26 January 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 16 to 22 January

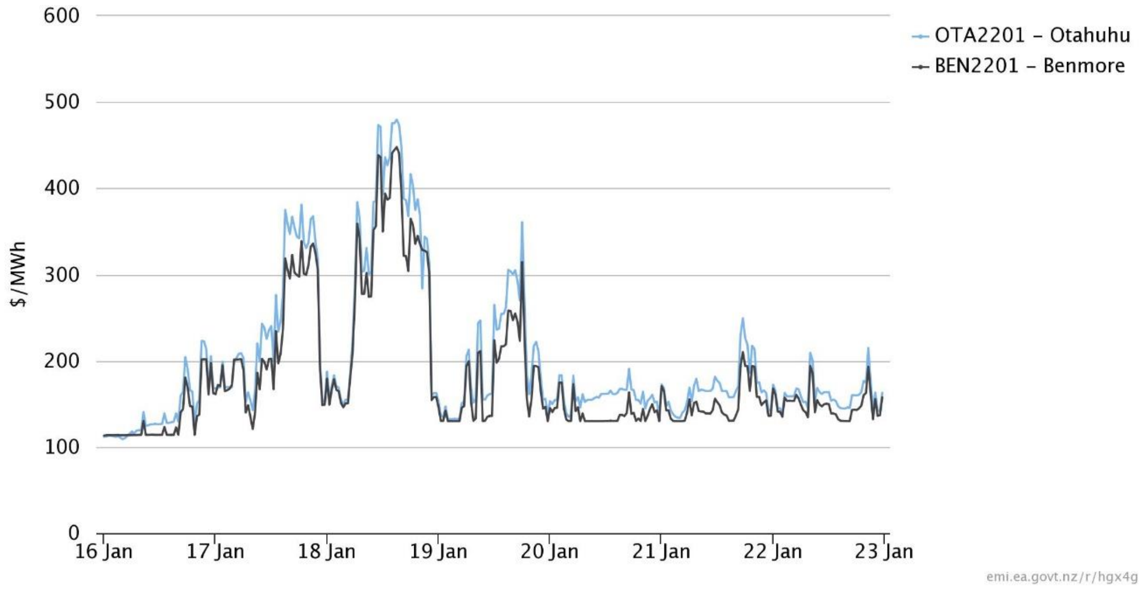
1.1. While supply and demand conditions, such as increased demand and low wind generation, have contributed to higher prices this week, further analysis will be done in relation to recent high prices, especially on 17 and 18 January.

2. Prices

Energy prices

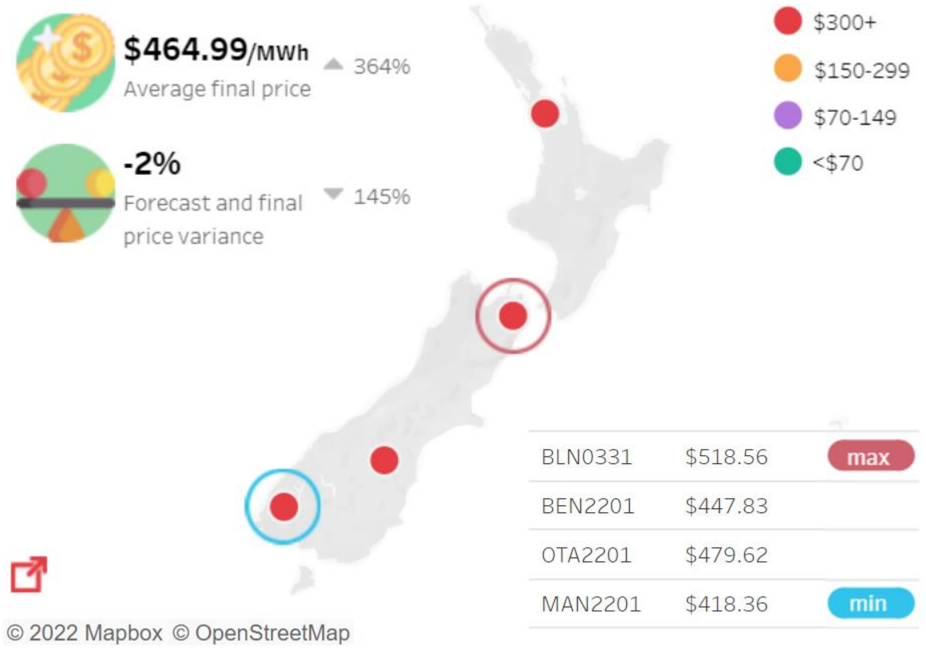
2.1. The average spot price this week was $191MWh[1], 32% higher than last week. Prices did not fall below $110/MWh this week and reached $479/MWh at Otahuhu on TP31 on 18 January (see Figure 2). Prices were highest from 17 to 19 January.

