Trading Conduct Report

Market Monitoring Weekly Report

6 October 2021

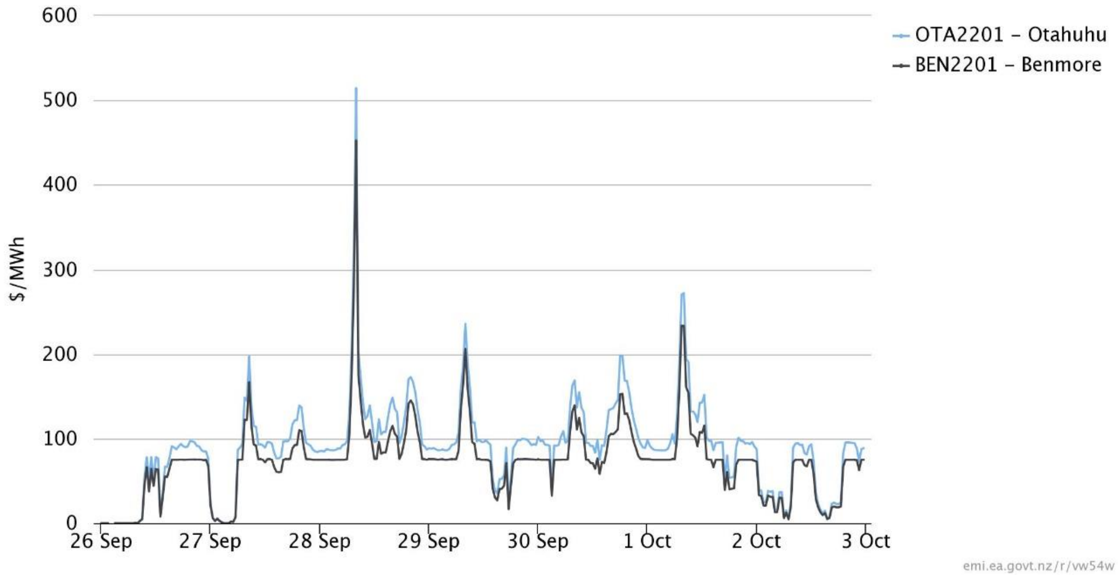
1 Overview for the week of 26 September to 2 October

1.1 Prices this week appeared to be consistent with underlying supply and demand conditions. High prices were due to a combination of high demand, transmission and generation outages and low wind.

2 Prices

Energy prices

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



2.1 Average spot price this week was $81/MWh[1], about 50% higher than the previous week. For most of the week the price was $75/MWh at Benmore, with higher prices during peaks and occasionally lower prices (see Figure 1). The highest price was $514/MWh at Otahuhu during TP 17 on 28 September

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

Reserve Prices

2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 2, stayed below $13/MWh for the entire week. There has been an increase in interruptible load since Auckland moved to level 3 on September 21 which increased available reserves (figure 3).

