High Standard of Trading conduct

Market Monitoring Weekly Report

20 July 2021

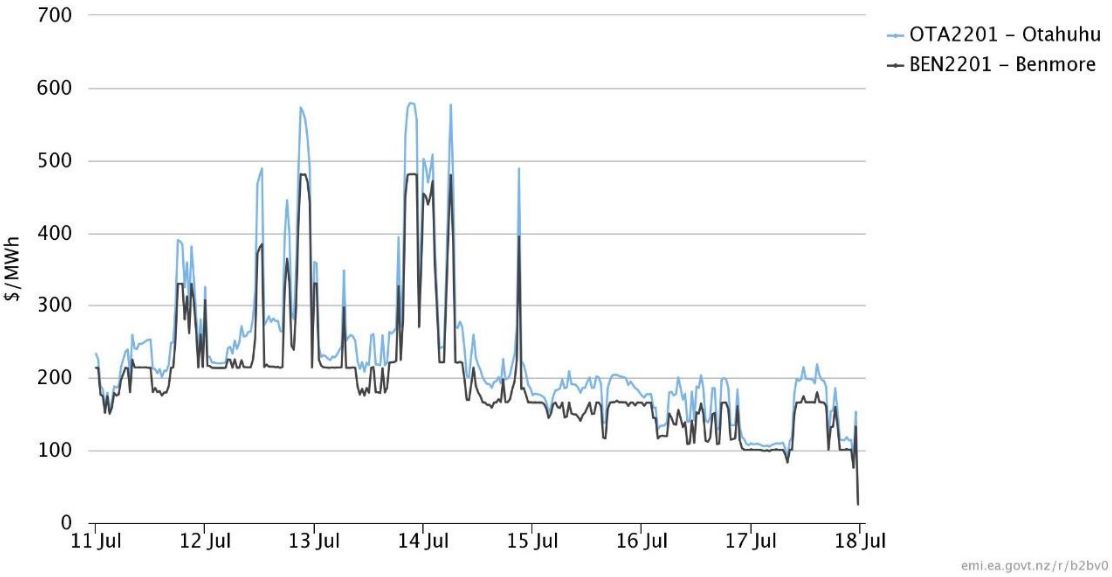
1 Overview for the week of 11 to 17 July 2021

1.1 High prices this week appear to be due to tight supply condition coinciding with high demand, but some trading periods will be further analysed. The trading periods we will investigate further are listed at the end of this report.

2 Prices

Energy prices

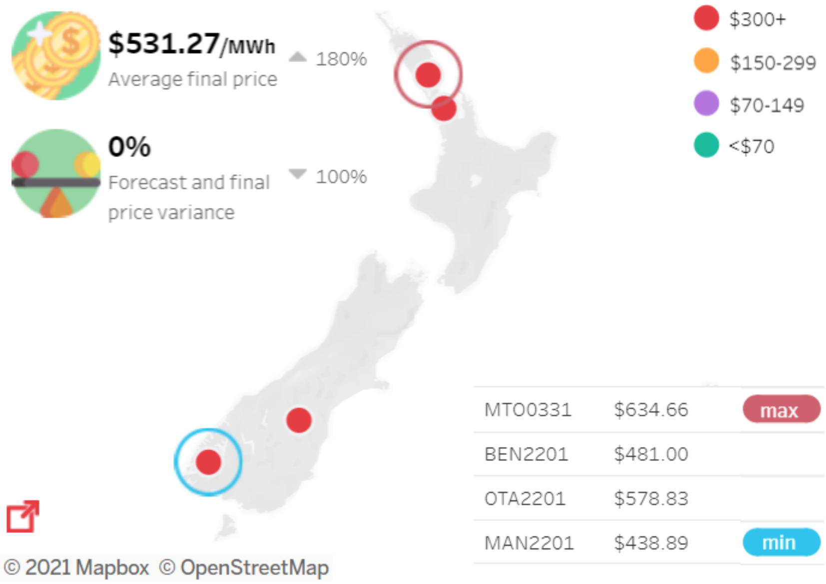
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.1 Average spot prices this week were $216/MWh[1], up 7% from the previous week. The highest prices occurred during TP 43 on 13 July with an average price of $531/MWh[1] (see Figure 2). Prices were highest from 12 to 14 July. Prices from 15 July onwards stayed around $175/MWh at Benmore, with occasional fluctuations (see Figure 1).

