

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 14 to 20 November

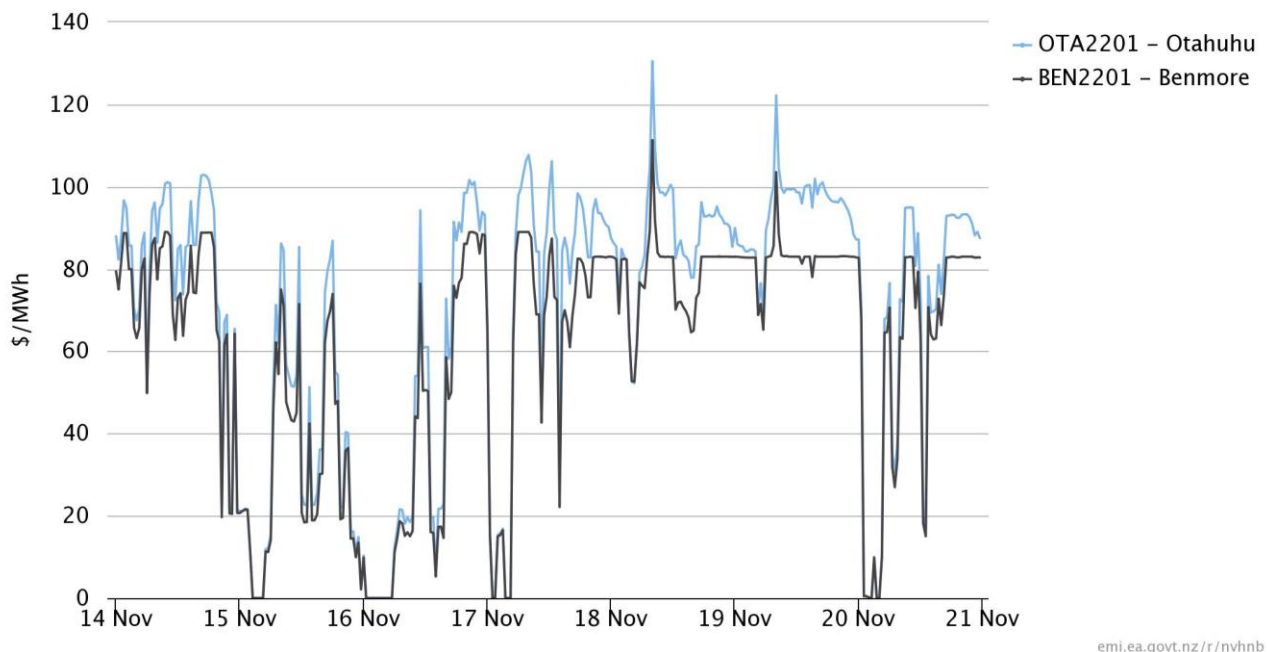
- 1.1. Energy prices this week appear to be consistent with underlying supply and demand conditions. Some trading periods with high reserve prices will be analysed further.

2. Prices

Energy prices

- 2.1. The average spot price this week was \$64/MWh¹, 41% lower than last week. Prices were below \$120/MWh the whole week except for TP17 on 18 November and 19 November when prices at Otahuhu were \$131/MWh and \$122/MWh respectively. There were four nights this week when prices collapsed to close to \$0/MWh.

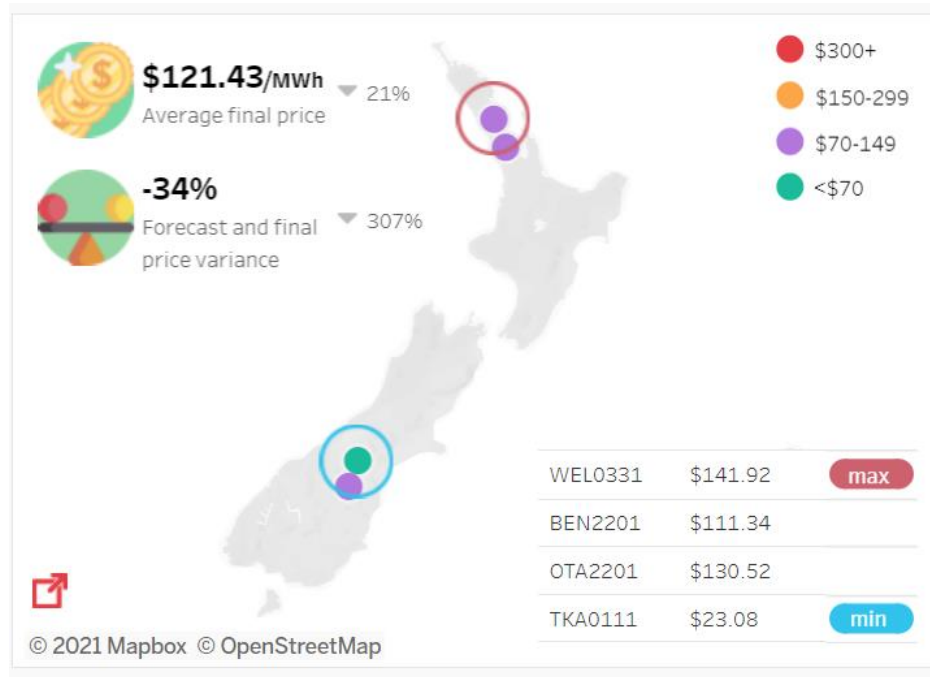
Figure 1: Spot prices by trading period at Otahuhu and Benmore



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

- 2.2. Figure 2 shows the average price for TP17 on 18 November, the nodal price at Otahuhu, Benmore, the highest price node and lowest price node. The average price across nodes was 21% lower than the same trading period the week before, indicative of lower prices this week. There was price separation between Tekapo A and Benmore due to ongoing transmission outages. While this caused lower prices at the Tekapo A node, it unlikely had a significant impact on prices due to the small capacity of Tekapo A.

