High Standard of Trading conduct

Market Monitoring Weekly Report

7 July 2021

Please Note

0.1 The following report is for the week 27 June to 3 July. The new high standard of trading conduct (HSoTC) provisions took effect on 30 June 2021. The first three days covered in this report therefore are not subject to the new HSoTC

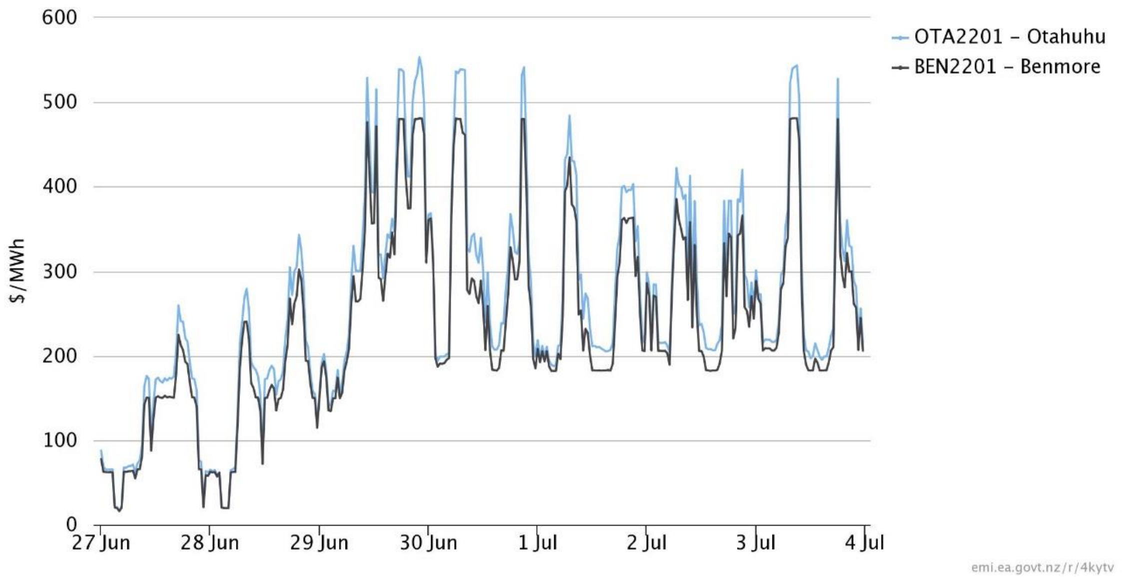
1 Overview for the week of 27 June to 3 July 2021

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

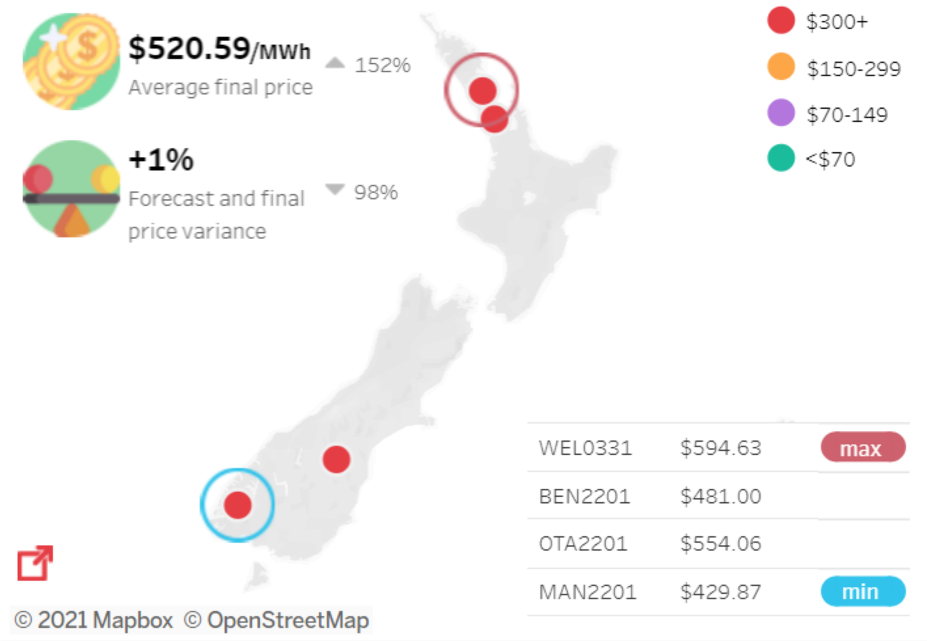
Energy prices

Figure 1: Spot prices by trading period at Otahuhu and Benmore, 27 June to 3 July



2.1 Average spot prices this week were $253/MWh, up 5% from the previous week. The highest prices occurred during trading period (TP) 18 on 3 July (see figure 2). However, prices frequently reached over $400/MWh after 29 June.

