ELECTRICITY AUTHORITY TE MANA HIKO

Trading Conduct Report

Market Monitoring Weekly Report

11 November 2021

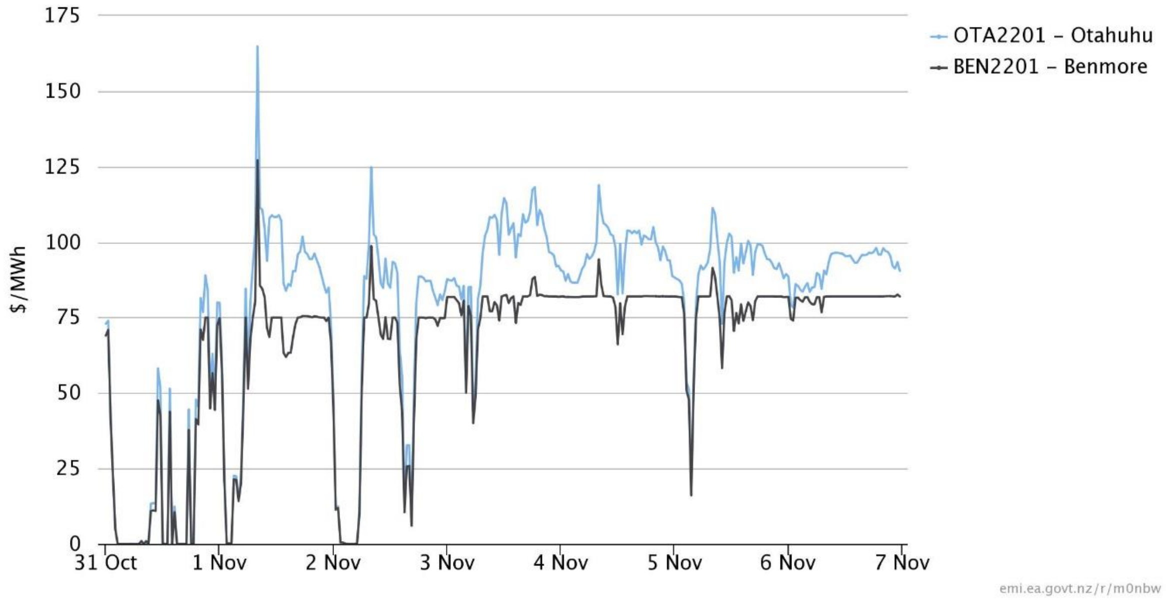
1 Overview for the week of 31 October to 6 November

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



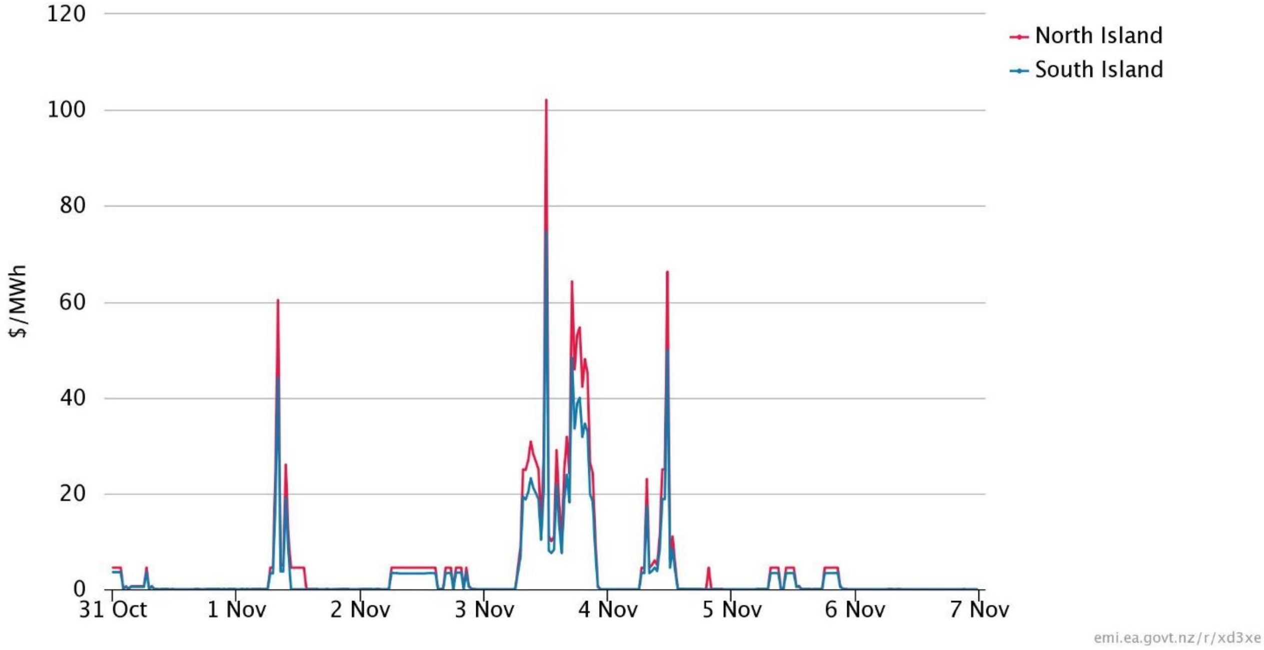
2.1 Average spot price this week was $70/MWh[1], similar to the previous week. Prices were often low early in the week, and then settled around $82/MWh at Benmore in the latter half of the week (see Figure 1). The highest price of $163/MWh at Otahuhu occurred at TP17 on 1 November.