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

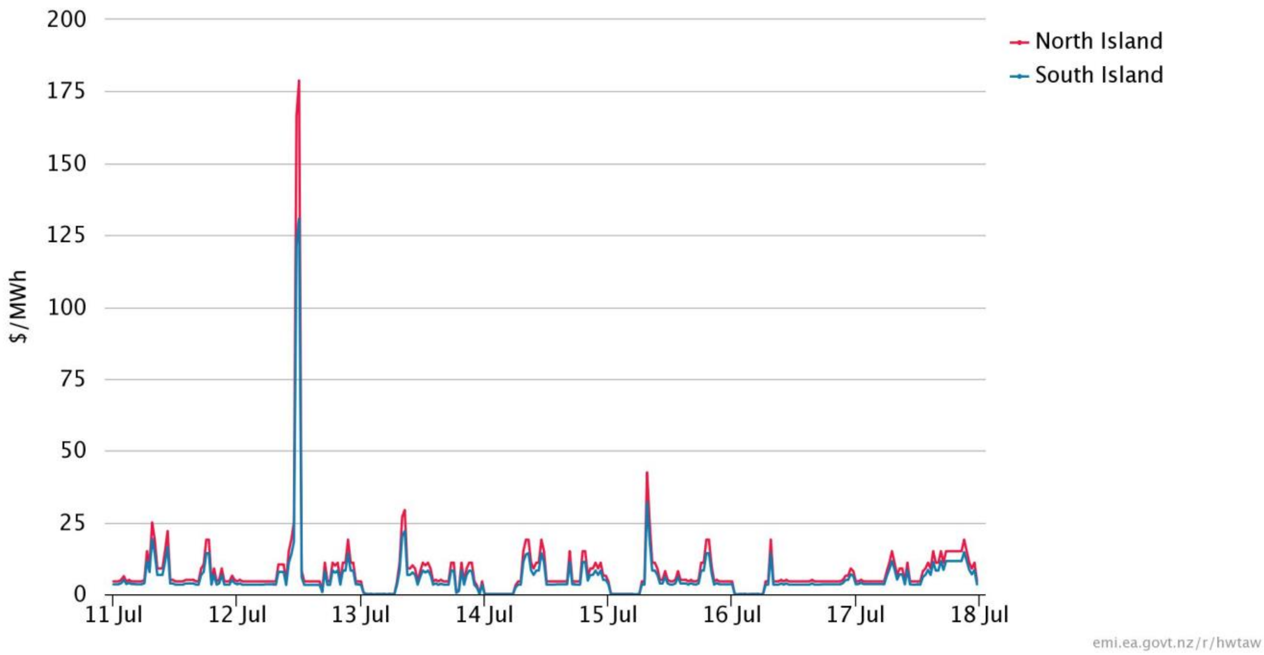
Figure 2: Spot prices for trading period 43 on 13 July compared to previous week



Reserve Prices

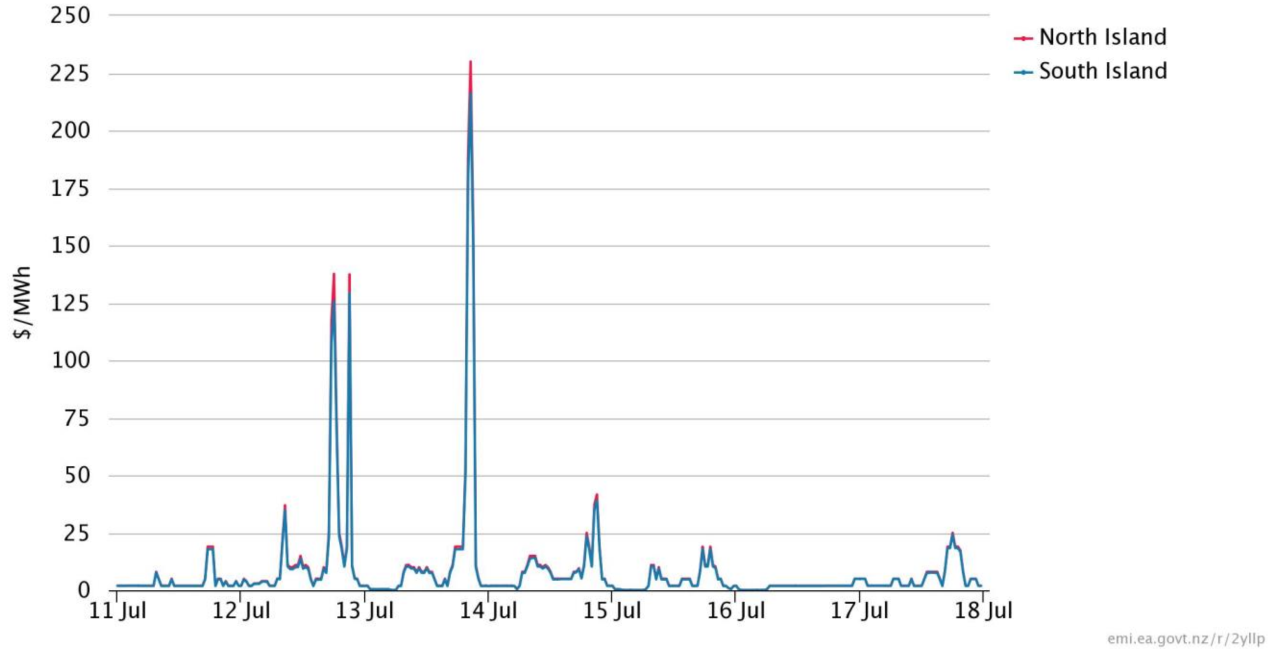
2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 3, were usually below $5/MWh, with prices up to $40/MWh during peak hours. The one exception was the price spiking to $178/MWh in the North Island around midday on the 12 July.

Figure 3: FIR prices by trading period by Island



2.3 The prices for sustained instantaneous reserves (SIR), shown in Figure 4for this week, were usually below $5/MWh, with 3 instances of prices over $100/MWh early in the week.

