices appear to be due to low wind generation and an increase in planned outages.

2. Prices

Energy prices

2.1. The average spot price this week was $108/MWh[1], 53% higher than last week. This was due to more frequent prices over $100/MWh and fewer low priced periods overnight (see Figure 1). The highest prices occurred on Thursday, peaking at $255/MWh at Otahuhu, TP23 on 11 November.

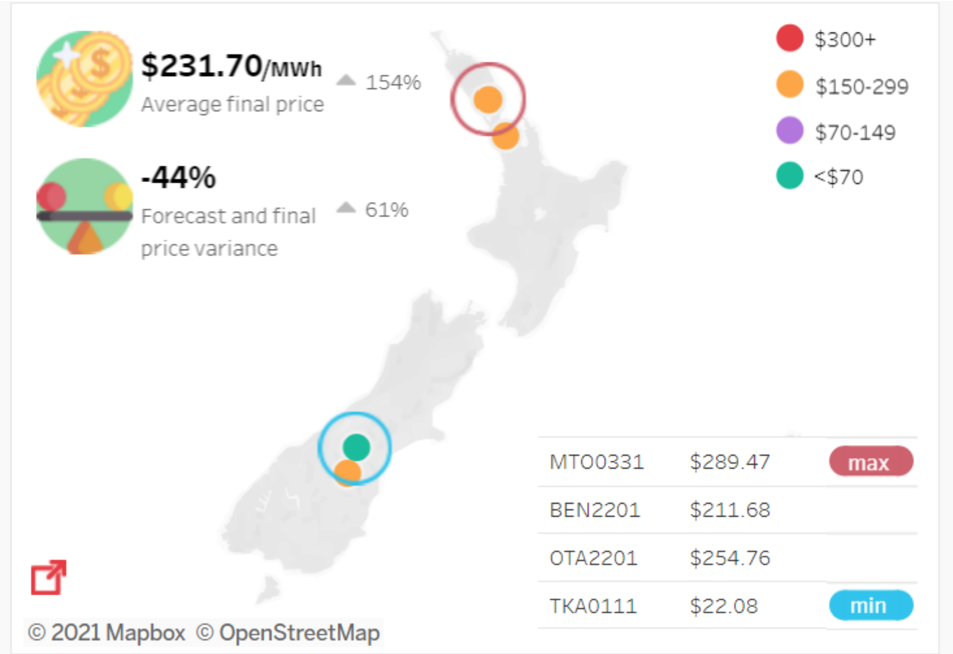
Figure 1: Spot prices by trading period at Otahuhu and Benmore



[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

2.2. Figure 2 shows the average price for TP23 on 11 November, as well as the price at Otahuhu, Benmore, the highest price node and lowest price node. Most prices were above $200/MWh with higher prices further north. There was price separation between Tekapo A and Benmore due to a transmission outage from 8 to 12 November of a Tekapo A transmission line. While this caused lower prices at the Tekapo A node, it unlikely had a significant impact on prices due to the small capacity of Tekapo A.

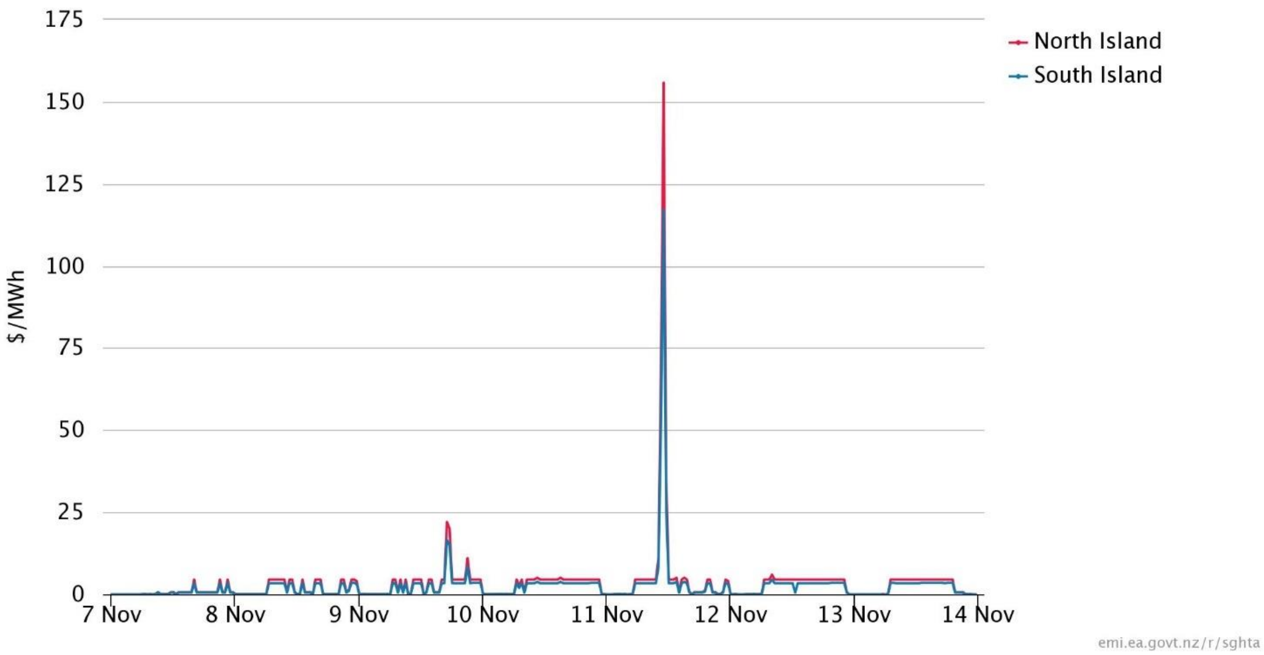
Figure 2: Spot prices for TP23 on 11 November compared to the previous week