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

Reserve Prices

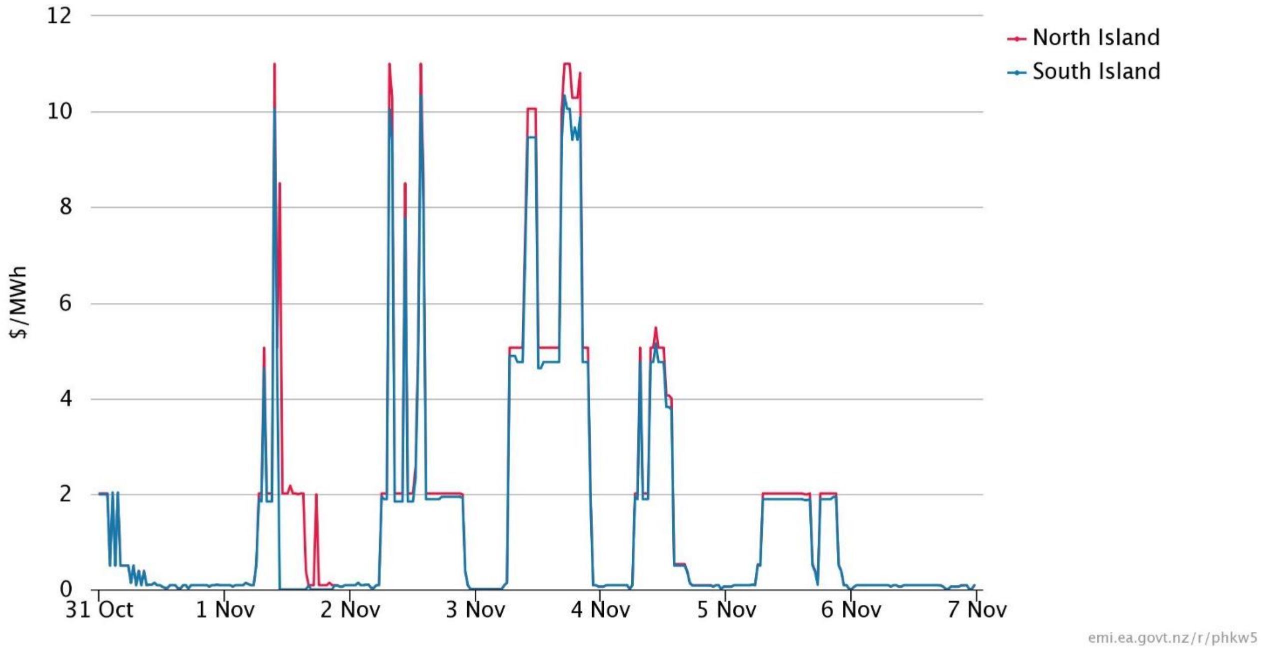
2.2 Fast instantaneous reserves (FIR) prices were usually below $10/MWh, indicating spare capacity in the system. However, there were a few trading periods with high FIR prices, the highest of $102/MWh occurring at TP25 3 November (see Figure 2).

Figure 2: FIR prices by trading period by Island



2.3 Sustained instantaneous reserves (SIR) prices were below $12/MWh the entire week (see Figure 3), indicating spare capacity in the system.

Figure 3: SIR prices by trading period by Island



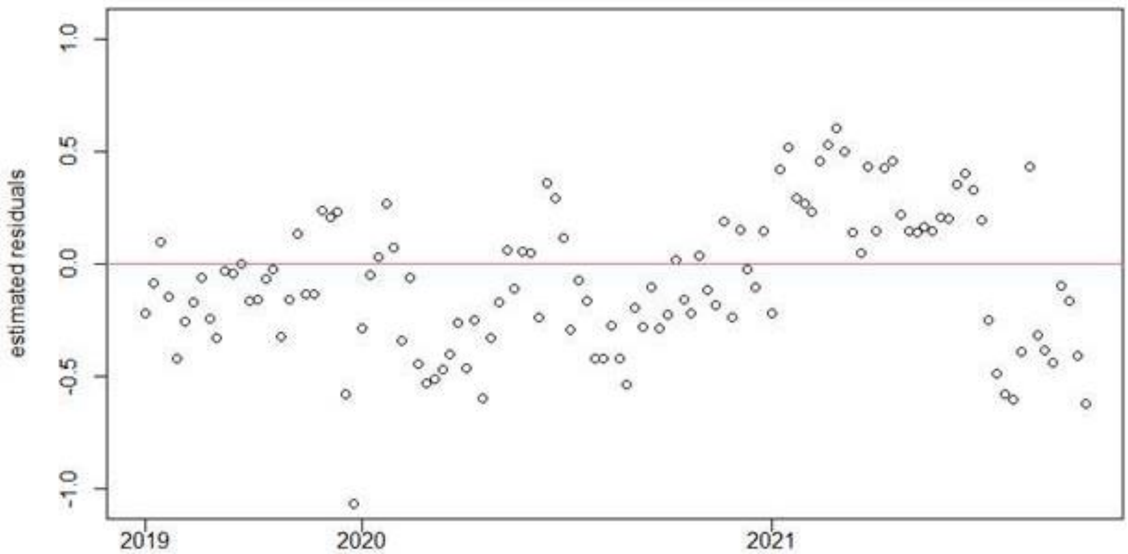
2.4 Trading periods with higher reserve prices this week and last week have been further analysed by comparing with offers during similar trading periods. We found that higher reserve prices occurred when less interruptible load was offered, resulting in more reserve dispatched from generators. Offer curves were also steep, so it was optimal to dispatch costly reserve instead of costly energy.