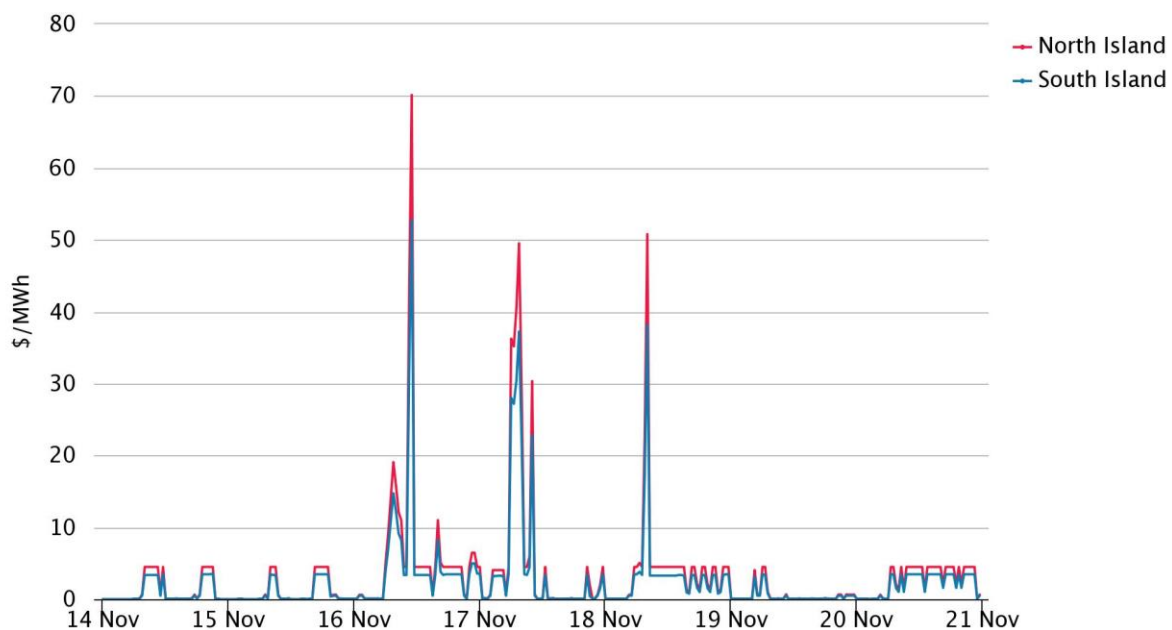
Figure 2: Spot prices for TP17 on 18 November compared to the previous week



Reserve Prices

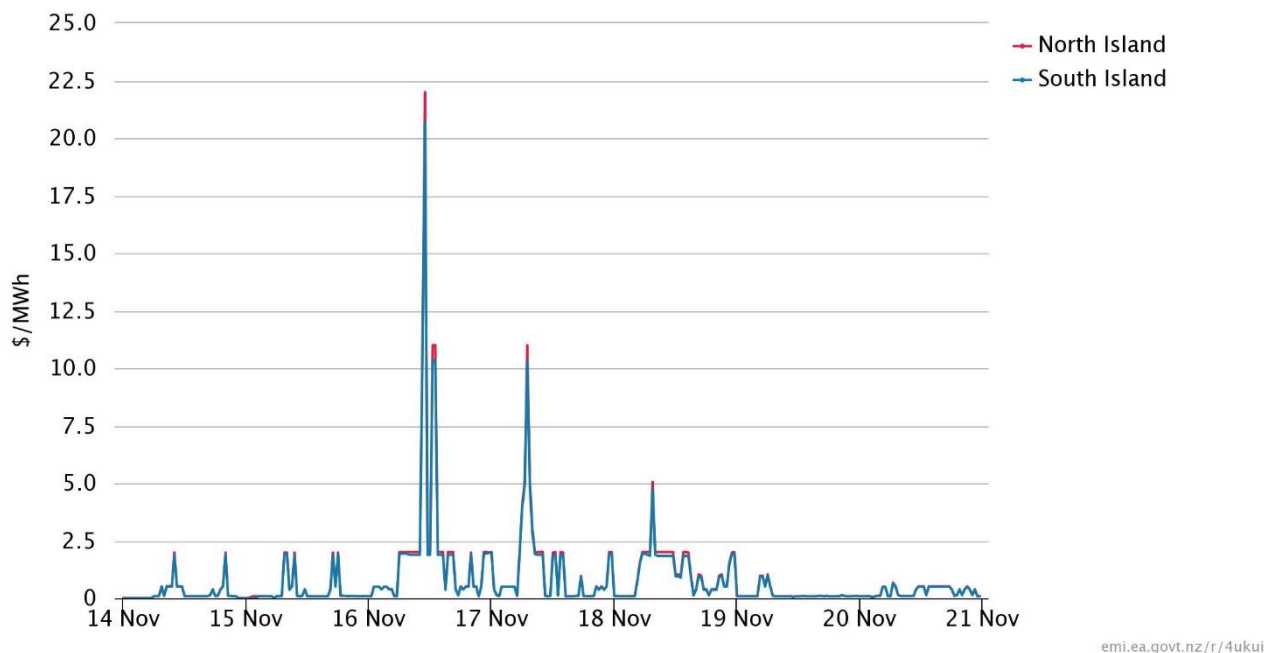
- 2.3. Fast instantaneous reserves (FIR) prices were usually below \$10/MWh. There were higher prices between 16 and 18 November, with the highest price of \$70/MWh occurring on TP23 16 November in the North Island.

Figure 3: FIR prices by trading period and Island



- 2.4. Sustained instantaneous reserves (SIR) prices were below \$25/MWh the entire week (see Figure 4), with most prices below \$5/MWh. The highest SIR price did coincide with the highest FIR price on TP23 16 November.

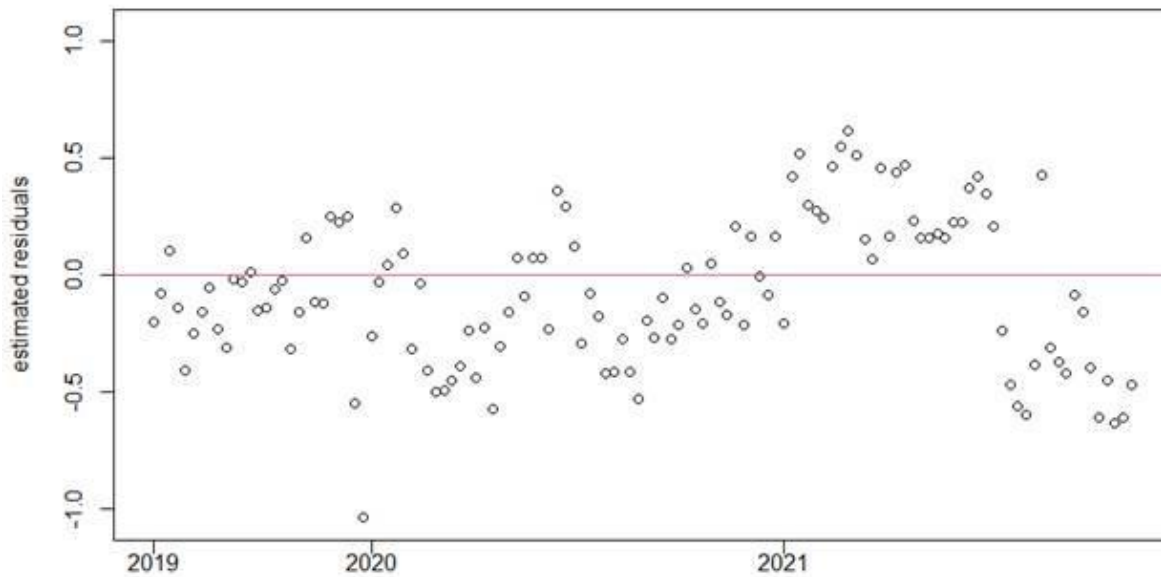
Figure 4: SIR prices by trading period and Island



