Trading Conduct Report

Market Monitoring Weekly Report

10 August 2021

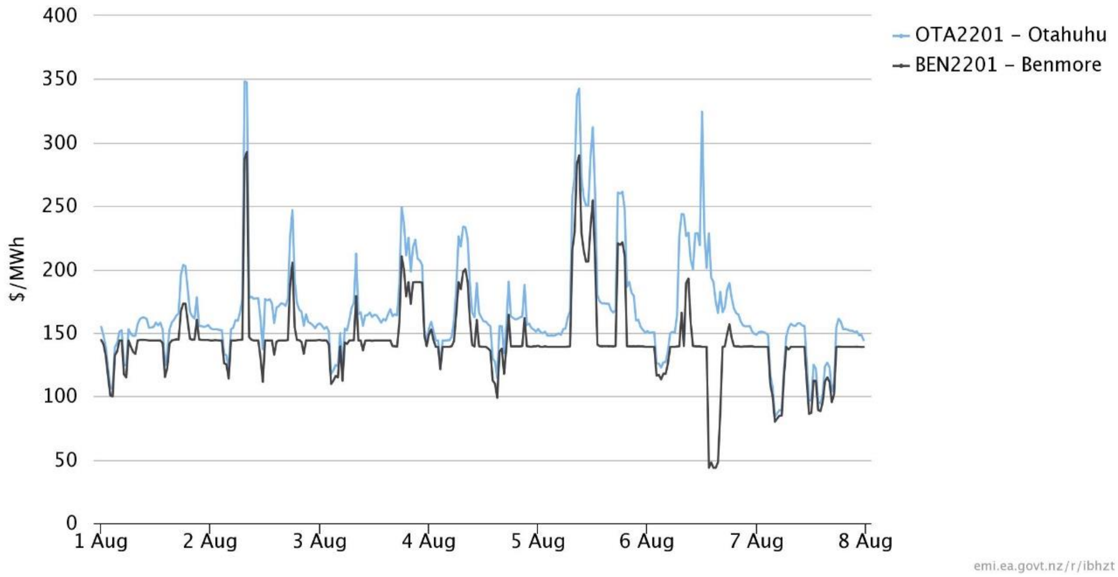
1 Overview for the week of 1 to 7 August 2021

1.1 High prices this week may be due to high demand and tight supply conditions, but some trading periods warrant further analysis. The trading periods we will investigate further are listed at the end of this report.

2 Prices

Energy prices

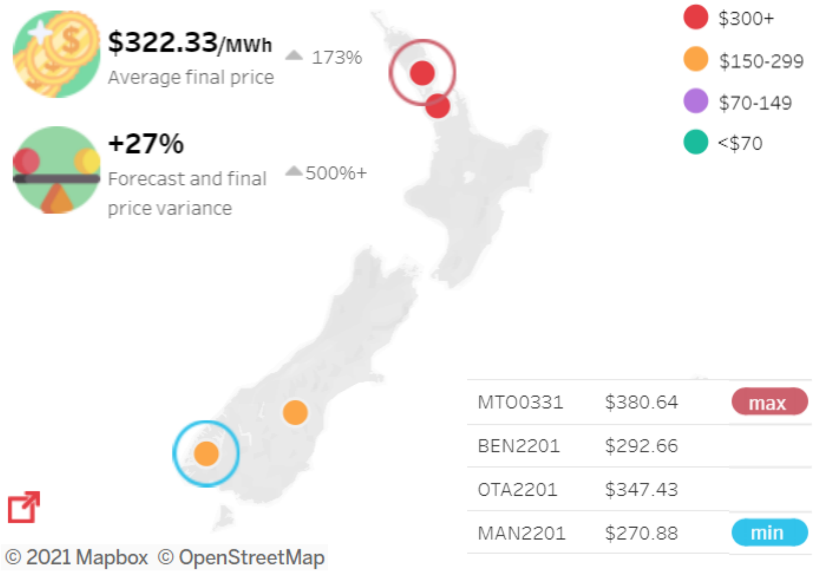
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.1 Average spot prices this week were $156/MWh[1], up 20% from the previous week. Prices at Benmore were close to $140/MWh for most of this week (see Figure 1).The highest prices occurred during TP 16 and 17 on 2 August when the price reached $350/MWh at Otahuhu (see Figure 2). While most of the high prices occurred around peak demand, there were also high prices during the day on 5 August and price separation on 6 August.