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.

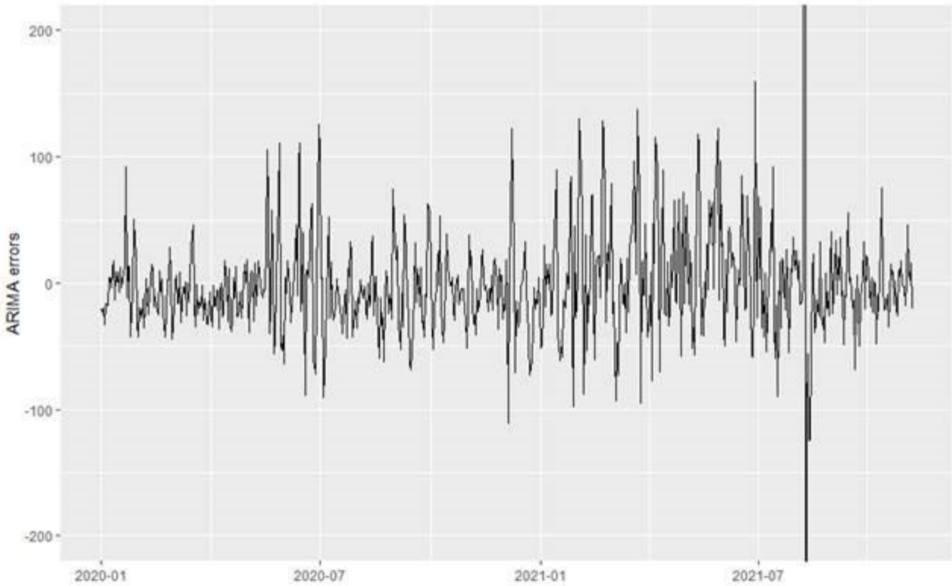
2.6 Figure 4 shows the residuals from the weekly model. During September 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 4: Residual plot of estimated weekly price from 2 July 2019 to 30 September 2021



2.7 Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were within the normal range.

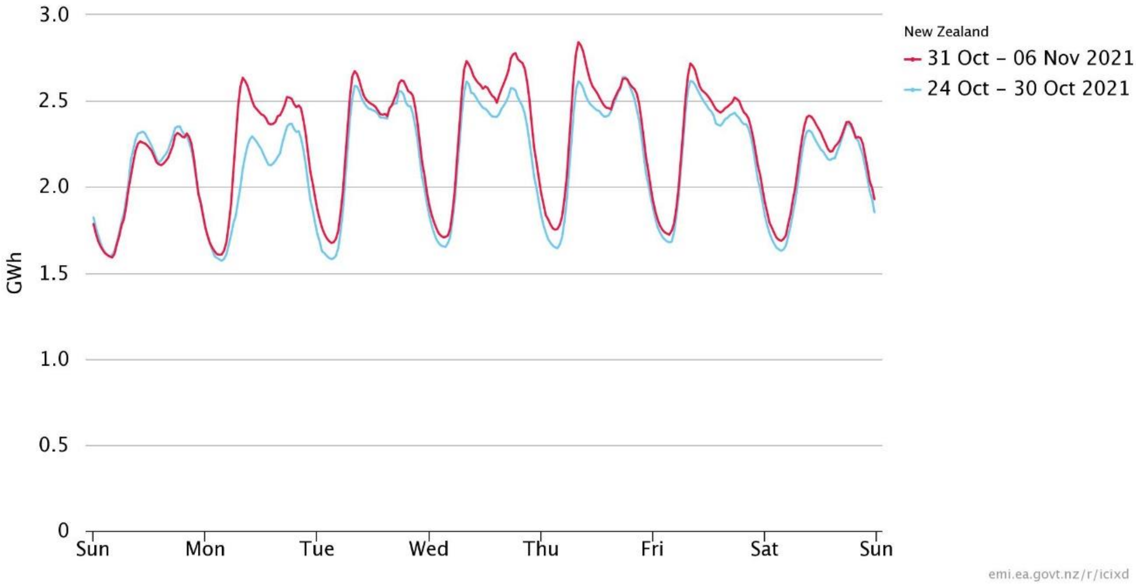
Figure 5: Residual plot of estimated daily average spot price from 1 July 2020 to 6 November 2021