Reserve Prices

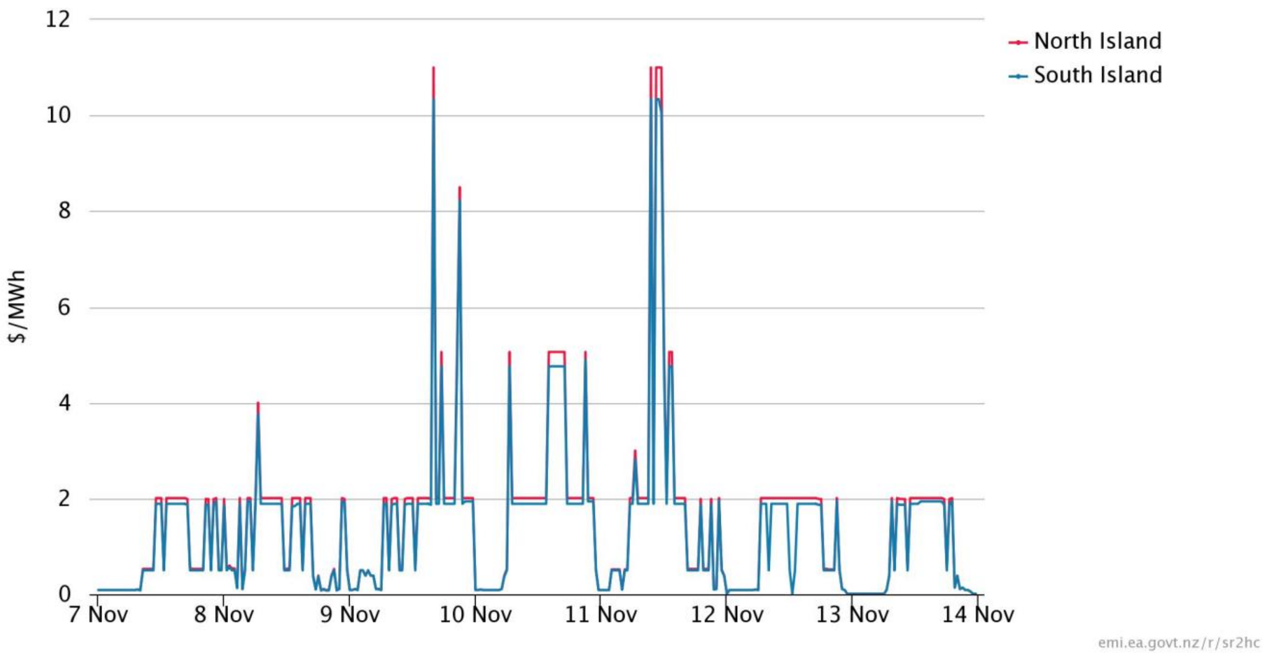
2.3. Fast instantaneous reserves (FIR) prices were usually below $25/MWh. However, the price reached $156/MWh during at TP23 11 November (see Figure 3), which is also when the highest energy price occurred.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were below $12/MWh the entire week (see Figure 4)

Figure 4: SIR prices by trading period and Island

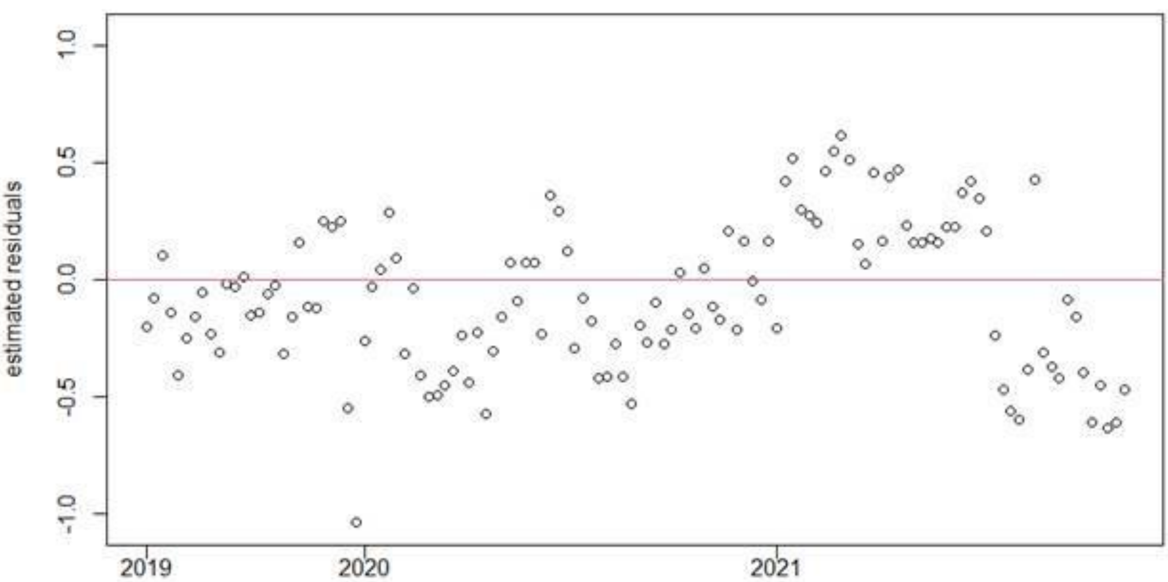


Residuals from regression models

2.5. 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.

