15 December 2021

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 5 to 11 December

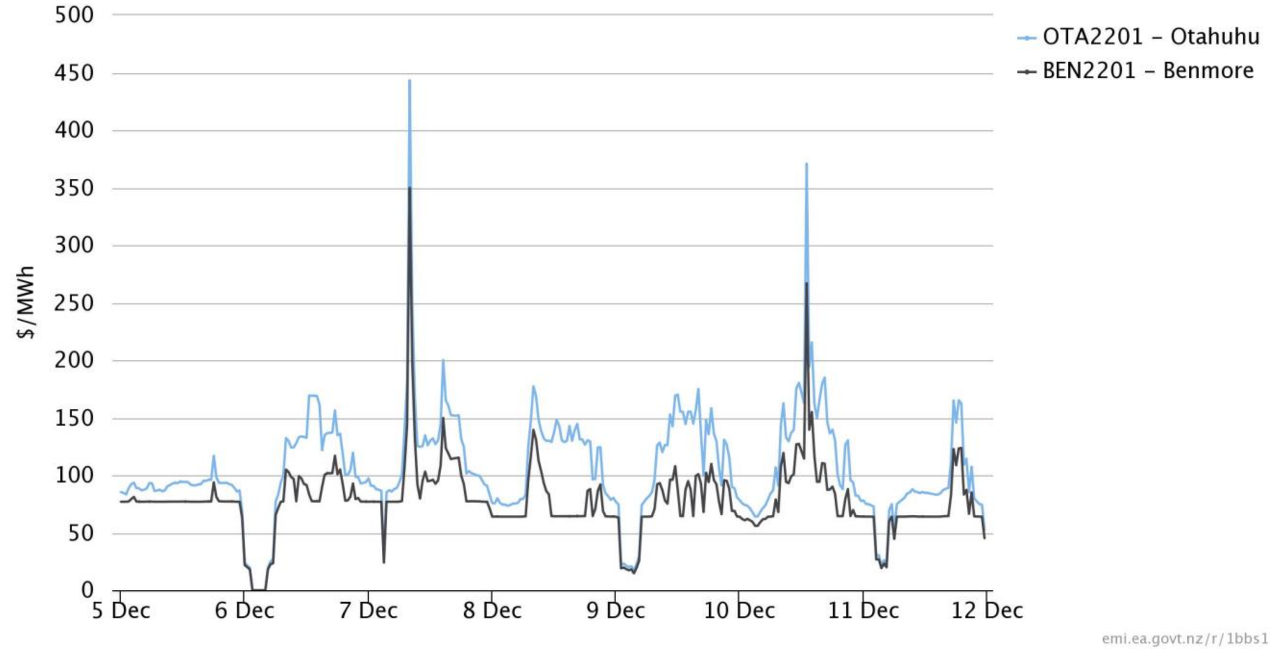
1.1. Prices this week appear to be consistent with underlying supply and demand conditions.

2. Prices

Energy prices

2.1. The average spot price this week was $91/MWh[1], 2% higher than last week. There was some price separation between Benmore and Otahuhu, with Otahuhu prices frequently more than $50/MWh higher than Benmore prices. There were also two trading periods with high prices compared to the rest of the week, TP17 on 7 December with the highest price of $443/MWh at Otahuhu and TP27 on 10 December with a price of $371/MWh at Otahuhu.

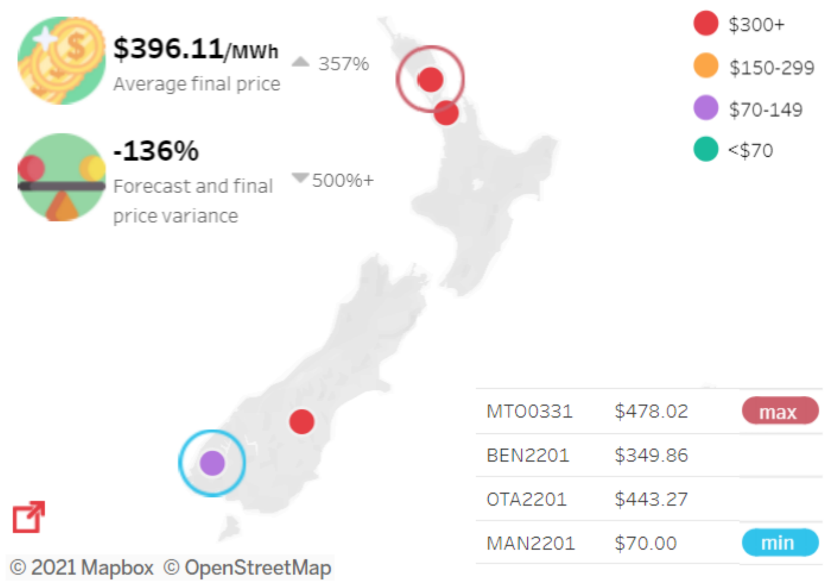
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.2. Figure 2 shows the average price for TP17 on 7 December, when the highest average price occurred of $396/MWh. The price was lowest at Manapouri at $70/MWh, due to an outage of one of the transmission lines connected to Manapouri from 6 to 10 December. This limited capacity out of Manapouri.

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

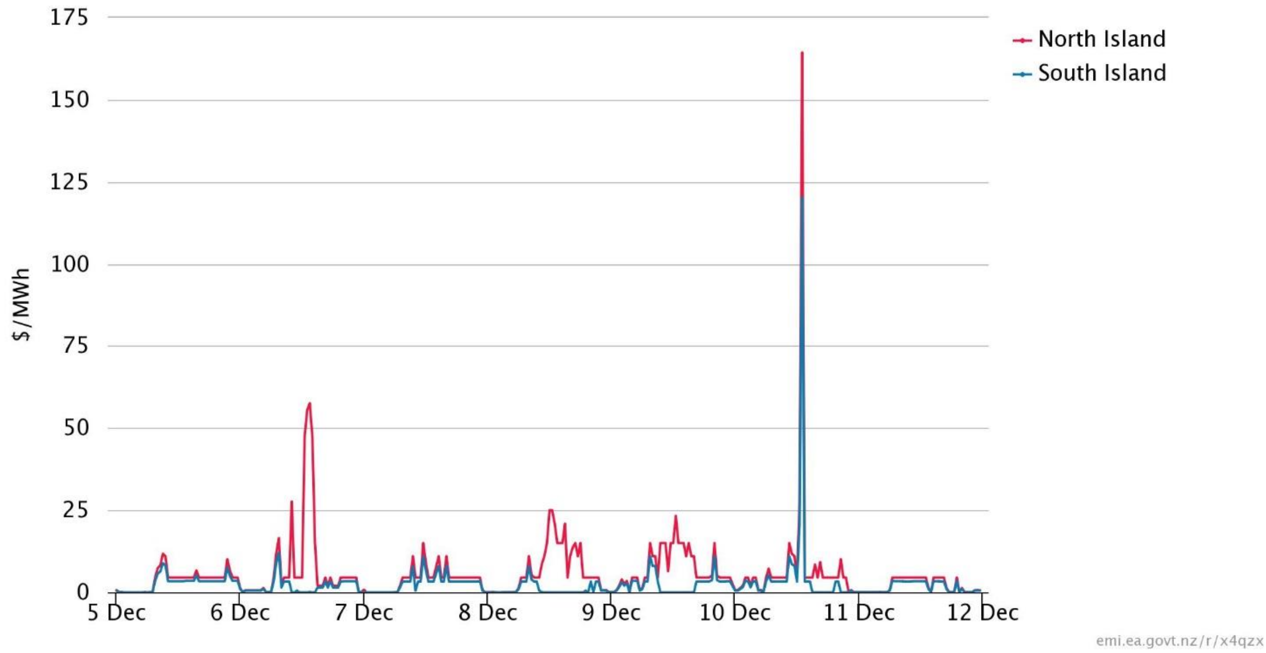
Figure 2: Spot prices for TP17 on 7 December compared to the previous week