3 Demand Conditions

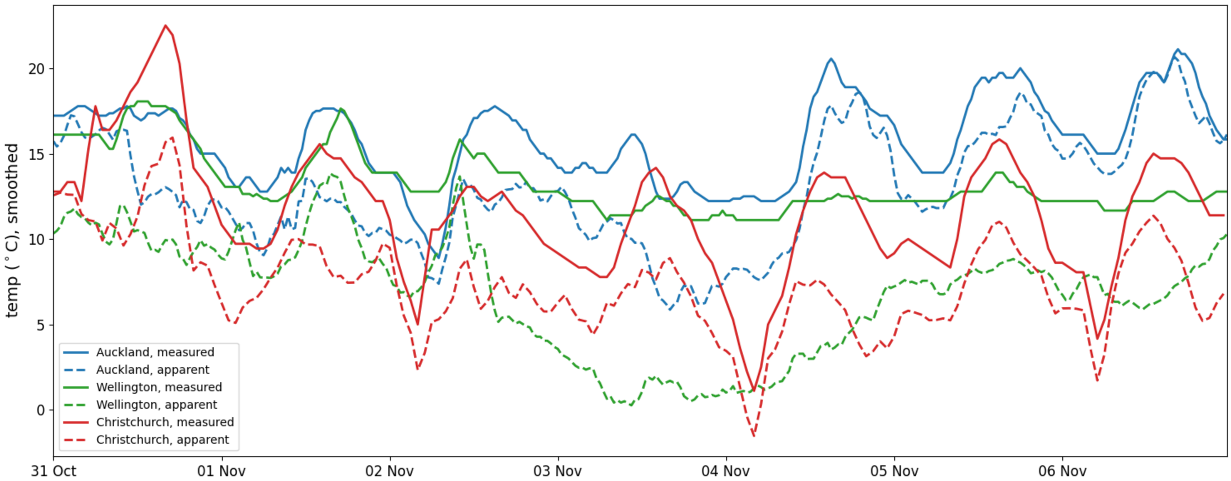
3.1 National demand was higher than the previous week (see Figure 6), partly due to a public holiday on the previous Monday which reduced demand. Demand was highest on 3 and 4 November, which were also the coldest days this week in the main population centres (see figure 7).

Figure 6: National demand compared to previous week



3.2 Figure 7 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. Temperatures were mild at the beginning of the week, then fell in the middle of the week, with apparent temperatures in Wellington and Christchurch reaching below 5°C.

Figure 7: Hourly temperature data at main population centres.