Figure 2: FIR prices by trading period by Island

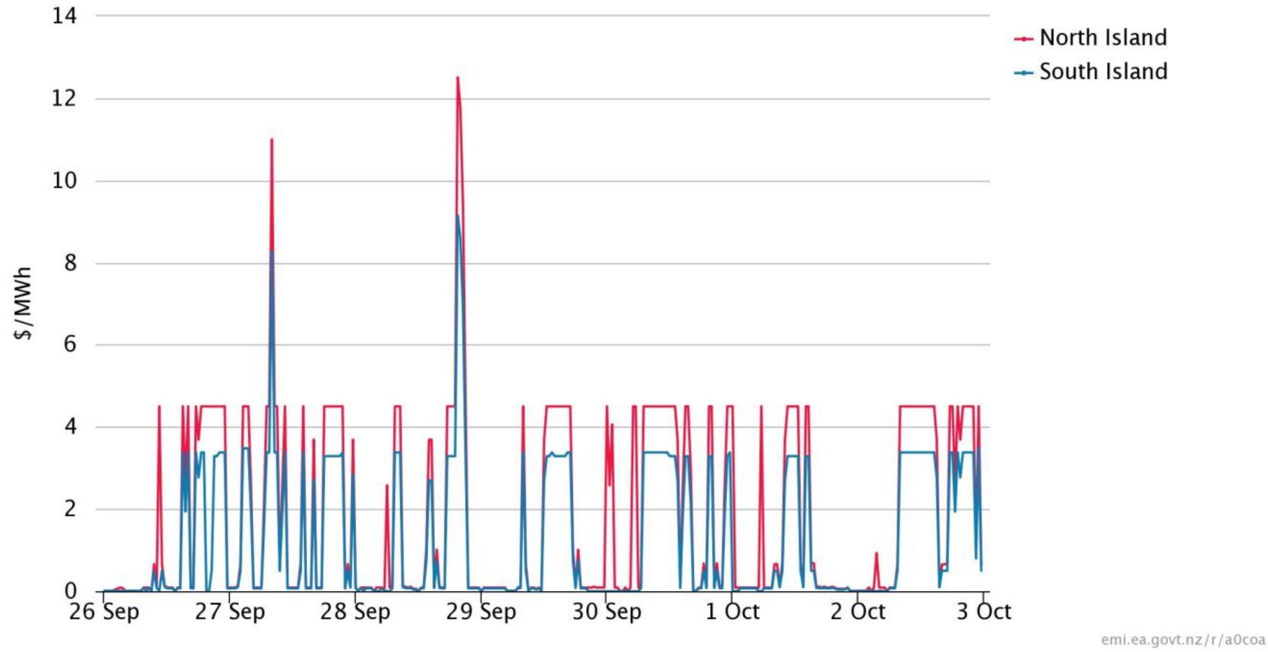
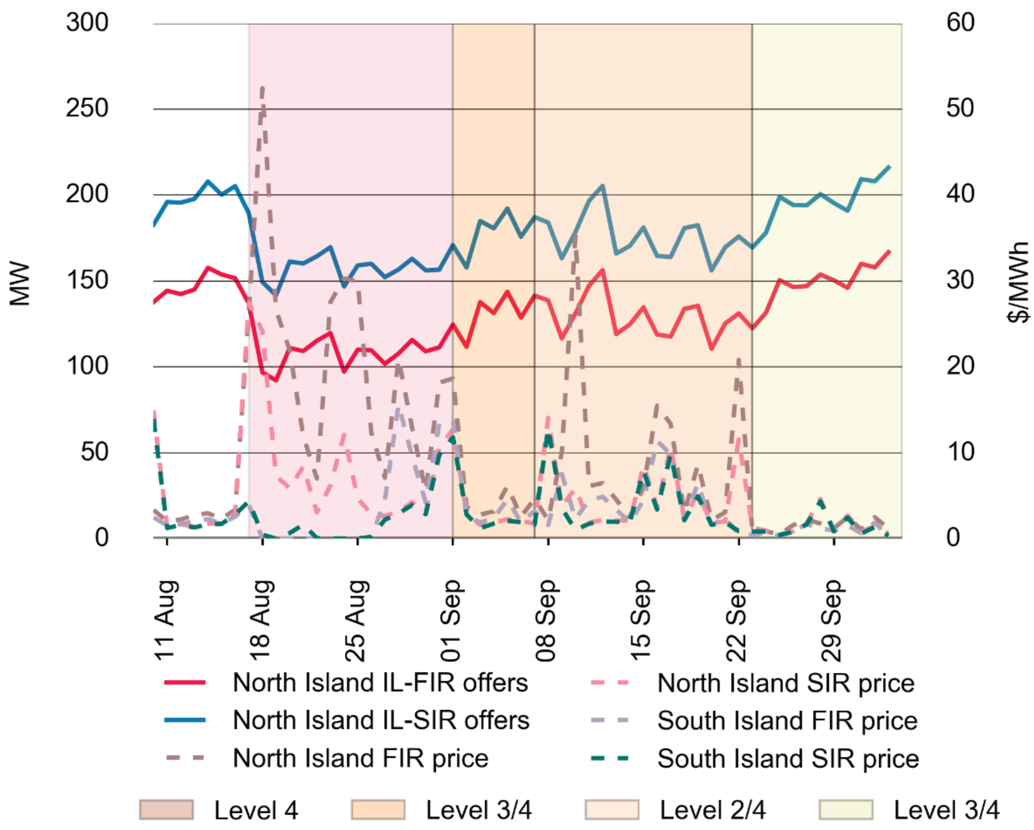
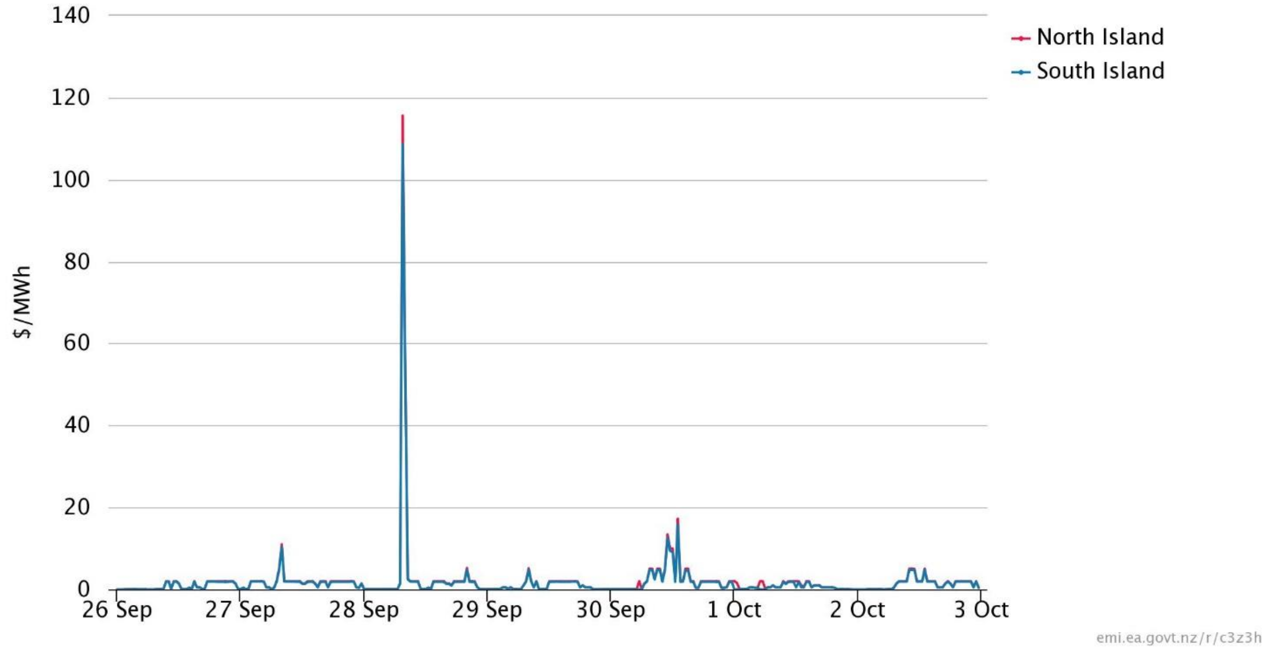


Figure 3: Interruptible load and FIR and SIR prices



2.3 The prices for sustained instantaneous reserves (SIR), shown in Figure 4, were below $20/MWh for most of the week. There was a high price spike on TP16 on 28 September, one trading period prior to highest energy prices. This high price was likely due to co-optimisation- the energy market was tight so it was efficient to increase reserve prices in order to keep energy prices lower.