Reserve Prices

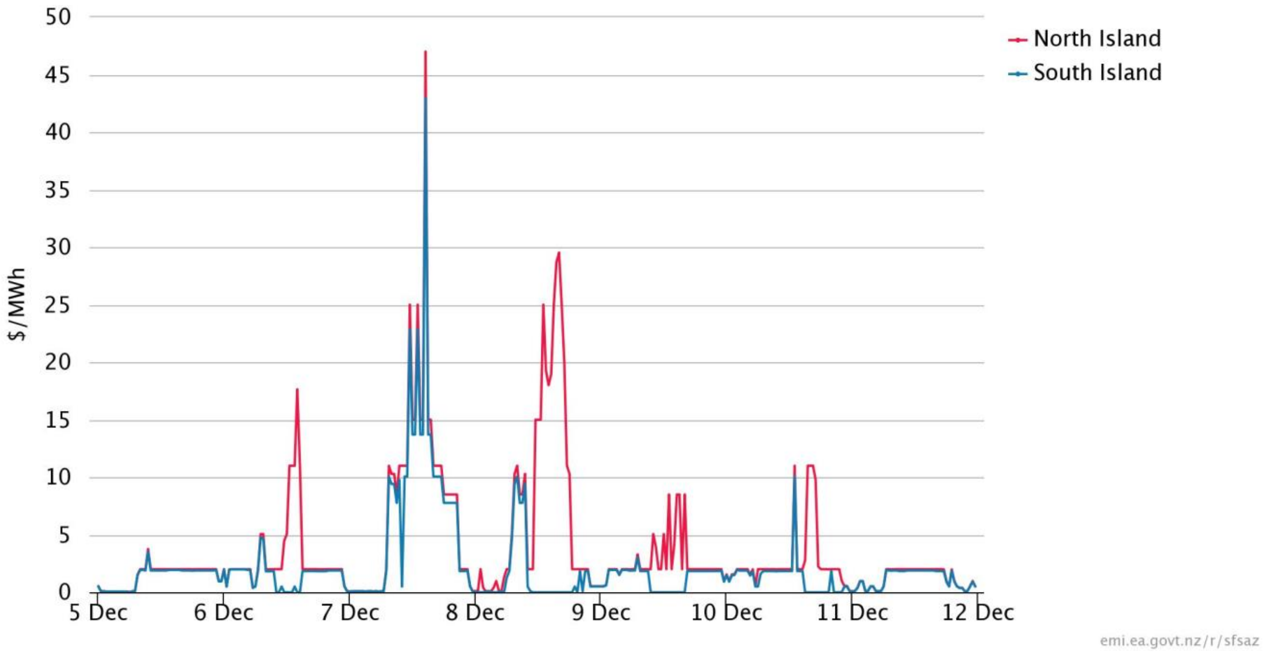
2.3. Fast instantaneous reserves (FIR) prices were usually below $25/MWh this week, with some price separation between the North and South Island. There was one high price when FIR reached $164/MWh at TP27 on 19 December, which coincided with the second highest energy price this week.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were between $0/MWh and $20/MWh for most of this week. Similar to FIR, there was price separation between the North and South Island on some days. The highest price was TP30 on 7 December when the price reached $47/MWh

Figure 4: SIR prices by trading period and Island

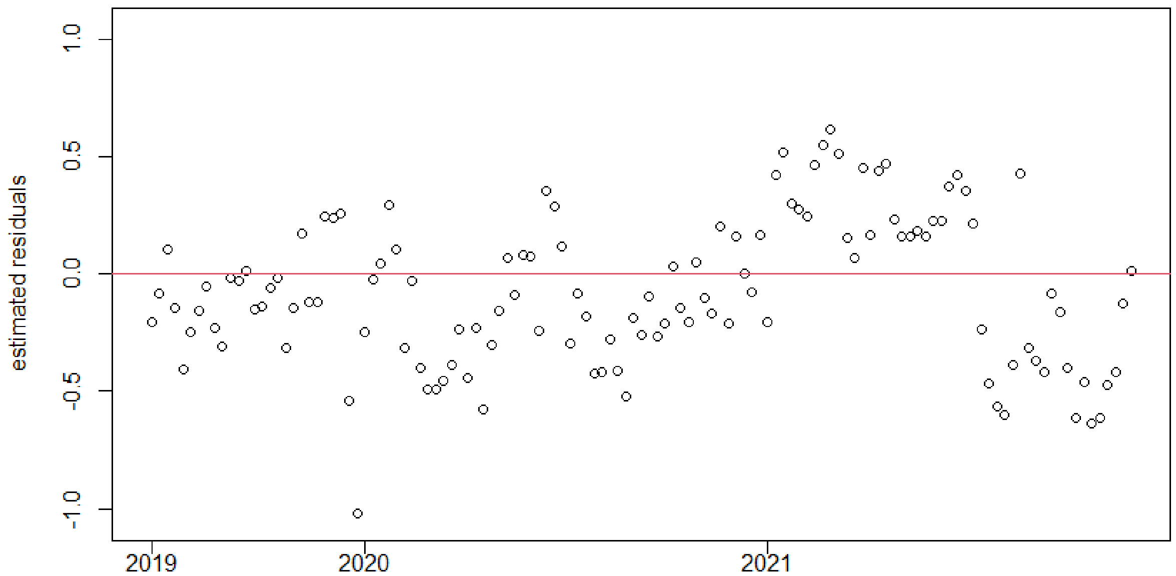


Residuals from regression models

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.