Figure 4: SIR prices by trading period by Island

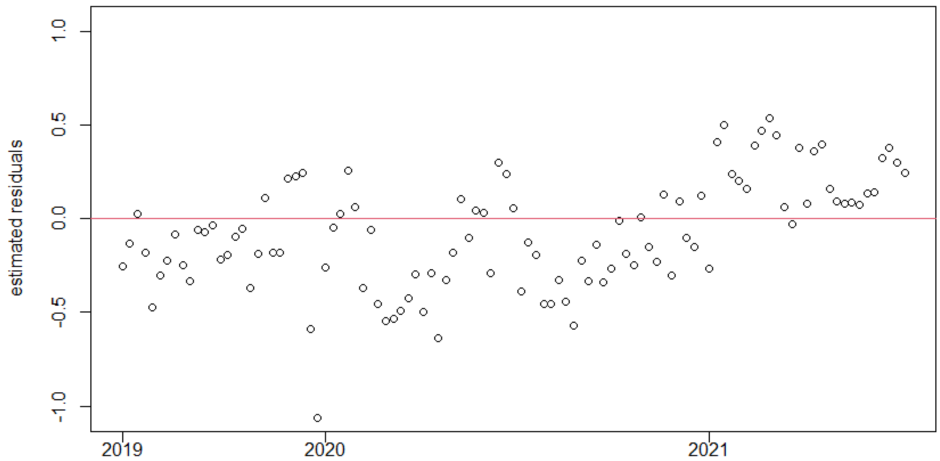


Residuals from regression models

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]

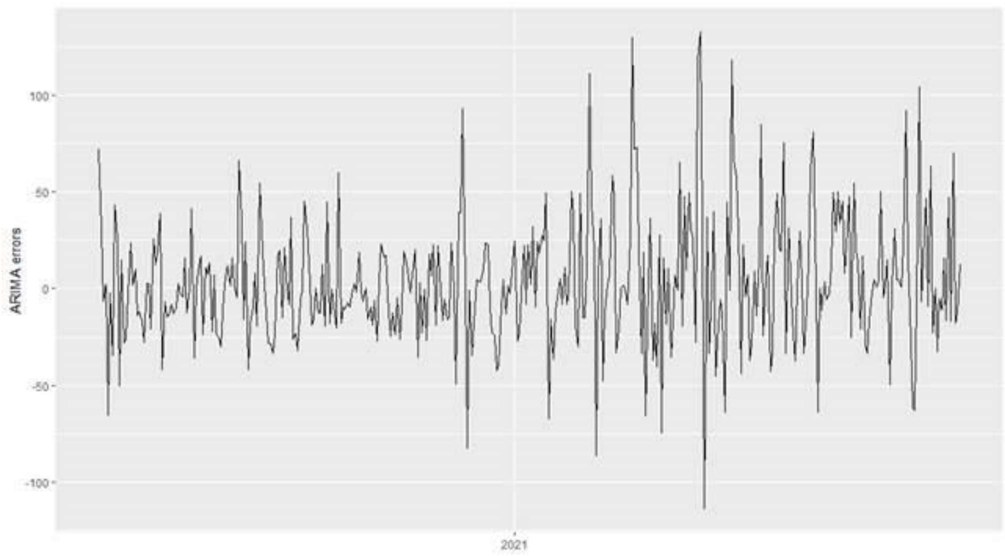
Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 30 June 2021



2.6 Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residual was highest on 14 July, but otherwise the residuals were within the normal range, indicating prices were close to the expected price from the model.

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

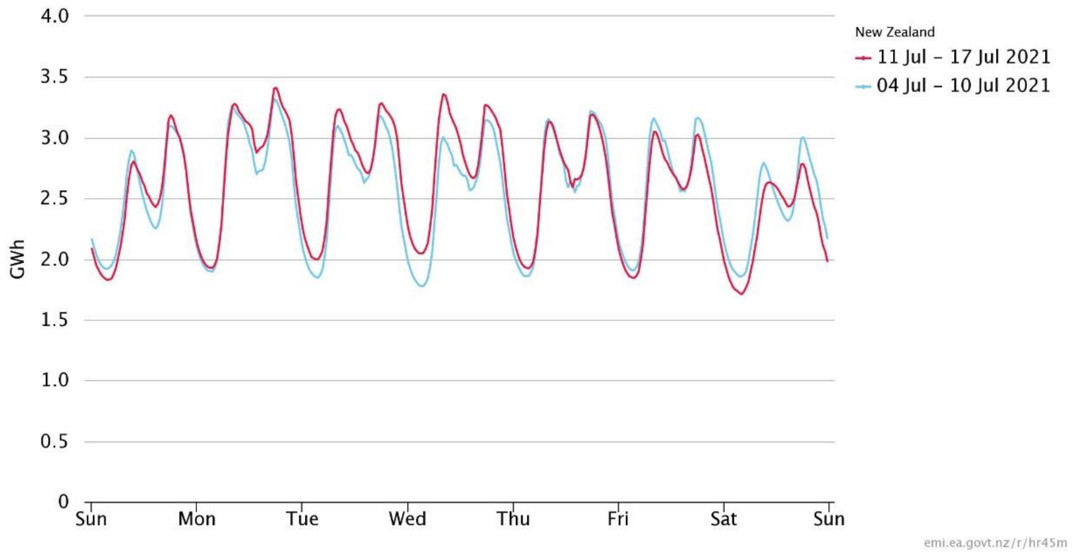
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 17 July 2021