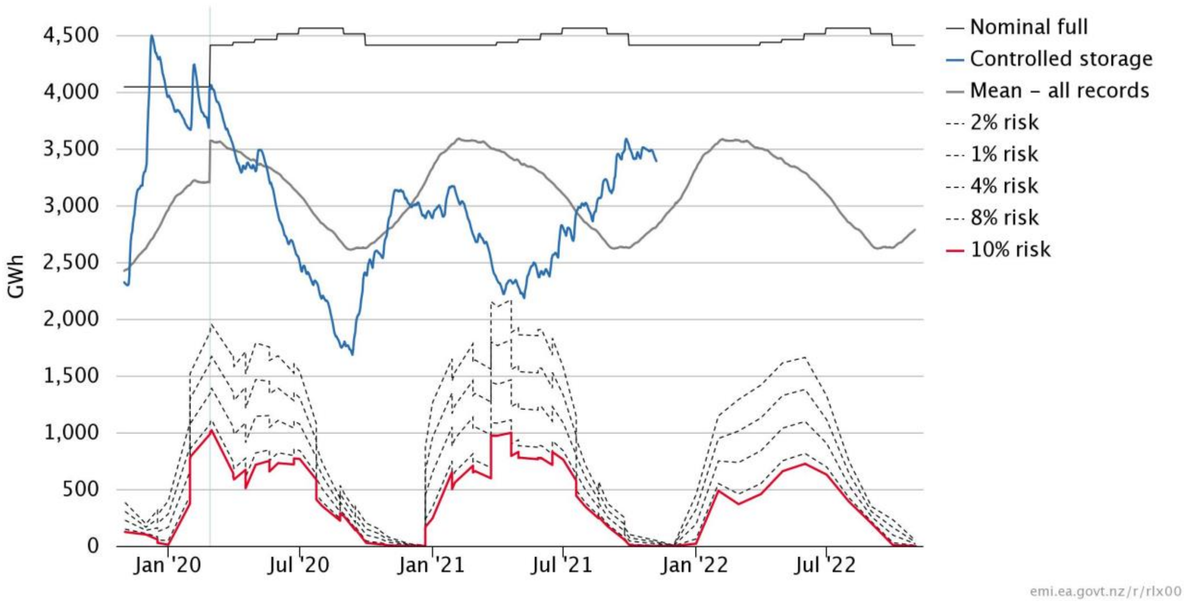


4 Supply Conditions

Hydro conditions

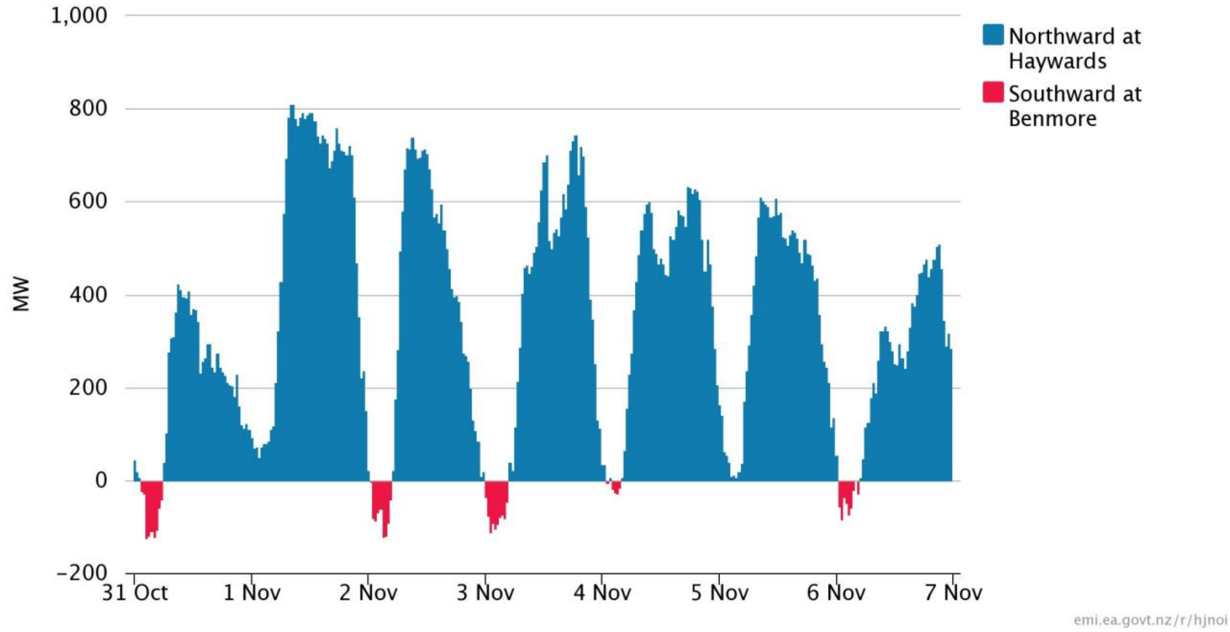
4.1 This week national hydro storage fell this week to below 3,400GWh, shown in Figure 8. This is due to a decrease in inflows.

Figure 8: Electricity risk curves and current hydro supply



HVDC transfer

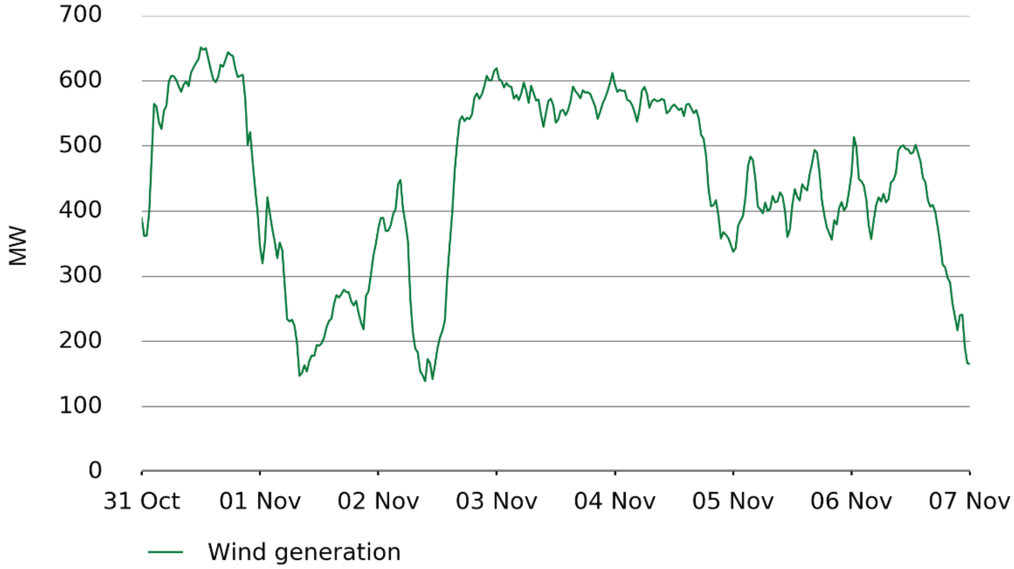
4.2 This week there was Southwards transfer for the first time in over a month. Southward transfer occurred overnight when wind generation was high. Northward transfer was also lower on days with higher wind generation.



Wind conditions

4.3 Total wind generation was 75GWh, more than double last week. Wind generation was lowest on 1 and 2 November (see Figure 9) with generation below 200MW coinciding with the highest prices.