Figure 4: SIR prices by trading period by Island

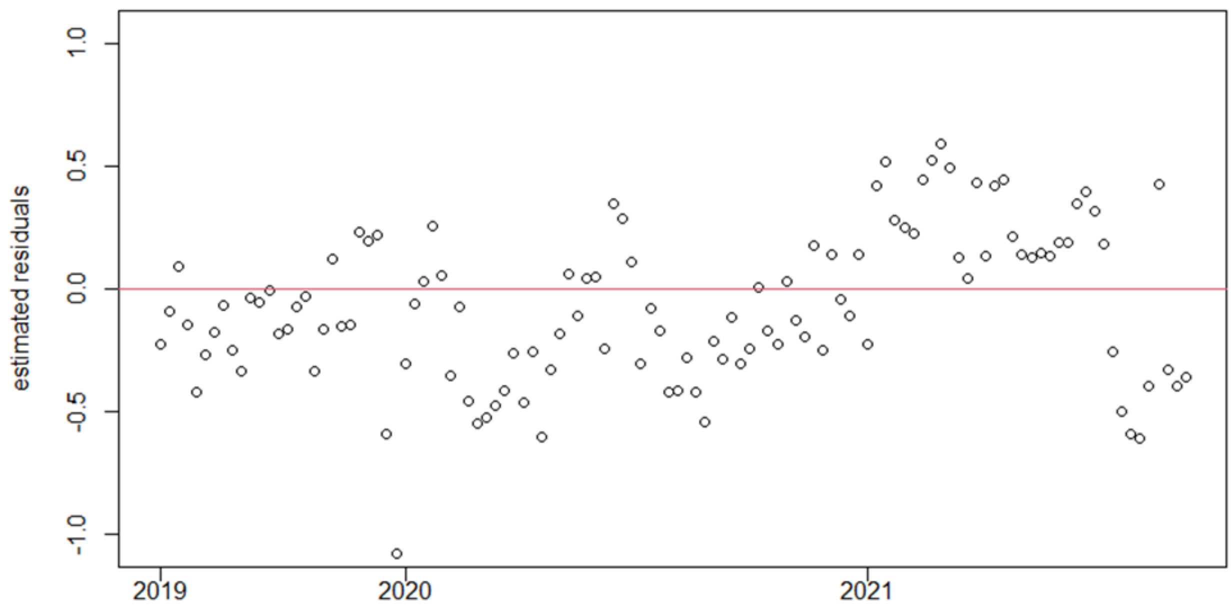


Residuals from regression models

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.

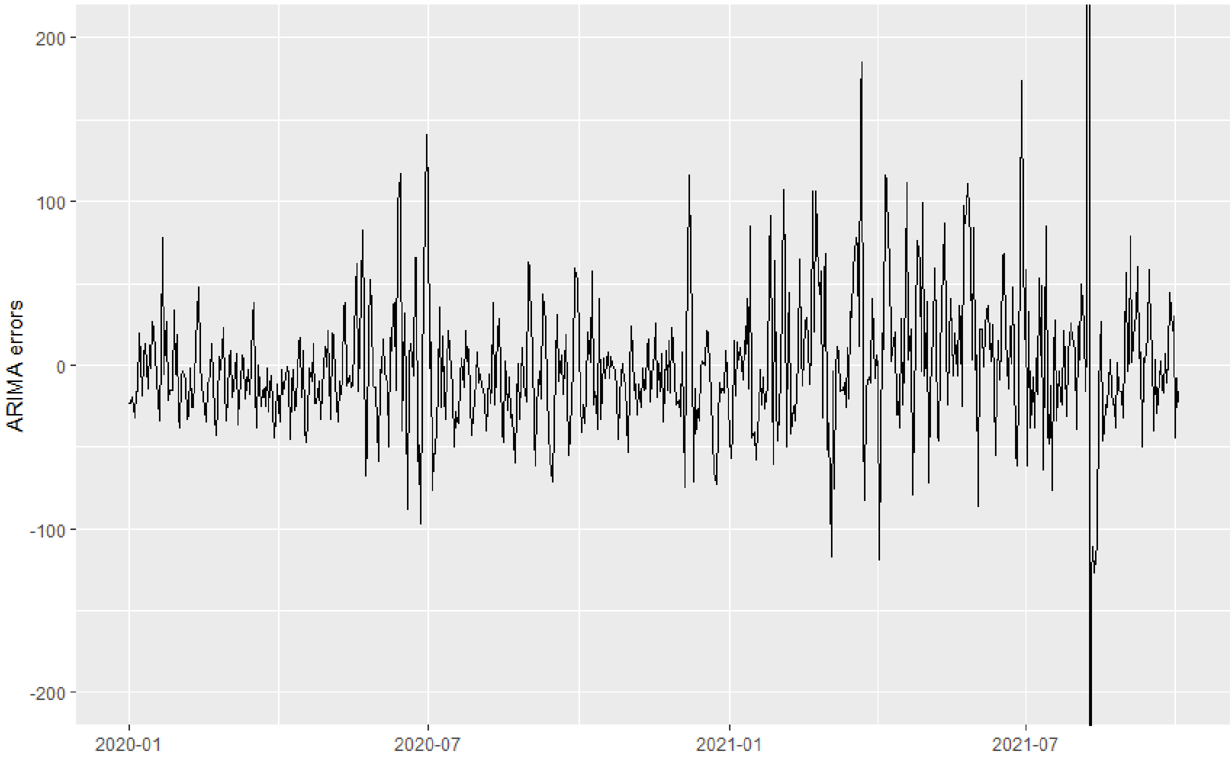
2.5 Figure 5 shows the residuals from the weekly model. During August 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 2 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 within the normal range.