3 Demand Conditions

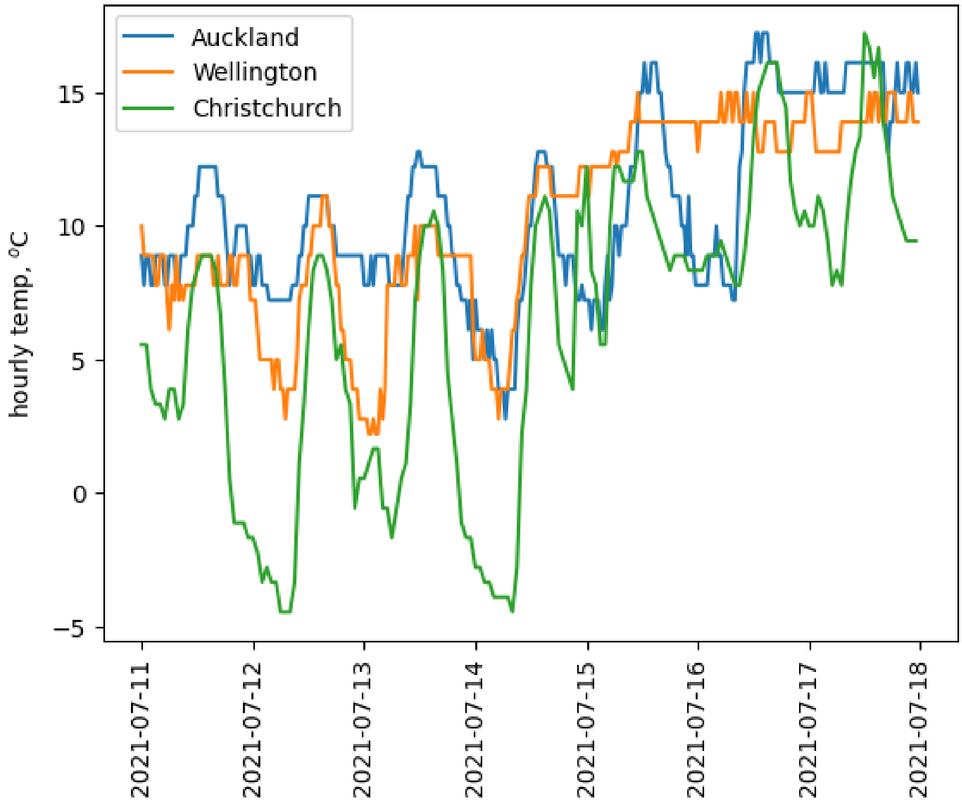
3.1 Demand was particularly high from 12 to 14 July. This is consistent with the timing of high prices, with lower prices from 15 July onwards.

Figure 7: National demand compared to previous week



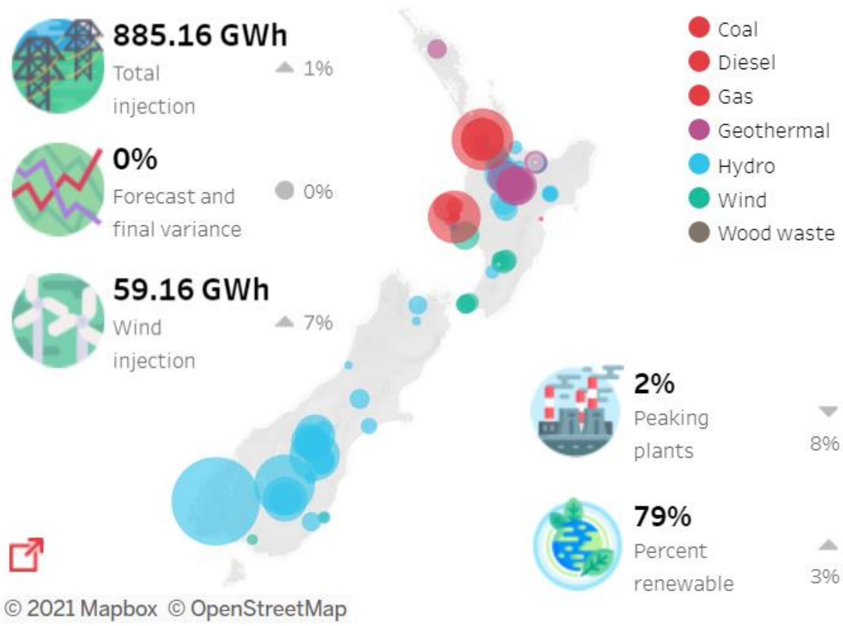
3.2 High demand was driven by cold temperatures in the main population centres. Overnight temperatures fell below freezing in Christchurch from 12 to 14 July. Auckland had a particular cold night on 13/14 July, resulting in high demand the morning of 14 July. Temperatures in the main centres have increased since the 15 July coinciding with decreased demand.

Figure 8: Hourly temperatures in Auckland, Christchurch and Wellington



4 Supply Conditions

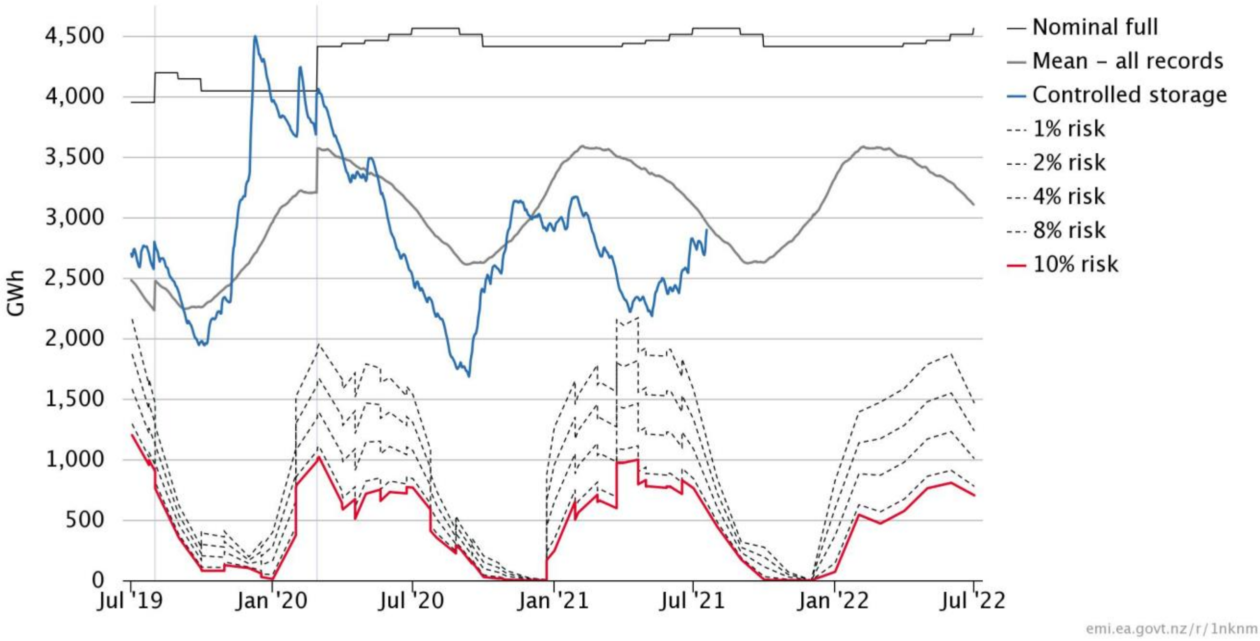
Figure 9: Generation by type and location for the last week