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

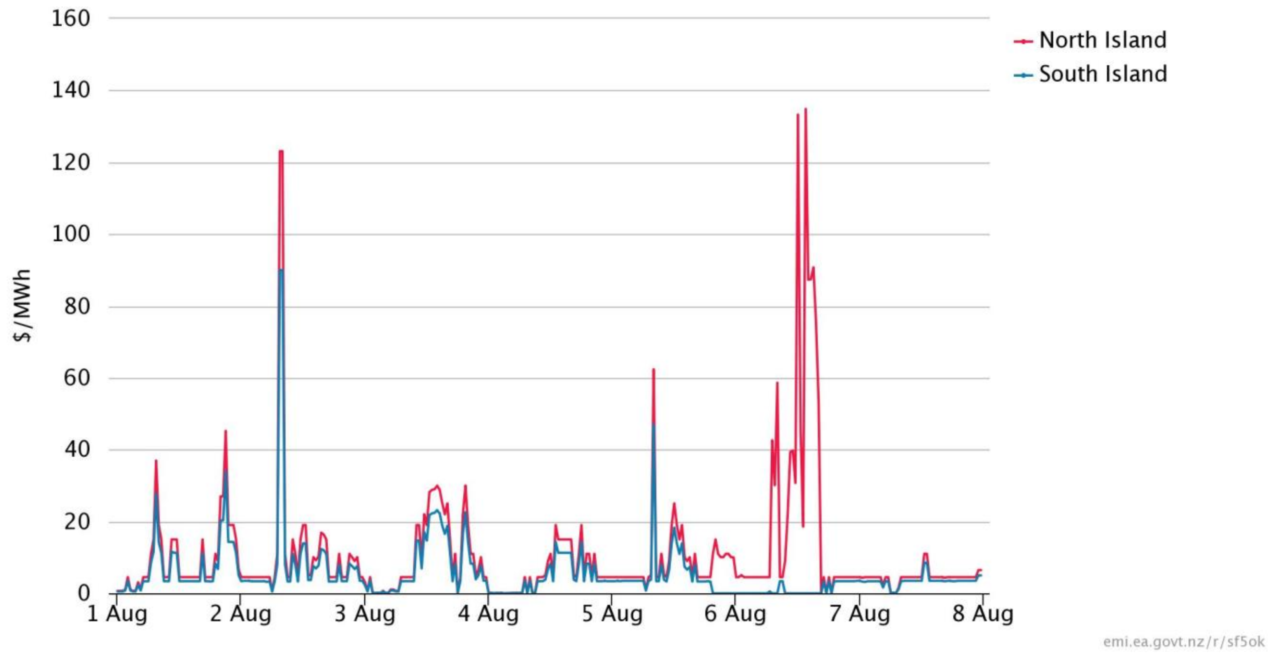
Figure 2: Spot prices for TP 17 on 2 August compared to previous week



Reserve Prices

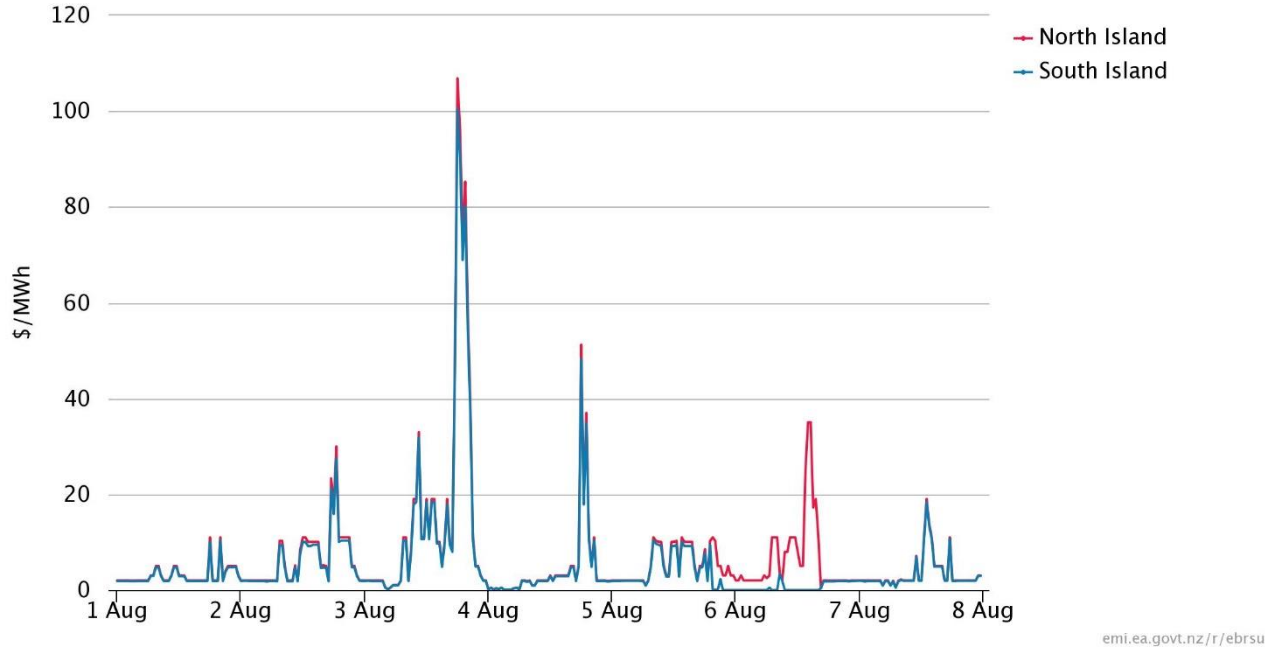
2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 3, were usually below $5/MWh. There was a price spike that coincided with the high energy price on TP 16/17 2 August. North Island prices for FIR were also high on 6 August.

Figure 3: FIR prices by trading period by Island



2.3 The prices for sustained instantaneous reserves (SIR), shown in Figure 4 for this week, were usually below $5/MWh. The highest price occurred on TP 37 on 3 August reaching $107/MWh.

Figure 4: SIR prices by trading period by Island

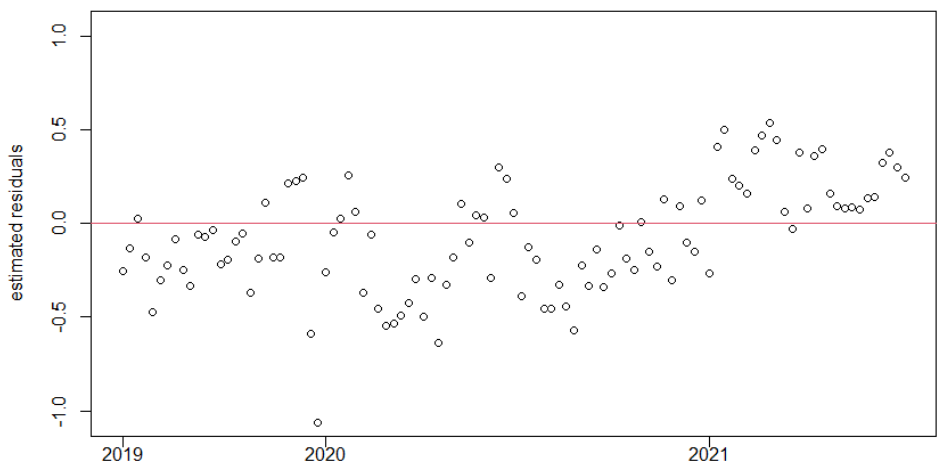


Residuals from regression models

2.4 The Authority's monitoring team has developed two regression models of the spot price. The residuals show how closely 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 June 2021 the residuals were higher than in May, but still within the normal range.[2]