Residuals from regression models

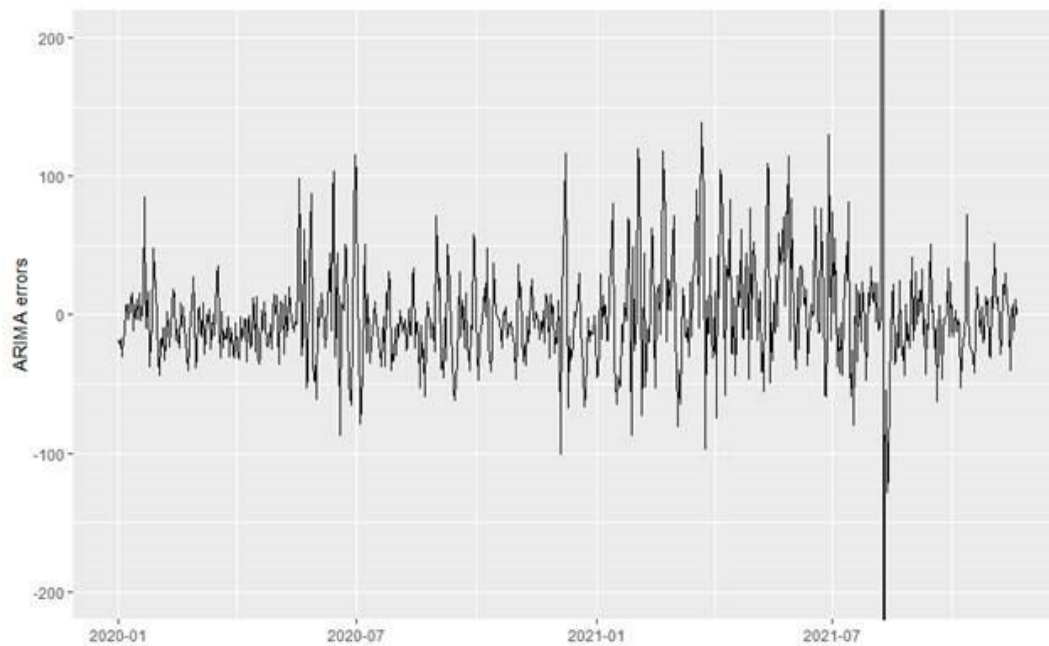
- 2.5. The Authority's monitoring team has developed two regression models of the spot price. The residuals show how close the predicted prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A.
- 2.6. Figure 5 shows the residuals from the weekly model. During October 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 28 October 2021



2.7. 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.

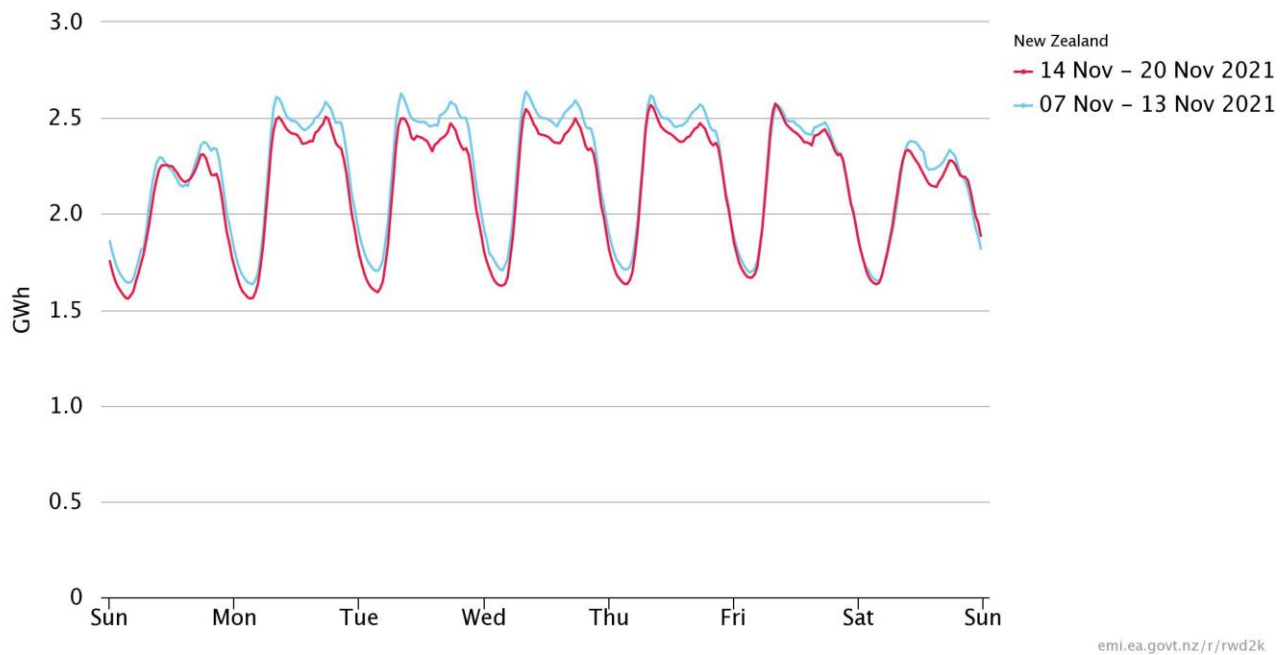
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 20 November 2021



3. Demand Conditions

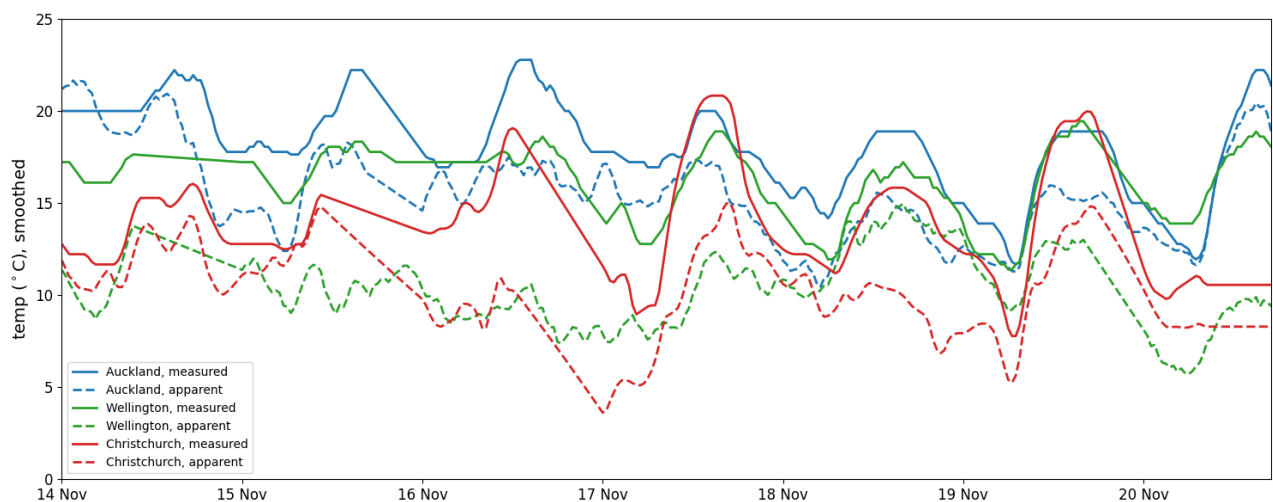
3.1. National demand was 3% lower than the previous week (see Figure 7) as warm weather continued, particularly in Auckland.

