Trading Conduct Report

Market Monitoring Weekly Report

27 October 2021

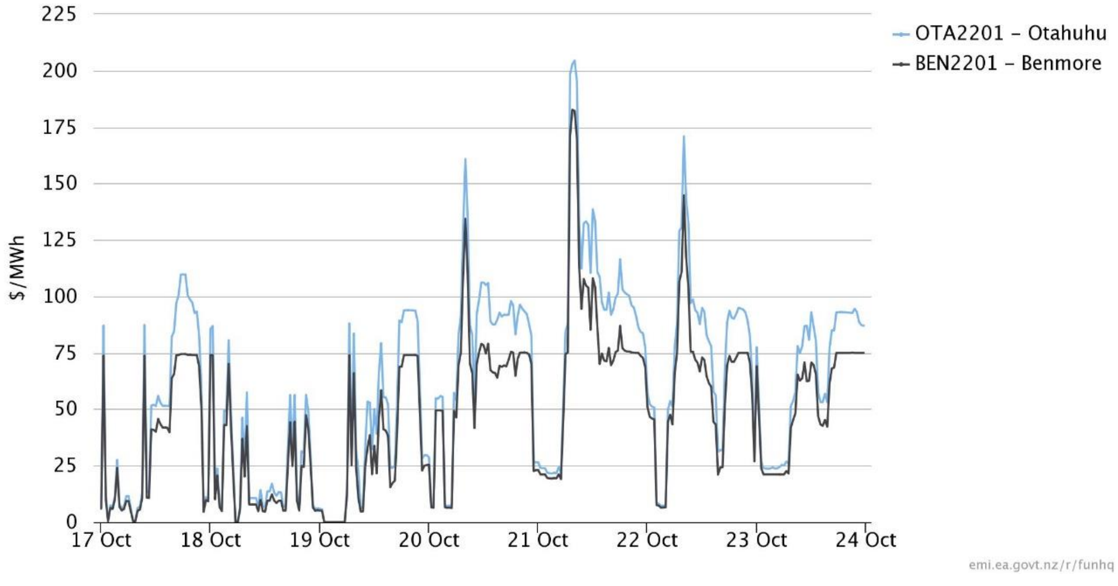
1 Overview for the week of 17 to 23 October

1.1 Prices this week appear to be consistent with underlying supply and demand conditions.

2 Prices

Energy prices

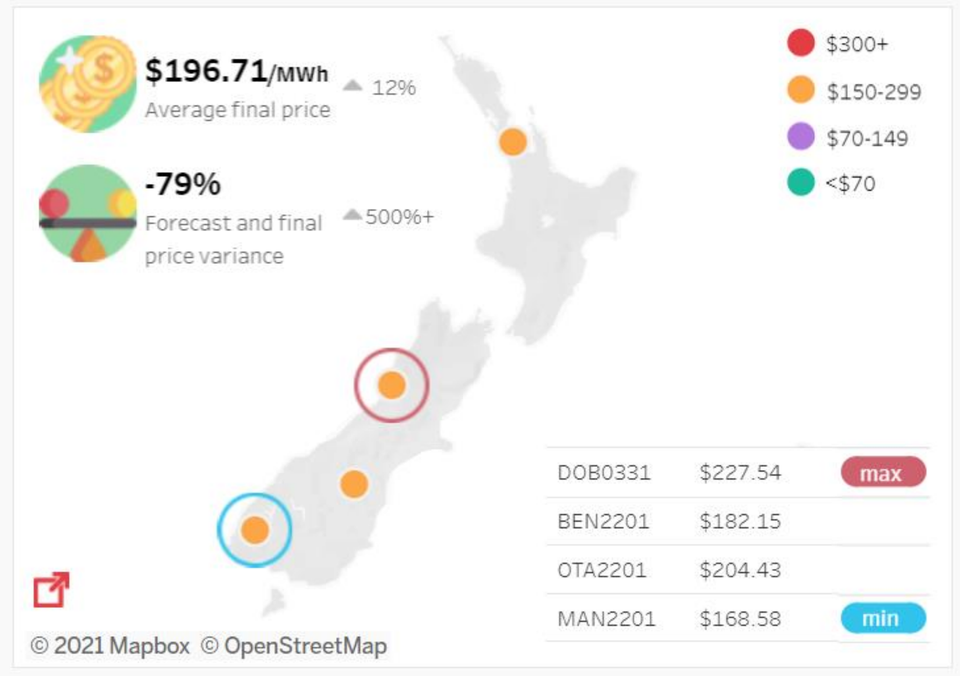
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.1 Average spot price this week was $53.50/MWh[1], 23% lower than the previous week. Prices above $100/MWh were less frequent than previous weeks (see Figure 1) with the highest price of $204/MWh at Otahuhu occurring at TP17 on 21 October (see Figure 2).