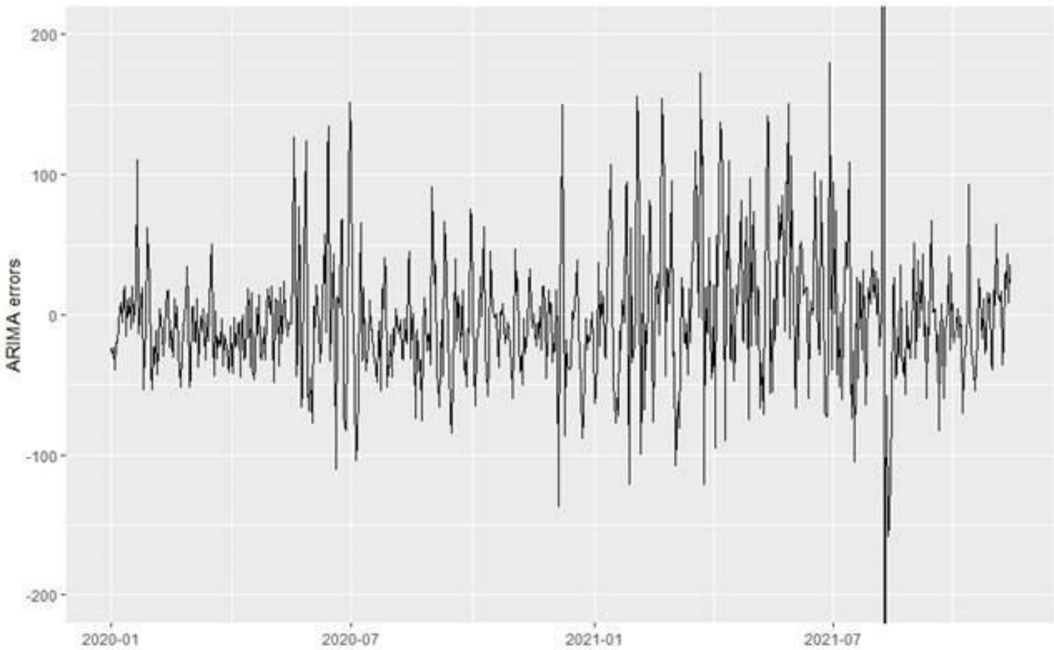
2.6. Figure 5 shows the residuals from the weekly model. During October 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 28 October 2021



2.7. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were within the normal range.

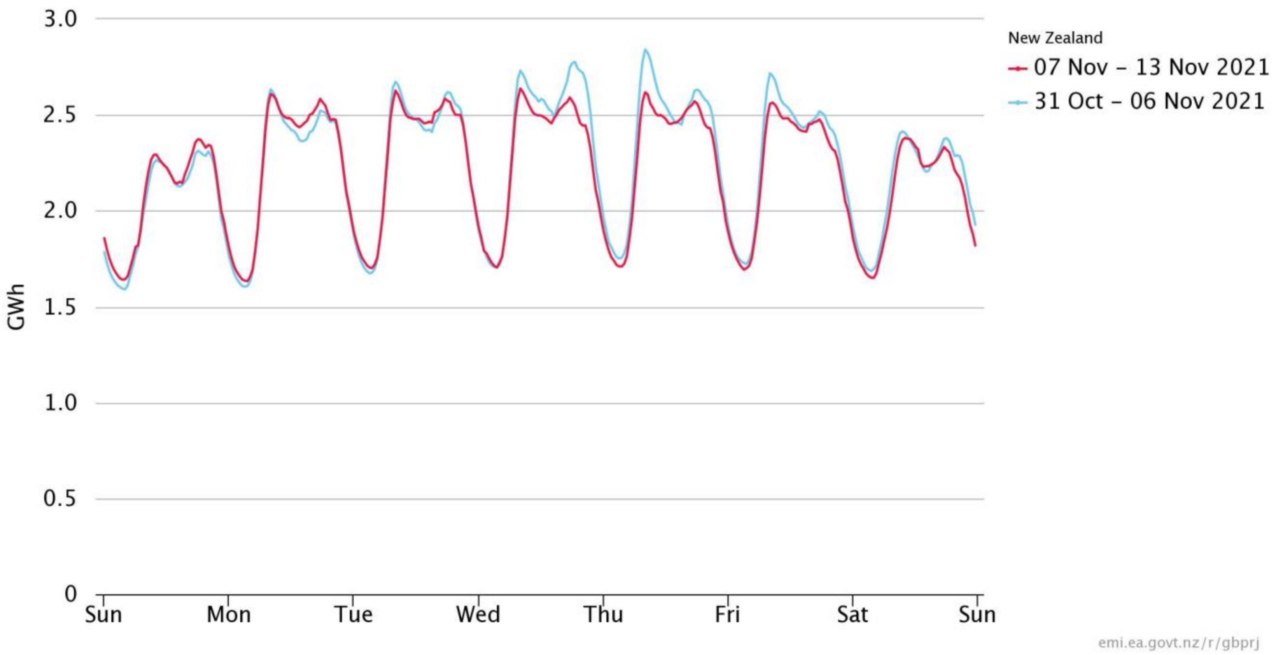
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 13 November 2021



3. Demand Conditions

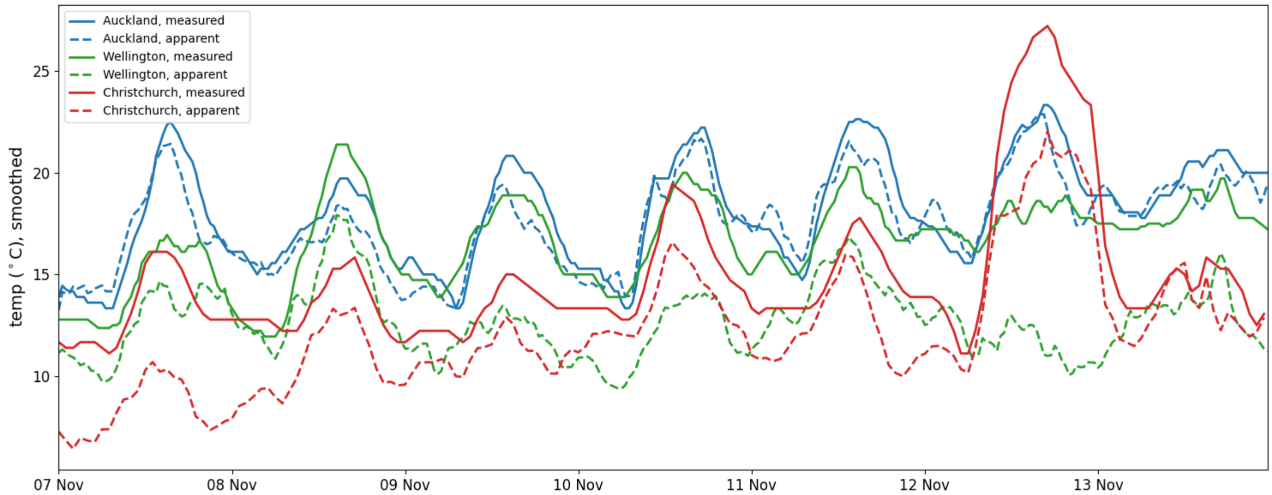
3.1. National demand was 1% lower than the previous week (see Figure 7). This was due to warmer temperatures than last week, especially from Wednesday to Friday (see Figure 8).