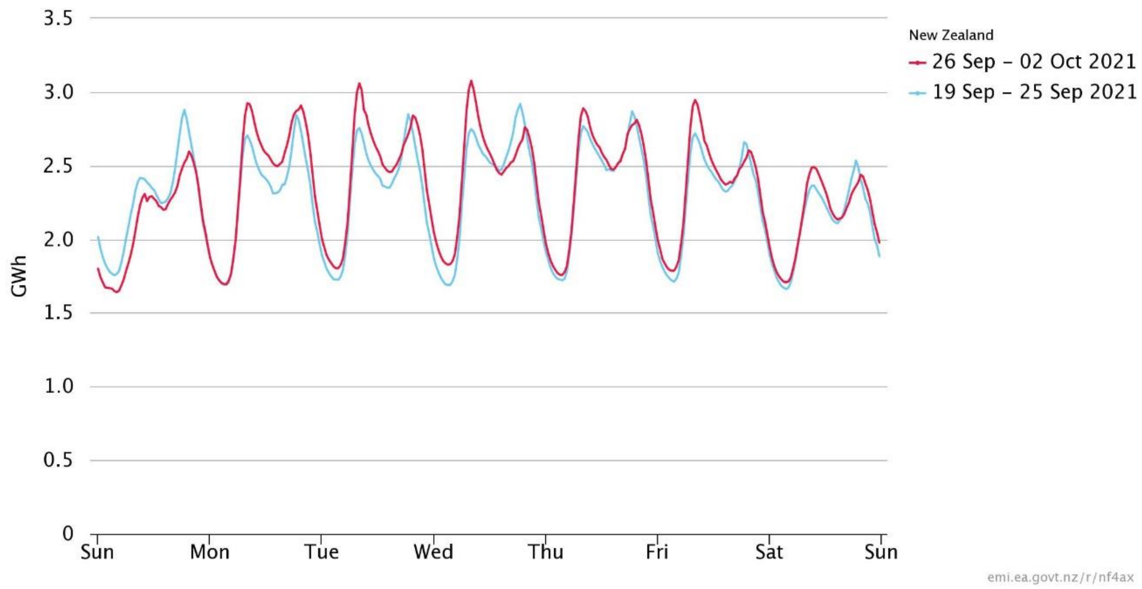
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 2 October 2021



3 Demand Conditions

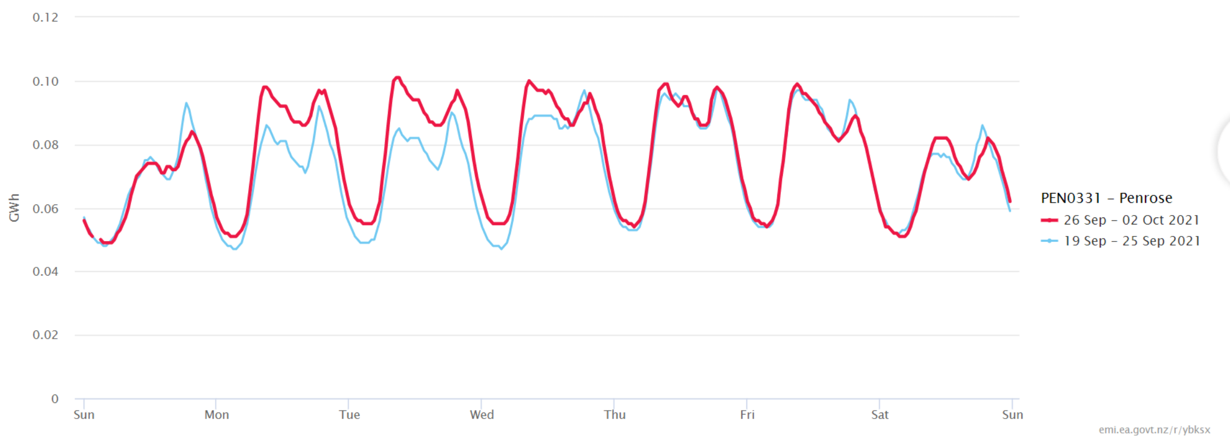
3.1 National demand was higher than the previous week (see Figure 7), due to colder weather. The daily demand profile also changed with the highest demand occurring in the morning and a later evening peak. This is likely due to the start of daylight savings, which caused darker mornings, but lighter, warmer evenings, as well as cold mornings (see Figure 9).

Figure 7: National demand compared to previous week



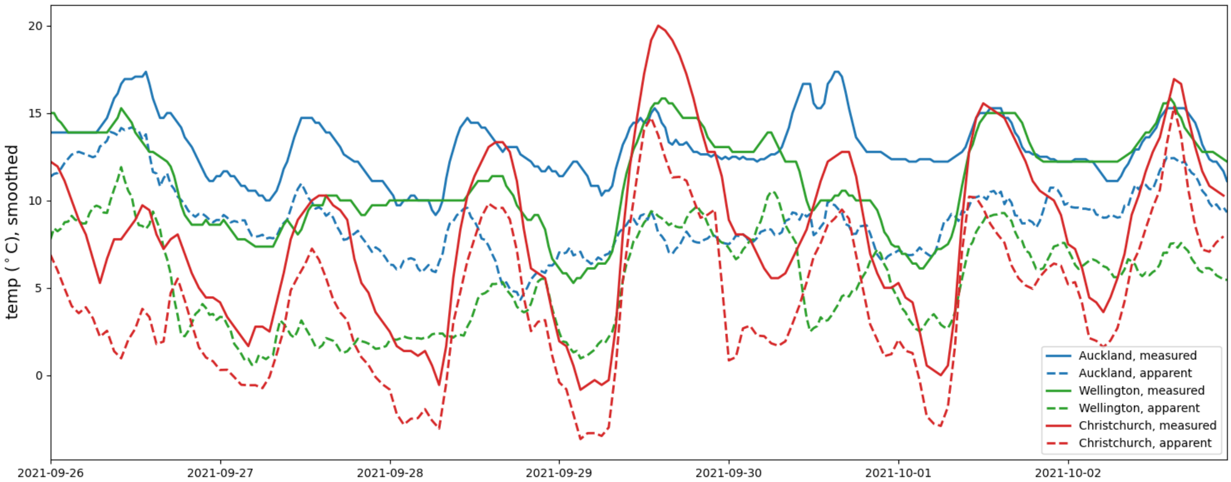
3.2 Auckland transitioned from alert level 4 to alert level 3 on 21 September. Figure 7 shows the demand profile for Penrose, which covers a large part of central Auckland, including both domestic and commercial demand. There was an increase in demand from Monday to Wednesday compared to the previous week, with the biggest difference on Monday and Tuesday. Some of the difference, especially Wednesday morning may be due to colder weather, but some of the difference on Monday and Tuesday will be due to the change in alert levels.

Figure 8: Penrose demand compared to previous week



3.3 Figure 8 shows hourly temperature data at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors, such as wind speed and humidity, to estimate how cold it feels. This week was colder than the previous week, especially on the mornings of 28 and 29 September, and 1 October, when apparent temperature dropped below 0°C in Christchurch. This resulted in higher morning demand on these days.