Figure 2: Spot prices for trading period 18 on 3 July compared to previous week

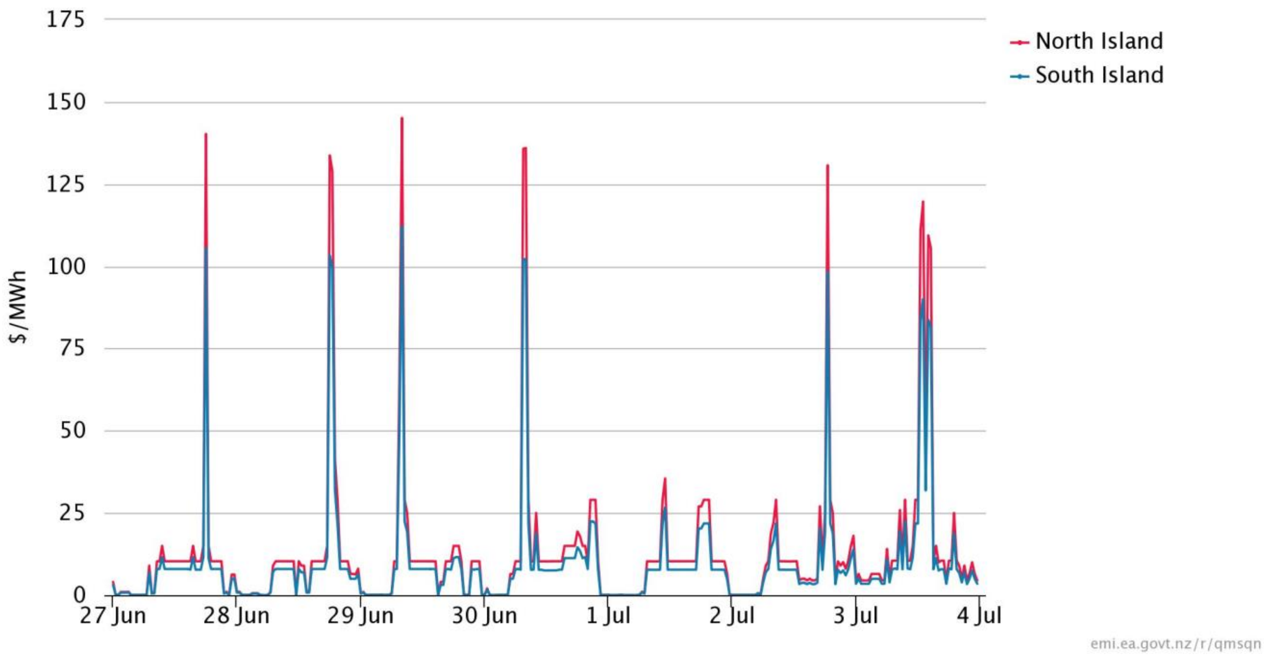


WEL0331	$594.63	max
BEN2201	$481.00	
OTA2201	$554.06	
MAN2201	$429.87	min

Reserve Prices

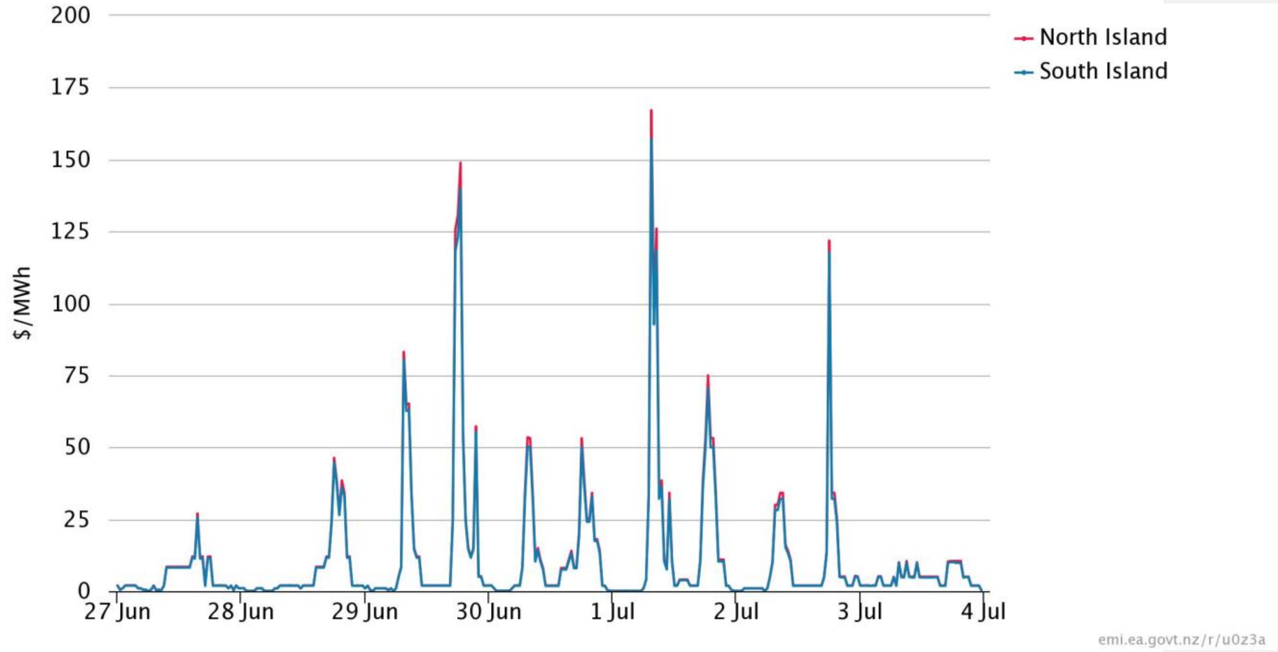
2.2 The prices for fast instantaneous reserves (FIR), shown in figure 4 for this week were usually about $10/MWh, but prices increased to over $100/MWh in the North Island 11 times this week.

Figure 3: FIR prices by trading period by Island, 27 June to 3 July



2.3 The prices for sustained instantaneous reserves (SIR), shown in figure 5 for this week were volatile, ranging from close to $0/MWh to over $150/MWh.