Figure 7: National demand compared for current and previous week



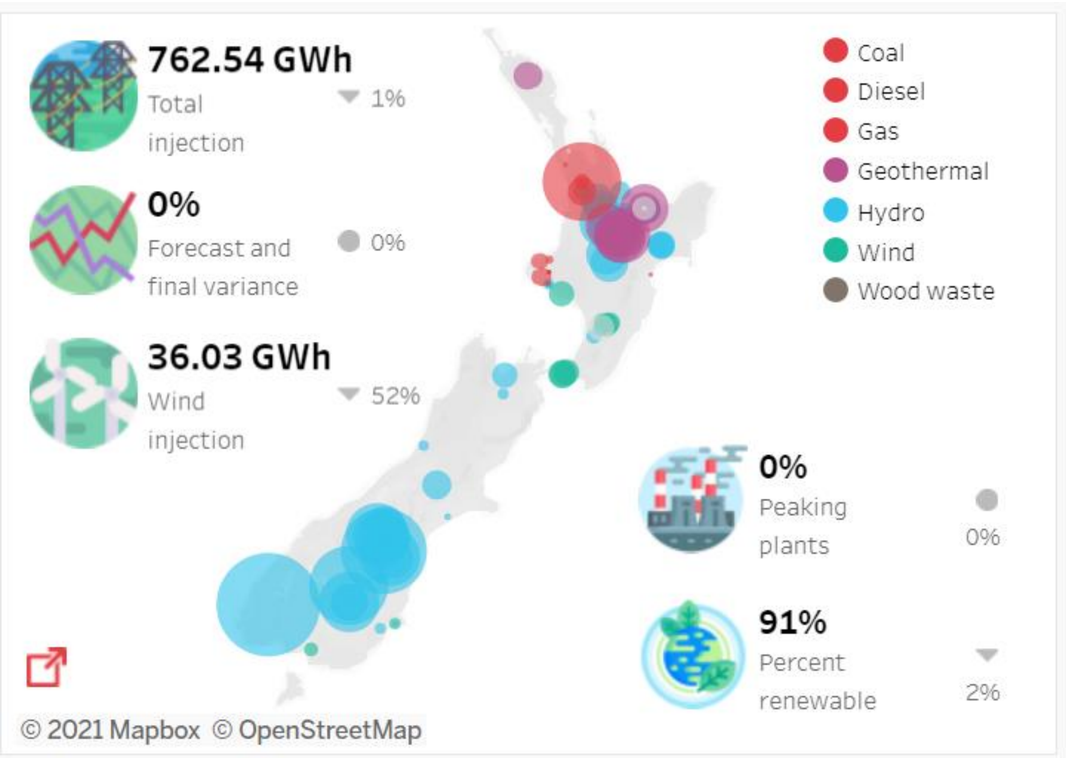
3.2. Figure 8 shows hourly temperature data at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. This week was warmer than last week with measured temperatures staying above 10°C the whole week.

Figure 8: Hourly temperature data (actual and apparent) at main population centres



4. Supply Conditions

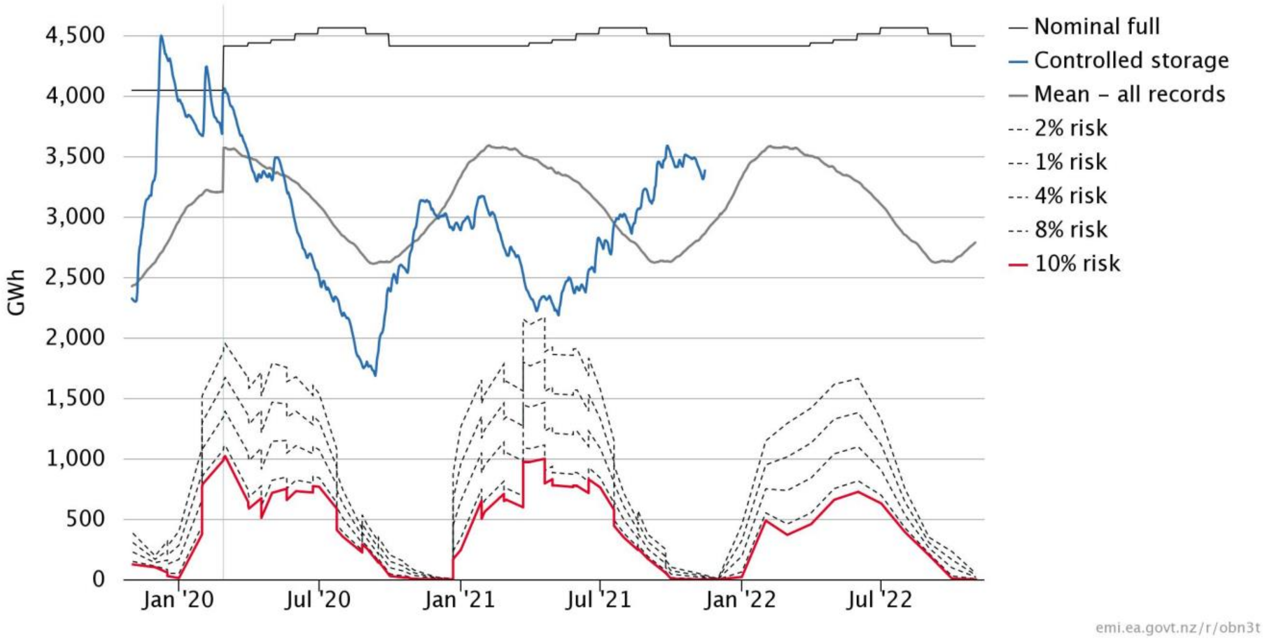
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage continued declining until high inflows on 13 November increased storage, shown in Figure 10.