Figure 9: Hourly temperature data at main population centres.

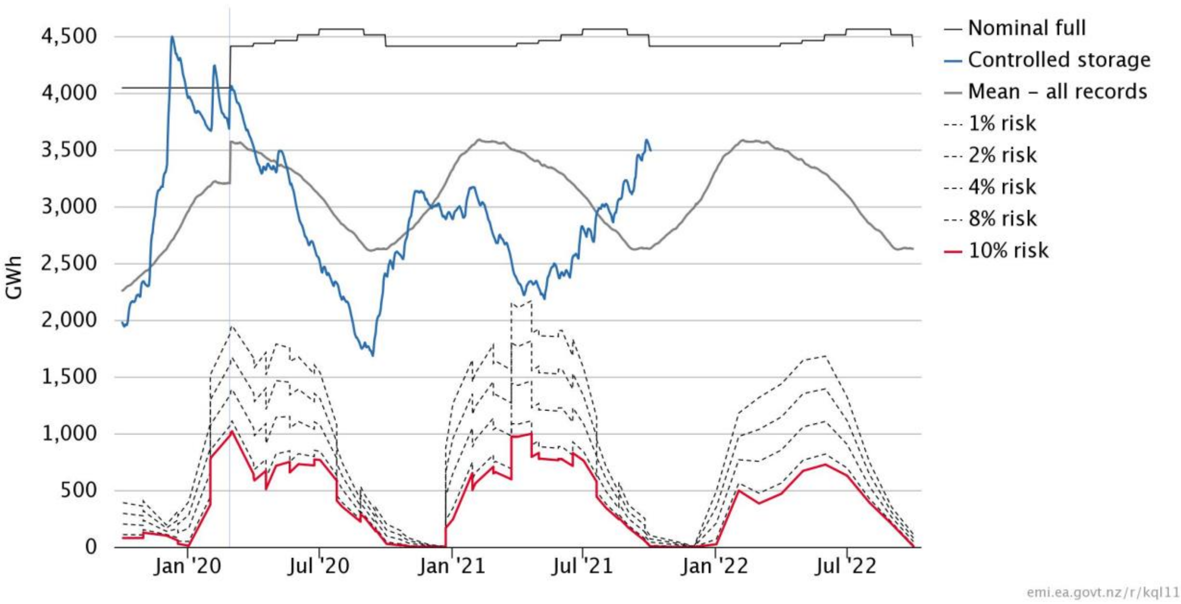


4 Supply Conditions

Hydro conditions

4.1 This week national hydro storage decreased and is now just below 3,500GWh which is high for this time of year, shown in Figure 10.

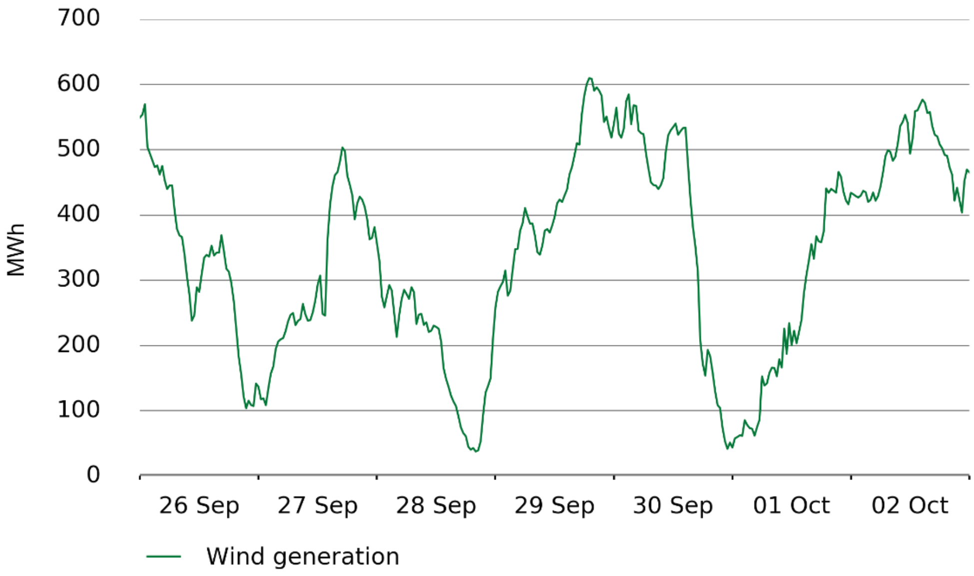
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 57GWh, down 12% from last week. Wind generation was variable throughout the week(see Figure 11), highest on 29 September and lowest on 28 September and 1 October, which contributed to high prices on those days.