Figure 4: SIR prices by trading period by Island, 27 June to 3 July



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 can therefore indicate times when prices may 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 May 2021 the residuals were close to zero, indicating that actual prices in May were close to the expected prices given market conditions. [1]

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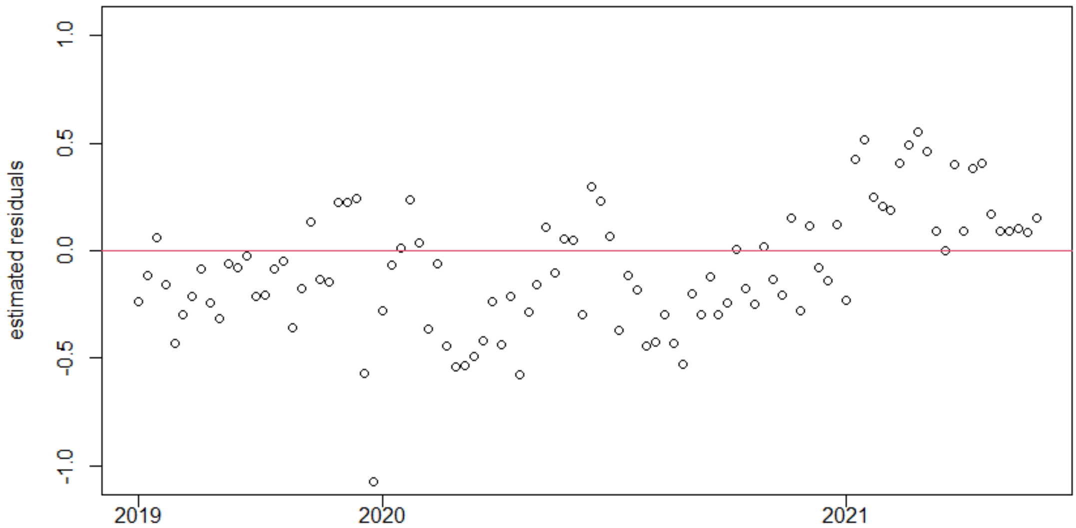
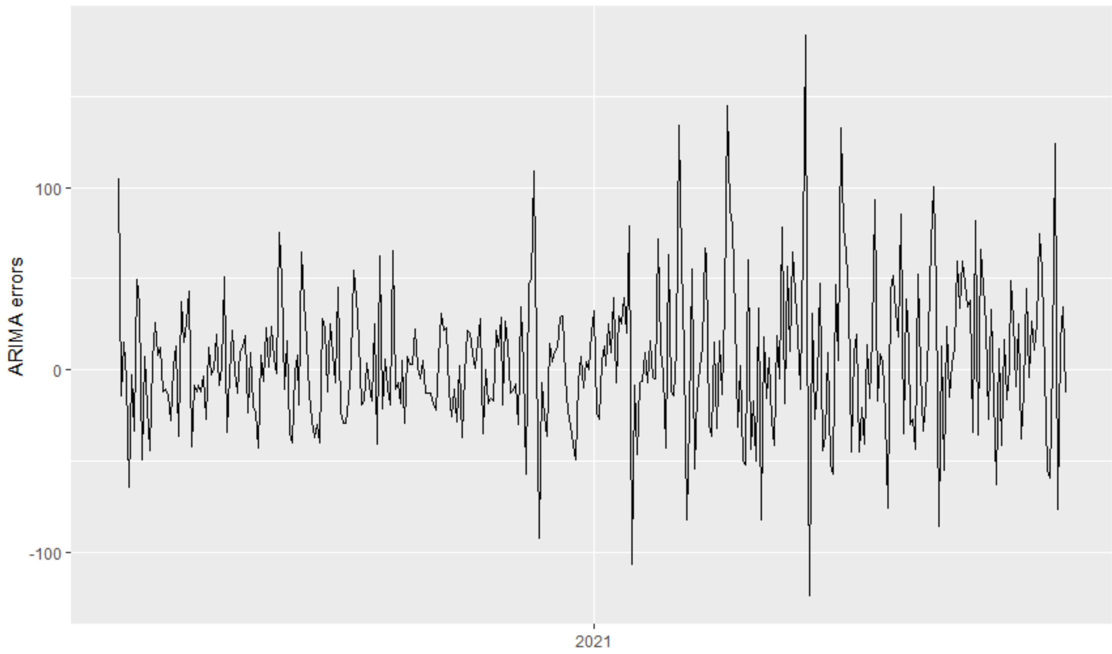
Figure 5: Residual plot of estimated weekly prices from 2 July 2019 to 27 May 2021