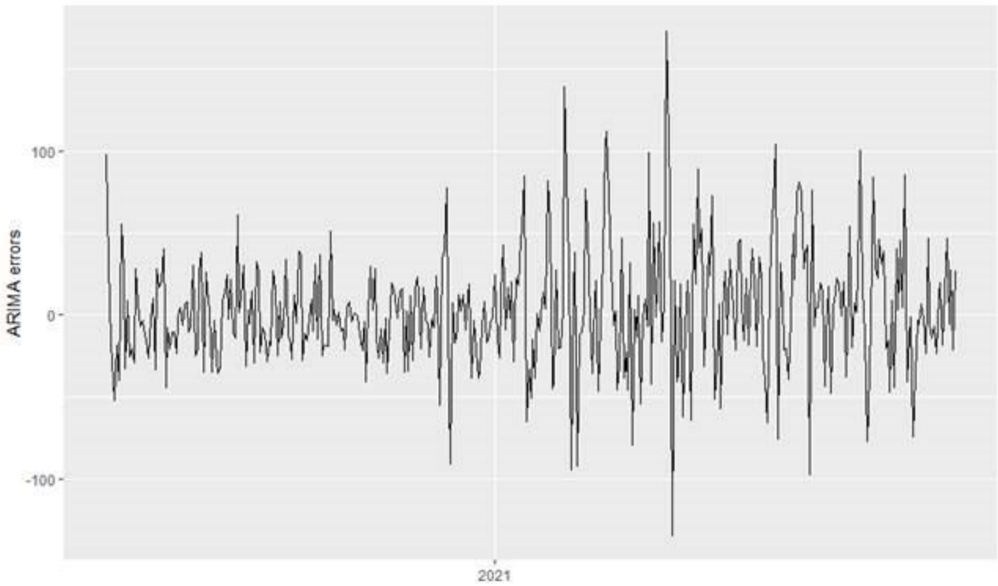
Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 30 June 2021



2.6 Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residual was largest on 3 August and the residuals were relatively small, indicating prices were close to the model's predictions.

[2] This model uses reconciled data and will be updated to end of July in mid-August.

Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 7 August 2021



3 Demand Conditions

3.1 Total demand was higher this week than the previous week. Demand often stayed high during the day compared to last week, especially on 5 August, when temperatures stayed low in Christchurch and Wellington (Figure 8).