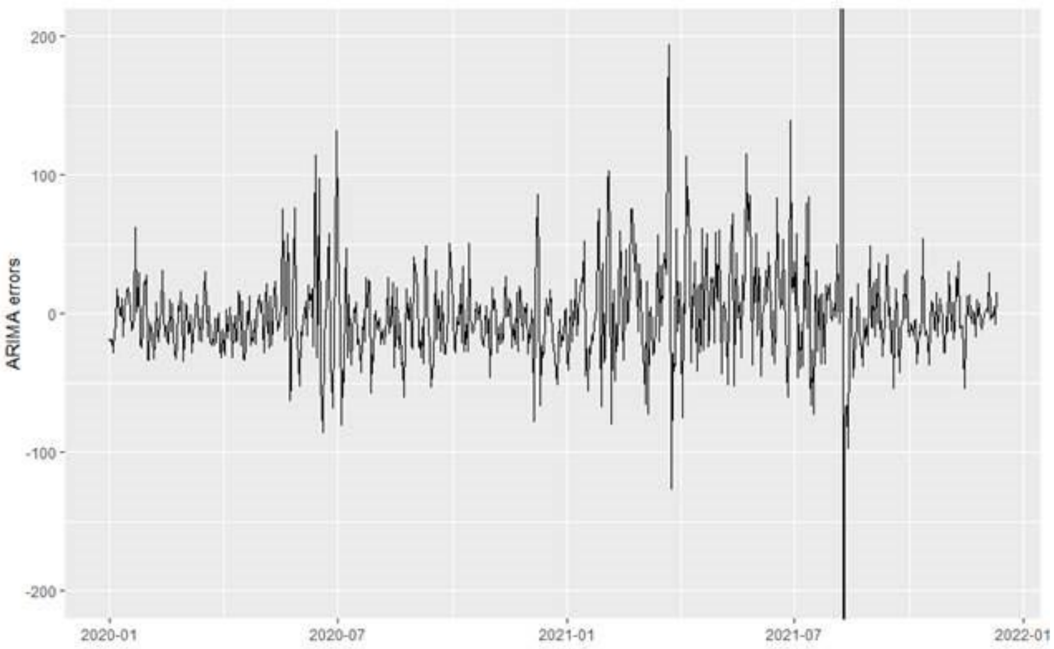
2.6. Figure 5 shows the residuals from the weekly model. During November 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 25 November 2021



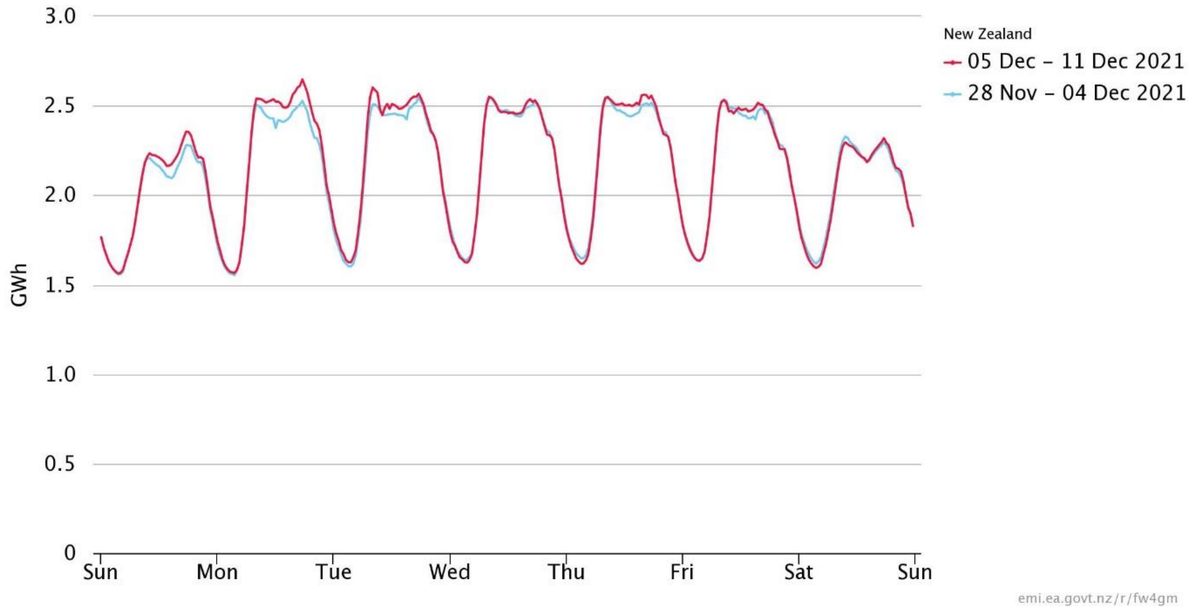
2.7. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were within the normal range.

Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 11 December 2021



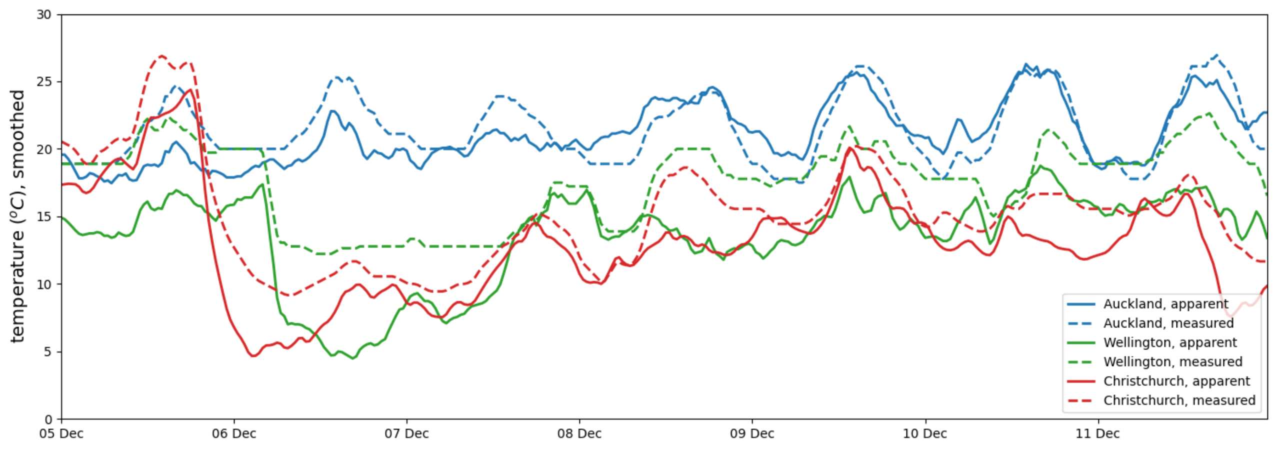
3. Demand Conditions

3.1. National demand was 1% higher than the previous week (see Figure 7). Demand this week was highest on Monday evening and Tuesday morning, due to colder weather (see Figure 8). This contributed to the high price on Tuesday morning. On most other days there was only a small difference between demand during the day and at the peaks. Figure 7: National demand compared for current and previous week