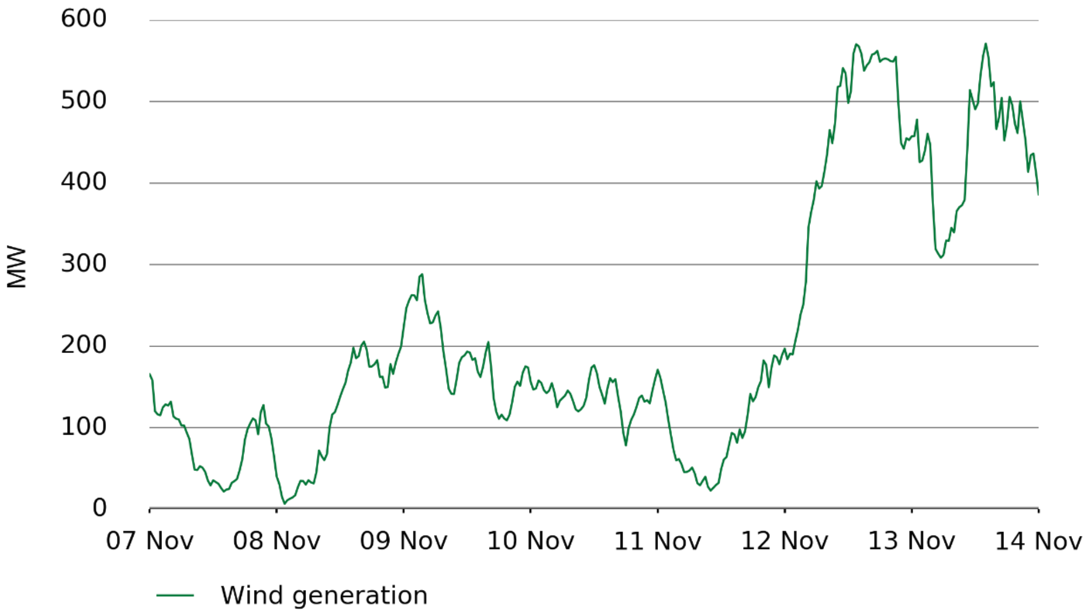
Figure 10: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 36GWh, 52% lower than wind generation last week. Wind generation was below 300MW from 7 to 11 November then increased on 12 and 13 November to over 500MW (see Figure 11). Wind generation was particularly low on morning of 11 November, which coincided with higher prices.

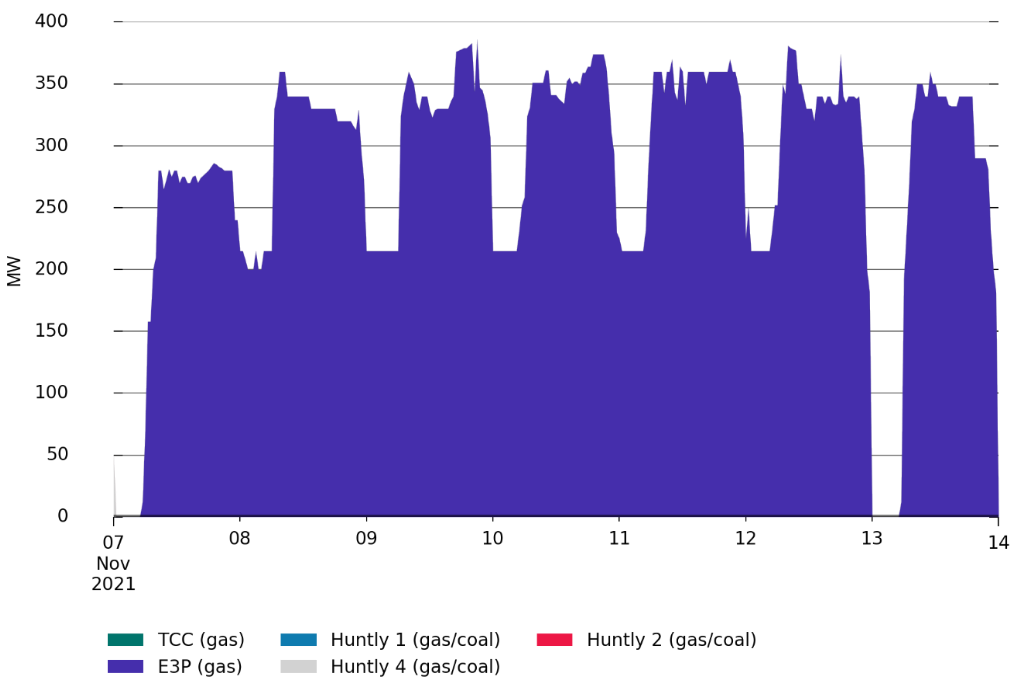
Figure 11: Wind generation by trading period



Thermal conditions

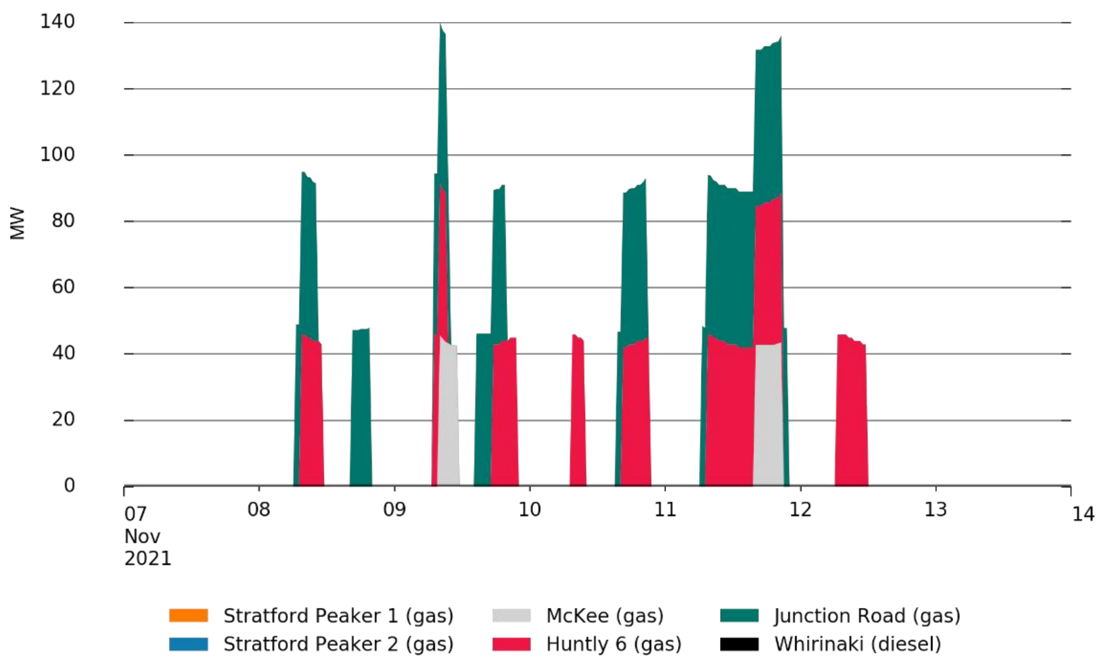
4.3. Baseload thermal generation remains low with only Huntly's E3P running as baseload this week (Figure 12).