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

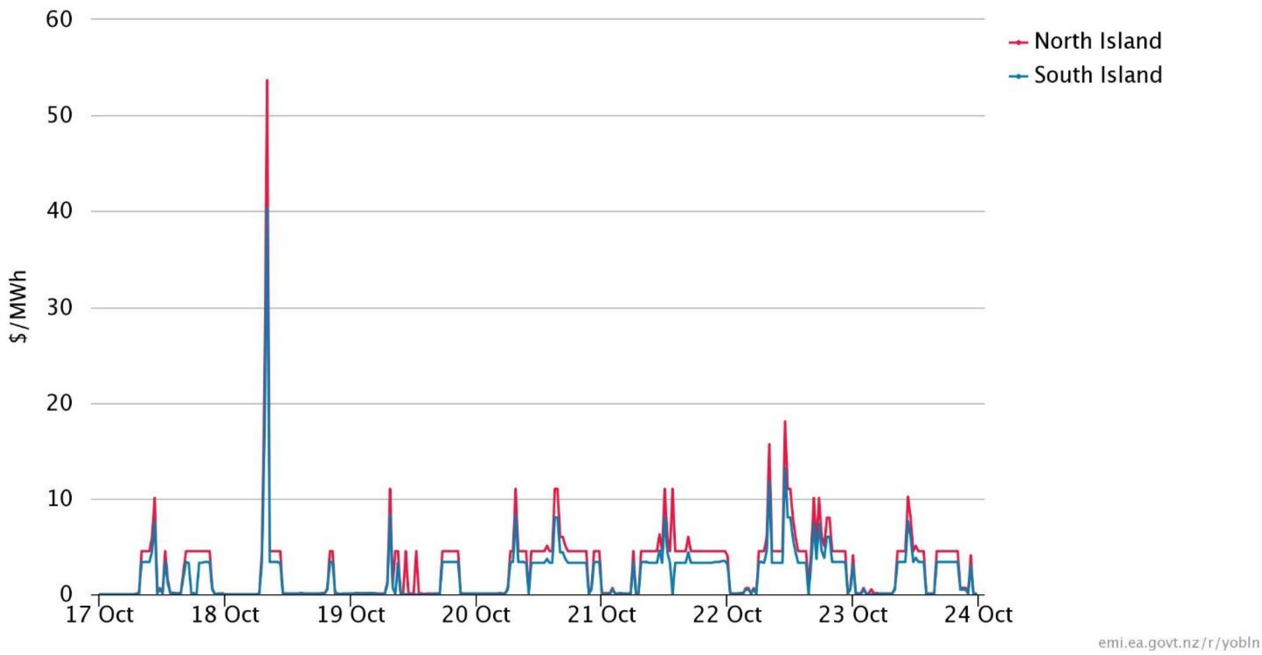
Figure 2: Spot prices for TP 17 on 21 October compared to previous week



Reserve Prices

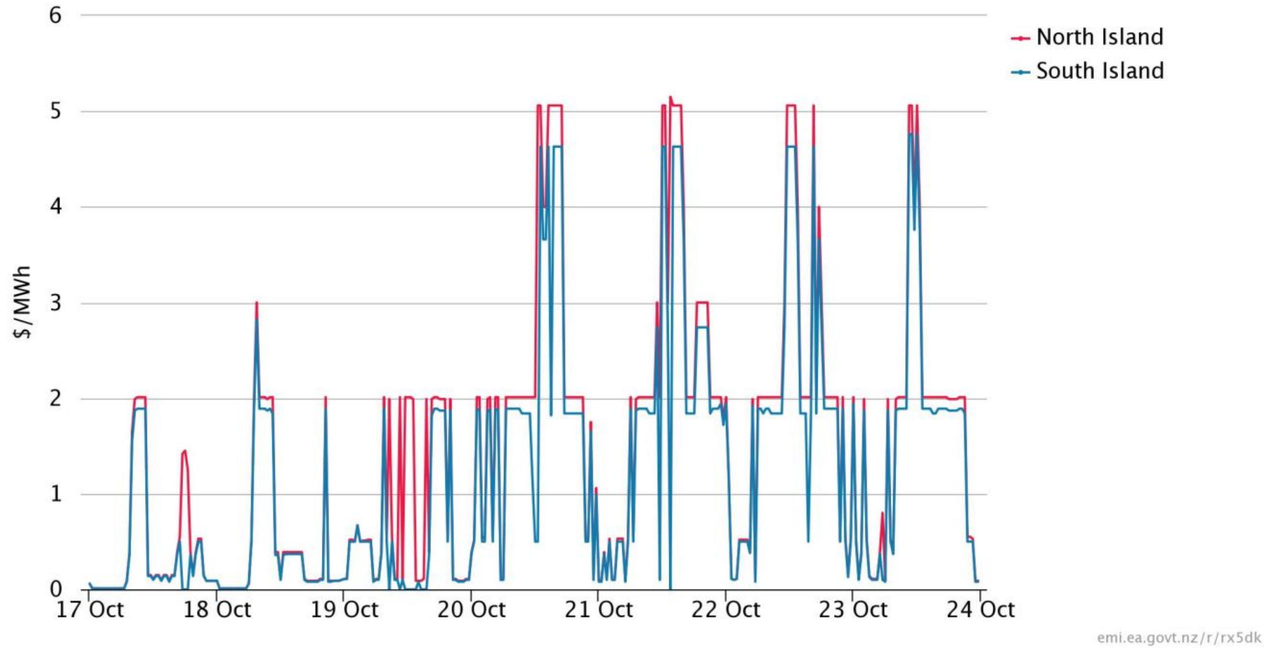
2.2 Fast instantaneous reserves (FIR) prices were usually below $20/MWh with one high price of $54/MWh in the North Island occurring at TP17 on 18 October (see Figure 3).

Figure 3: FIR prices by trading period by Island



2.3 Sustained instantaneous reserves (SIR) prices were below $6/MWh for the entire week (see Figure 4), indicating spare capacity in the system.