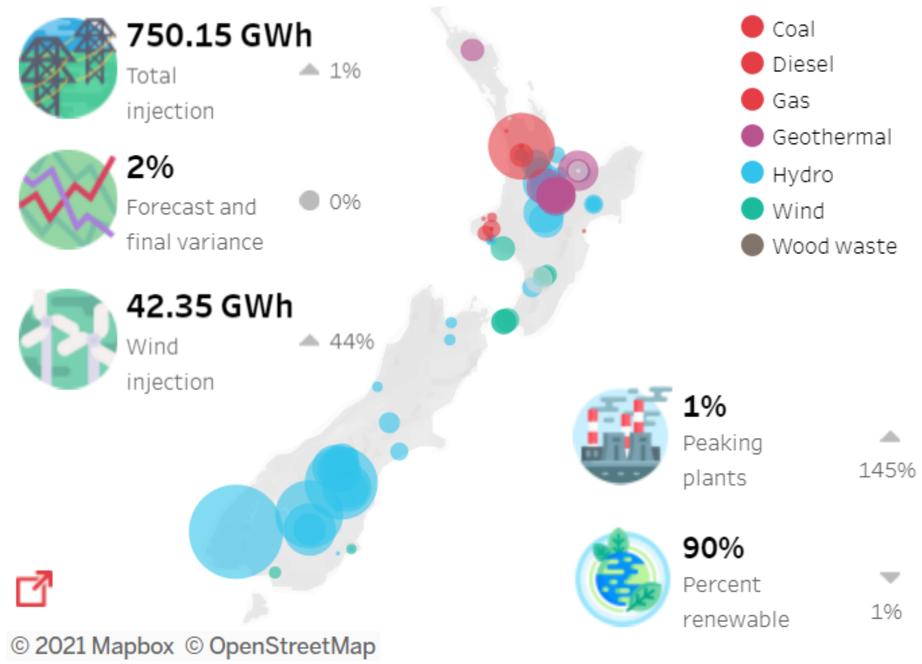
3.2. Figure 8 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures dropped overnight on 5/6 December in Wellington and Christchurch, which contributed to higher demand, especially during the morning and evening peaks. The rest of the week temperatures were relatively warm.

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



4. Supply Conditions

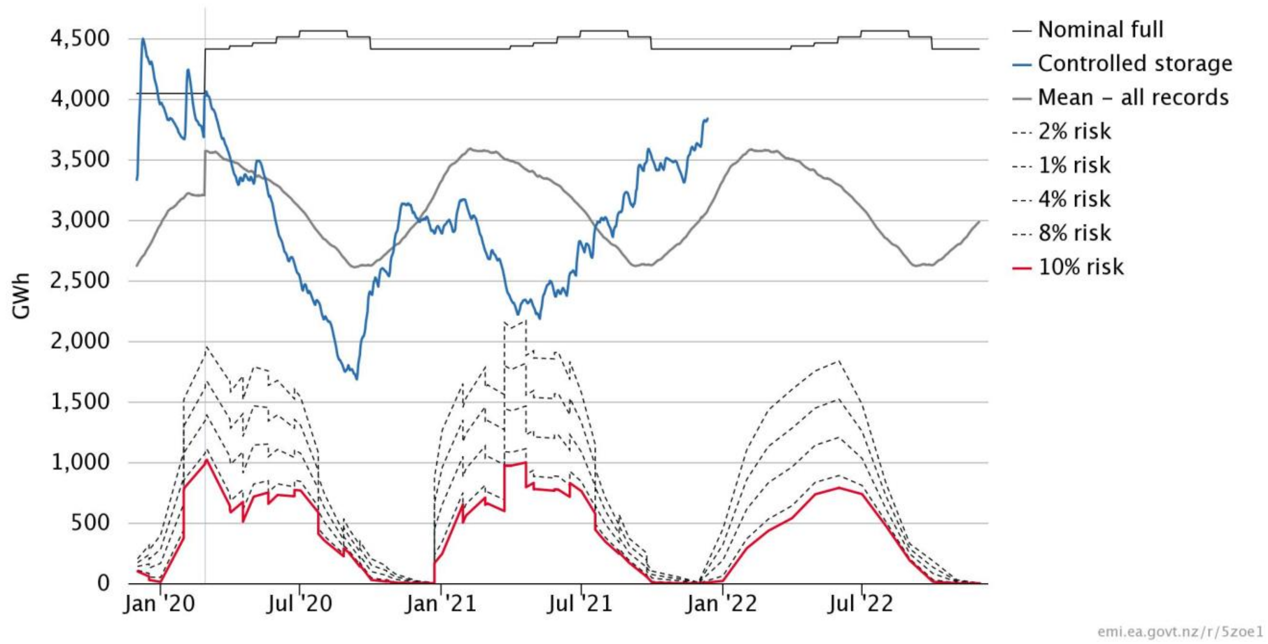
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage increased this week, particularly on 6 December, to 80% of nominal full, shown in Figure 10.

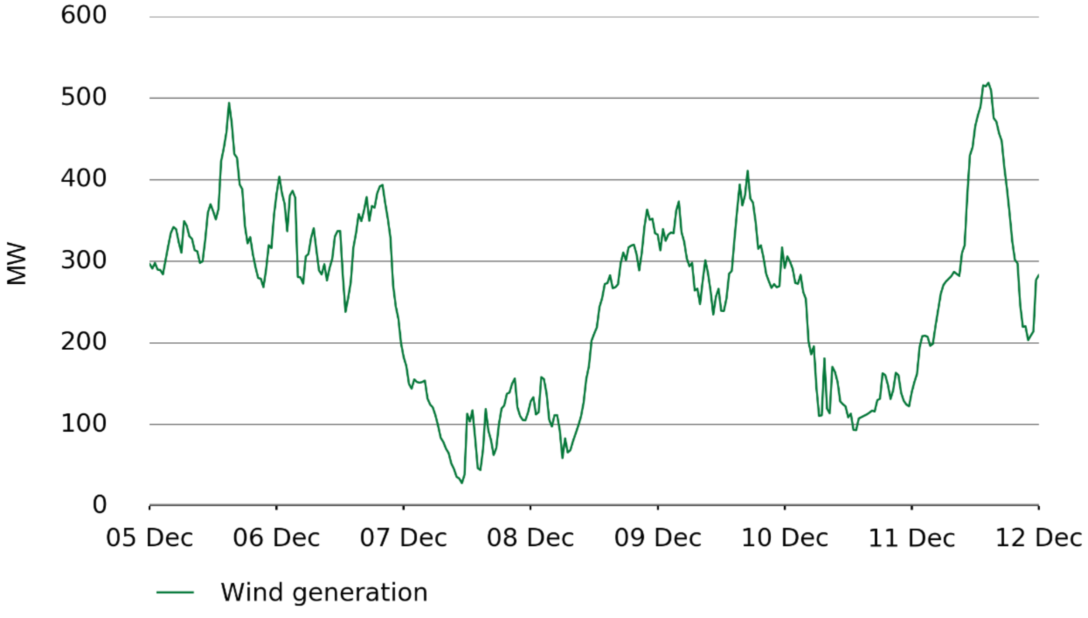
Figure 10: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 42GWh, 44% higher than last week. Wind generation was quite variable this week, from 30 MW on 7 December to 520MW on 11 December. The two trading periods with the highest prices this week both coincided with times when wind generation was below 100MW.