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

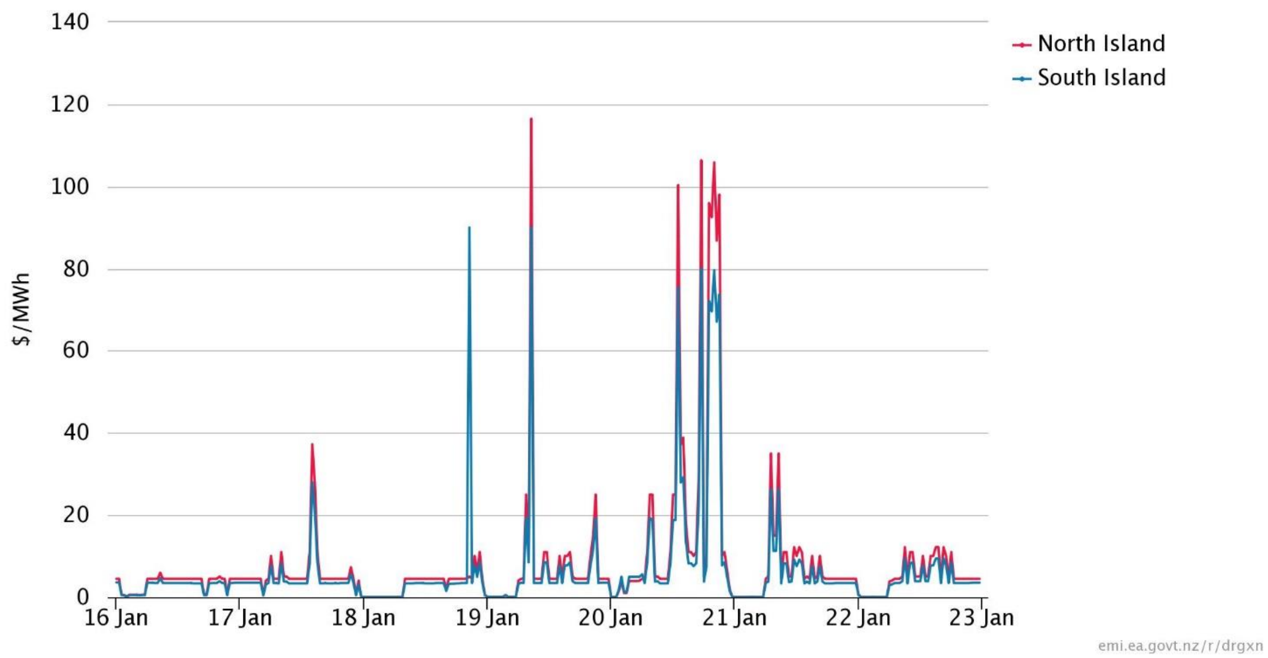
Figure 2: Spot prices for TP31 on 18 January compared to the previous week