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

2.6 Figure 6 shows the residuals from the daily model. This week the residuals were larger around 29 June to 1 July then they had been in the weeks before, but within the normal range seen so far in 2021.

Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 3 July 2021



3 Demand Conditions

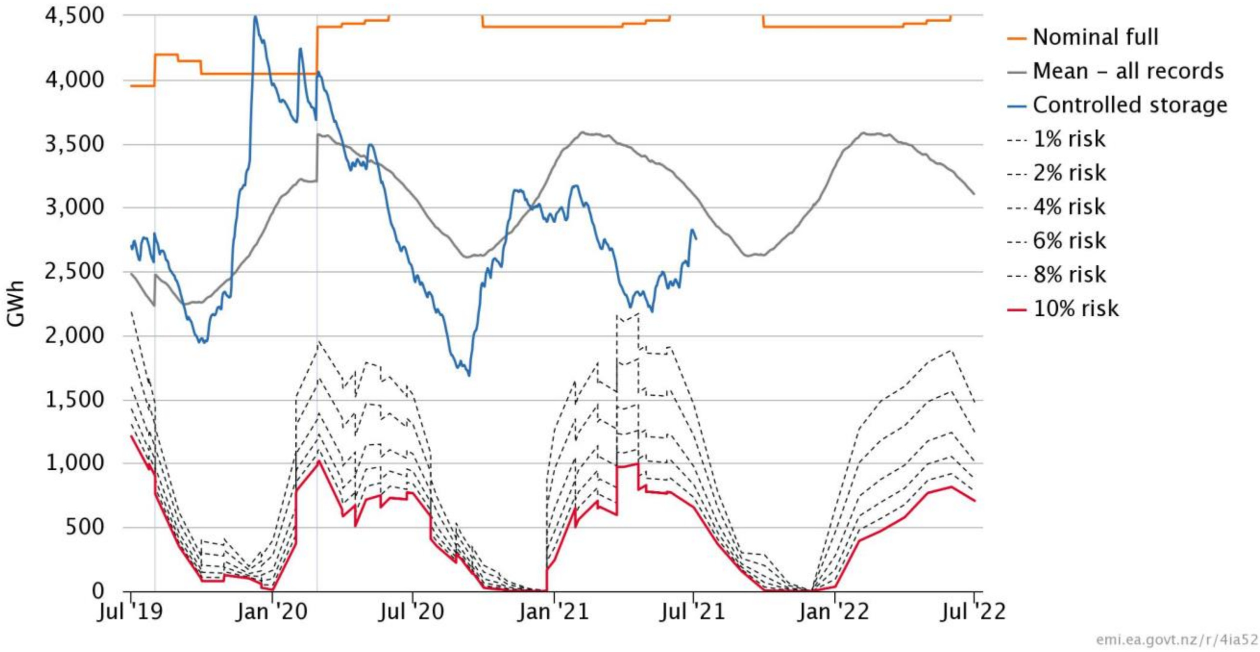
3.1 Demand was 4% higher than the previous week and was especially high on Tuesday 29 June when the record for peak demand was reached at 6,924MW. The previous record was almost 10 years ago, during August 2011.