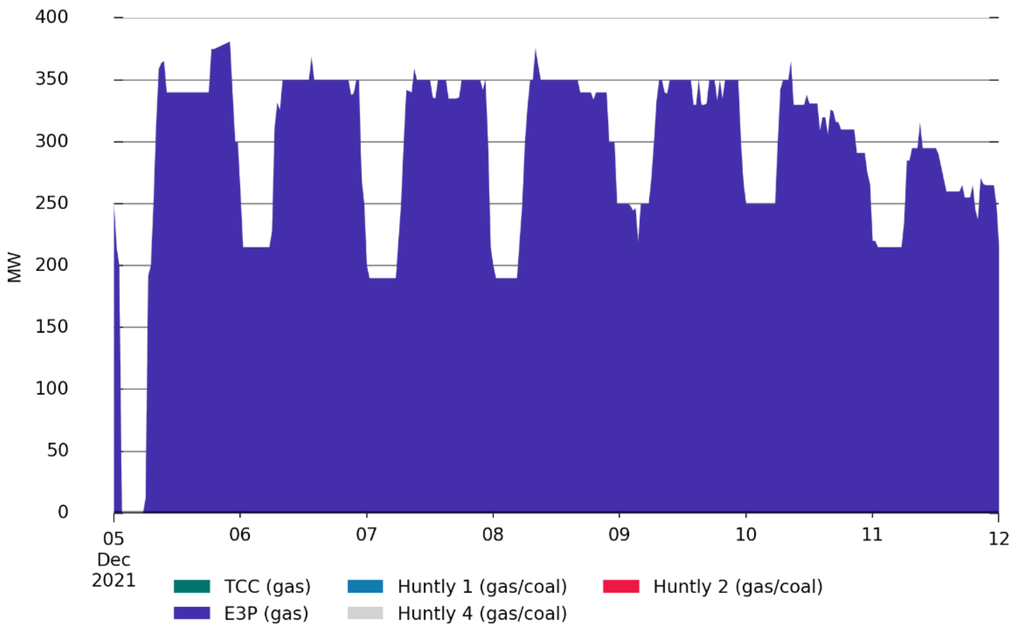
Figure 11: Wind generation by trading period



Thermal conditions

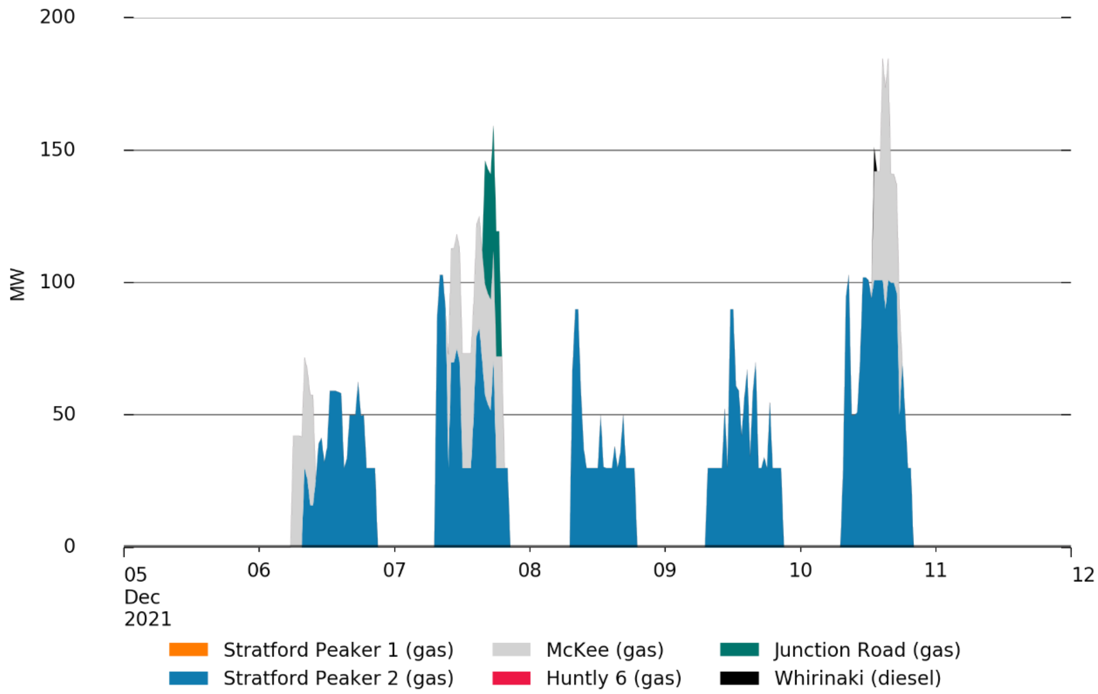
4.3. Huntly's E3P continued to run as thermal baseload this week.

Figure 12: Generation from baseload thermal by trading period



4.4. Generation from thermal peakers was 145% higher than last week. Stratford Peaker 2 ran every weekday this week, with McKee also running frequently. However, Stratford Peaker 1, one unit at Junction Road, and Huntly 6 were on outage for most of the week (see 4.7(h) to 4.7(k) for list of thermal outages), which reduced available peaker generation and may have contributed to some of the higher prices. The second Junction Road unit was also on outage on 10 December, which meant it was not available when the high price occurred and instead Whirinaki was dispatched.

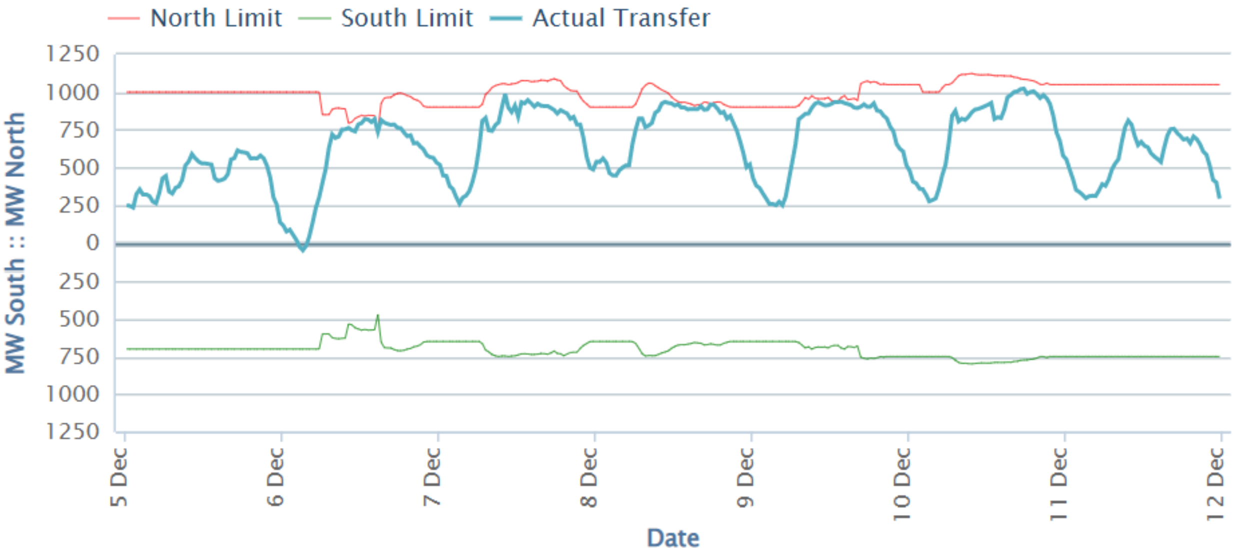
Figure 13: Generation from thermal peakers by trading period



HVDC transfer

4.5. Figure 14 shows the HVDC transfer for the past week as well as the transfer limit, as published by the system operator. While the northward HVDC bipole capacity is nominally 1200 MW, the system operator frequently reduces this for operational reasons, sometimes as low as 750 MW. This increases the likelihood of the HVDC being constrained, which can cause price separation. This was the cause of most of the price separation that occurred this week.