Reserve Prices

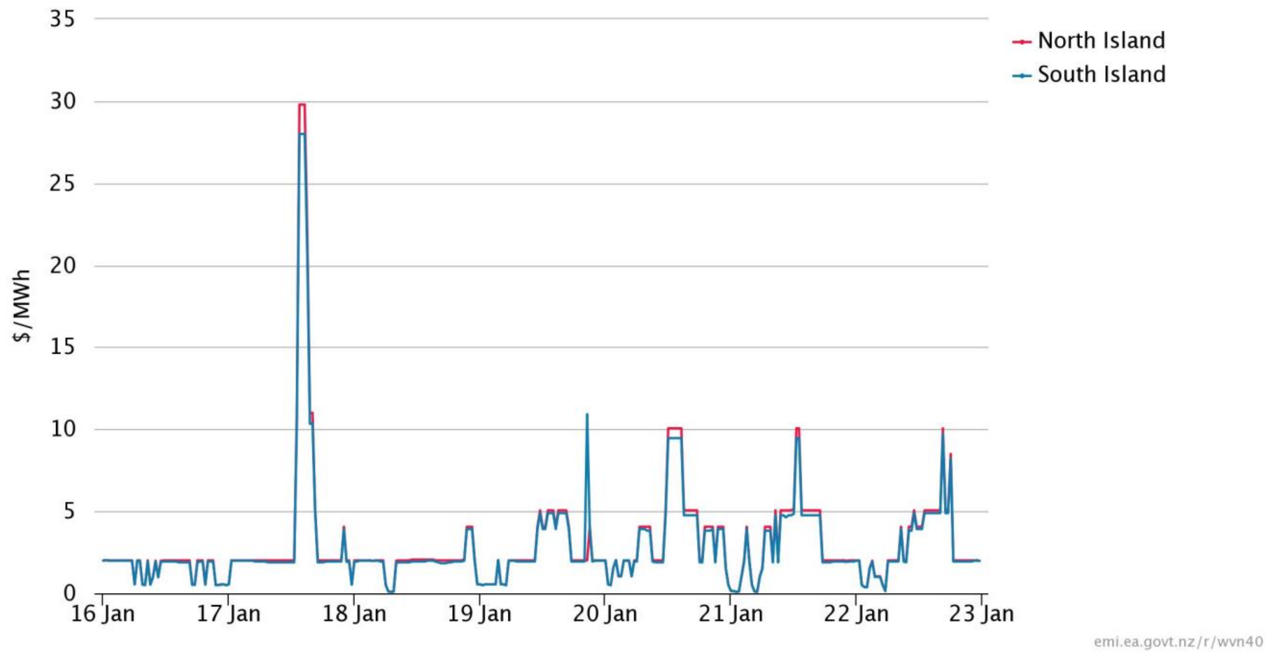
2.2. Fast instantaneous reserves (FIR) prices were higher this week, reaching prices between $80 and $120/MWh several times between 18 and 20 January. However, prices were usually below $10/MWh.

Figure 3: FIR prices by trading period and Island



2.3. Sustained instantaneous reserves (SIR) prices were usually below $11/MWh, with prices around $30/MWH from TP28 to TP30 on 17 January.