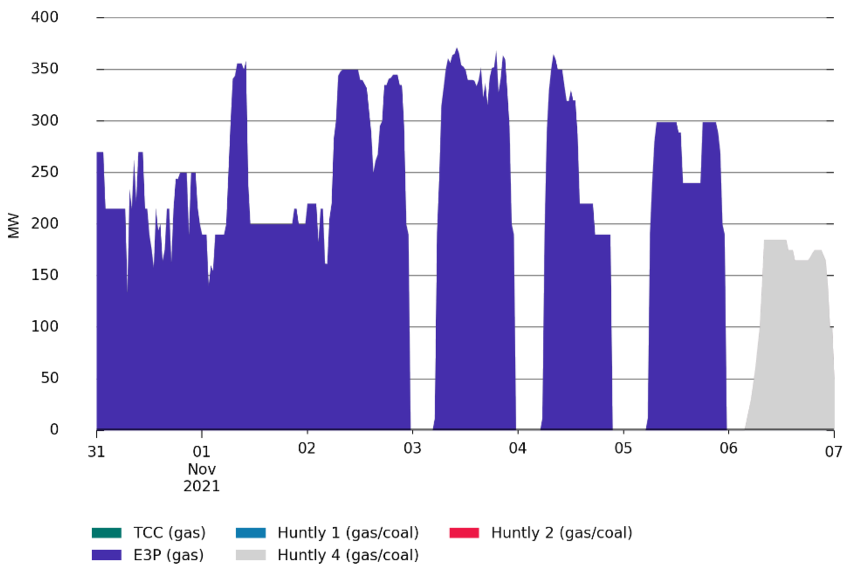
Figure 9: Wind generation for the week



Thermal conditions

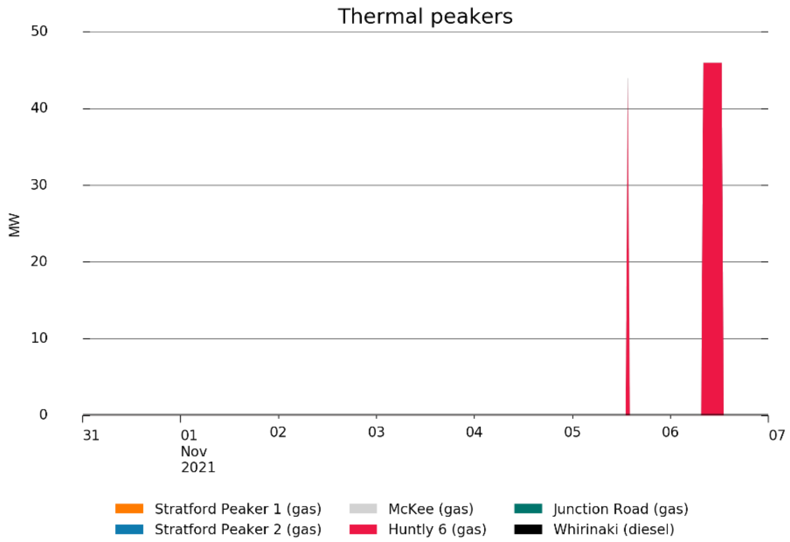
4.4 Baseload thermal generation remains low with only Huntly's E3P running as baseload for most of the week, though it did turn off overnight when demand was low from 3 November which increased overnight prices. On 6 November Huntly unit 4 ran instead of the E3P which may have been to test the Rankine unit after it came back from a planned outage (see 4.6).

Figure 10: Generation from baseload thermal



4.5 There only thermal peaker which ran this week was Huntly 6 on 5 and 6 November which may have been due to testing after its outage and the Huntly 4 outage (see 4.6).

Figure 11: Generation from thermal peakers



Significant outages

4.6 There was a noticeable increase in the number of outages this week, as we enter the summer period of the year. 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 (7am-5pm, 5 November)

(c) Manapouri, 125MW (19 July – 9 November)

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

(e) Huntly,

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

    (ii) Rankine unit; 240MW (4-5 November)

    (iii) Peaker; 45MW (31 October – 5 November)

    (iv) E3P; 145MW (1am-2:30am; 2 and 3 November)

(f) Ohau,

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

    (ii) 100MW (9am-4pm, 1 November)

    (iii) 198MW (11am-2pm, 6 November)

(g) McKee, 50MW (26 October – 4 November)

(h) Waikaremoana, 116MW (27 October – 3 November)

(i) Stratford,

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

    (ii) 100MW (7-24 November)