Figure 4: SIR prices by trading period by Island

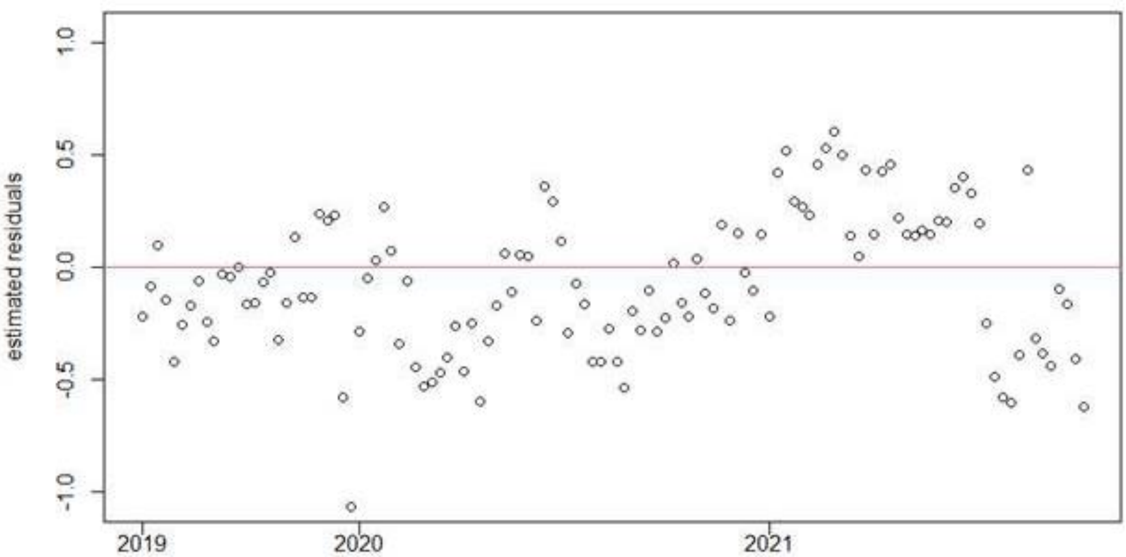


Residuals from regression models

2.4 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.

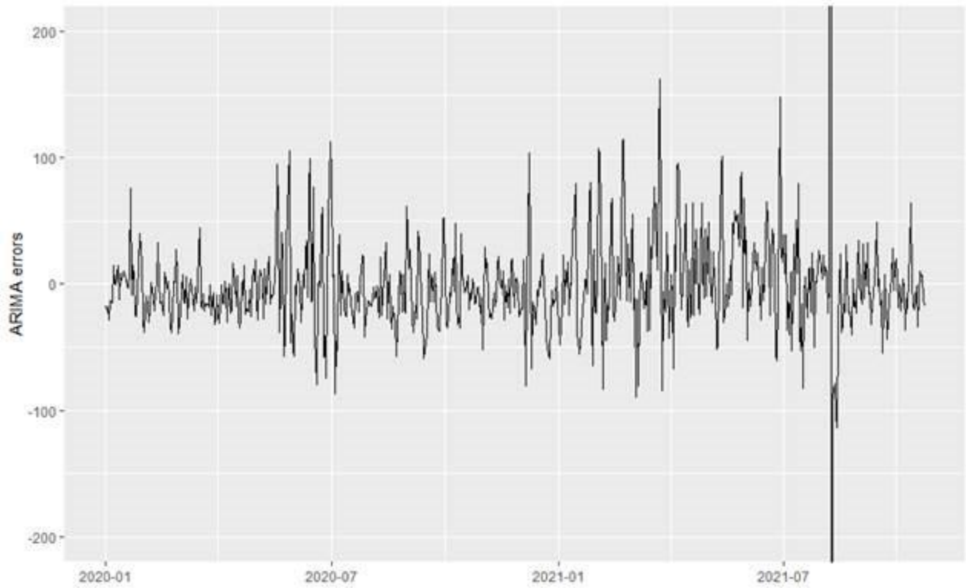
2.5 Figure 5 shows the residuals from the weekly model. During September 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 30 September 2021



2.6 Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were small indicating prices were close to the model's prediction.

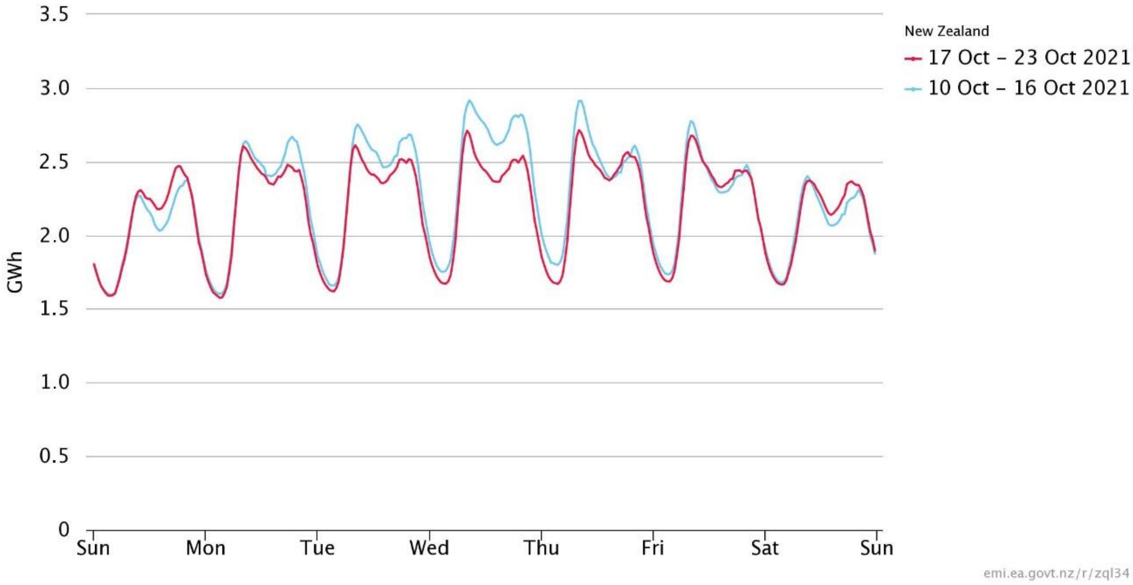
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 16 October 2021