Hydro conditions

4.1 Total hydro supply last week was 53% of nominal full. Strong inflows at the end of the week have increased supply to close to the seasonal mean for the first time this year.

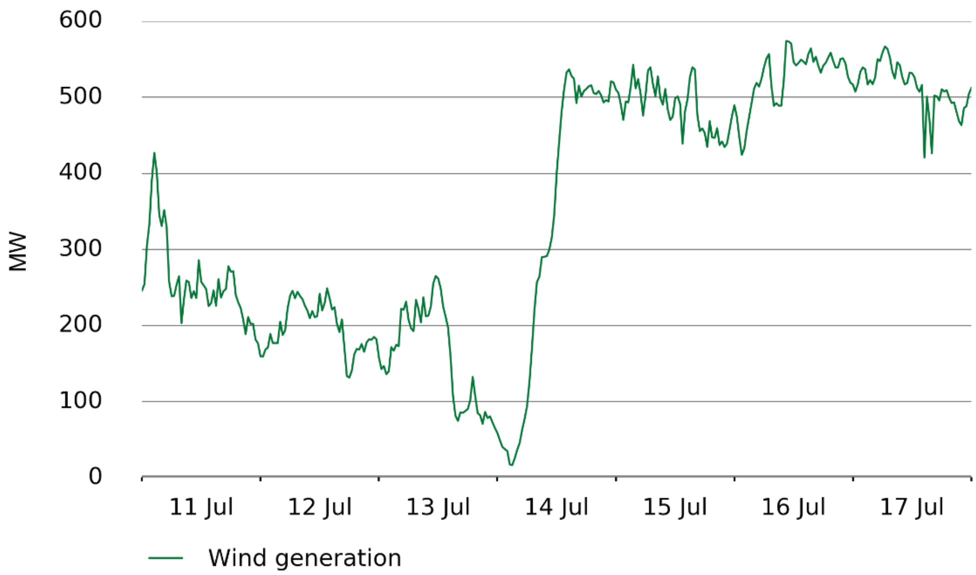
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 59GWh, up 7% from last week. Wind conditions were lower in the first half of the week, almost reaching 0MW in the early hours of the 14 July before weather conditions changed increasing wind generation to be around 500MW. This is consistent with lower prices at the end of the week.

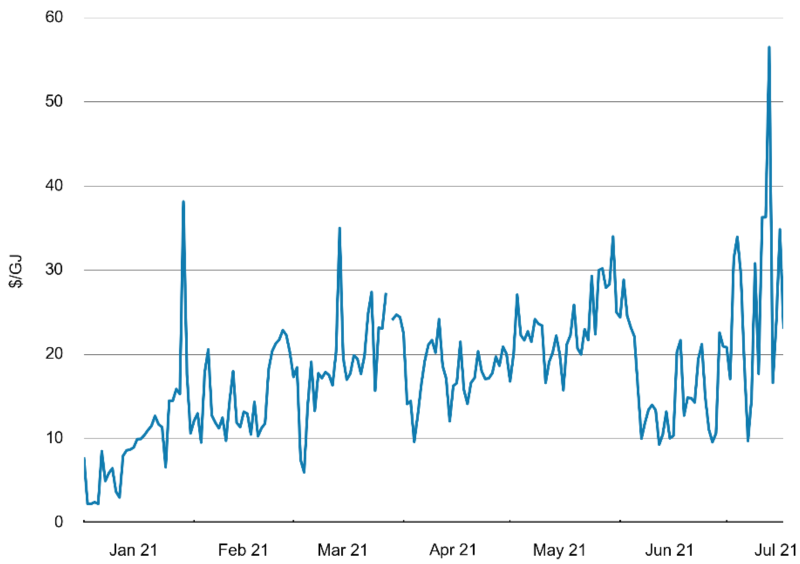
Figure 11: Wind generation for the week



Thermal fuel market conditions

4.3 There were a couple of gas production outages, unplanned and planned, this week. The most significant was the planned outage at Kupe on 13 July. This outage reduced supply by almost 43TJ which resulted in prices reaching $56/GJ. This followed an unplanned outage at McKee on 12 July, reducing supply by around 20TJ. The quantities of gas traded at spot prices is only a small part of the total gas market but does provide the opportunity cost of buying or selling an additional unit of gas.[3]

Figure 12: Spot gas, traded VWAP, daily, 1 January to 17 July



4.4 Likely due to the Kupe gas outage, Genesis shut down their combined cycle overnight on 13 July. This coincided with low wind generation and some large outages (see below) increasing reliance on hydro and thermal peakers to meet demand, which was higher than usual overnight.