Figure 7: National demand compared for current and previous week



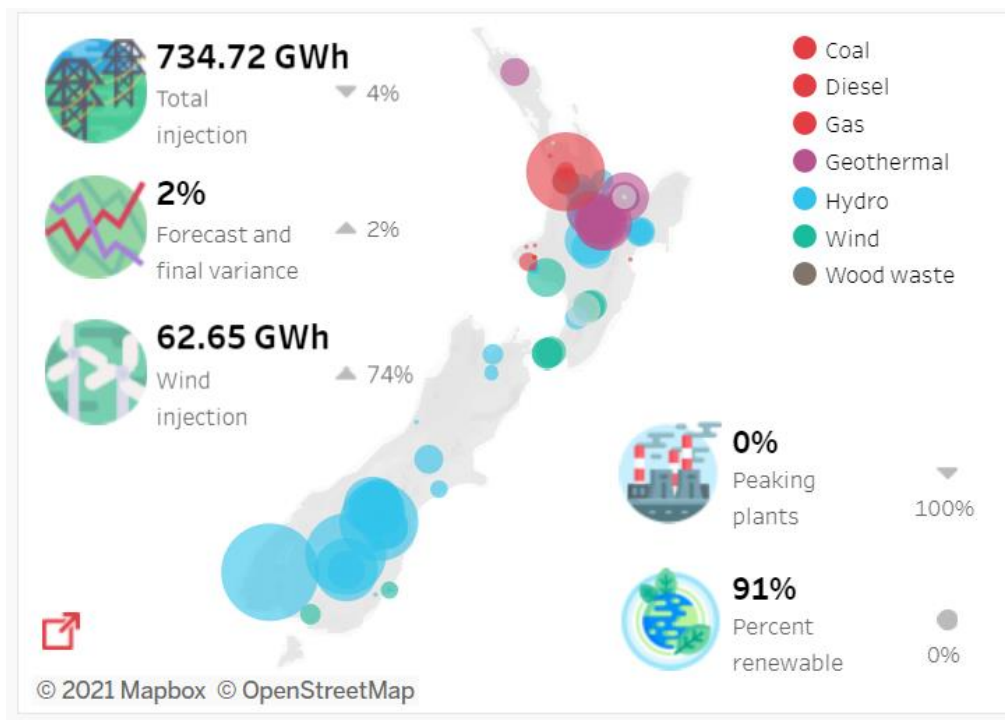
3.2. Figure 8 shows hourly temperature data at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Warm temperatures continued from last week, with Auckland temperatures in particular warmer than last week.

Figure 8: Hourly temperature data (actual and apparent) at main population centres



4. Supply Conditions

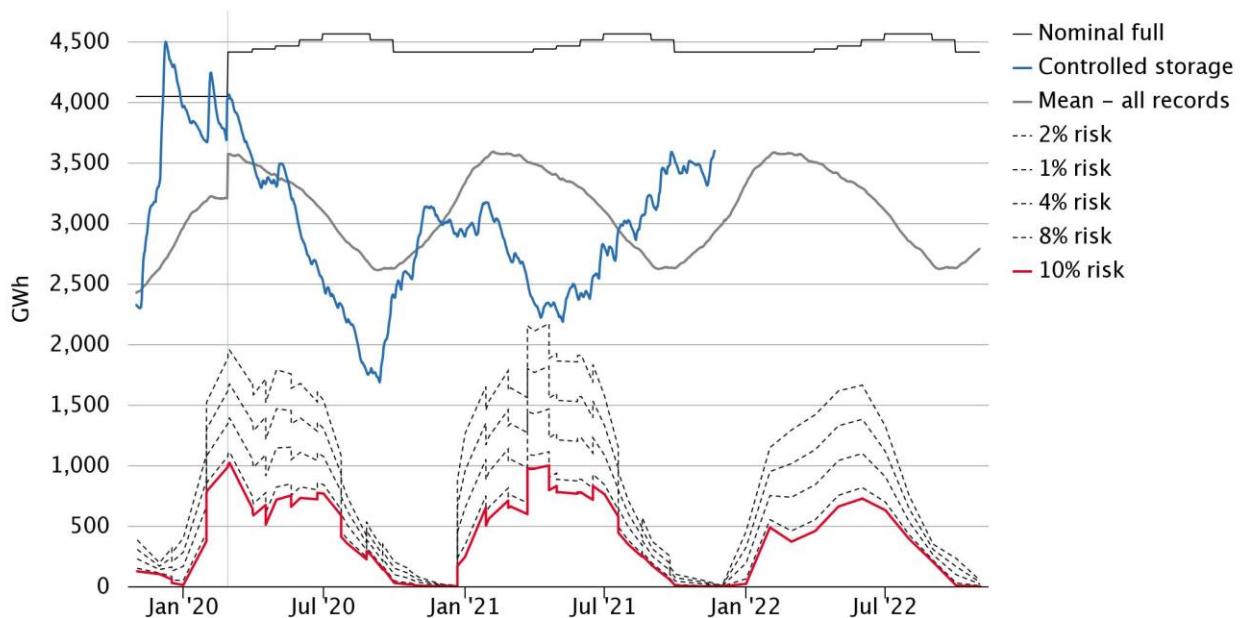
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage increased this week to 73% of nominal full, shown in Figure 10.

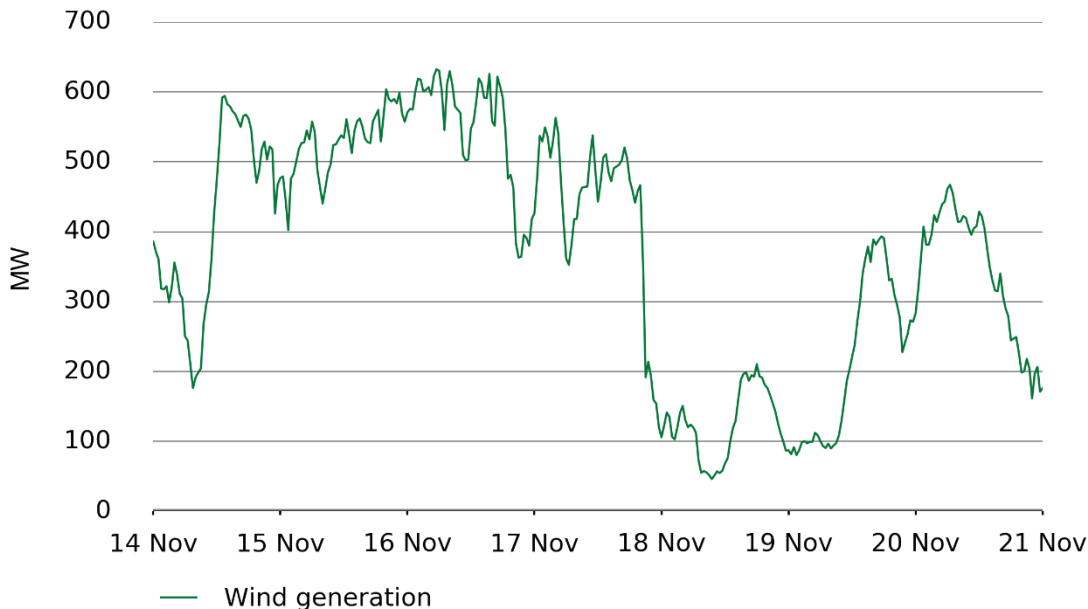
Figure 10: Electricity risk curves and hydro supply