3 Demand Conditions

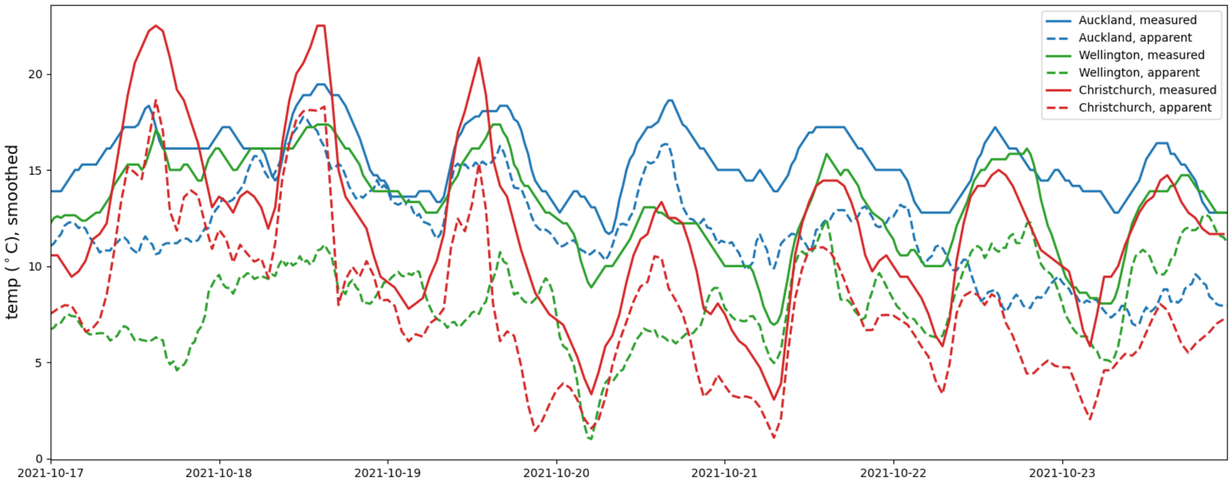
3.1 National demand was 3% lower than the previous week (see Figure 7). Demand continues to be highest in the mornings, with the highest demand on 20 and 21 October.

Figure 7: National demand compared to previous week



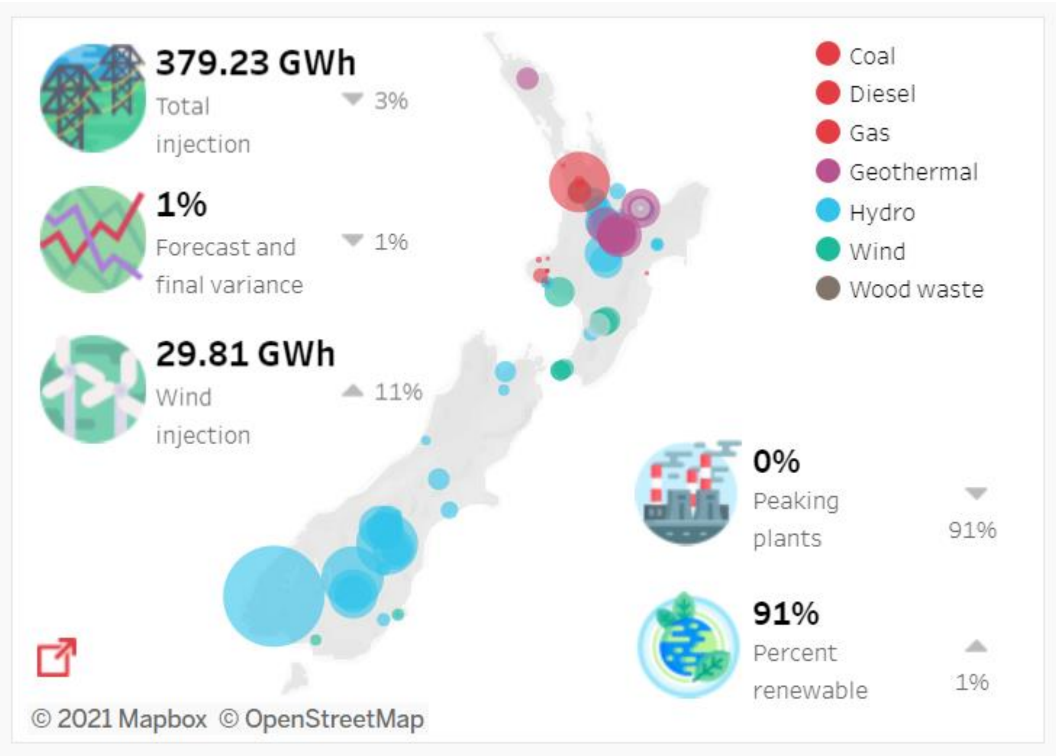
3.2 Figure 8 shows hourly temperature data at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Actual and apparent temperatures were higher than the previous week; the lowest temperatures on 20 and 21 October were still about 5 degrees higher than the same time last week.