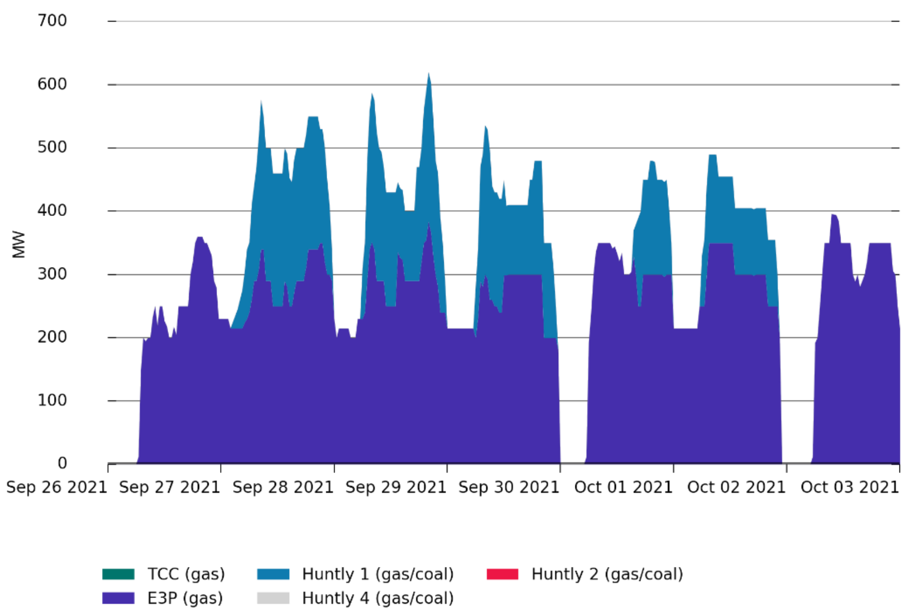
Figure 11: Wind generation for the week



Thermal conditions

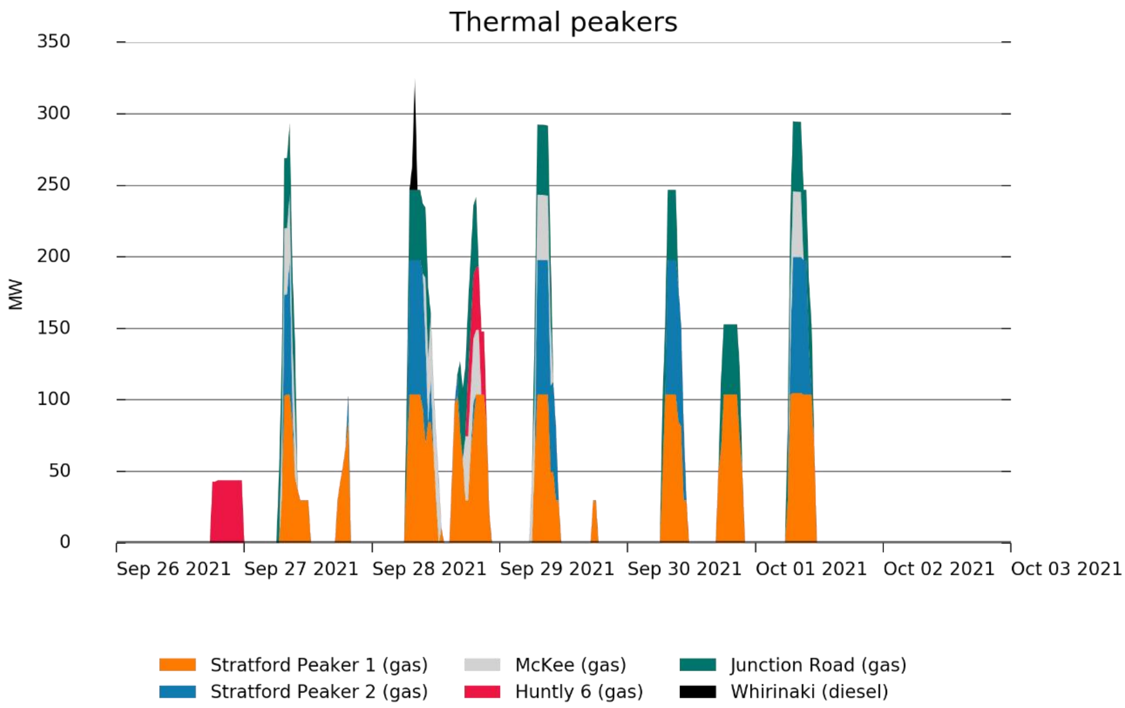
4.3 Baseload thermal generation remains low with only Huntly's E3P running as baseload and one of the Rankine units was running during most days. This reflects an overall decrease in demand for thermal generation as hydro storage increases and demand drops.

Figure 12: Generation from baseload thermal



4.4 Thermal peakers frequently contributed up to 300MW during peak periods this week. Whirinaki ran briefly on 28 September when prices reached over $500/MWh. This was due to high demand, low wind and outages.

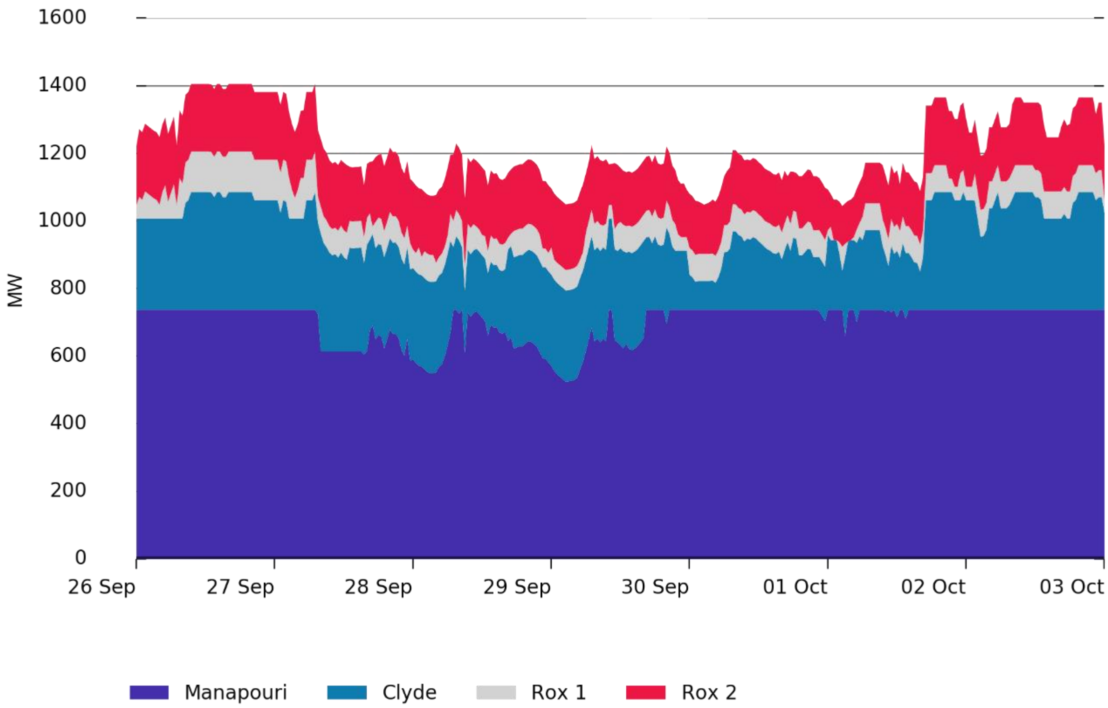
Figure 13: Generation from thermal peakers



Significant outages

4.5 There was a transmission outage of one of the Clyde-Cromwell-Twizel circuits from 7:30am 27 September to 5pm 1 October. This outage caused the other circuit and the Naseby-Roxbourgh circuit to bind, resulting in price separation between the lower South Island and the rest of New Zealand. Figure 14 shows the generation of hydro generators in the lower South Island which dropped by about 200MW on the morning of 27 September and until 1 October.