Figure 12: Generation from baseload thermal by trading period



4.4. There was an increase in generation from thermal peakers this week, likely due to low wind generation (Figure 13) and generation outages. The Stratford peakers did not run as they were on outage this week (see 4.6(g)). McKee also had one unit on outage from 8 to 10 November (4.6(i)). and Junction Road had one unit on outage from 11 November (4.6(l))

Figure 13: Generation from thermal peakers by trading period



Significant outages

4.5. There was a noticeable increase in outages this week, and this likely contributed to higher prices. In particular, 3 significant outages started on 11 November, reducing available generation by an additional 173MW. One of these was a geothermal unit at Te Mihi which reduced baseload generation by 83MW and the highest price this week occurred shortly after the start of this outage.

4.6. The following outages reduced available generation by at least 50MW:

(a) Clyde, 116MW (long term outage)

(b) Benmore,

  (i) 90MW (5 July – 26 November)

  (ii) 90MW (8am-3pm 9 November)

  (iii) 450MW (6:30am-9pm 13 November)

(c) Manapouri,

  (i) 125MW (19 July –8 November)

  (ii) 125MW (11am-3pm 9 November)

(d) Tekapo, 80MW (13 September – 16 January 2022)

(e) Huntly,

  (i) Rankine unit; 240MW (4 October-19 December)

  (ii) Rankine unit; 240MW (8-9 November)

(f) Ohau,

  (i) 53MW (1-12 November)

  (ii) 66MW (11am-4pm 12 November)

(g) McKee, 50MW (8-10 November)

(h) Maraetai (Waikato River)

  (i) 35.2MW (10-19 November)

  (ii) 35.2MW (11 November -17 December)

(i) Stratford,

  (i) 100MW, (31 October-13 December)

  (ii) 100MW (7-24 November)

(j) Waipipi, 133MW (7:30am-5pm, 7 November)

(k) Waipori, 72MW (8 November – 28 January 2022)

(l) Junction Road,

  (i) 50MW (11-14 November)

  (ii) 50MW (13-16 November)

(m) Te Mihi geothermal, 83MW, (10:00am-3pm, 11 November)

(n) Aviemore, 55MW (11-26 November)

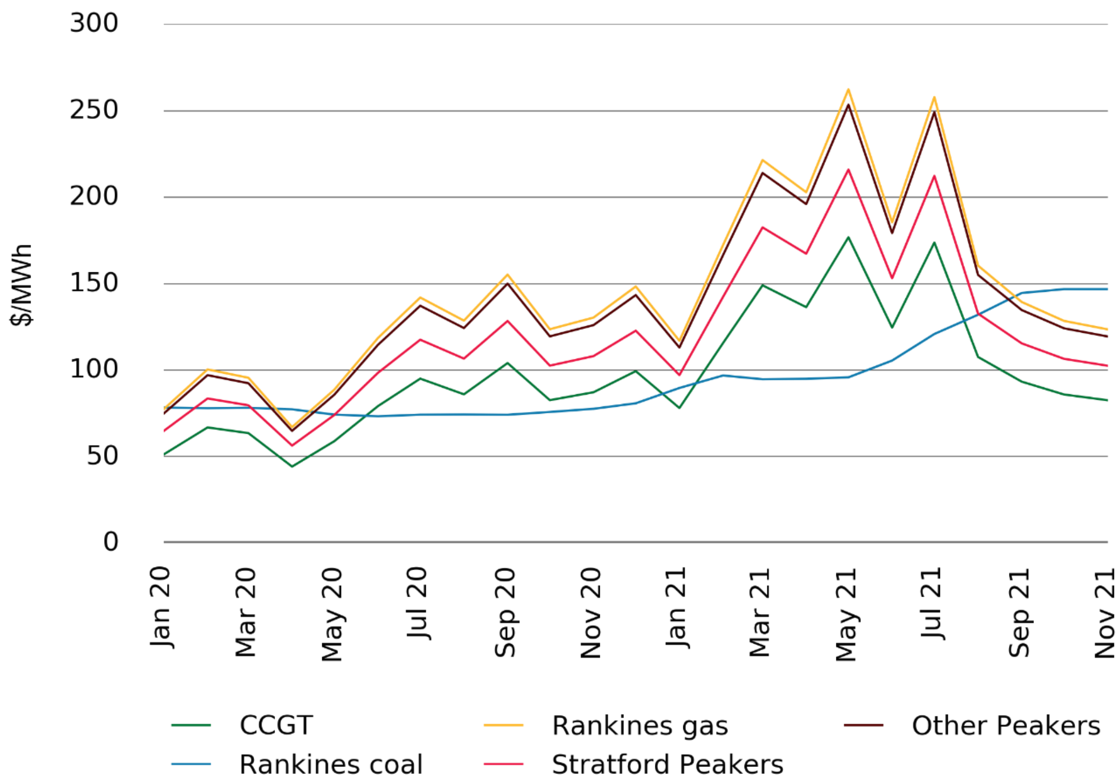
5. Price versus estimated costs

5.1. In a competitive market prices should be close to (but not necessarily at) the short run marginal cost (SRMC) if the marginal generator (where SRMC includes opportunity cost).