Significant outages

4.5 The following outages reduced available generation by at least 100MW:

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

(b) Huntly 4, 240MW (9 July-19 July)

(c) Stratford Peaker 2, 100MW (12 July 1pm-3pm)

(d) Manapouri, 125MW (13 July-16 July)

[3] Opportunity cost for gas generators – when storage of gas is available - also includes the expected price of generating at a later date.

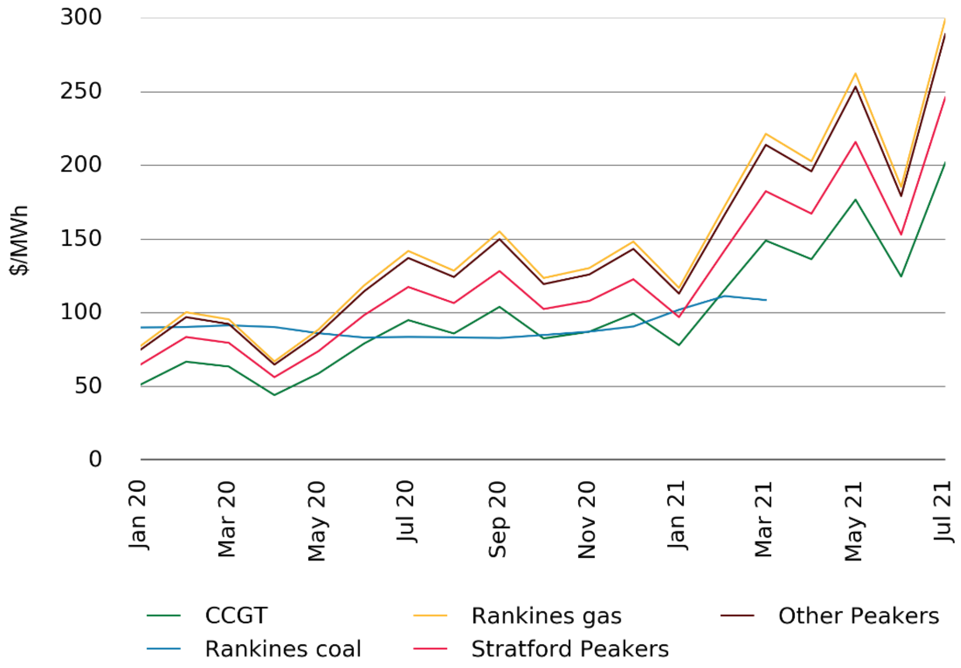
5 Price versus estimated costs

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).[4]

5.2 The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices[5] and the average heat rates for each thermal unit. Figure 13 shows estimates of thermal SRMCs as a monthly average. High gas spot prices have increased the thermal SRMC this month. Coal is purchased by contract in advance and the SRMC is based on coal prices up to March 2021. Historically coal has been more expensive than gas but is currently cheaper.

5.3 While this figure is monthly (the July value is for the month up to 17 July), gas prices do change daily which can impact the SRMC especially for any peakers who buy gas off the spot market. This week the daily spot market gas price (BGIX) peaked at $56/GJ.

Figure 13: Estimated monthly SRMC for thermal fuels



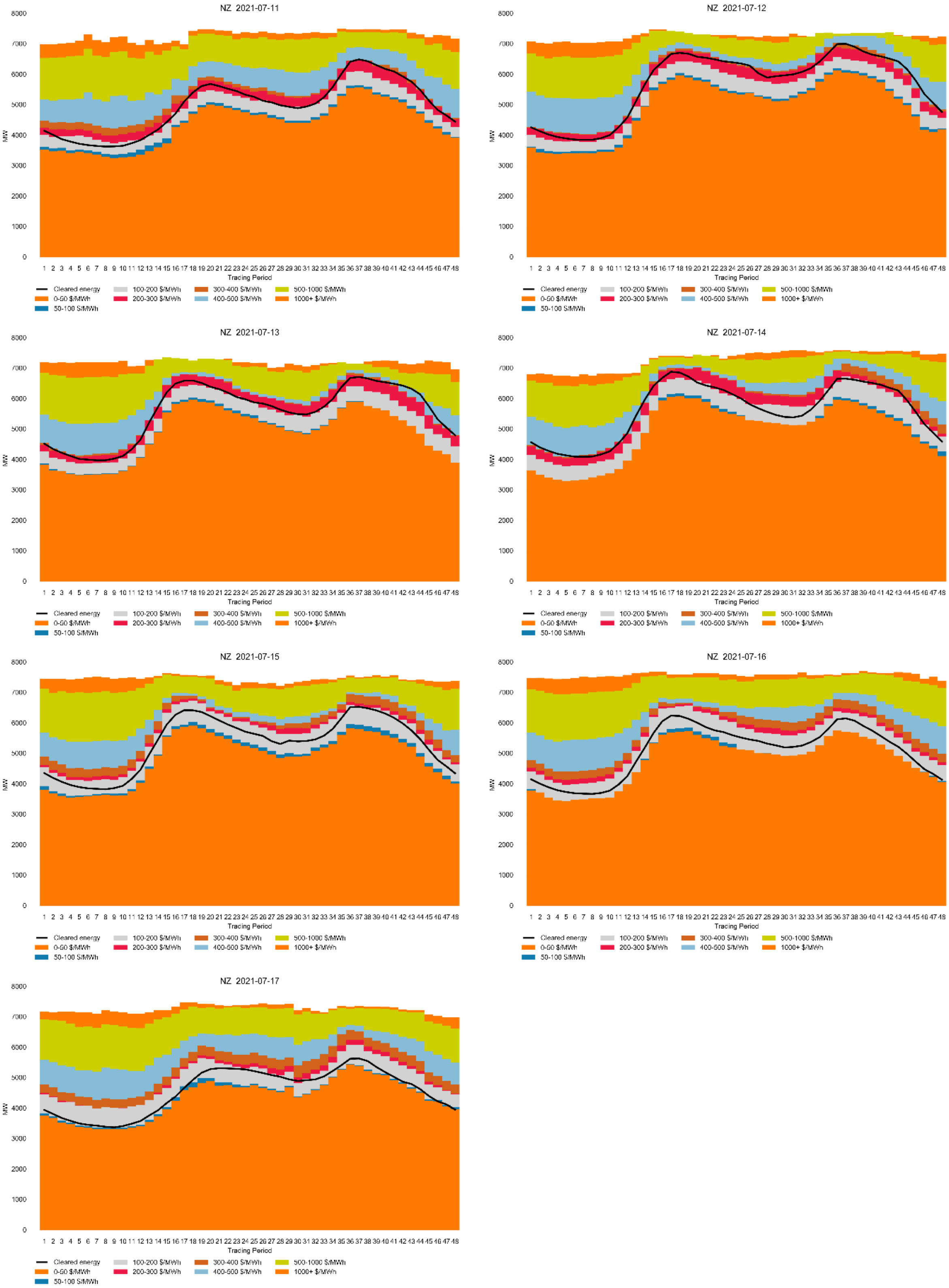
[4] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