Figure 14: HVDC Transfer and Transfer Limit, Source: Transpower[2]



Significant outages

4.6. There continues to be a high number of outages this week, predominantly of hydro generators and thermal generators. The outage at Clyde on 10 December was likely a contributor to the high price that occurred shortly after the outage started.

4.7. The following outages reduced available generation by at least 50MW:

- (a) Clyde,
  - (i) 116MW (long term outage)
  - (ii) 116MW (1pm-3pm, 10 December)
- (b) Benmore, 90MW (29 November – 17 December)
- (c) Manapouri,
  - (i) 125MW (6-10 December)
  - (ii) 125MW (11-12 December)
- (d) Tekapo, 80MW (13 September – 16 January 2022)
- (e) Waipori, 80MW (8 November – 28 January 2022)
- (f) Ohau,
  - (i) 55MW (29 November-17 December)
  - (ii) 50MW (6-10 December)

[2] Transpower, HVDC Transfer, weekly summary, https://www.transpower.co.nz/system-operator/operational-information/hvdc-transfer, 13 December 2021

(g) Roxburgh, 40MW, (15 November – 17 December)

(h) Huntly,

  (i) Rankine unit; 240MW (4 October-19 December)

  (ii) Peaker, 45MW (29 November – 10 December)

(i) McKee, 50MW (2-7 December)

(j) Stratford peakers, 100MW, (31 October-20 December)

(k) Junction Road,

  (i) 50MW (2-15 December)

  (ii) 50MW (10am-2pm 10 December)

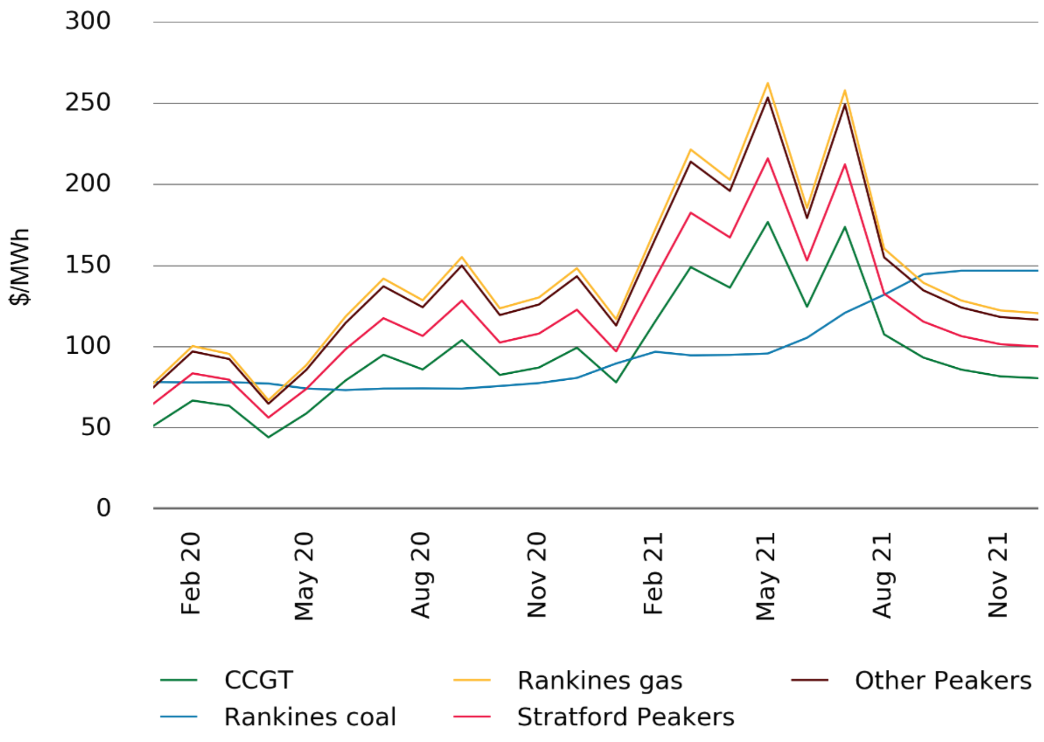
5. Price versus estimated costs

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 of gas (to 12 December) is slightly lower than the previous months and the SRMC of coal remains higher than gas[3].

Figure 15: Estimated monthly SRMC for thermal fuels

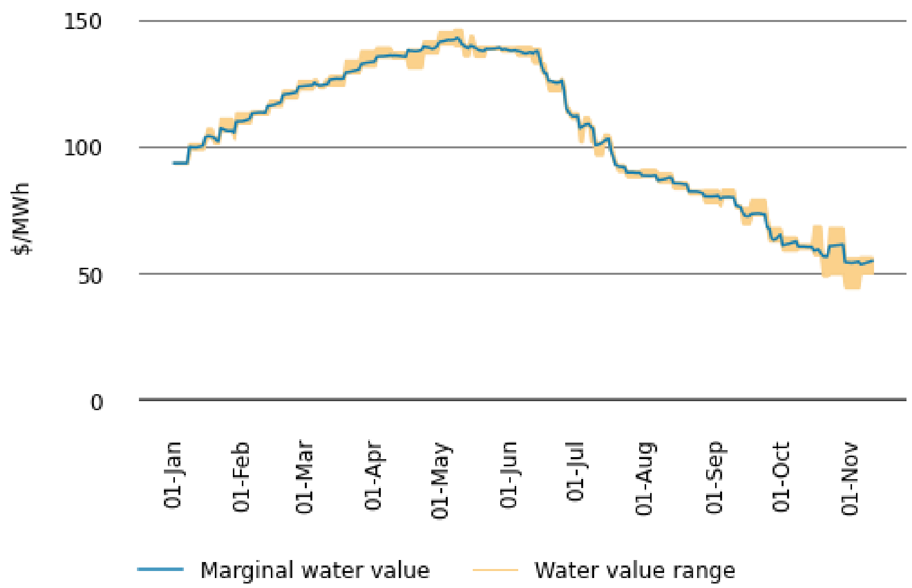


[3] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

DOASA Water values

5.3. The DOASA[4] 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 16 shows the national water values[5] 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 line[6]. Figure 16 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased.