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

5 Price versus estimated costs

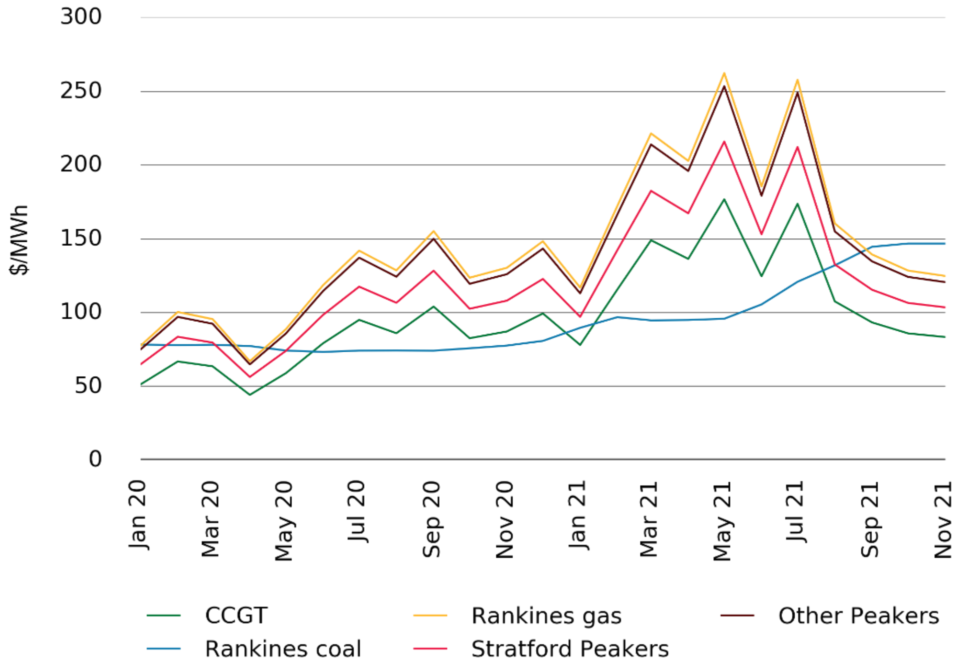
5.1 In a competitive market prices should be close to (but not necessarily at) the short run marginal cost (SRMC) if the marginal generator (where SRMC includes opportunity cost).[2]

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 12 shows estimates of thermal SRMCs as a monthly average. The thermal SRMC for both gas and coal fuelled generation so far in November (to 7 November) is similar to October.

[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 12: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

Final daily offer stacks

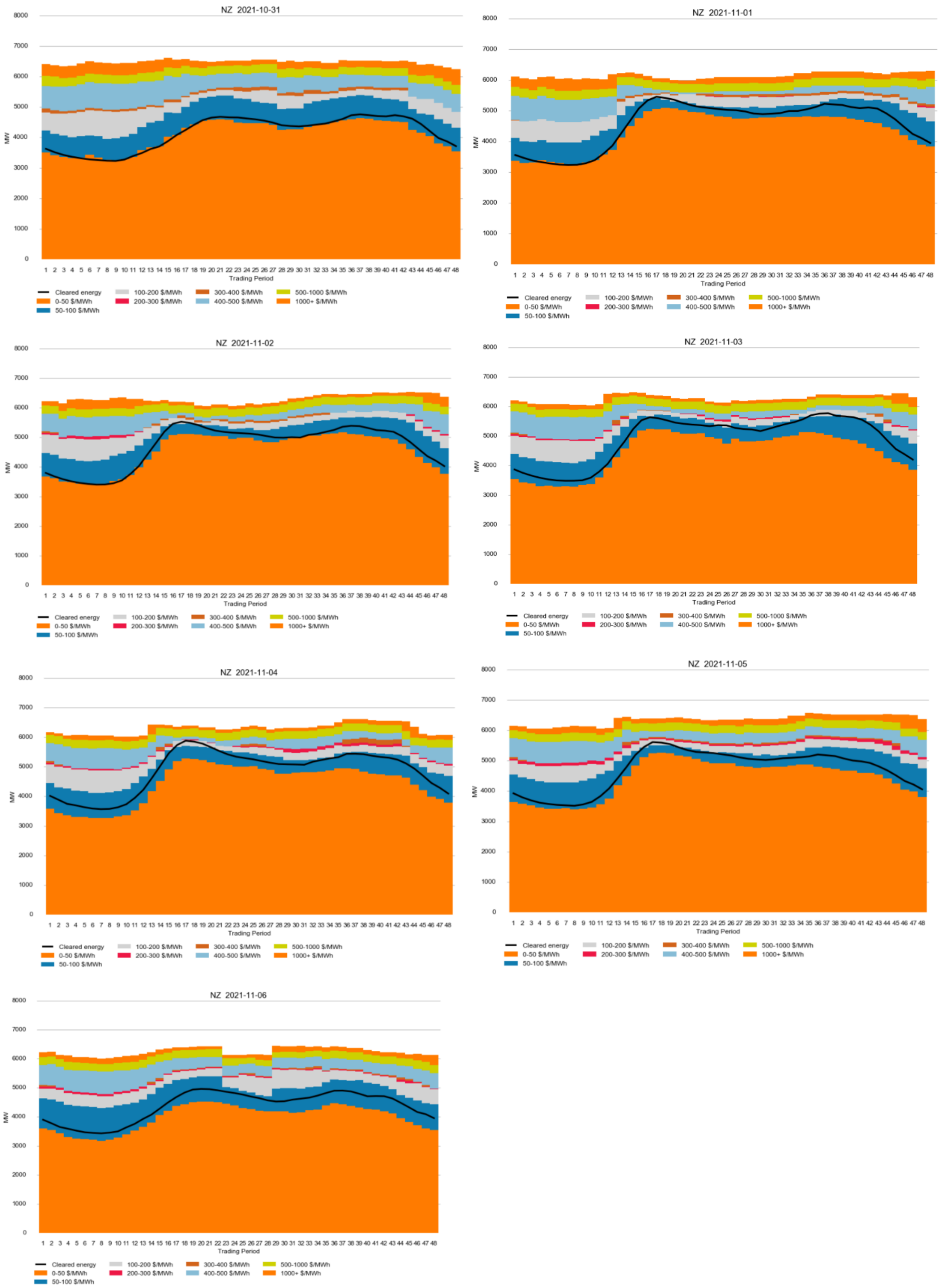
6.1 Figure 13 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[4] The black line shows the cleared energy, indicating the range of the average final price[5].