Figure 8: Hourly temperature data at main population centres.



4 Supply Conditions

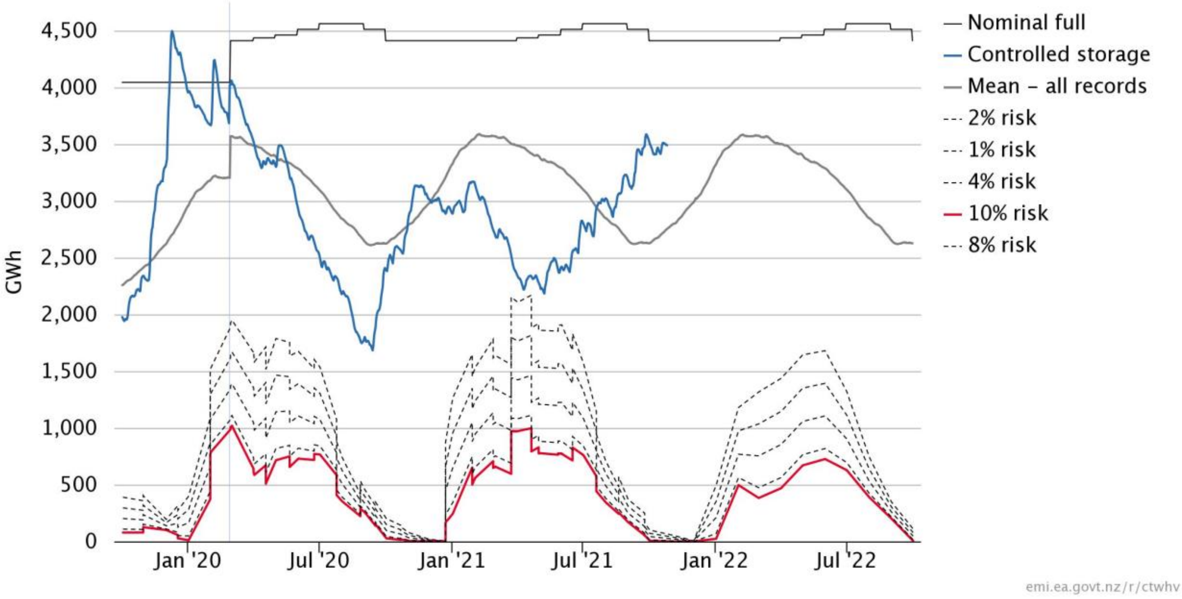
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1 This week national hydro storage increased slightly and continued to be around 3,500GWh, shown in Figure 10.

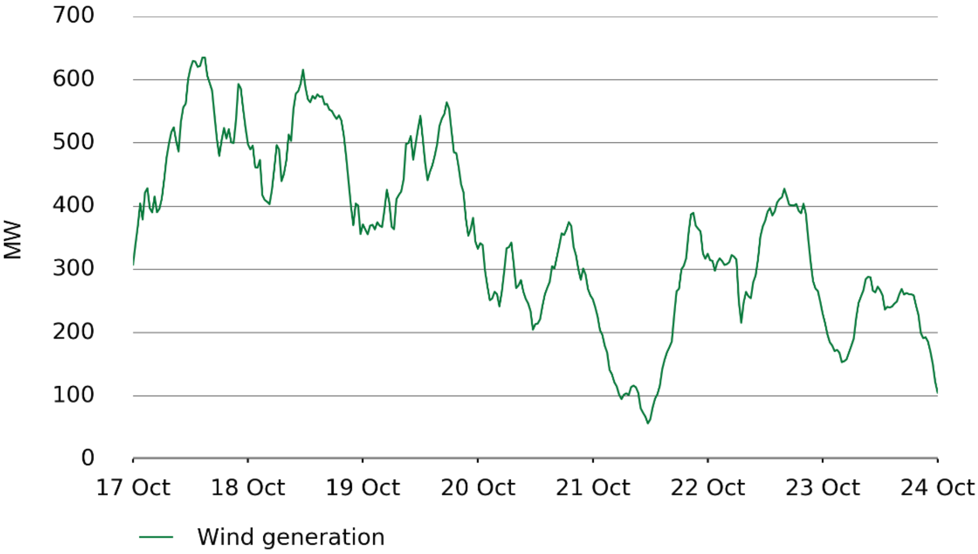
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 30GWh, up 11% from last week. Wind generation was highest at the beginning of the week (see Figure 11) when prices were lowest. Wind generation dropped on 20 and 21 October, contributing to higher prices during peak morning demand on these days.