Thermal Fuels

5.2. 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. Figure 12 shows estimates of thermal SRMCs as a monthly average. The thermal SRMC for both gas and coal fuelled generation in November (to 14 November) is similar to October[2].

Figure 14: Estimated monthly SRMC for thermal fuels



[2] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

Offer Behaviour

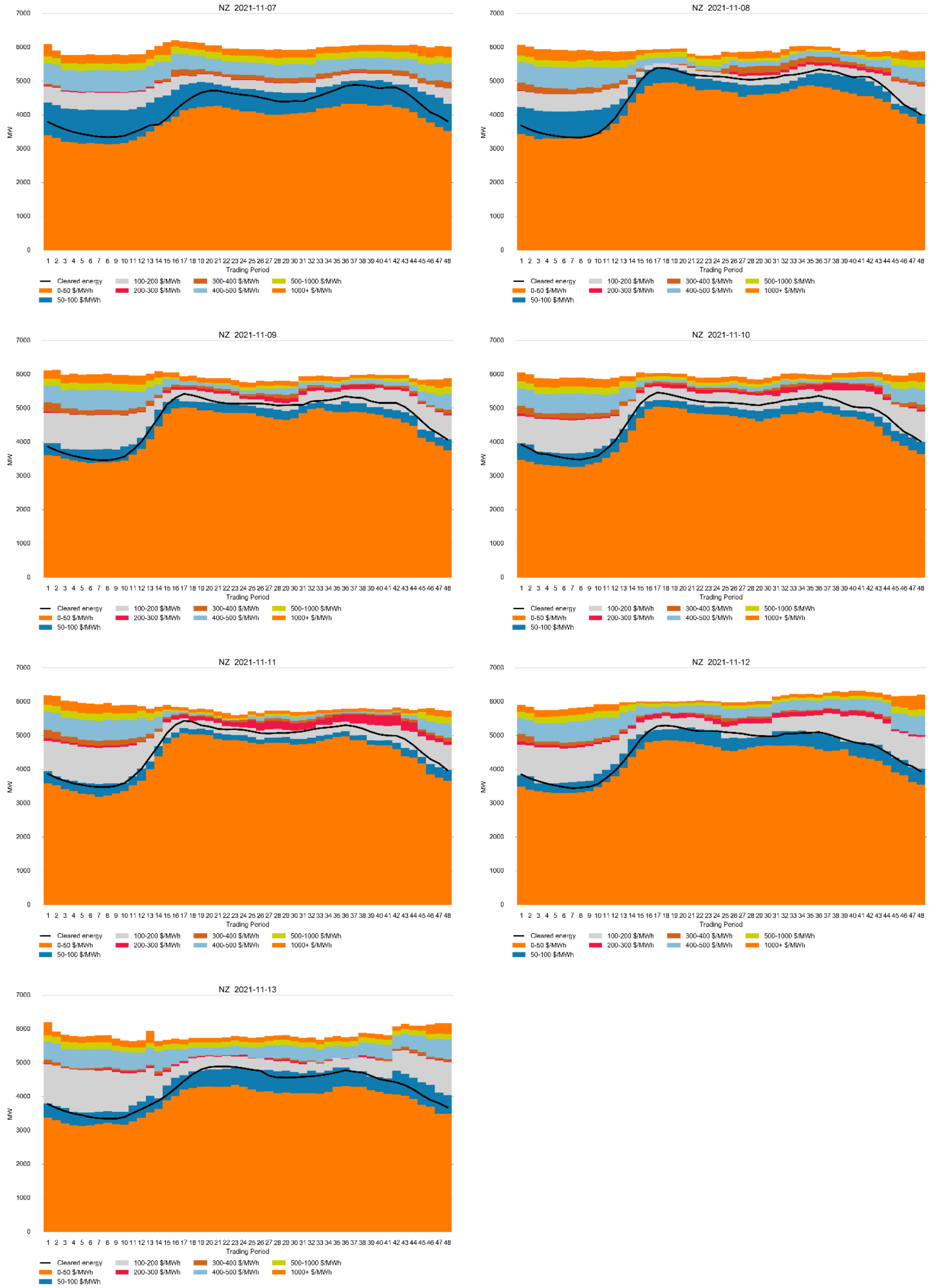
Final daily offer stacks

5.3. Figure 13 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[3] The black line shows the cleared energy, indicating the range of the average final price.

5.4. This week low wind and outages had a noticeable impact on the offer stacks, reducing total generation offered to the market and creating steep offer stacks. The quantity of offers above $350/MWh reduced by 8% over the whole week, but there were more offers between $100-$200/MWh, resulting in a similar quantity weighted offer price as last week. This is particularly noticeable on 11 November, as total quantity offered decline, less generation was offered between $50-$100/MWh compared to surrounding days and more offered between $200-$300/MWh.

[3] 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 15: Daily offer stack



Offers by trading period

5.5. The trading period (TP) with the highest price at Otahuhu was TP23 (11:00am) on 11 November is shown on Figure 14 as well as the day immediately before on Figure 15). Each graph shows the offer stack, the generation weighted average price (GWAP) and cleared generation.

5.6. Cleared generation as similar at TP23 on both days, however the offer stack was steeper on 11 November than on 10 November which caused higher prices. The timing of the high price coincided with the outage of the geothermal unit at Te Mihi, which ramped down production between 10 and 11 am. Wind generation was also only around 20MW.