6.2 Most offers continued to be below $200/MWh, with a thin offer stack between $200 and $400/MWh, especially due to the increase in outages this week. Low wind generation on 1 and 2 November and outages both reduced generation offered.

[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 13: Daily offer stack



Offers by trading period

6.3 The trading period (TP) with the highest price at Otahuhu was TP17 (8:00am) on 1 November (Figure 14) as well as the trading period immediately before (Figure 15). Each graph shows the offer stack, the generation weighted average price (GWAP) and cleared generation.

6.4 The offer stacks of both curves are steep at prices above $100/MWh. So, while cleared generation during TP 17 was only slightly higher than TP 16 the price was noticeable higher.

Figure 14: Offer Stack for trading period 17 on 1 November

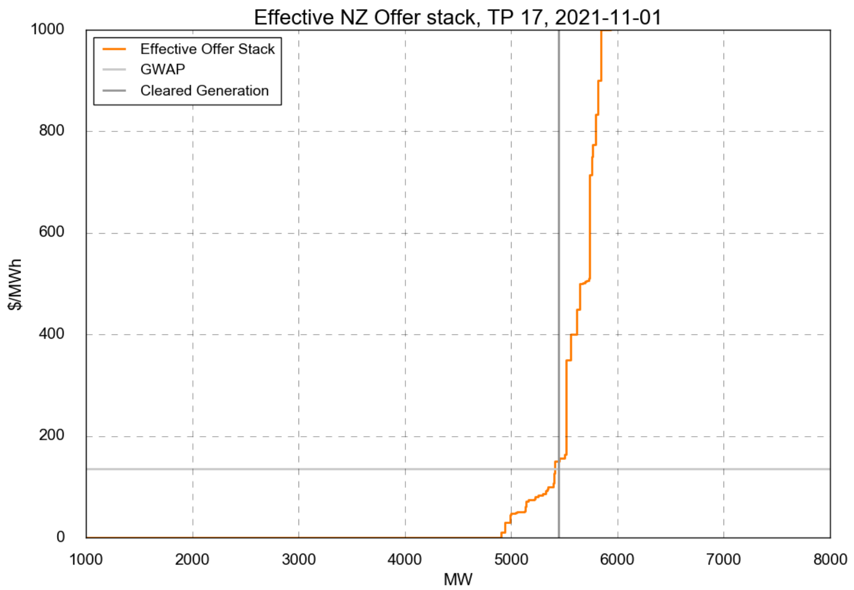
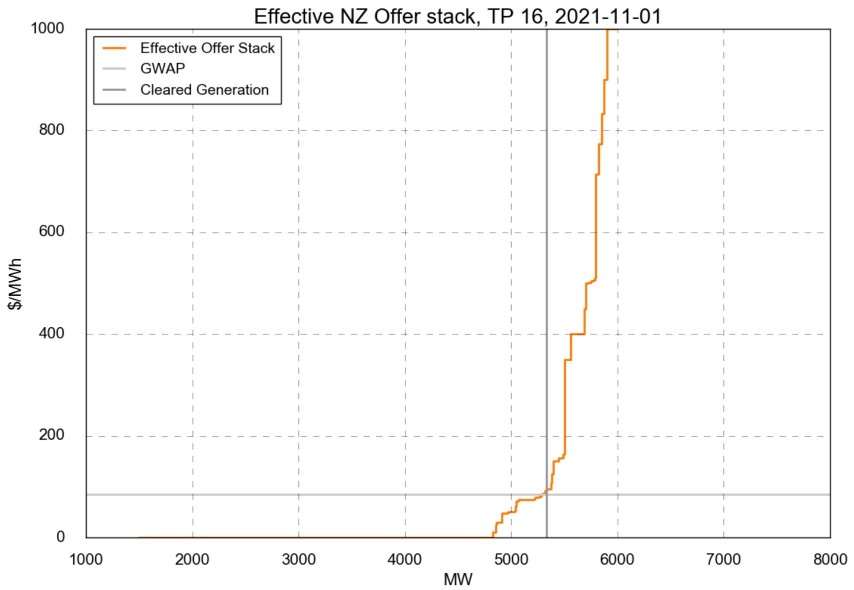


Figure 15: Offer Stack for trading period 16 on 1 November



Ongoing Work in Trading Conduct

6.5 North Island reserve offers on 28 October have been further analysed and resolved (see 2.4).

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
28/10/21	21-35	Resolved	Reserve offers were not changed to increase energy prices in North Island. Higher prices due to higher reserve dispatched and lower IL compared to similar TP.
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; $t = week\ 1, \ldots, 52$ 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 $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$