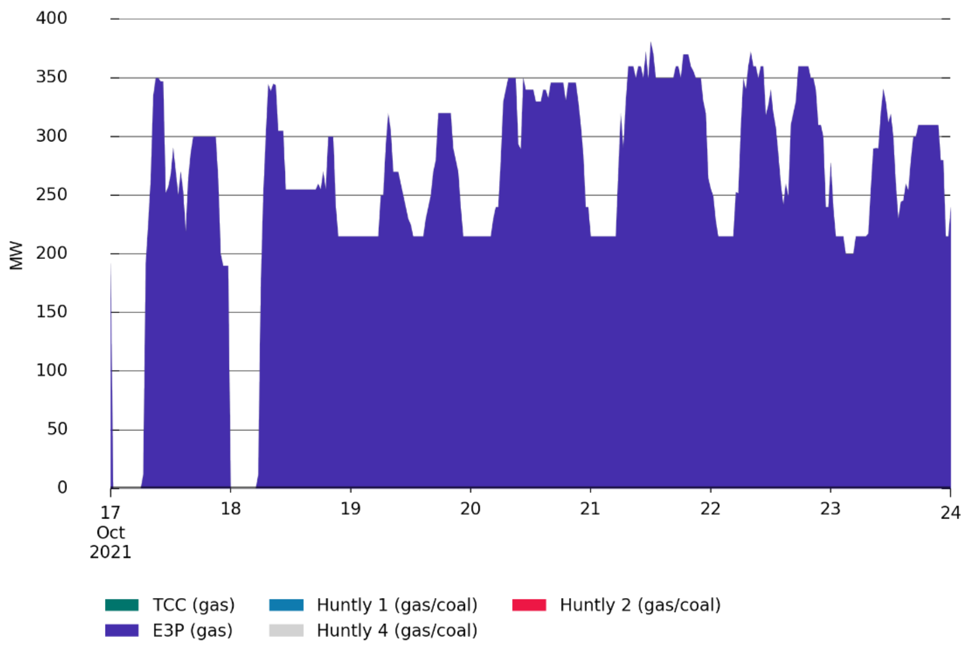
Figure 11: Wind generation for the week



Thermal conditions

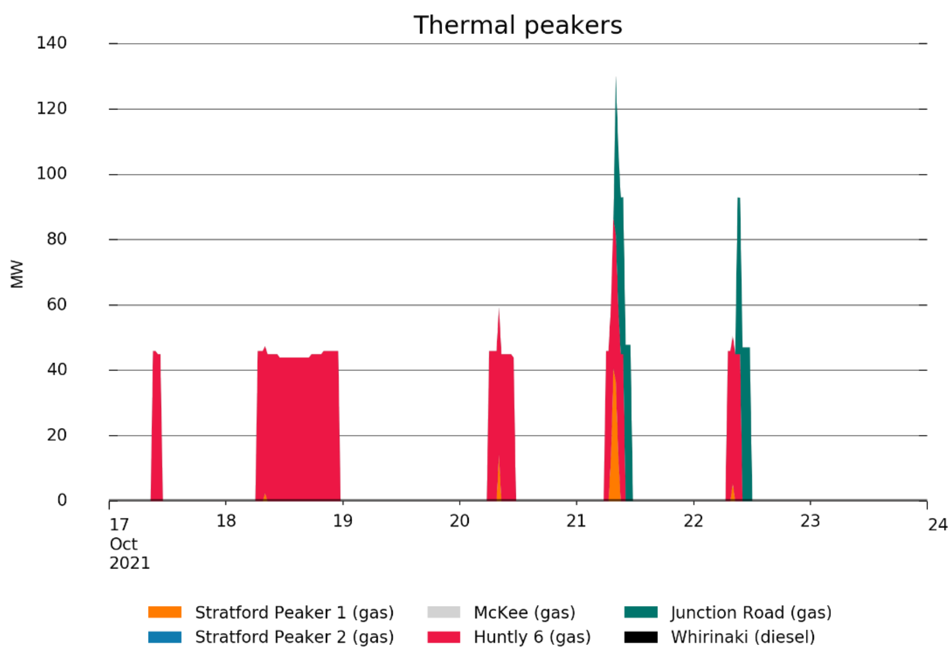
4.3 Baseload thermal generation remains low with only Huntly's E3P running as baseload all week.

Figure 12: Generation from baseload thermal



4.4 There was not much generation from thermal peakers this week, making up less than 1% of total generation. The only time generation from thermal peakers reached over 100MW was on TP17 21 October, when prices were at their highest.

Figure 13: Generation from thermal peakers



Significant outages

4.5 The following outages reduced available generation by at least 80MW:

(a) Clyde,

  (i) 116MW (long term outage)

  (ii) 116MW (19-20 October)

  (iii) 116MW (21-22 October)

(b) Benmore, 90MW (5 July – 26 November)

(c) Manapouri,

  (i) 125MW (19 July – 15 November)

  (ii) 125MW (13:30-15:30 17 October)

(d) Huntly, Rankine unit; 240MW (4 October-19 December)

(e) Tekapo,

  (i) 80MW (13 September – 16 January 2022)

  (ii) 80MW (14:00-22:00 18 October)

  (iii) 30MW (20-21 October)

(f) Ohau A,

  (i) 55MW (11 October-1 November)

  (ii) 50MW (06:00-10:30 18 October)

(g) Aviemore, 165MW (16-17 October)