Wind conditions

- 4.2. Total wind generation was 63GWh, 74% higher than last week. Wind generation was particularly high from 14 to 17 November at 400 to 600MW (see Figure 11) which was when prices were lowest (particularly overnight). Wind generation was low (below 100 MW) when prices were highest on 18 and 19 November.

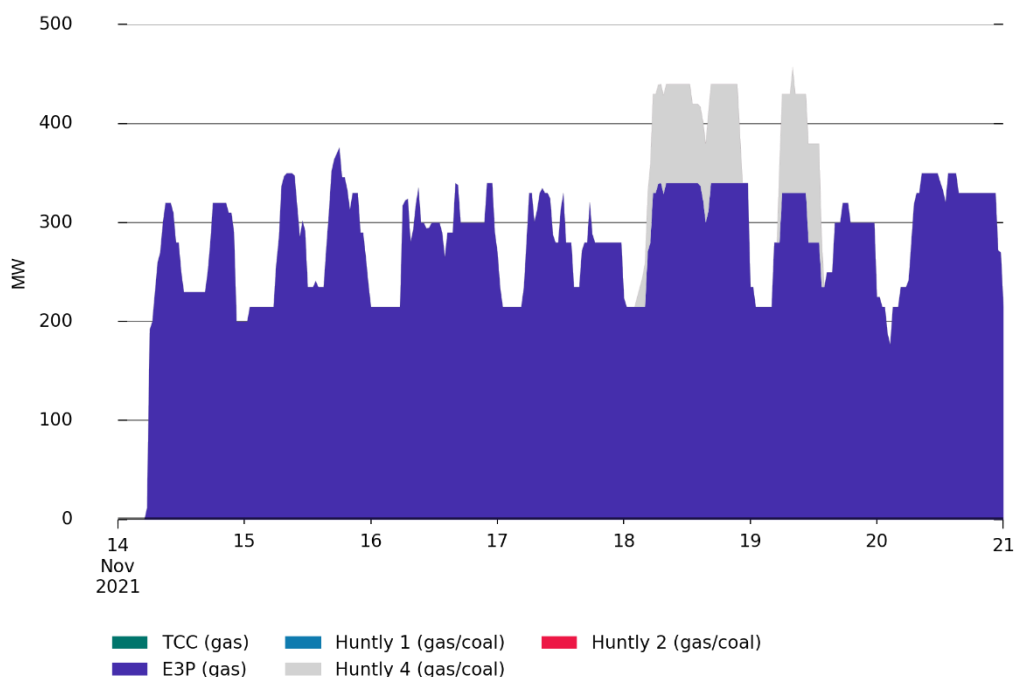
Figure 11: Wind generation by trading period



Thermal conditions

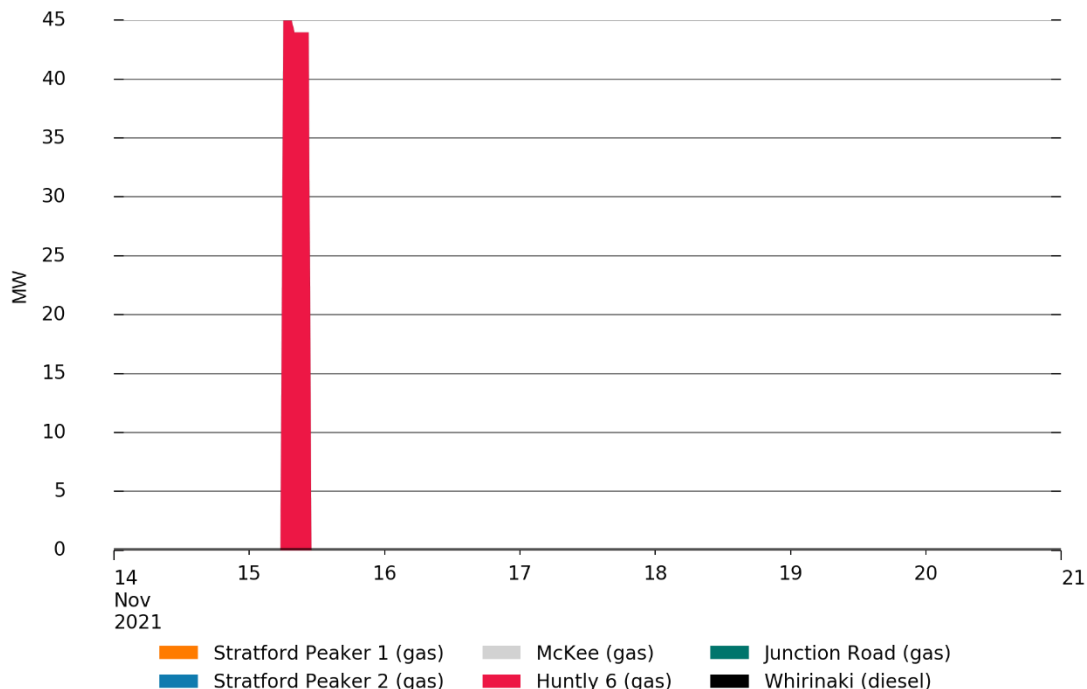
- 4.3. Huntly's E3P continued to run as thermal baseload this week (Figure 12). Huntly unit 4 also ran on 18 and 19 November when wind generation was at its lowest and Manapouri had several outages.

Figure 12: Generation from baseload thermal by trading period



- 4.4. Thermal peakers contributed well below 1% of total generation this week, due to low prices and high wind. Only Huntly unit 6 briefly ran from TP13 to TP22 on 15 November. Several thermal peaker were also on outage, such as Stratford and Junction Road.