Figure 16: Offer Stack for trading period 23 on 11 November

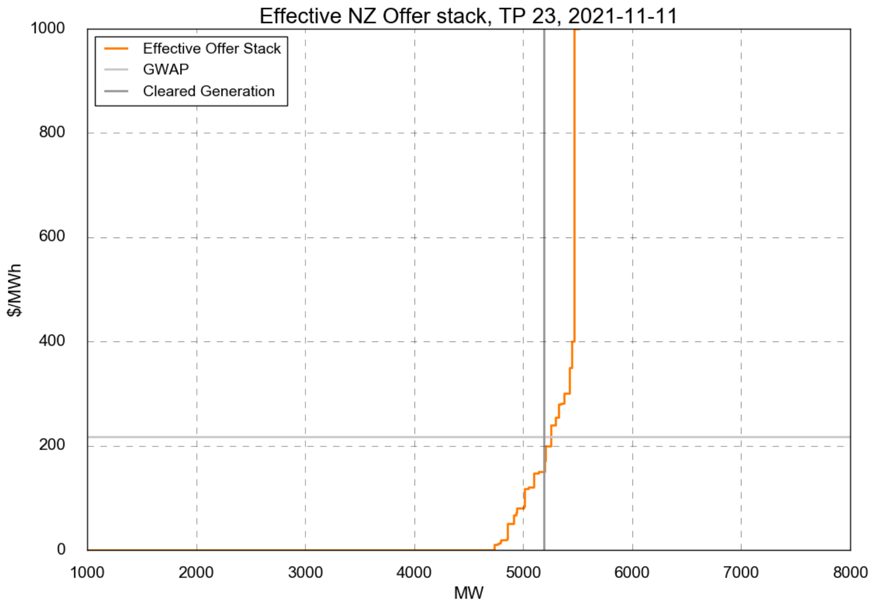
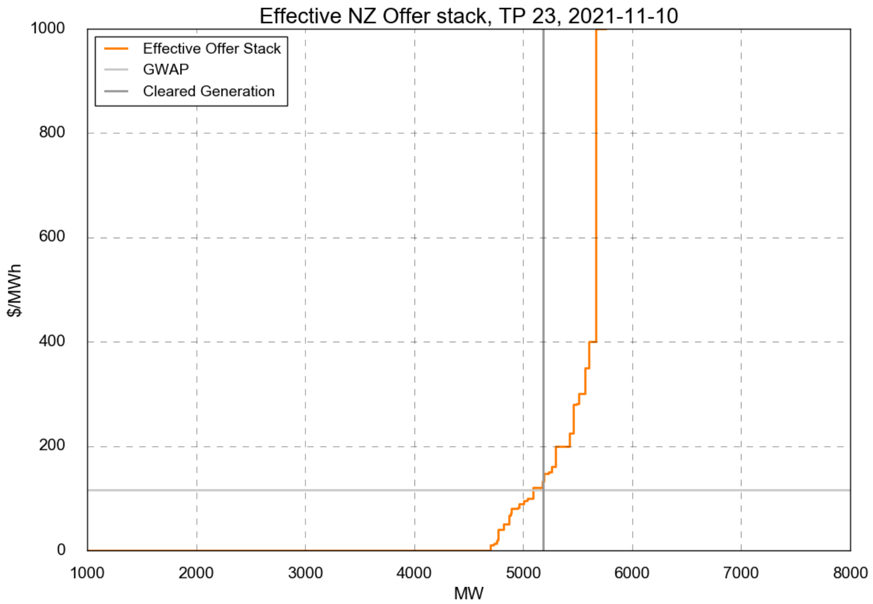


Figure 17: Offer Stack for trading period 22 on 10 November



Ongoing Work in Trading Conduct

5.7. No trading periods have been identified this week as needing further analysis.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
30/06-20/08	Several	Compliance: review	High energy prices in shoulder periods
30/06-21/08	Several	Compliance: review	Withdrawn reserve offers

Appendix A Regression Analysis

1. The Authority's monitoring team has developed two regression price models. The purpose of these models is to understand the drivers of the wholesale spot price and if outcomes are indicative of effective competition.

Weekly Model

2. The weekly model is an updated version of the model published in https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf, Section 8, pg. 21-25

3. The regression equation is

$$\begin{aligned}\log(P_t - \theta_t) = \beta_0 &+ \beta_1(Storage_t - Seasonal.mean.storage_i) \\ &+ \beta_2(Demand_t - Ten.year.mean.demand_t) + \beta_3 Wind.generation_t \\ &+ \beta_4 \log(Gas.price_t) + \beta_5 Generation.HHI_t \\ &+ \beta_6 Ratio.of.adjusted.offer.to.generation_t + \beta_7 Dummy.gas.supply.risk_t\end{aligned}$$

where P_t is the PPI and trend adjusted weekly average spot prices; t =week 1,…,52 for each year; i = spring, summer, autumn, and winter

Daily Model

4. The daily model estimates the daily average spot price based on daily storage, demand, gas price, wind generation, the HHI for generation (as a measure of competition in generation), the ratio of offers to generation (a measure of excess capacity in the market), a dummy variable for the period since the 2018 unplanned Pohokura outage started, and the weekly carbon price (mapped to daily). The units for the raw data are as following: storage and demand are GWh, spot price is \$/MWh, gas price is \$/PJ, and wind generation is MW, carbon price is in New Zealand Units traded under NZ ETS, \$/tonne.

5. We used the Augmented Dicky-Fuller (ADF) to test all variables to see if they are stationary. If not, we tested the first difference and then the second difference using the ADF test until the variable was stationary. The first difference of a time series is the series of changes from one period to the next. For example, if the storage is not stationary, we use $storage_t - storage_{t-1}$.

6. We fitted the data using a dynamic regression model with Autoregressive with five lags (AR(5)). Dynamic regression is a method to transform ARIMAX (Autoregressive Integrated Moving Average with covariates model) and make the coefficients of covariates interpretable.

7. Once we dropped the insignificant variables; the ratio of offers to generation, the dummy variable for 2018 and carbon price, we got the following model[4], where diff is the first difference:

$$y_t = \beta_0 - \beta_1\left(storage_t - 20.year.mean.storage_{dayofyear}\right) + \beta_2 diff(demand_t) - \beta_3\, wind.generation_t + \beta_4\, gas.price_t - \beta_5 diff(generation\ HHI_t) + \beta_6 dummy + \eta_t$$

$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

8. ε_t, the residuals of ARMA errors (from AR(5)), should not significantly different from white noise. Ideally, we expect the ARIMA errors are purely random, and are not correlated with each other (show no systematic pattern). ARIMA errors equals y_t minus the estimate $\hat{y}$ with their five time lags.

[4] Updated, $diff(storage_t)$ has been replaced with $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$