Figure 14: Generation from hydro generators in lower South Island



4.6 The two additional generation outages at Clyde and Manapouri were likely scheduled to coincide with the transmission outage. There was also a generation outage at Maraetai (Waikato river) which contributed to the high prices on 28 September.

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

(a) Clyde,

(i) 116MW (long term outage)

(ii) 116MW (7am-4:30pm, 28 September)

(b) Benmore,

(i) 90MW (5 July – 19 November)

(c) Manapouri,

(i) 125MW (19 July – 29 October)

(ii) 125MW, (8am-4:30pm, 27 September)

(d) Huntly,

(i) 240MW (24 September-3 October)

(ii) 45MW (11am-5pm, 29 September)

(e) Tekapo,

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

(ii) 30MW (1pm-2pm 29 September)

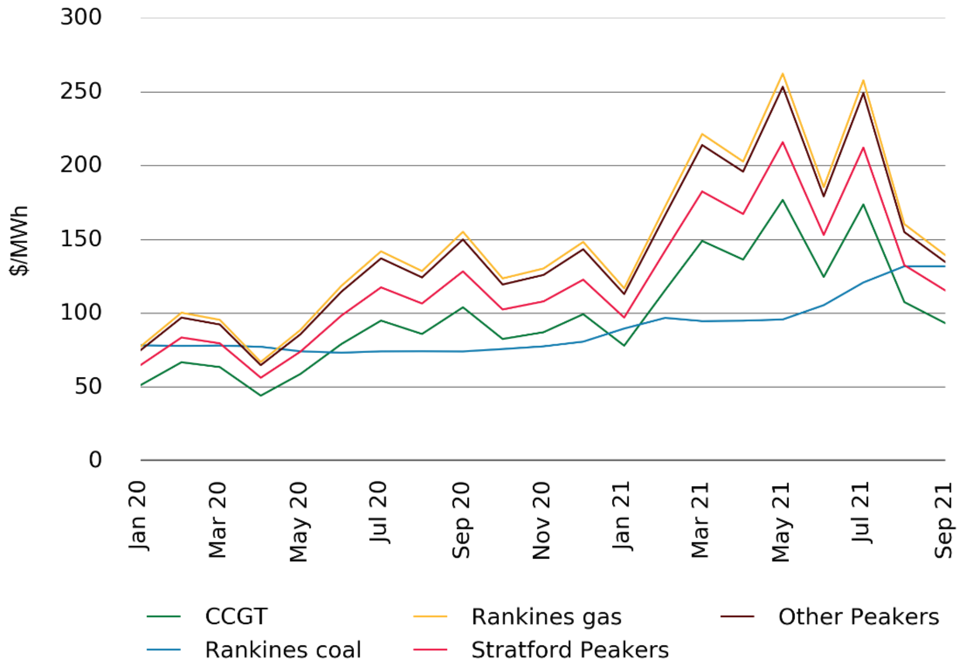
(f) Maraetai, 176MW, (27-30 September)

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).[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 15 shows estimates of thermal SRMCs as a monthly average. High gas spot prices increased the thermal SRMC for July with prices dropping in August and September as demand for gas for thermal generation dropped.

Figure 15: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

Final daily offer stacks

6.1 Figure 16 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 final prices, though this is less reliable for the period of the HVDC outage due to price separation.

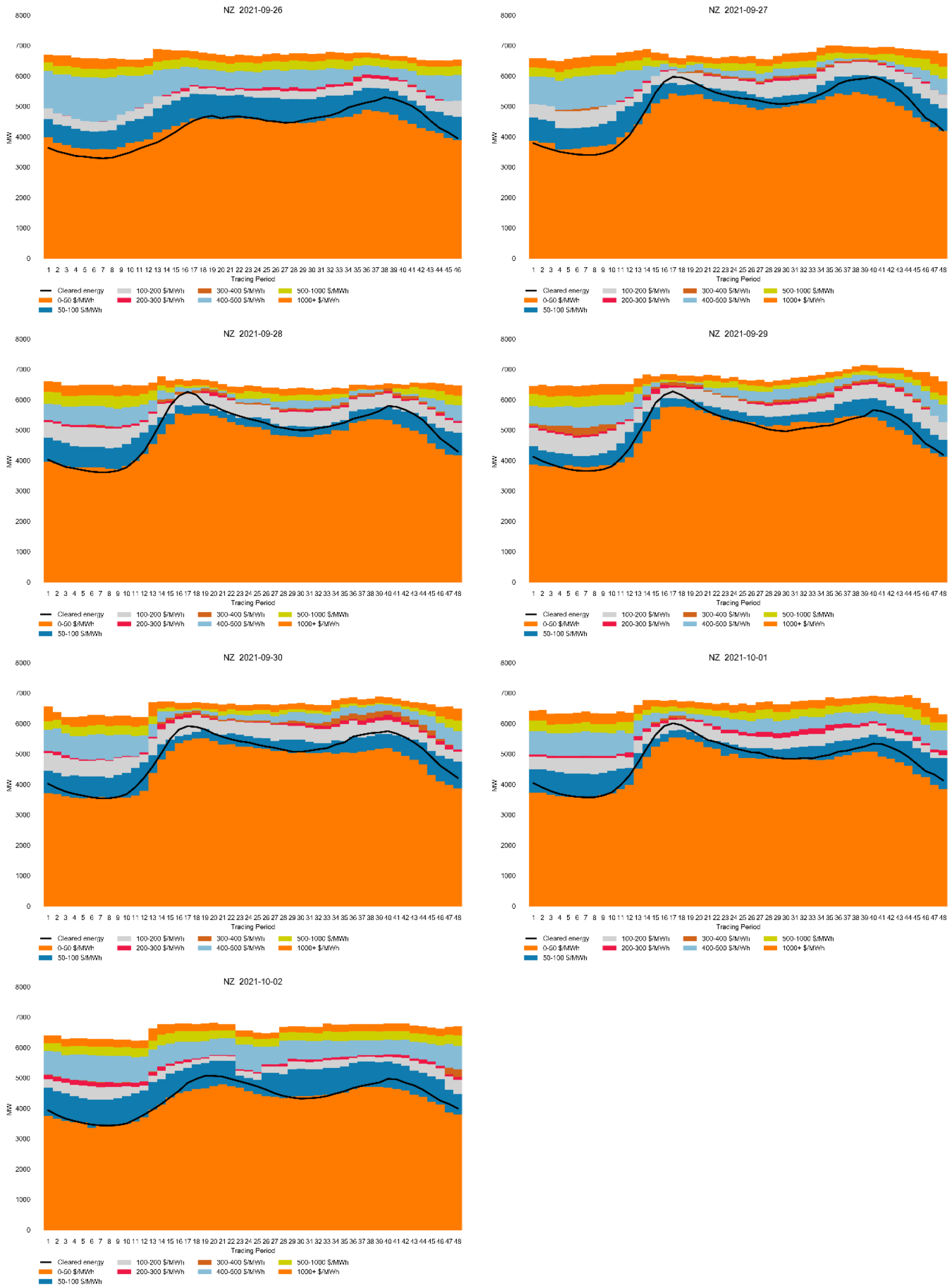
[2] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