[5] 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.

6 Offer Behaviour

Final daily offer stacks

Figure 14: Daily offer stacks



6.1 Figure 14 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[6] The black line shows the cleared energy, indicating the range of final prices.

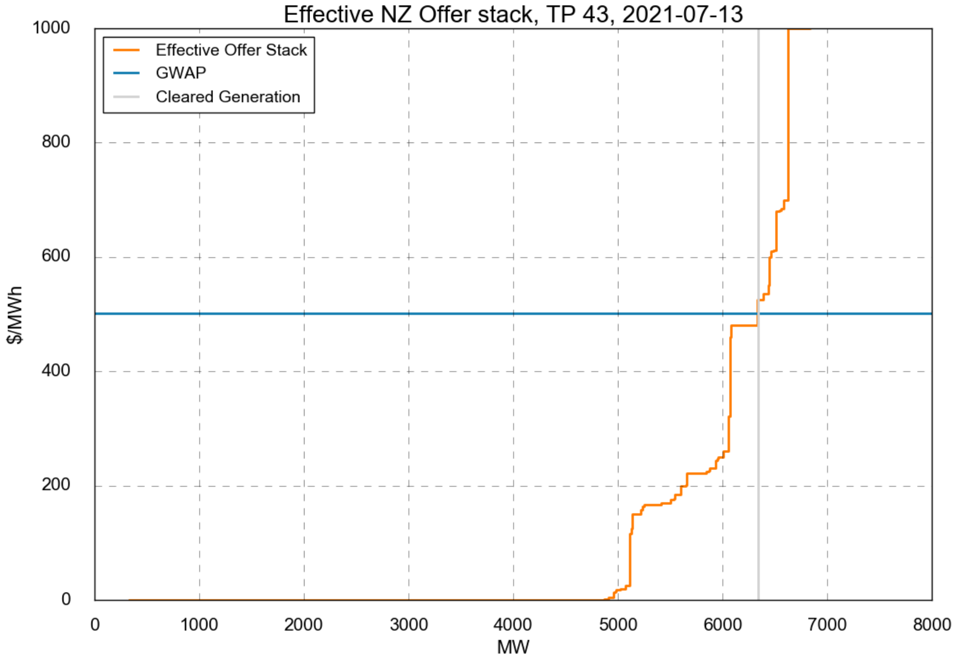
6.2 Overall, the offer curves look consistent with a tighter market earlier in the week than later in the week. On the days when supply was tight more generation was offered in the $200-300/MWh band while later in the week more was offered in the $100-$200/MWh price band. Demand was also high early in the week, resulting in the price more frequently reaching the higher bands.

Offers by trading periods

6.3 The following section highlights a few of the trading periods with high prices periods that the Authority's monitoring team will be looking into further. The offer stacks are shown with the generation weighted average price (GWAP) and cleared generation.