Figure 16: DOASA water values for January- to November 2021



Monthly prices

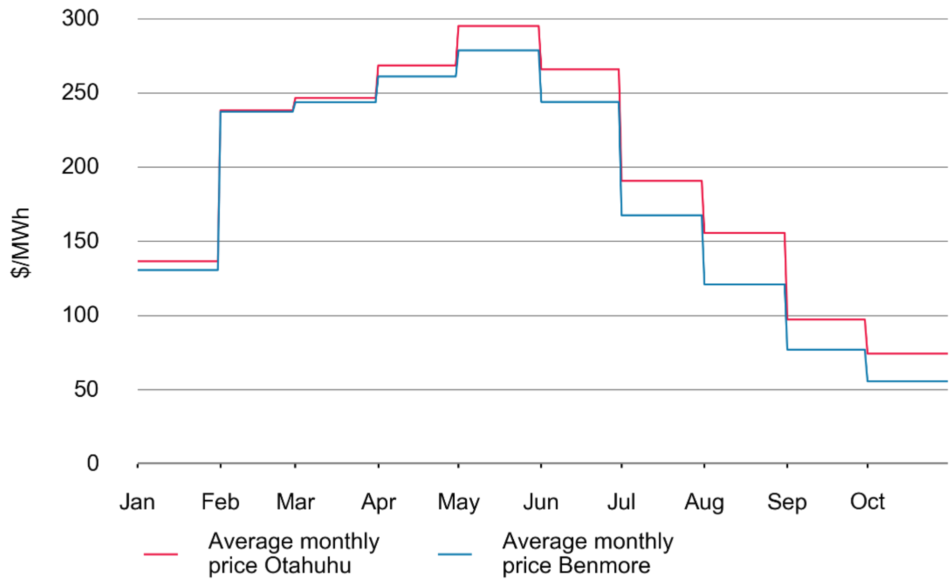
5.4. Figure 17 shows the average price each month at Otahuhu and Benmore for 2021. It shows that prices have declined since June, similar to the trend for gas costs and water values. The high prices over winter were closer to the SRMC of thermal but as thermal generation decreased average prices have been closer to the marginal water value.

[4] 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)

[5] The national water values are estimated assuming all hydro storage reservoirs are equally full.

[6] See Appendix B, 2 for more details

Figure 17: Average monthly prices at Otahuhu and Benmore January-October 2021



Offer Behaviour

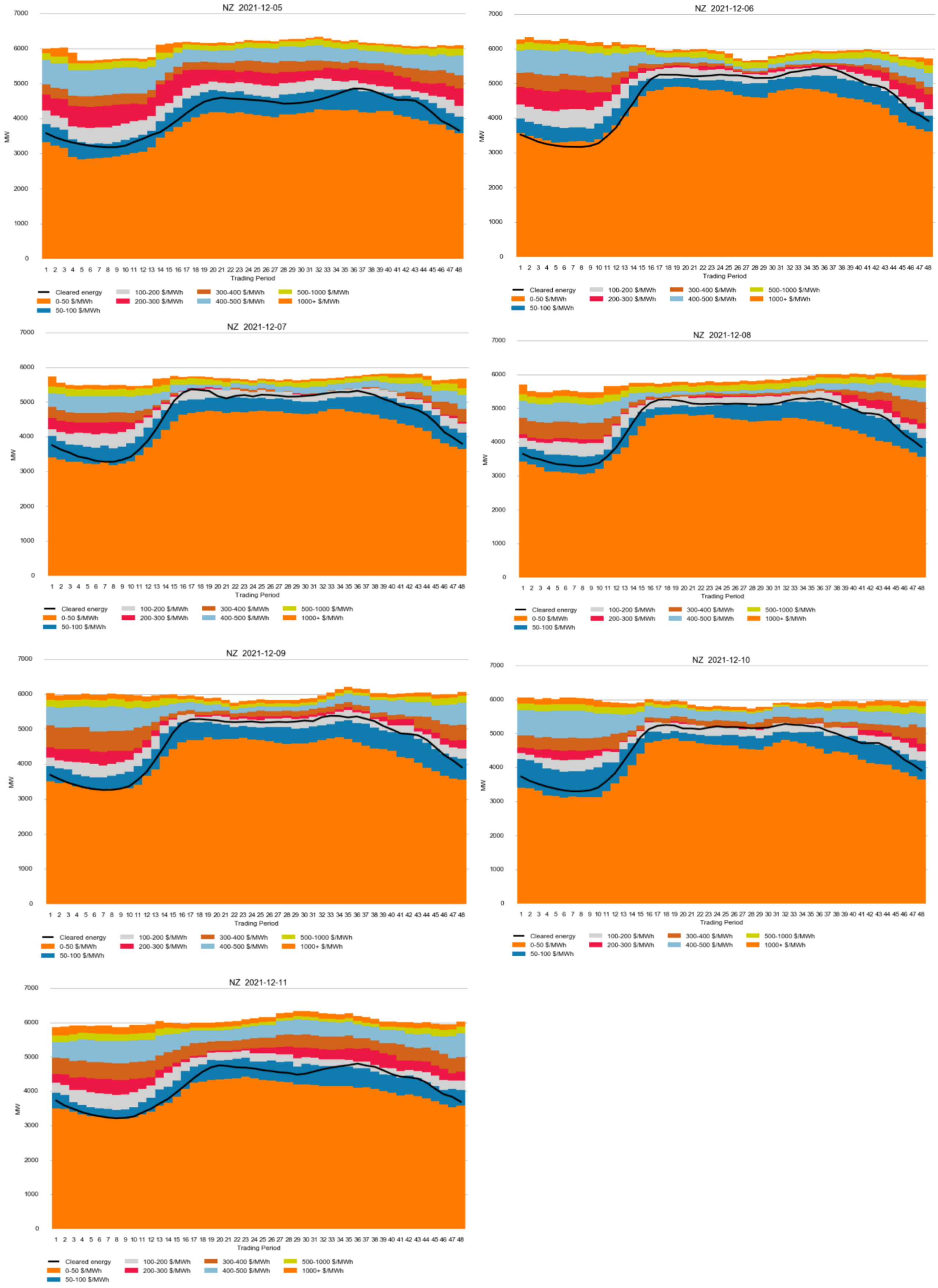
Final daily offer stacks

5.5. Figure 18 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[7] The black line shows the cleared energy, indicating the range of the average final price.

5.6. This week the quantity weighted offer price dropped by 1% from last week, likely as hydro storage increased in the South Island. 13% of total offered generation was priced over $350/MWh. The offer stack was thinner on 2 December and morning of 3 December than the other days, likely due to the combined impact of lower wind generation and generation outages.

[7] 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 18: Daily offer stack



Offers by trading period

5.7. The offer stacks of the trading periods (TP) with the highest prices are TP17 on 7 December shown on Figure 19, with a similar trading period from last week shown on Figure 20, along with the generation weighted average price (GWAP) and cleared generation.

5.8. Cleared generation was higher on 7 December then a similar day the previous week, and this appears to be the primary driver of the high price. Wind generation was low and several outages reduced the available generation, so while only 6% of offers were over $350/MWh, compared to 13% for the whole week, some of these offers were dispatched to meet demand.