5 Price versus estimated costs

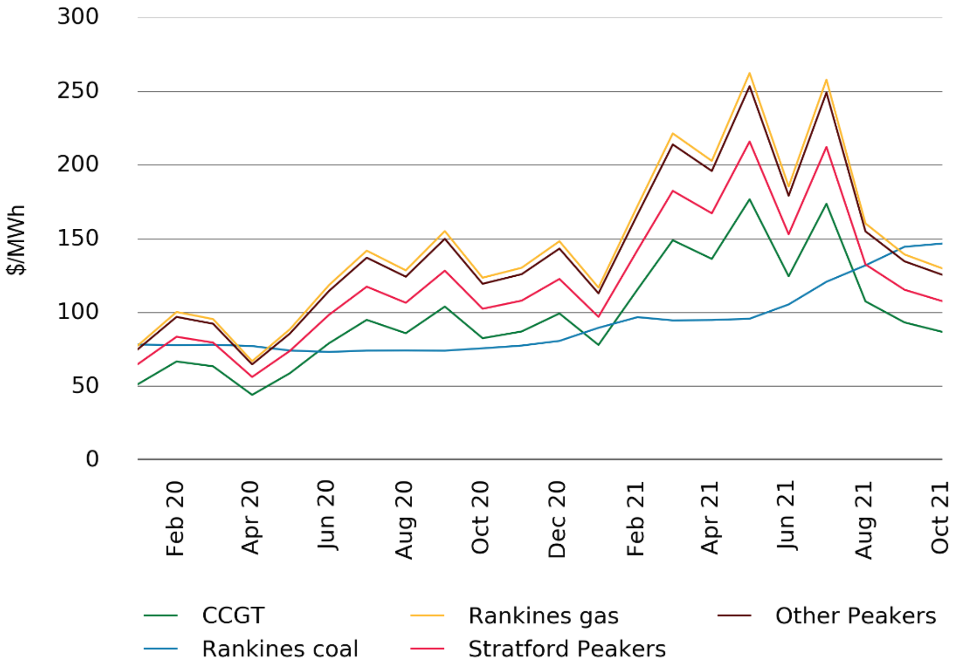
5.1 In a competitive market prices should be close to (but not necessarily at) the short run marginal cost (SRMC) if the marginal generator (where SRMC includes opportunity cost).[2]

5.2 The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices[3] and the average heat rates for each thermal unit. Figure 14 shows estimates of thermal SRMCs as a monthly average. The thermal SRMC for gas fuelled generation continues to drop in October (to 24 October), while the thermal SRMC for coal increased.

[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/

[3] The SRMC for thermal fuels includes the carbon price. The gas price already includes the carbon price, but not the coal price, so the carbon price is added to the coal price before estimating the SRMC of coal.

Figure 14: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

Final daily offer stacks

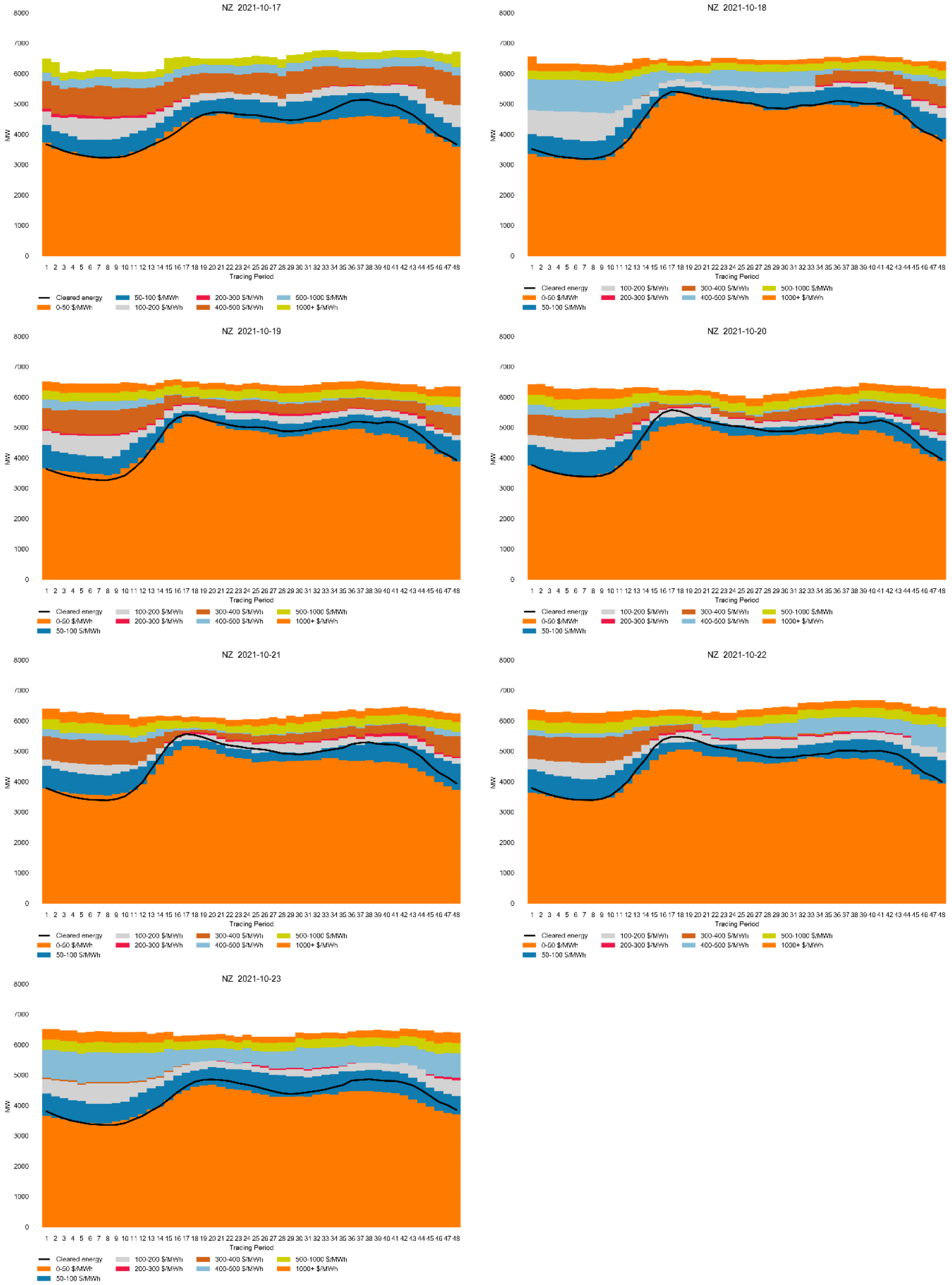
6.1 Figure 15 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[4] The black line shows the cleared energy, indicating the range of the average final price[5].