4 Supply Conditions

Hydro conditions

4.1 Total controlled storage is 2,768 GWh, up 2% from last week. Supply has been below average all year.

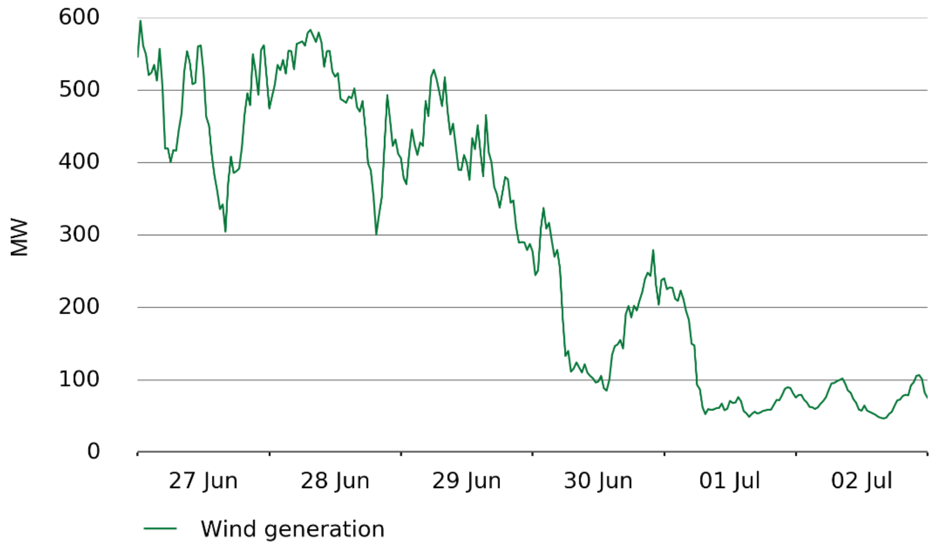
Figure 7: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind output was 43GWh this week, down 32% from last week. This fall was due to dying wind conditions halfway through the week with wind generation below 100MW on the 1 and 2 July (figure 9).

Figure 8: Wind generation for the week 27 June to 2 July

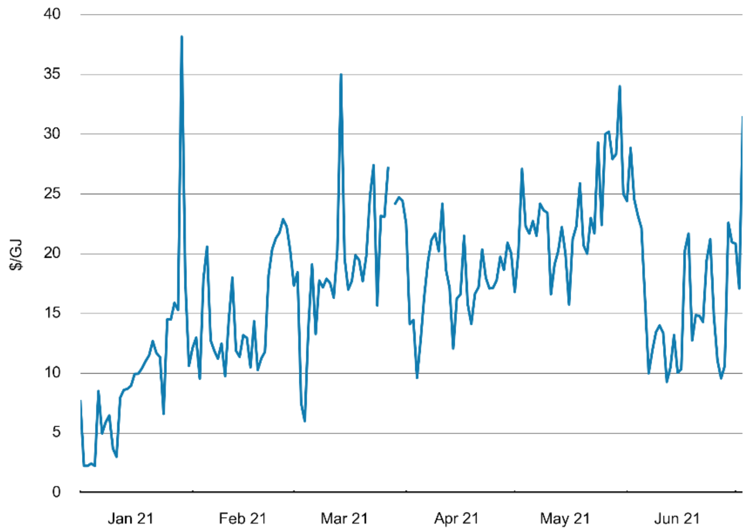


Thermal fuel market conditions

4.3 Spot gas prices increased this week reaching $31/GJ on 3 July. This was the highest price for gas since 6 June when Methanex reduced its production as part of a gas swap deal with Genesis.