Figure 19: Offer Stack for trading period 17 on 7 December

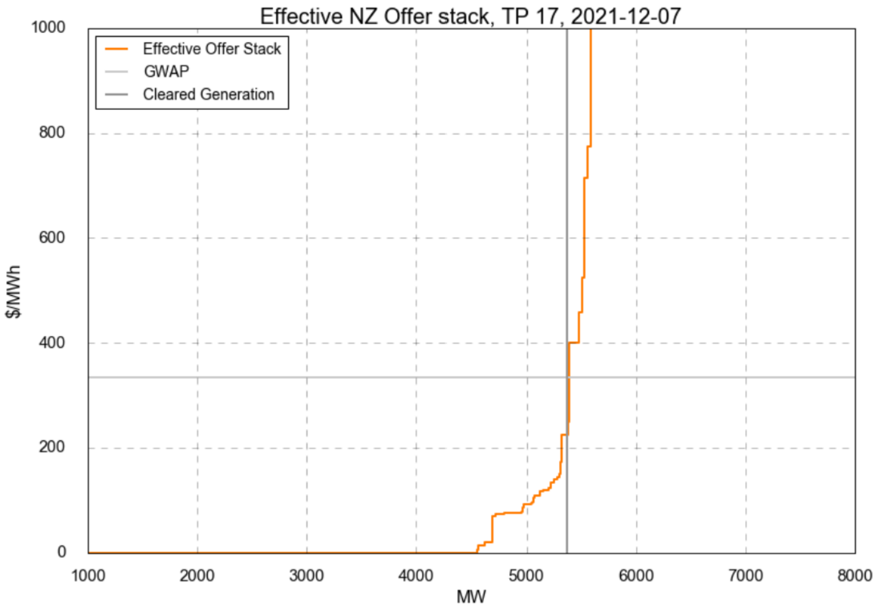
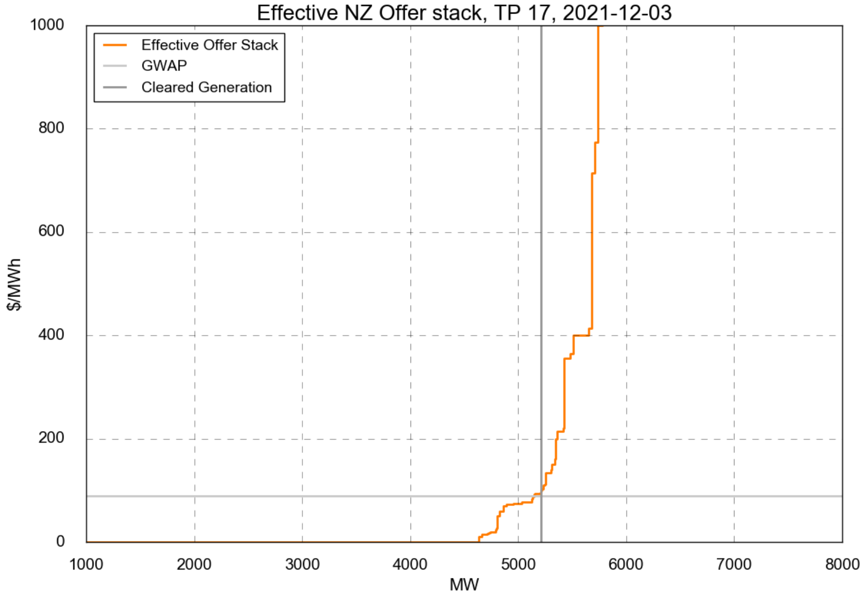
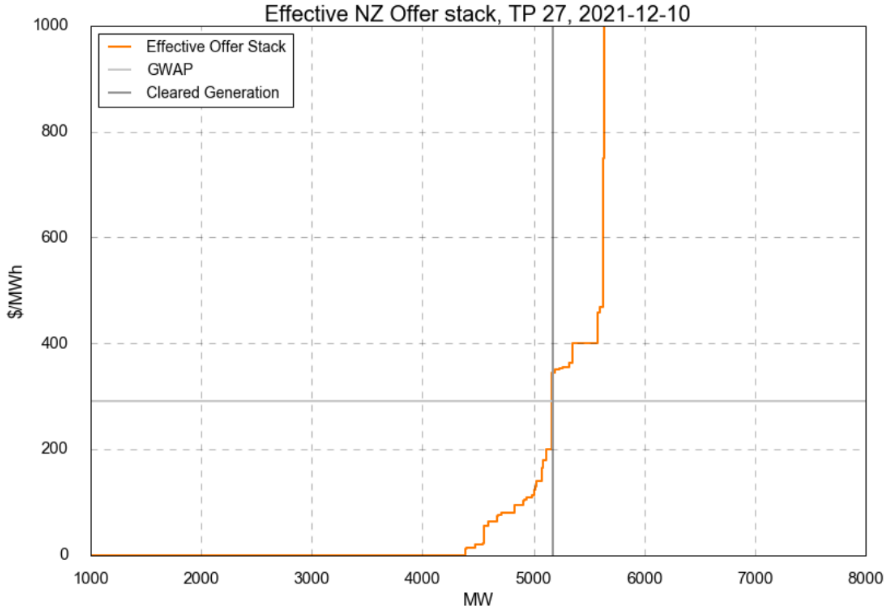


Figure 20: Offer Stack for trading period 17 on 3 December (low wind day of previous week)



5.9. The high price on TP27 on 10 December (show on Figure 20), appears to be due to a combination of the outage at Clyde from TP27 to TP30, low wind generation and thermal generation outages. Available thermal peakers, include Whirinaki, were dispatched to meet demand, making up 3% of total generation. There was also limited North Island reserve available to cover the largest risk setter which further increased the price of both energy and FIR.

Figure 20: Offer Stack for trading period 27 on 10 December



Ongoing Work in Trading Conduct

5.10. No trading periods have been identified for further analysis.

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

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

$$\begin{aligned}\log(P_t - \theta_t) = \beta_0 + \beta_1(Storage_t - Seasonal.mean.storage_i) \\ + \beta_2(Demand_t - Ten.year.mean.demand_t) + \beta_3 Wind.generation_t \\ + \beta_4 \log(Gas.price_t) + \beta_5 Generation.HHI_t \\ + \beta_6 Ratio.of.adjusted.offer.to.generation_t + \beta_7 Dummy.gas.supply.risk_t\end{aligned}$$

where P_t is the PPI and trend adjusted weekly average spot prices; t =week 1,…,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 $storage_t - storage_{t-1}$.

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 model[8], where diff is the first difference:

$$y_t = \beta_0 - \beta_1\left(storage_t - 20.year.mean.storage_{dayofyear}\right) + \beta_2 diff(demand_t) - \beta_3\, wind.generation_t + \beta_4\, gas.price_t - \beta_5 diff(generation\ HHI_t) + \beta_6 dummy + \eta_t$$

$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

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.

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

Appendix B DOASA water value model

1. DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[9] DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[10] 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.[10]

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).

    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

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

[10] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

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