Figure 7: National demand compared to previous week

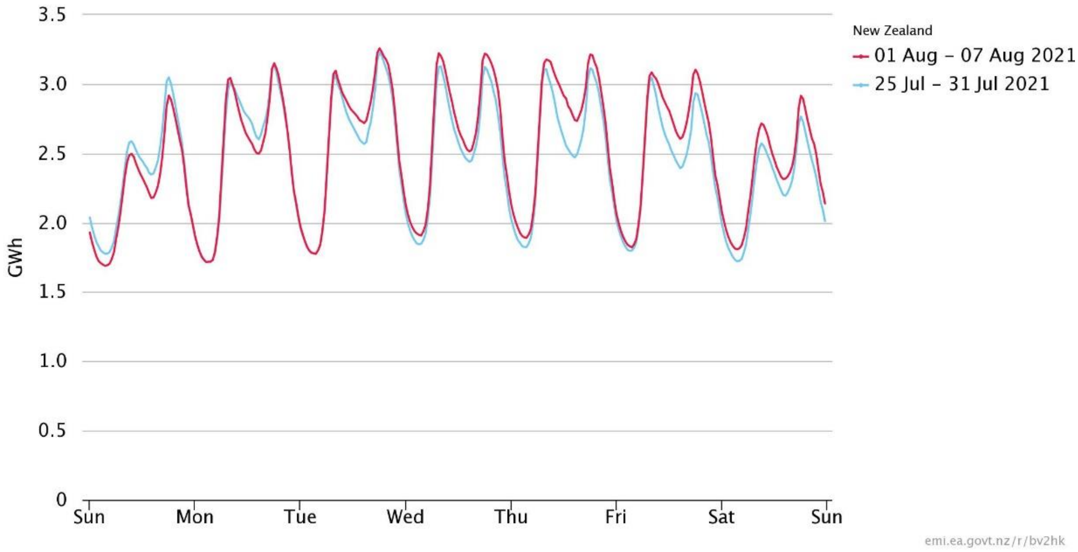
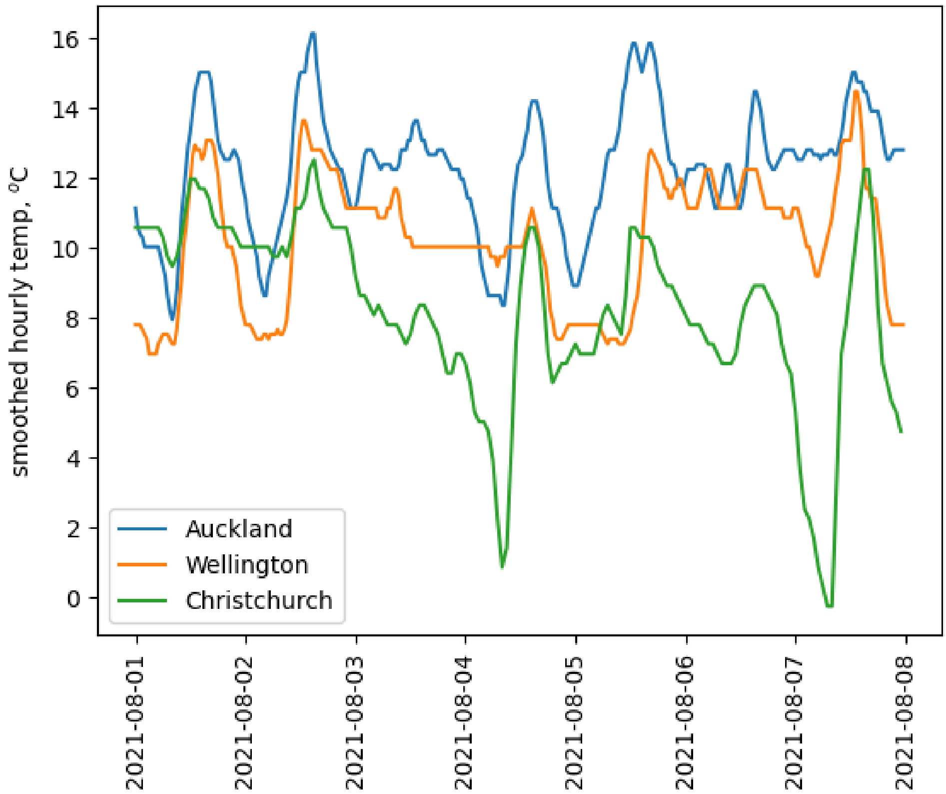
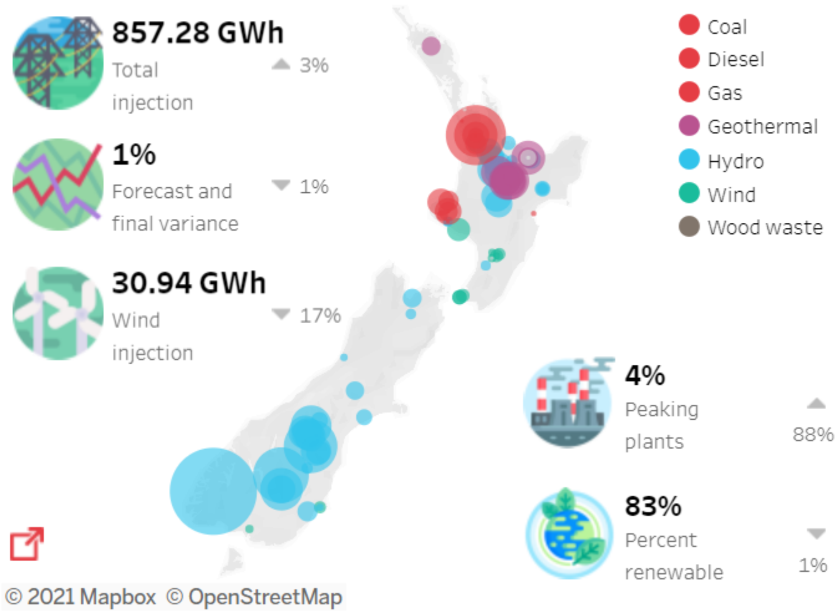


Figure 8: Hourly temperature data at main population centres



4 Supply Conditions

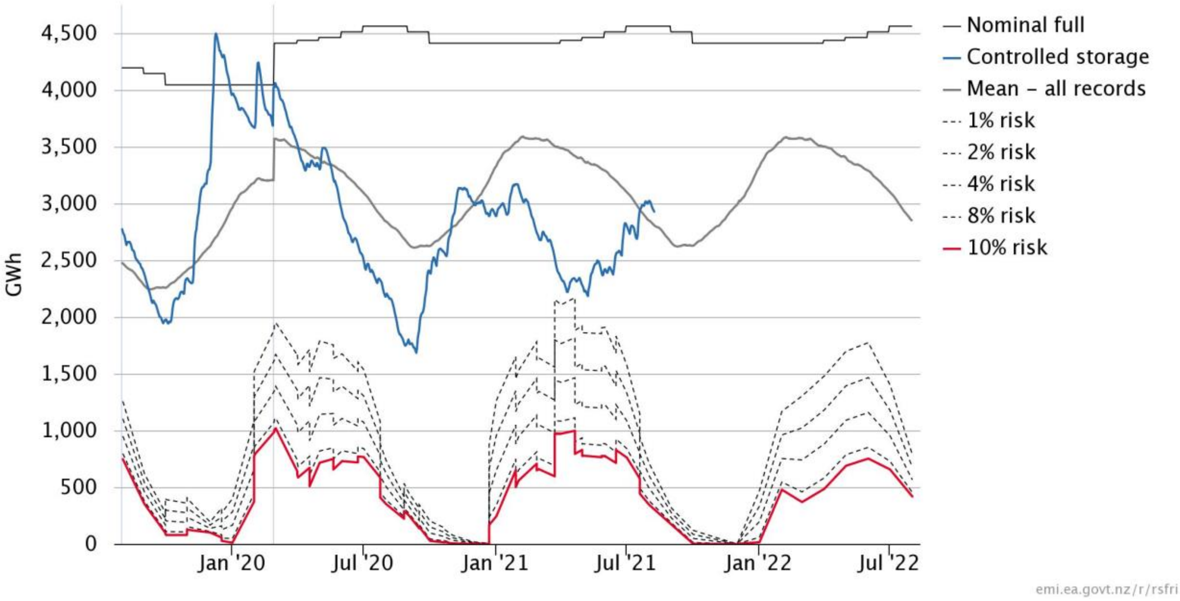
Figure 9: Electricity risk curves and current hydro supply