4.4 The quantities of gas traded in the spot market are only a small part of the gas market but can be used to estimate the opportunity cost of the marginal unit of gas used for thermal generation.[2]

Figure 9: Spot gas, traded VWAP, daily,



Significant outages

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

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

(b) Kawerau, 106MW (7 June to 19 July)

(c) Huntly 1, 125MW (3 July, 12pm-4pm)

(d) Manapouri, 125MW (30 June -2 July)

(e) Stratford Peaker 1, 100MW (30 June 10am-1pm)

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). The Authority is currently working on a DOASA model which will estimate water values, providing an estimate of opportunity cost for hydro generators.[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 10 shows estimates of thermal SRMC as a monthly average. High gas spot prices have increased the thermal SRMC this month. Coal is purchased by contract in advance and

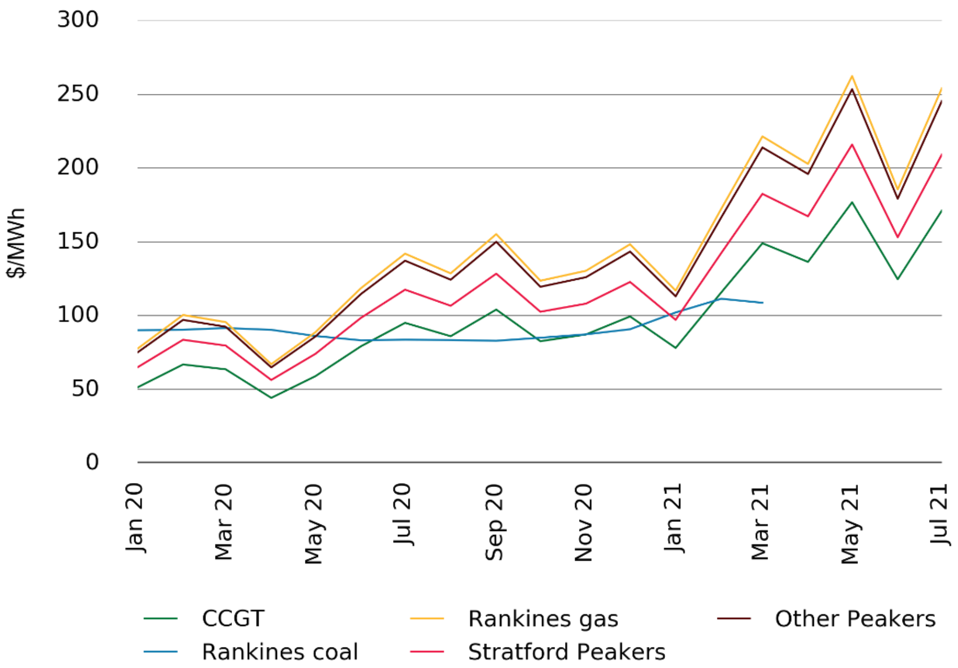
[2] Opportunity cost for gas generators – when storage of gas is available - also includes the expected price of generating at a later date

[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] We have assumed that the gas price includes the cost of carbon. Adding the cost of carbon to the current gas prices would increase the gas SRMC by $15-20/MWh. The cost of carbon has been added to the coal price.

the SRMC is based on coal prices up to March 2021. Historically coal has been more expensive than gas but is currently cheaper.