6.2 Most offers continued to be below $200/MWh, with a thin offer stack at higher prices. There was more generation offered between $300-400/MWh compared to last week, though these offers were never cleared. Higher prices on 20 and 21 October were due to a combination of higher demand and lower wind generation.

[4] 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.

[5] This is less accurate during periods of price separation due to binding constraints.

Figure 15: Daily offer stack



Offers by trading period

6.3 The trading period (TP) with the highest price at Otahuhu was TP17 (8:00am) on 21 October, shown by Figure 16, as well as the same trading period the week before (Figure 17). Both show with the offer stack, the generation weighted average price (GWAP) and cleared generation.

6.4 Cleared generation was lower than the same time the previous week, but the price was slightly higher. This was because there was less wind generation and less thermal baseload which caused a steeper offer stack.

Figure 16: Offer Stack for trading period 17 on 21 October

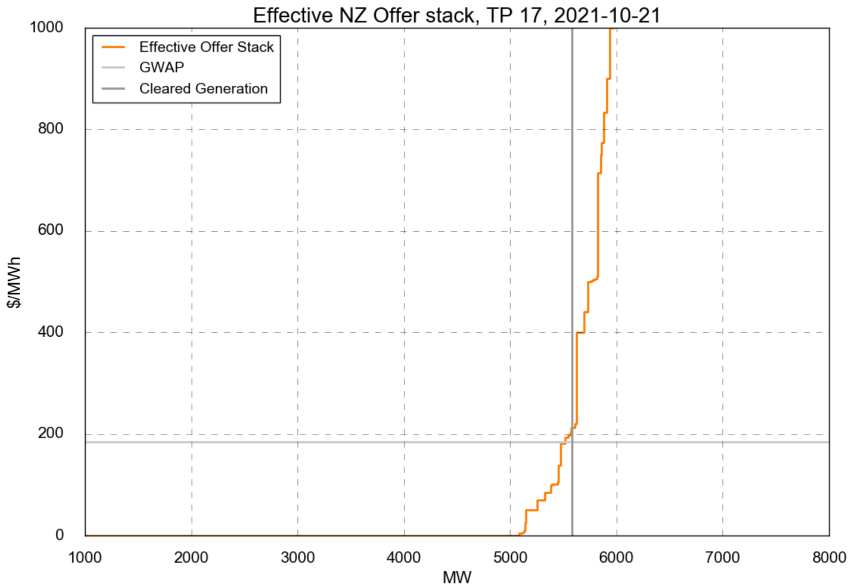
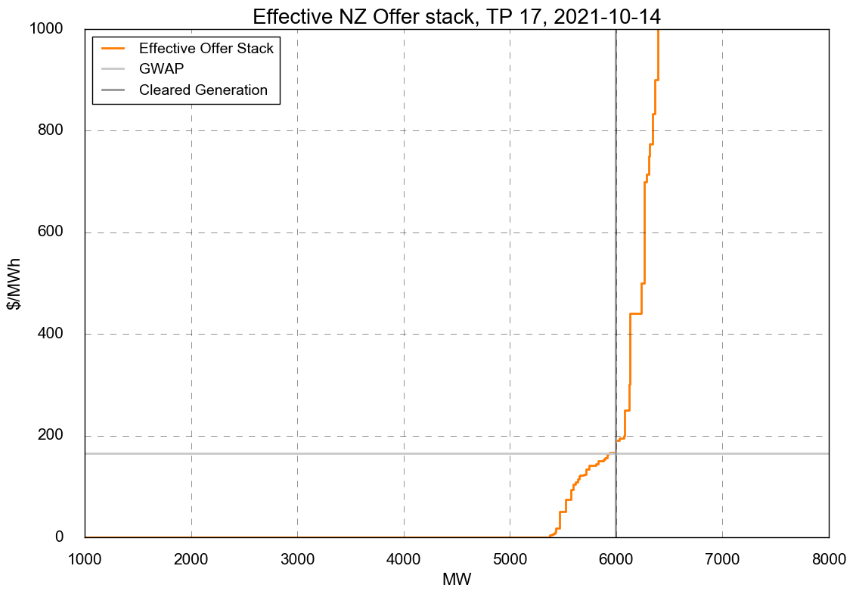


Figure 17: Offer Stack for trading period 17 on 14 October



Ongoing Work in Trading Conduct

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

6.6 Some of the trading periods identified for further analysis will be grouped in with ongoing work referred to compliance

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

A.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

A.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

A.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; $t = week\ 1, \dots, 52$ for each year; i= spring, summer, autumn and winter

Daily Model

A.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.

A.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 $storage_t - storage_{t-1}$.

A.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.

A.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[6], where *diff* is the first difference:

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

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

A.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.

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