Figure 13: Generation from thermal peakers by trading period



Significant outages

- 4.5. There continues to be a high number of outages this week, most noticeable Manapouri had 4 units on outage during this week.
- 4.6. The following outages reduced available generation by at least 50MW:
- (a) Clyde, 116MW (long term outage)
 - (b) Benmore, 90MW (5 July – 24 November)
 - (c) Manapouri,
 - (i) 125MW (7am-4:30pm 14 November)
 - (ii) 125MW (15-18 November)
 - (iii) 125MW (16-18 November)
 - (iv) 125MW (6am-5pm 17 November)
 - (d) Tekapo, 80MW (13 September – 16 January 2022)
 - (e) Huntly,
 - (i) Rankine unit; 240MW (4 October-19 December)
 - (ii) Rankine unit; 240MW (20-21 November)
 - (f) McKee, 50MW (17-23 November)
 - (g) Maraetai (Waikato River)
 - (i) 35.2MW (10-19 November)
 - (ii) 35.2MW (11 November -17 December)

- (h) Stratford,
 - (i) 100MW, (31 October-13 December)
 - (ii) 100MW (7-29 November)
- (i) Waipori, 72MW (8 November – 28 January 2022)
- (j) Junction Road,
 - (i) 50MW (11-15 November)
 - (ii) 50MW (13-16 November)
 - (iii) 50MW (16-18 November)
- (k) Aviemore, 55MW (11-26 November)

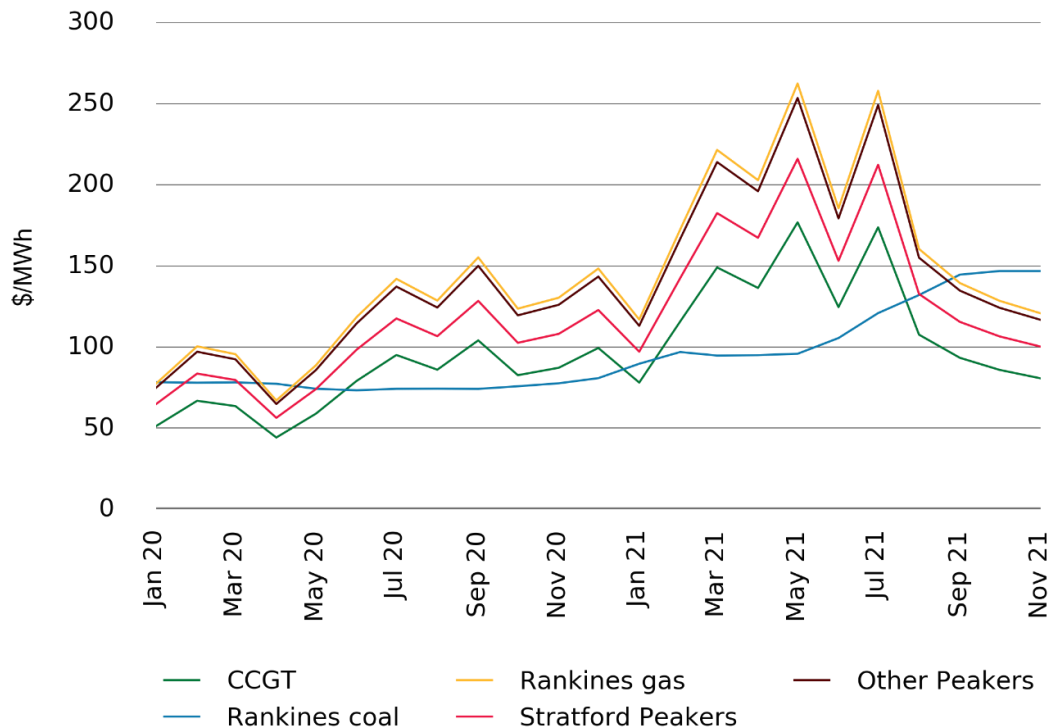
5. Price versus estimated costs

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

Thermal Fuels

- 5.2. The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices, 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 in November (to 21 November) is similar to October².

Figure 14: Estimated monthly SRMC for thermal fuels

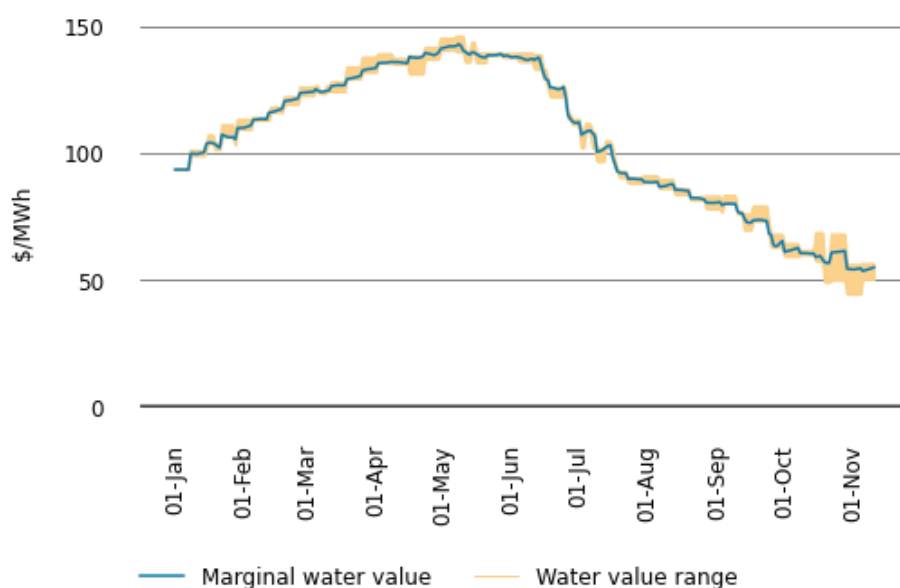


² For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: <https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/>

DOASA Water values

- 5.3. The DOASA³ model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 15 shows the national water values⁴ obtained from DOASA up to end of October 2021. The outputs from DOASA closest to actual storage levels are shown as the yellow water value range. These values are used to estimate marginal water value at the actual storage level, indicated by the blue line⁵. Figure 15 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased.

Figure 15: DOASA water values for January- to November 2021



Monthly prices

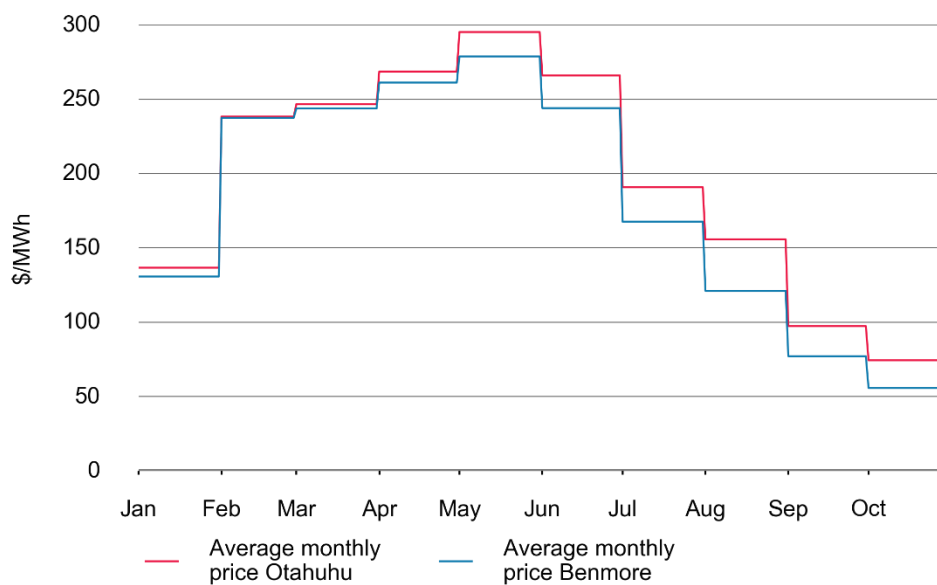
- 5.4. Figure 16 shows the average price each month at Otahuhu and Benmore for 2021. It shows that prices have declined since June, similar to the trend for gas costs and water values. The high prices over winter were closer to the SRMC of thermal but as thermal generation decreased average prices have been closer to the marginal water value.

³ DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market. (more details in Appendix B)

⁴ The national water values are estimated assuming all hydro storage reservoirs are equally full.

⁵ See Appendix B, 2 for more details

Figure 16: Average monthly prices at Otahuhu and Benmore January-October 2021



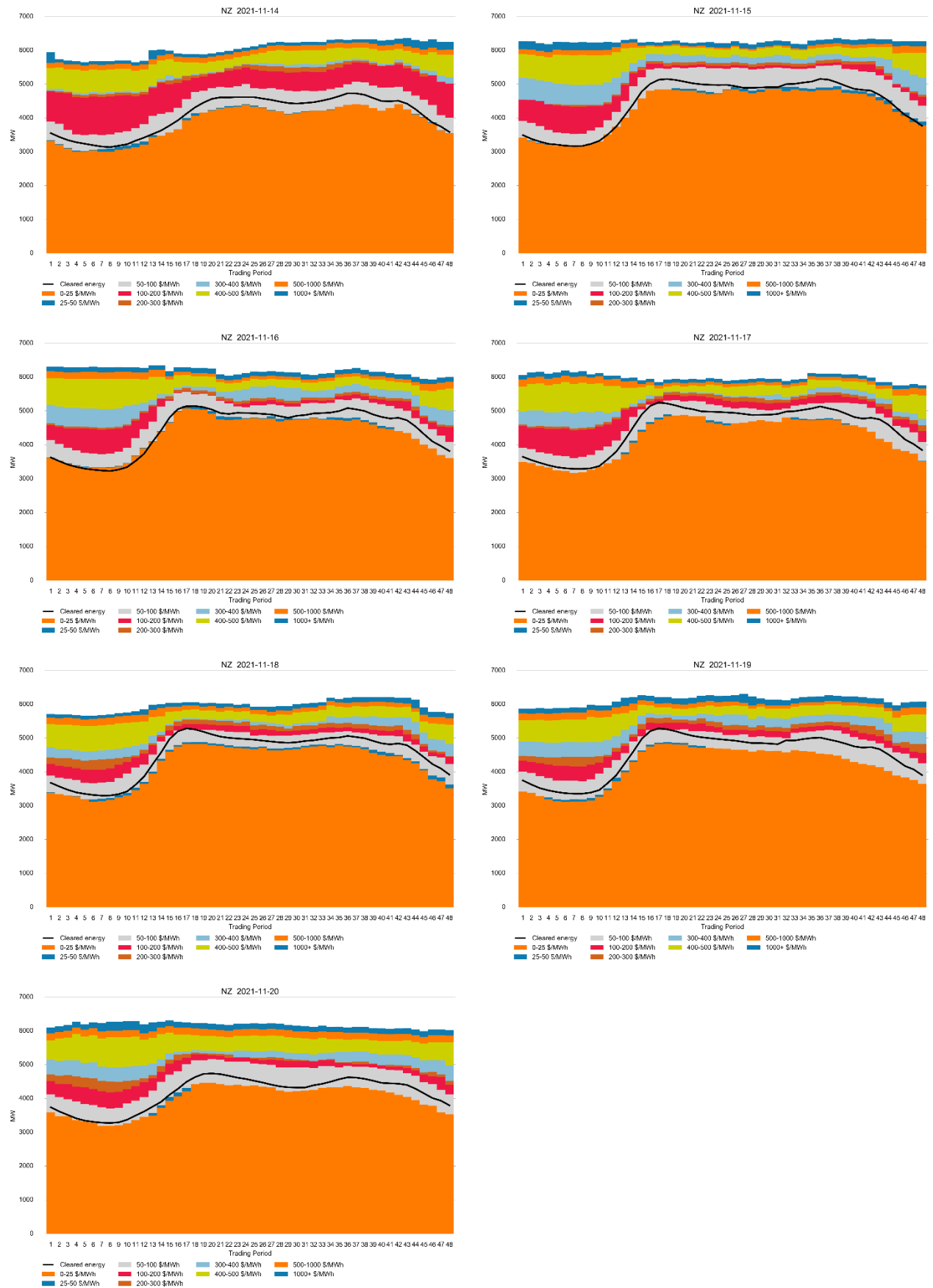
Offer Behaviour

Final daily offer stacks

- 5.5. Figure 13 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 the average final price.
- 5.6. This week increased wind generation and hydro storage resulted in more generation offered between \$50-\$100/MWh. The quantity of offers above \$350/MWh was 6% lower than one month ago. Outages did have a noticeable impact on total generation offered some days this week.

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 17: Daily offer stack



Offers by trading period

- 5.7. The trading period (TP) with the highest price at Otahuhu was TP17 (8:00am) on 18 November is shown on Figure 18 as well as the day immediately before on Figure 19. Each graph shows the offer stack, the generation weighted average price (GWAP) and cleared generation.
- 5.8. The offer stacks and cleared generation on the two days were similar. However, wind generation was almost 200MW lower on 18 November than 17 November which resulted in slightly higher prices.