Figure 10: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

Final daily offer stacks

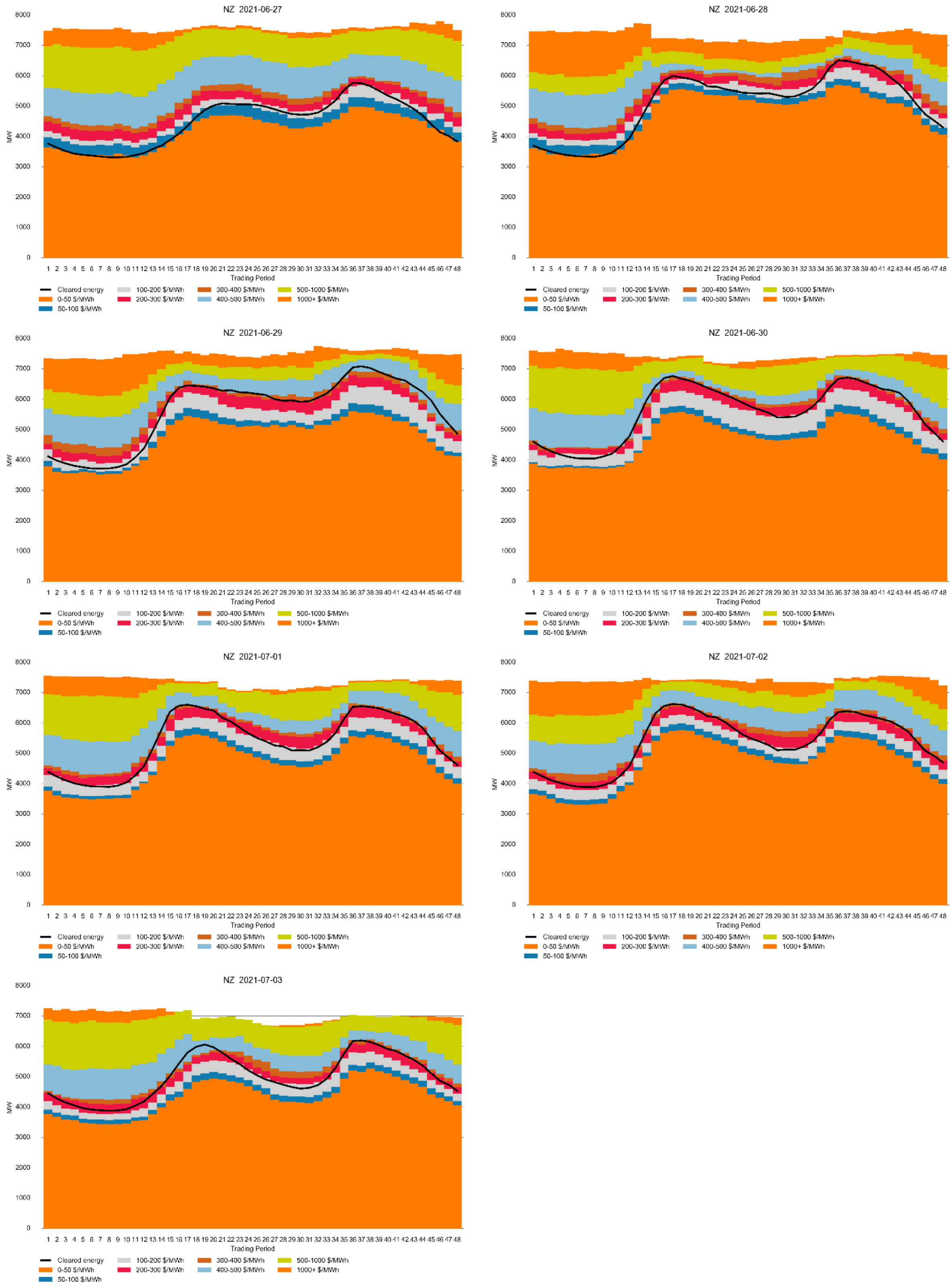
6.1 Figure 11 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[5] The black line shows the cleared energy, indicating the range of final prices.

6.2 Generators appear to manage their offers to approximately follow the daily demand curve. This generally has the effect of making prices more level over the day. This could be efficient for energy constrained plants, such as hydro, seeking to apply limited fuel to the highest value periods. It could also be efficient for plants subject to non-convexities, such as thermal start-up costs and minimum unit outputs. However, if generators' demand forecasts turn out to be wrong, for example, if demand remains high later than expected on cold winter evenings or if wind suddenly dies away, this strategy can cause much higher-priced offer tranches to be cleared, resulting in much higher prices.[6] Furthermore, these events frequently occur at times other than peak demand periods. Owing to the steepness of generators' offer curves, it may only take a small deviation in net demand to cause a significant price change. One such example occurred around 9 pm on 30 June—several hours after the evening demand peak. The Authority's monitoring team is considering whether prices during these trading periods are consistent with the new trading conduct provisions.

[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.

[6] Offers for each generating station or unit may contain up to 5 price tranches, with the first price tranche containing the lowest price offered, and each subsequent tranche having a higher price than the tranche preceding it.