Hydro conditions

4.1 Total hydro storage decreased this week, though supply remains above the seasonal mean.

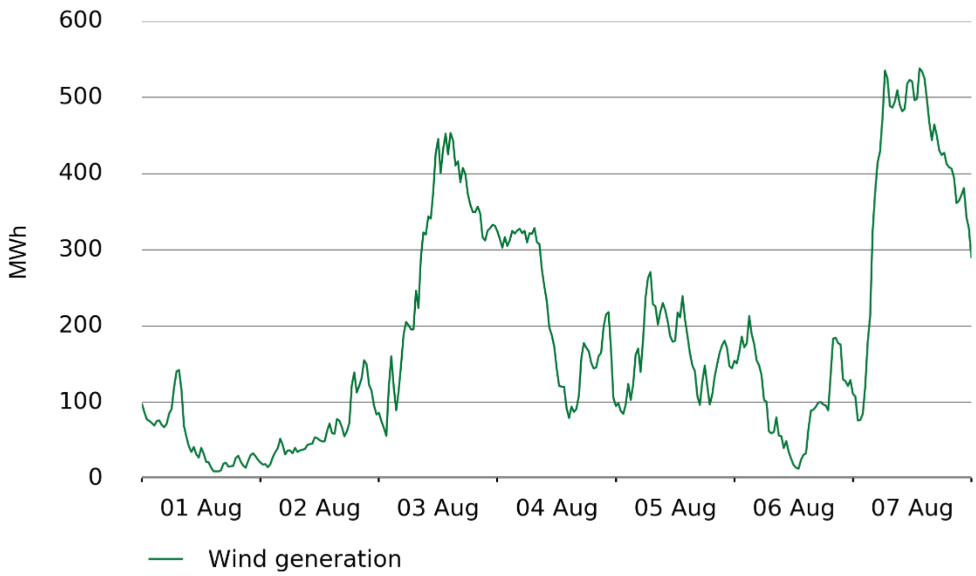
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 31GWh, down 17% from last week. Wind generation was variable this week, with low wind generation on 1, 2 and 6 August and high wind generation on 3 and 7 August (see Figure 11).

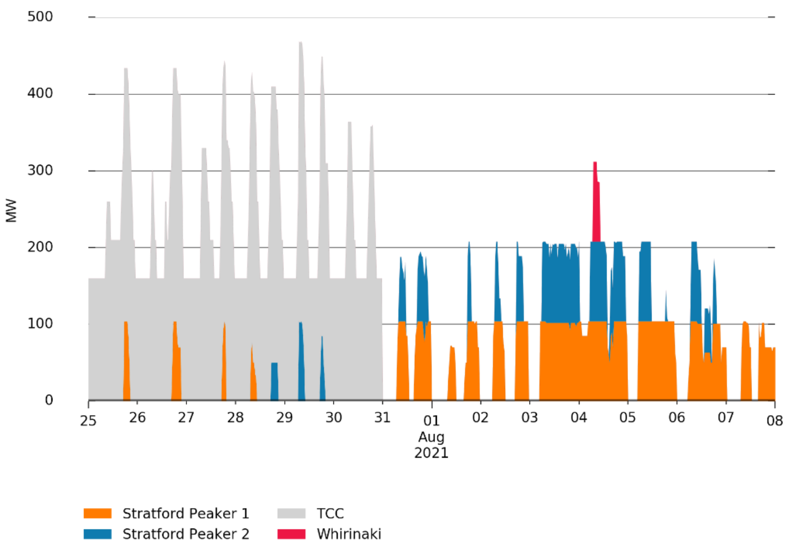
Figure 11: Wind generation for the week



Thermal conditions

4.3 Contact's combined cycle generation unit (TCC) has not been offered into the market since 31 July, though it is not recorded as on outage. This has been followed by an increase of dispatch from the Stratford peakers (see Figure 12).

Figure 12: Contact's thermal generation

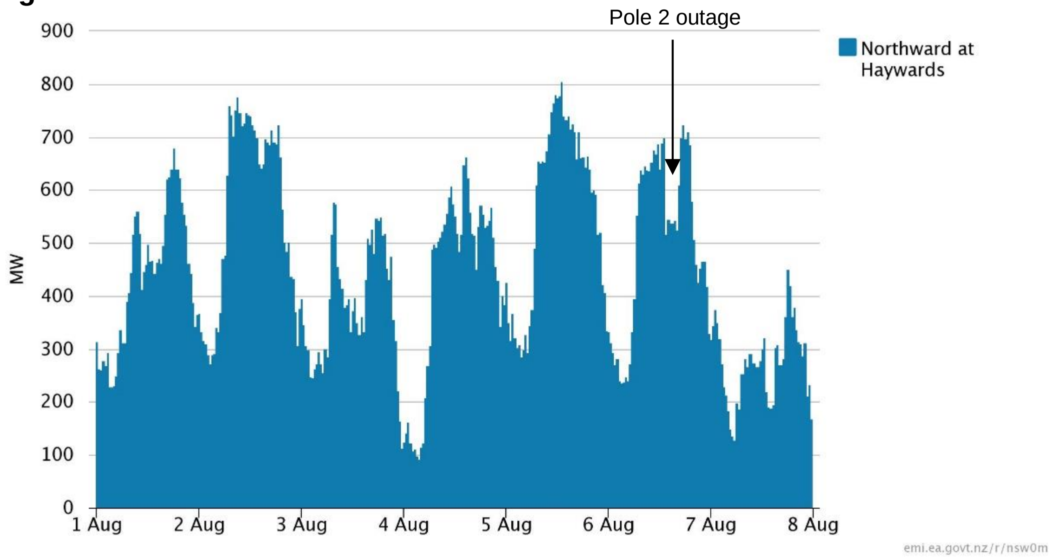


Significant outages

HVDC Outage

4.4 On 5 and 6 August the HVDC Pole 2 tripped and restarted several times. As a result, capacity on Pole 2 was reduced to 300MW followed by a full outage on 6 August from 1:30pm to 4pm. The outage reduced northbound capacity for both energy and reserves to 780MW from Pole 3. The northward energy transfer was about 100MW lower on the 6 August than 5 August and then dropped by about 200MW when Pole 2 went on outage (Figure 13). The reduction and unplanned outage of Pole 2 on the 6 August caused price separation in both the energy and reserve markets.