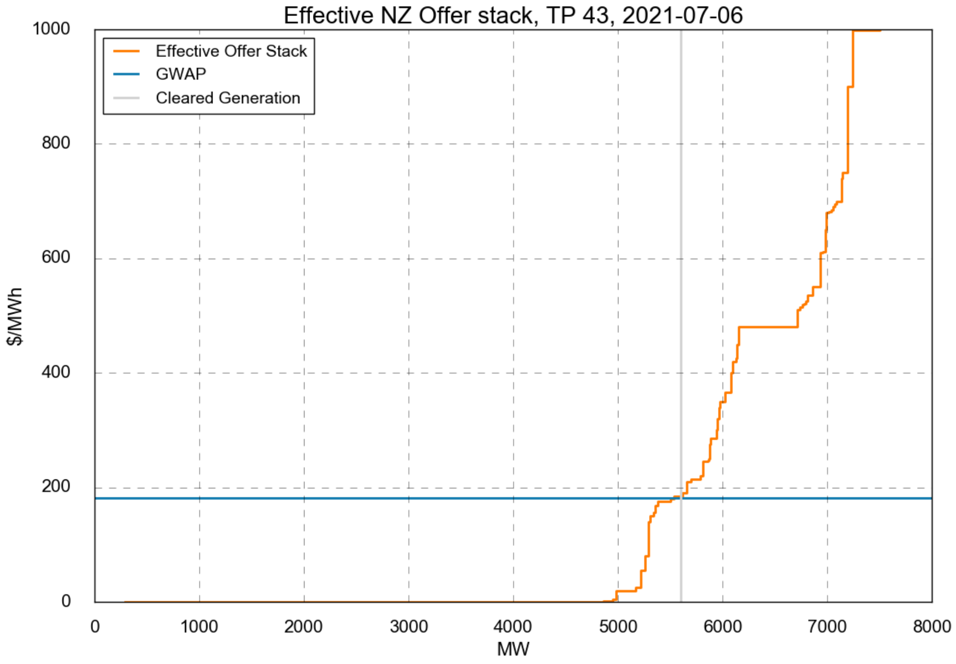
6.4 The trading period (TP) with the highest price was TP43 (9pm) on 13 July. The offer stack is shown in Figure 15 with the same trading period for the previous week shown in Figure 16. The higher price was primarily due to demand being 12% higher than the same TP the previous week, which would have cleared at a similar price if demand had been higher (or else being equal).

Figure 15: Offer Stack for trading period 43 on 13 July



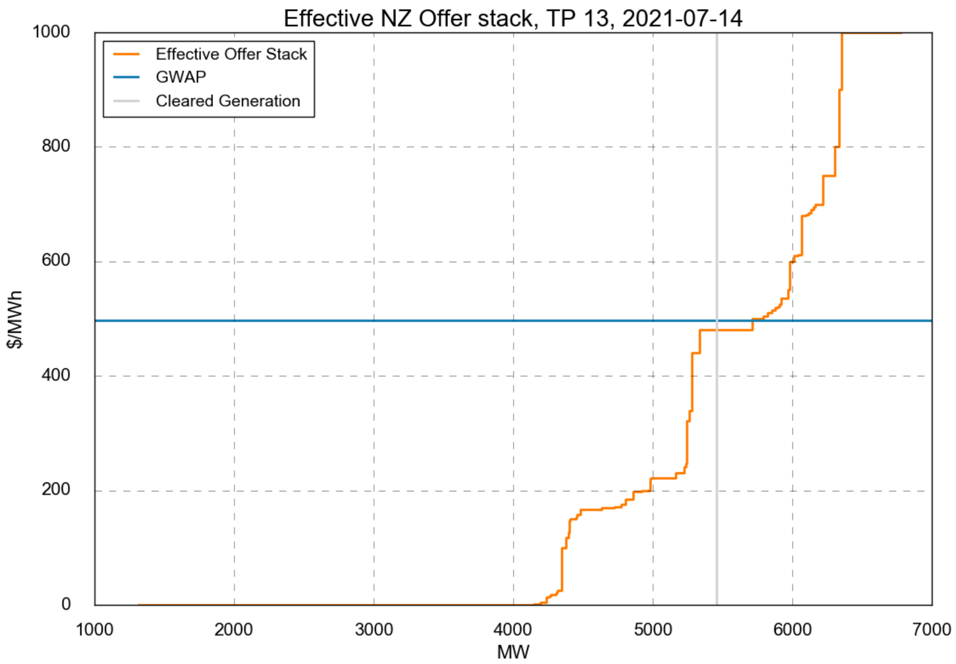
[6] The offer stacks show all offers bid into the market (where wind offers are truncated at their actual generation and excluding generation capacity cleared for reserves) in price bands and plots the cleared quantity against these.

Figure 16: Offer Stack for trading period 43 on 6 July



6.5 There were high prices on the morning of 14 July. Figure 17 shows the offer curve for TP 13 (6:00am), when prices were the highest that day. Demand was 16% higher than the previous week. Wind was also low, and Genesis shut down the E3P overnight, likely as a result of the Kupe outage, and only restarted during TP14.

Figure 17: Offer Stack for trading period 13 on 14 July



7 Ongoing Work in Trading Conduct

7.1 We have identified the following trading periods as warranting further analysis by the market monitoring team.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
14/07/2021	1-6	Further Analysis	Shoulder period, prices higher than peak, E3P shut down
14/07/2021	11-14	Further Analysis	Shoulder period, prices higher than peak, E3P shut down
14/07/2021	43	Further Analysis	Shoulder period, prices higher than peak
13/07/2021	41-46	Further Analysis	Shoulder period, prices higher than peak, high SIR price (41-42), Kupe on outage, demand high.
8/07/2021	43	Further Analysis	High price
8/07/2021	15-20	Further Analysis	High FIR prices
6/07/2021	18	Further Analysis	High FIR price
5/07/2021	34	Further Analysis	High price
5/07/2021	17-24	Further Analysis	High FIR/SIR prices, high prices
4/07/2021	36-43	Further Analysis	High prices, High SIR prices
4/07/2021	15-20	Further Analysis	High prices, High FIR price (19)
3/07/2021	16-20	Further Analysis	Highest prices, low wind
3/07/2021	26-30	Further Analysis	High FIR prices
3/07/2021	37	Further Analysis	Single price spike
2/07/2021	37-38	Further Analysis	High FIR and SIR price
1/07/2021	12-14	Further Analysis	Shoulder demand, low wind
1/07/2021	16-18	Further Analysis	High SIR price
30/06/2021	13-17	Further Analysis	Shoulder period to high demand period, FIR price also high
30/06/2021	42-44	Further Analysis	Shoulder period, prices higher than peak

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.