Figure 11: Daily offer stacks from 27/06 to 3/07



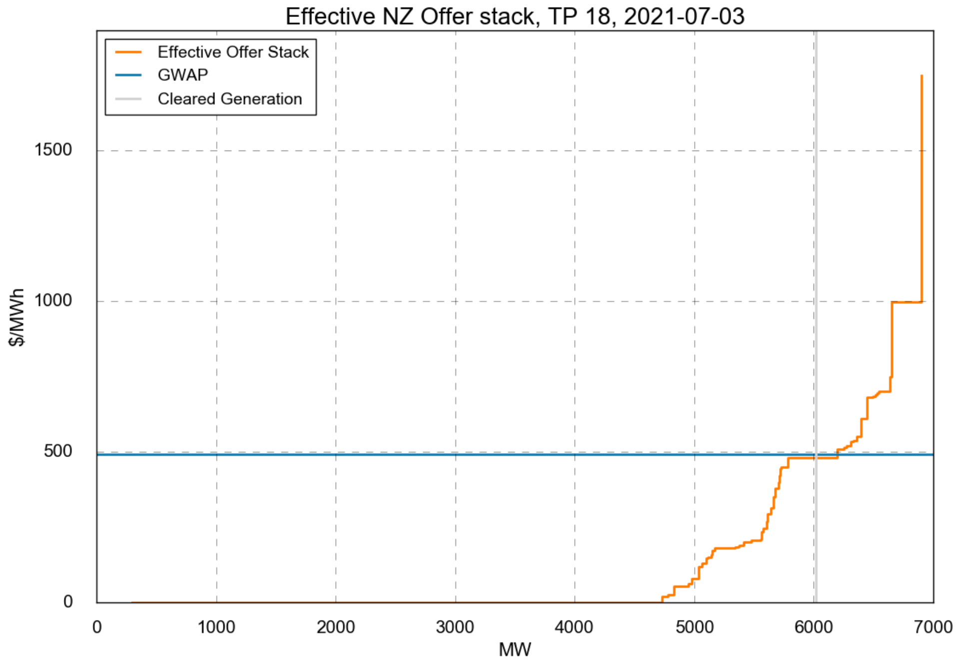
Offers by trading periods

6.3 The following section highlights a few of the trading 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 TP18 (8:30am) on 3 July. Wind generation was low at 66MWh, demand was 18% higher than the same time last week and the daily gas price was high at $31/GJ. While all these factors may explain a high price, it was a Saturday morning and demand was not as high as the weekday morning peaks with lower offers.

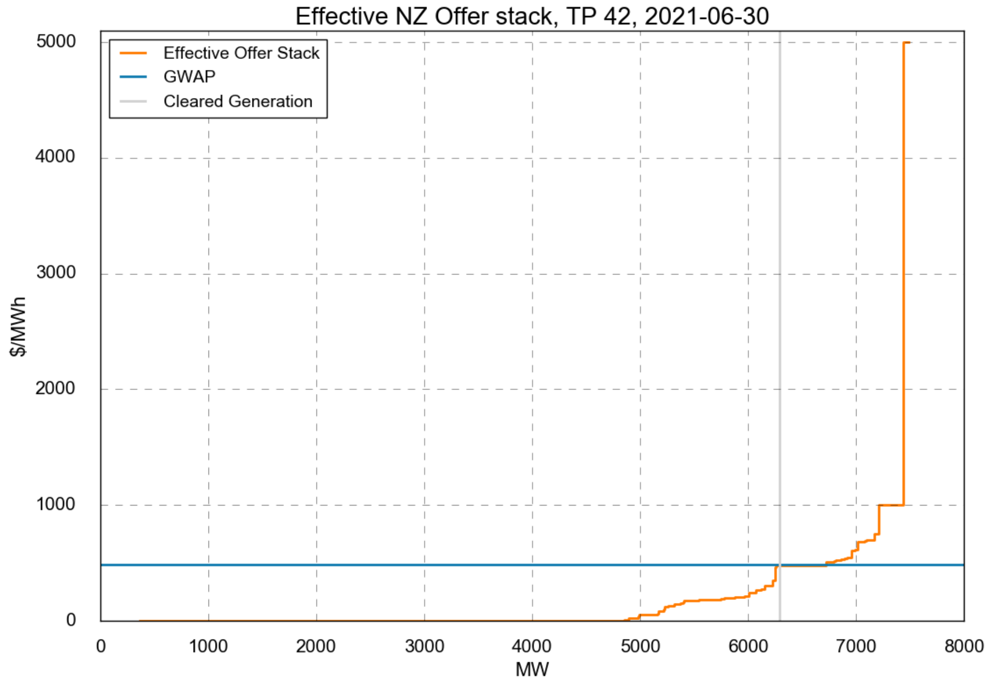
6.5 The offer stack (figure 12) shows there was more generation offered around $300/MWh and just under $500/MWh but not much offered between these two prices.

Figure 12: Offer Stack for trading period 18 on 3 July



6.6 Another trading period with a high price was TP42 (8:30pm) on 30 June. Peak evening demand occurred during TP37 (6pm) with an average final price of $351/MWh. Despite lower demand, prices were more than $150/MWh higher during TP42 and TP43.

Figure 13: Offer Stack for trading period 42 on 30 June



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
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 $/PJ, and wind generation is MW, carbon price is the New Zealand Units traded under NZ ETS, NZ/$t.

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.

$$y_t = 109.64 - 0.35 \times\ diff(storage) + 0.79 \times diff(demand) - 7.32 \times\ wind.generation + 1.67 \times\ gas.price - 0.03 \times\ diff(generation\ HHI) +\ \eta_t$$

$$\eta_t = 0.74 \times \eta_1 - 0.05 \times \eta_2 + 0.14 \times \eta_3 + 0.02 \times \eta_4 + 0.09 \times \eta_5 + \varepsilon_t$$

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.