Figure 13: HVDC transfer



Generation Outages

4.5 The following outages reduced available generation by at least 90MW:

(a) Clyde;

(i) 116MW (long term outage)

(ii) 116MW (3 August – 4 August)

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

(c) Manapouri;125MW (19 July – 25 September)

(d) Huntly 2; 240MW (31 July – 5 August)

(e) Ohau (several units)

(i) 121MW (2 August – 13 August)

(ii) 108MW (5 August)

(f) Tekapo, 93MW (7 August 1pm- 3pm)

5 Price versus estimated costs

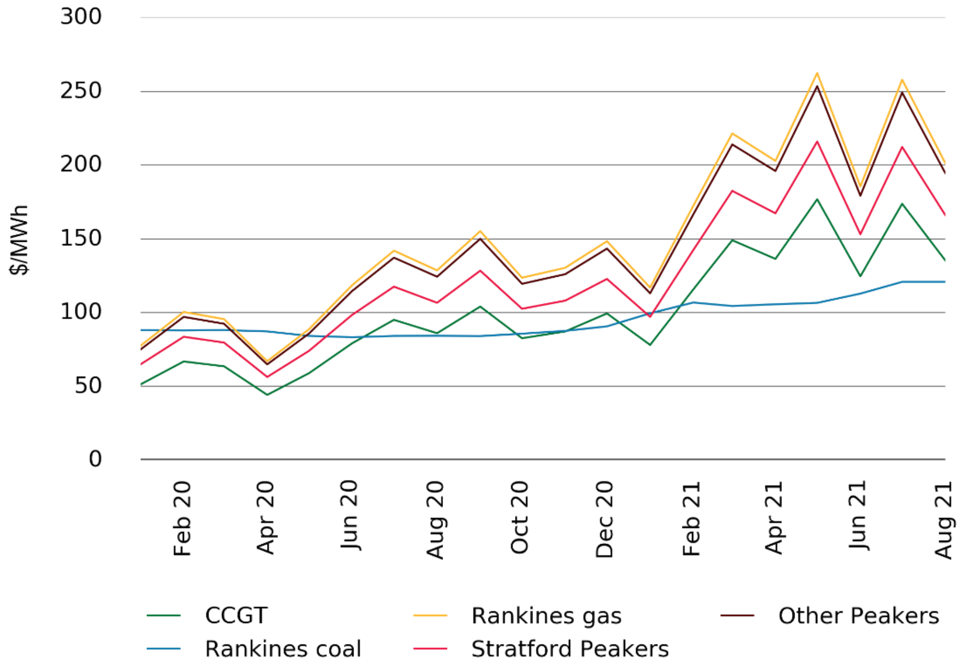
5.1 In a competitive market prices should be close to (but not necessarily at) the short run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).[3]

5.2 The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices[4] and the average heat rates for each thermal unit. Figure 14 shows estimates of thermal SRMCs as a monthly average. High gas spot prices increased the thermal SRMC for July, but the price has dropped so far in August (to 7 August). Coal is purchased by contract in advance and historically coal been more expensive than gas but is currently cheaper.