[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.

[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.

6.2 Most offers continued to be below $200/MWh, with a thin offer stack at higher prices. Low wind generation reduced the quantity of offers below $200/MWh on 28 September compared to surrounding days.

Figure 16: Daily offer stack



Offers by trading period

6.3 The trading period (TP) with the highest price was TP17 (7:00am) on 28 September, shown by Figure 17. Figure 18 shows the same trading period for the week before. Each shows the offer stack, the generation weighted average price (GWAP) and cleared generation.

6.4 Demand was higher on 28 September compared to the week before, likely due to colder weather and the impact of daylight savings. However, the offer curve was also steeper on 28 September, due to transmission and generation outages.

Figure 17: Offer Stack for trading period 17 on 28 September

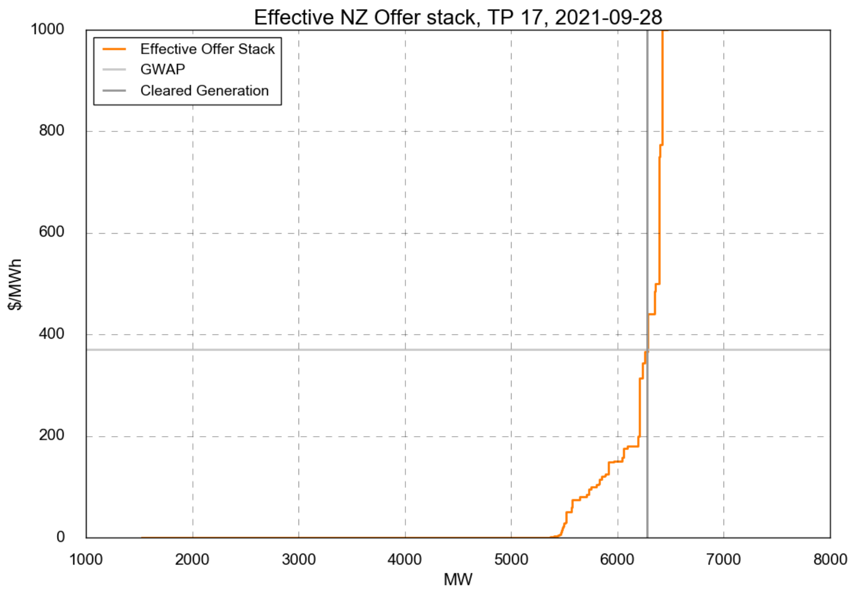
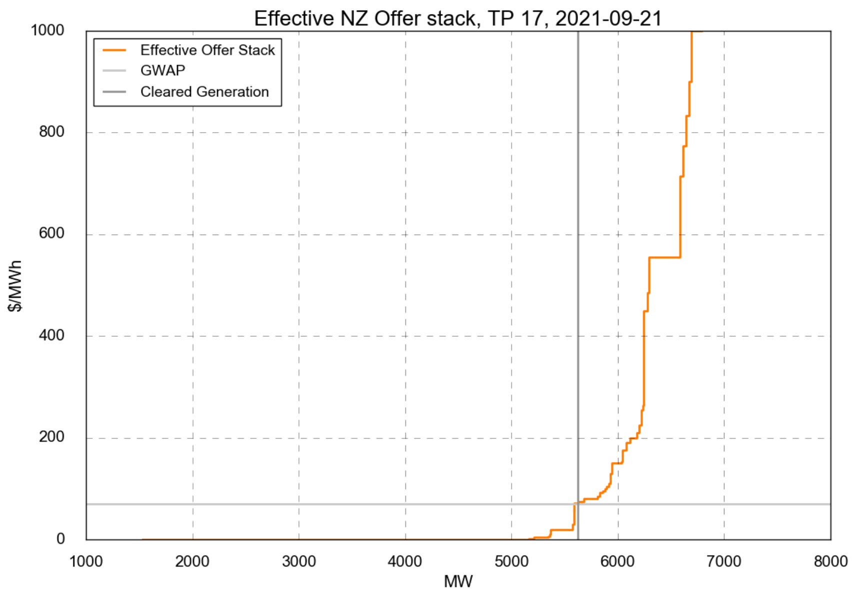


Figure 18: Offer Stack for trading period 17 on 21 September



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; $t = week\ 1, \ldots, 52$ 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[5], where *diff* is the first difference:

$$y_t = \beta_0 - \beta_1(storage_t - 20.year.mean.storage_{dayofyear}) + \beta_2 diff(demand_t) -$$
$$\beta_3\ wind.generation_t + \beta_4\ gas.price_t - \beta_5 diff(generation\ HHI_t) + \ \beta_6 dummy + \eta_t$$
$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

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.

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