Figure 18: Offer Stack for trading period 17 on 18 November

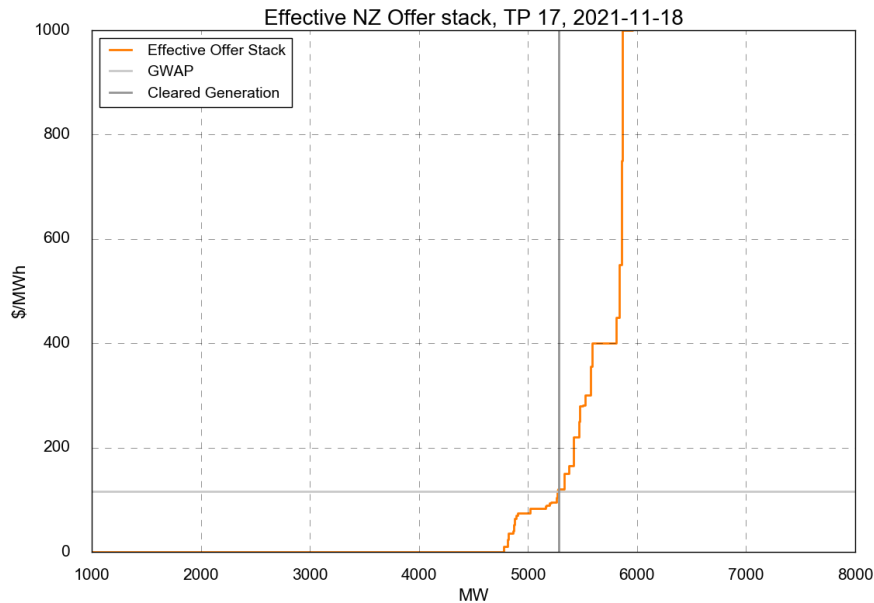
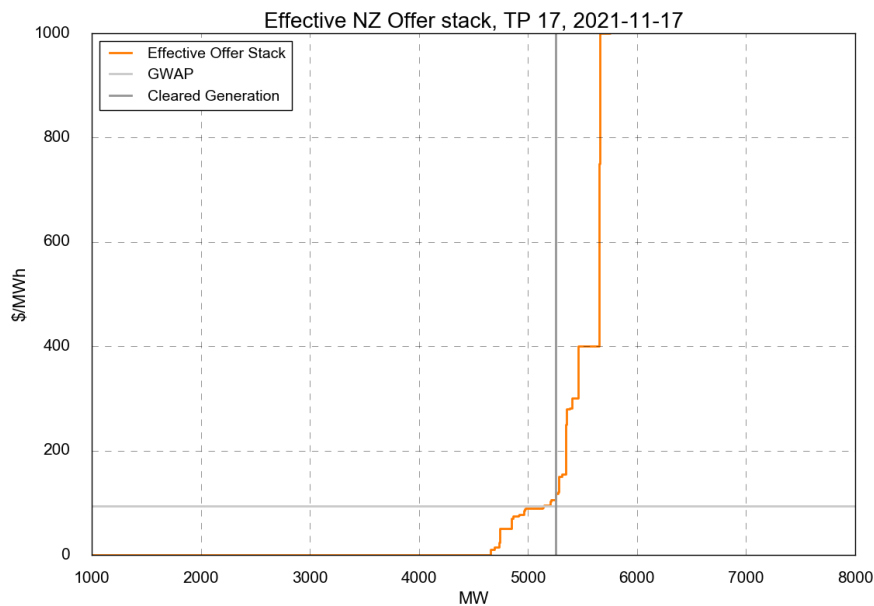


Figure 19: Offer Stack for trading period 17 on 17 November



Ongoing Work in Trading Conduct

5.9. Some trading periods have been identified this week for further analysis to understand high reserve prices.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
16/11-18/11		Further Analysis	High reserve prices
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

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

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

3. The regression equation is

$$\begin{aligned}\log(P_t - \theta_t) = & \beta_0 + \beta_1(\text{Storage}_t - \text{Seasonal.mean.storage}_i) \\ & + \beta_2(\text{Demand}_t - \text{Ten.year.mean.demand}_t) + \beta_3\text{Wind.generation}_t \\ & + \beta_4\log(\text{Gas.price}_t) + \beta_5\text{Generation.HHI}_t \\ & + \beta_6\text{Ratio.of.adjusted.offer.to.generation}_t + \beta_7\text{Dummy.gas.supply.risk}_t\end{aligned}$$

where P_t is the PPI and trend adjusted weekly average spot prices; t = week 1,...,52 for each year; i = spring, summer, autumn, and winter

Daily Model

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.
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 $\text{storage}_t - \text{storage}_{t-1}$.
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.
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 model⁷, where diff is the first difference:

$$\begin{aligned}y_t = & \beta_0 - \beta_1(\text{storage}_t - 20.\text{year.mean.storage}_{\text{dayofyear}}) + \beta_2\text{diff}(\text{demand}_t) - \\ & \beta_3\text{wind.generation}_t + \beta_4\text{gas.price}_t - \beta_5\text{diff}(\text{generation HHI}_t) + \beta_6\text{dummy} + \eta_t \\ \eta_t = & \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t\end{aligned}$$

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.

⁷ Updated, $\text{diff}(\text{storage}_t)$ has been replaced with $(\text{storage}_t - 20.\text{year.mean.storage}_{\text{dayofyear}})$

Appendix B DOASA water value model

1. DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.⁸ DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.⁹ A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well known and widely accepted modelling tool for hydro-thermal optimisation in electricity systems. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load.
2. The DOASA model outputs the marginal water value for a range of storage levels. The marginal water value, y , at the actual storage level, x , is estimated using the outputs closest to actual storage level (x_1, y_1) and (x_2, y_2) using the equation

$$y = y_1 + \left(\frac{x - x_1}{x_2 - x_1}\right)(y_2 - y_1)$$

3. The following are some of the limitations of the assumptions in the DOASA model:
 - a. Load is based on forecasts for future periods and recent periods where reconciled data was not yet available.
 - b. Forecast plant and HVDC outages based on current POCP data
 - c. The estimated thermal fuel costs used in DOASA may not accurately represent what hydro generators face, in terms of thermal generator offers. Hydro generators must manage their storage levels within the context of volatile thermal fuel prices and availability, and the thermal fuel cost estimates may not perfectly represent these.
 - d. Non-dispatchable plant, such as wind, is modelled as having constant power output instead of stochastic power output
 - e. Some hydro station head ponds and major reservoirs are governed by complex resource consent rules. The model limits used in DOASA are necessarily somewhat simplified and may not accurately reflect the actual flexibility of these limits.
 - f. Inflow probability distributions are based on past inflow sequences.
 - g. DOASA does not directly model stagewise dependence (i.e. from week to week) of inflows, e.g. if it was wet last week it's more likely to be wetter this week as well. However, DOASA approximates this effect by an approach called Dependent Inflow Adjustment (DIA), which artificially increases the variance of historical inflows when generating the cutting planes.⁹
4. We use the average water value over all of New Zealand from DOASA rather than the water values for individual reservoirs because the individual reservoir water values are very volatile. This is due to the following.
 - a. DOASA does a forward solve (linear programming), so as long as the objective values are the same, it is likely to use all water from one reservoir first until it hits some constraint, before moving to the next reservoir. This leads to the likely extreme usage of small reservoirs (ie, not using water proportional to total national storage by either holding back or letting it all go).

⁸ M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.

⁹ Electricity Authority, "Doasa overview," <https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa>.

- b. Therefore, small (constrained) reservoirs in DOASA are expectedly more likely to hit maximum or minimum levels or constraints, and this will be reflected in the water values (high price if likely to hit minimum level and low price if likely to hit maximum level).
- c. National water values are calculated based on absolute total national storage, not absolute individual reservoir storage, which tends to make the water values less volatile. That is, if we had two reservoirs with the same capacity and one had storage at 10 percent of capacity and the other at 90 percent, the national water value is based on total storage of 50 percent of total capacity