[3] 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/

[4] 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

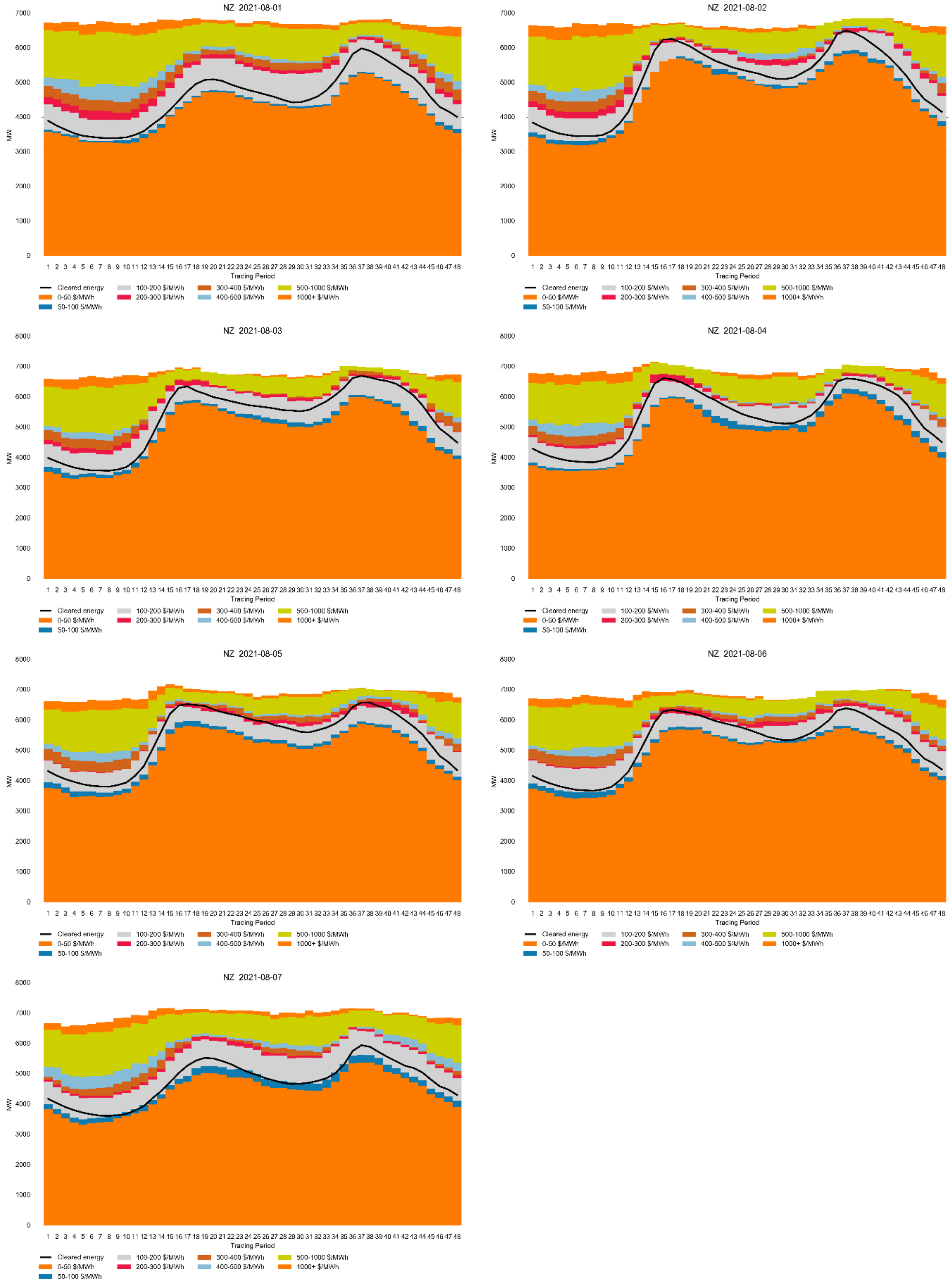
Final daily offer stacks

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

6.2 The quantity weighted offer price dropped by 7% compared to the previous week. The amount offered over $350/MWh dropped by 5%, with more offered between $100-$200/MWh.

[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 15: Daily offer stack



Offers by trading periods

6.3 As noted in section one, the trading period (TP) with the highest price was TP17 (8:00am) on 2 August. Figure 16 shows the offer stack, the generation weighted average price (GWAP) and cleared generation for TP17. Figure 17 shows the outcome for the same TP for one week earlier.

6.4 There was less generation offered below $200/MWh this week compared to the previous week, likely due to TCC not offering into the market as well as the outages. So, while cleared generation was about the same in both weeks, the price was a lot higher this week.

Figure 16: Offer Stack for trading period 17 on 2 August

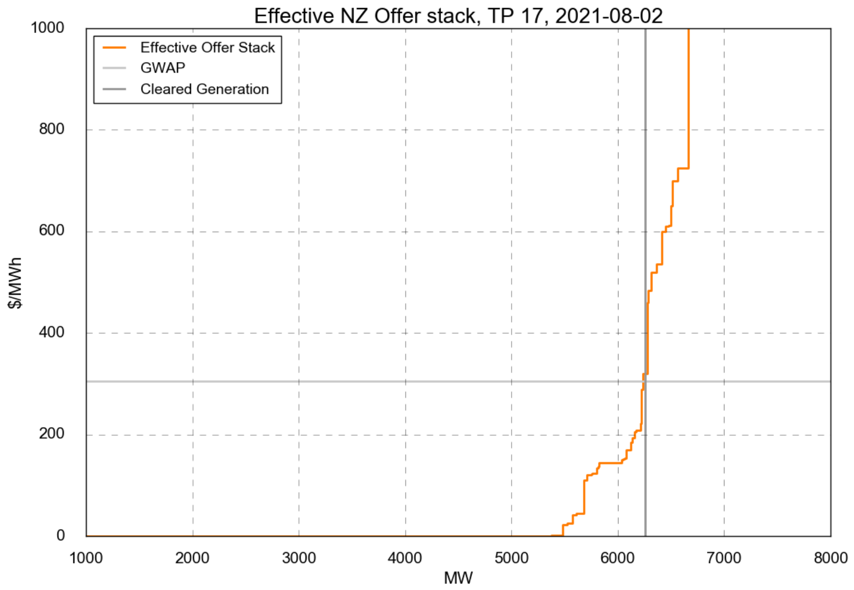
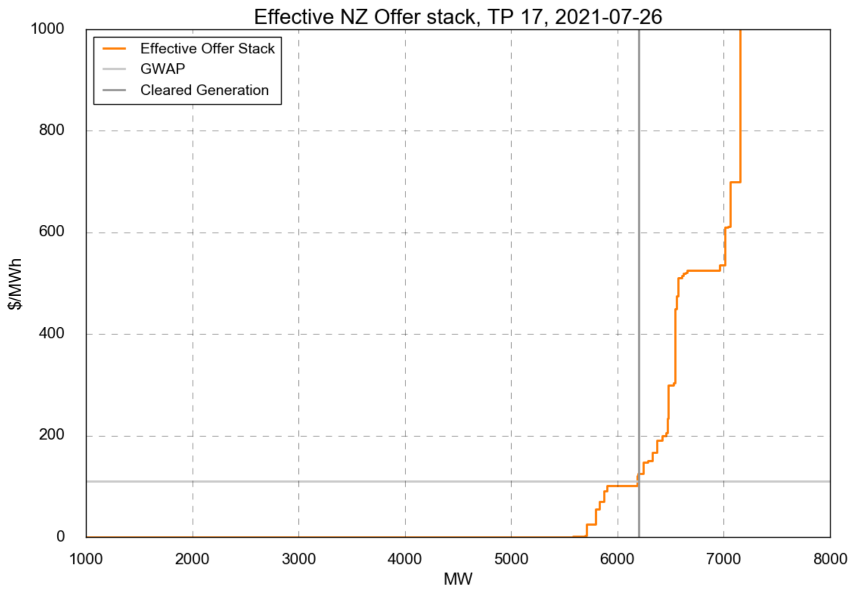


Figure 17: Offer Stack for trading period 17 on 26 July



6.5 Figure 18 and Figure 19 show the offer curves where high prices occurred on 5 August. Generation cleared on this day was high, which could explain high prices during peak demand (Figure 18), the prices remained high even when demand had dropped (Figure 19). This group of trading periods will be further analysed.

Figure 18: Offer Stack for trading period 17 on 5 August

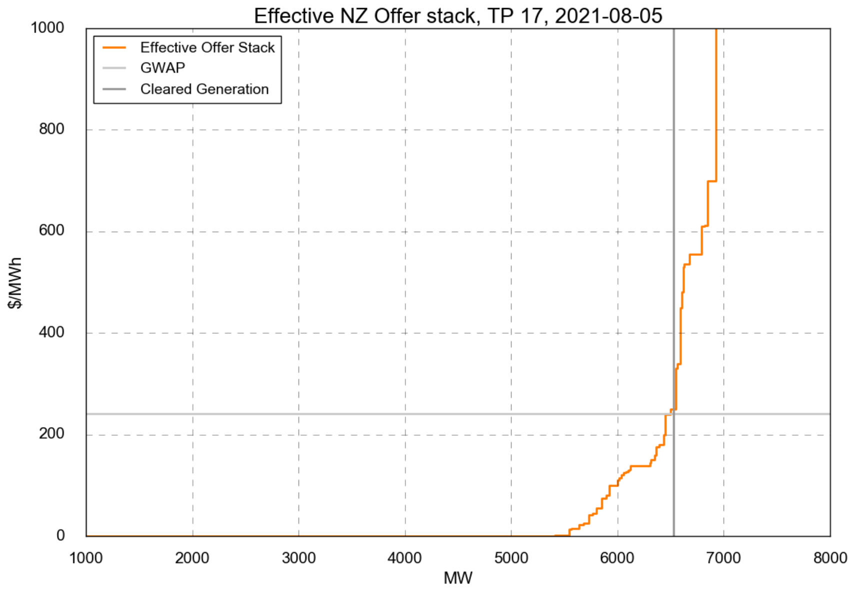
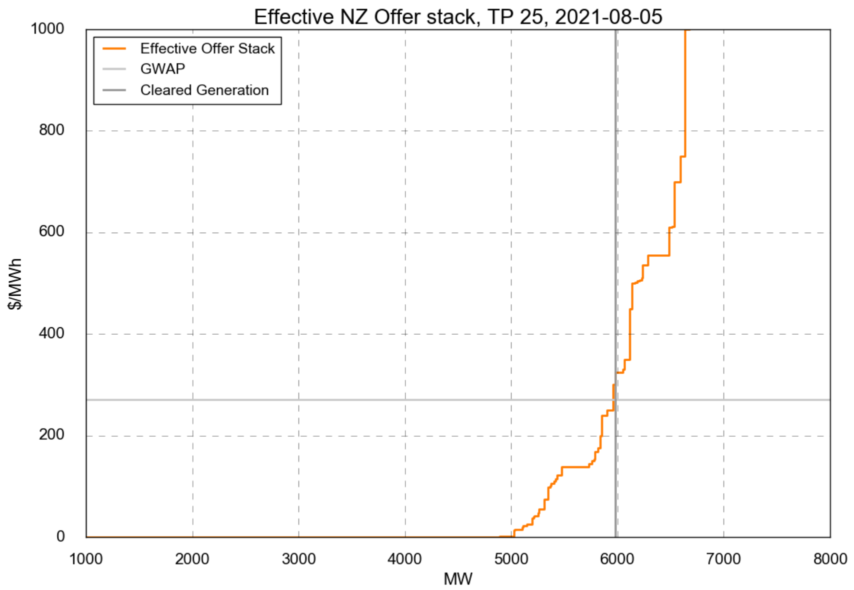


Figure 19: Offer Stack for trading period 25 on 5 August



7 Ongoing Work in Trading Conduct

7.1 We identified the following trading period for further analysis. We have grouped some trading periods together based on similar offer behaviour to pass to compliance to assess if this offer behaviour is consistent with the new trading conduct provisions.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
05/08/2021	17-26	Further Analysis	High prices in middle of day
03/08/2021	16-17	Further Analysis	High SIR prices
02/08/2021	36-40	Further Analysis	High FIR prices
30/07/2021	17	Resolved	High demand for FIR, drop in IL offered, high FIR price prevented higher energy prices.
12/07/2021	24-25	Further Analysis	High energy prices
5/07/2021	34	Resolved	Tight supply conditions due to outages and high demand
5/07/2021	17-24	Resolved	Tight supply conditions due to outages and high demand
4/07/2021	36-43	Resolved	Tight supply conditions due to low wind and outages, and high demand
4/07/2021	15-20	Resolved	Tight supply conditions due to low wind and outages, and high demand
3/07/2021	16-20	Resolved	Tight supply conditions due to low wind and outages, and high demand
3/07/2021	37	Resolved	Tight supply conditions due to low wind and outages, and high demand
30/06-14/07	Several	Compliance: review	High energy prices in shoulder periods
30/06-12/07	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, where *diff* is the first difference:

$$y_t = 109.64 - 0.35 \times\ diff(storage) + 0.79 \times diff(demand) - 7.32 \times\ wind.generation + 1.67 \times\ gas.price - 0.03 \times\ diff(generation\ HHI) +\ \eta_t$$
$$\eta_t = 0.74 \times \eta_1 - 0.05 \times \eta_2 + 0.14 \times \eta_3 + 0.02 \times \eta_4 + 0.09 \times \eta_5 + \varepsilon_t$$

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.