Figure 4: SIR prices by trading period and Island

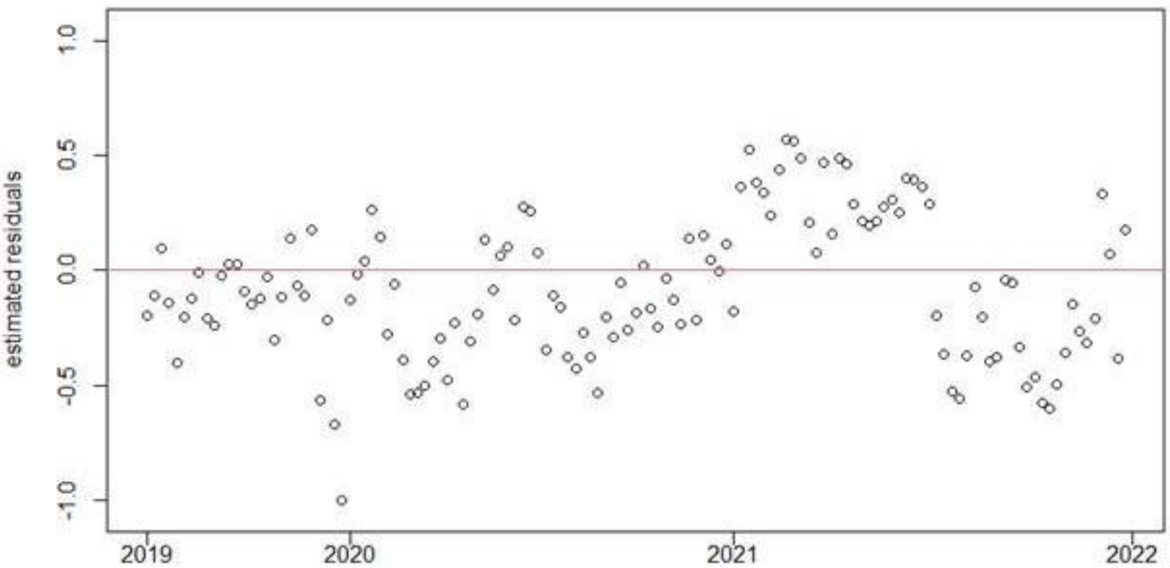


Residuals from regression models

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.

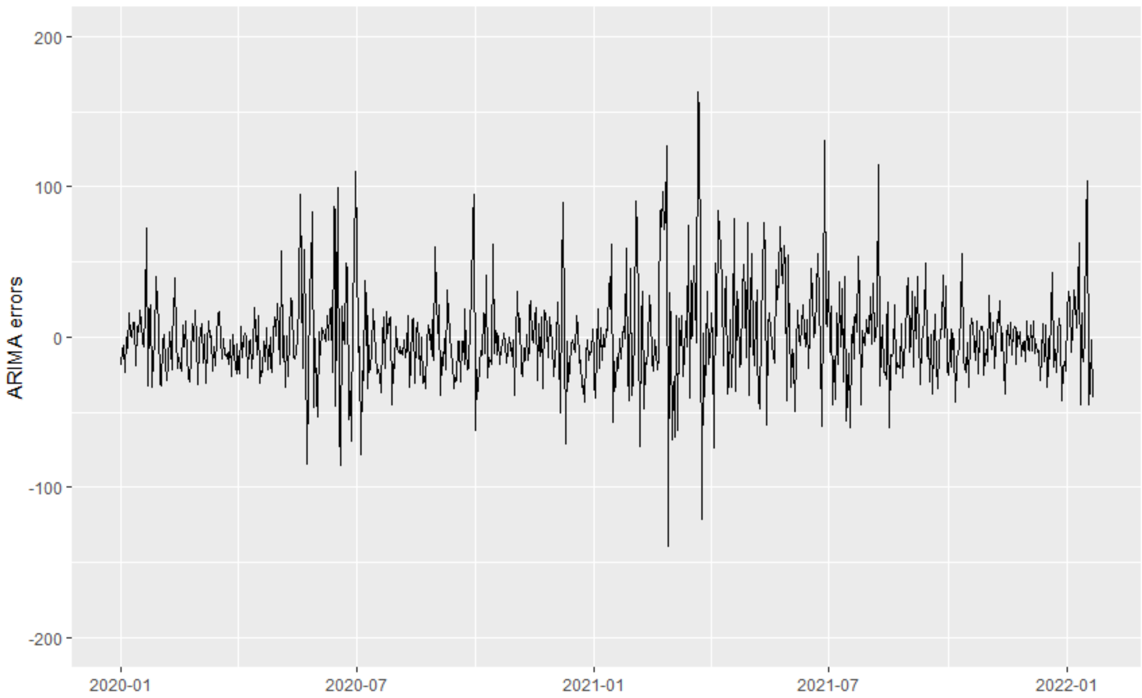
2.5. Figure 5 shows the residuals from the weekly model. During December 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 31 December 2021



2.6. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were larger on 17 and 18 January, indicating prices may warrant further analysis.

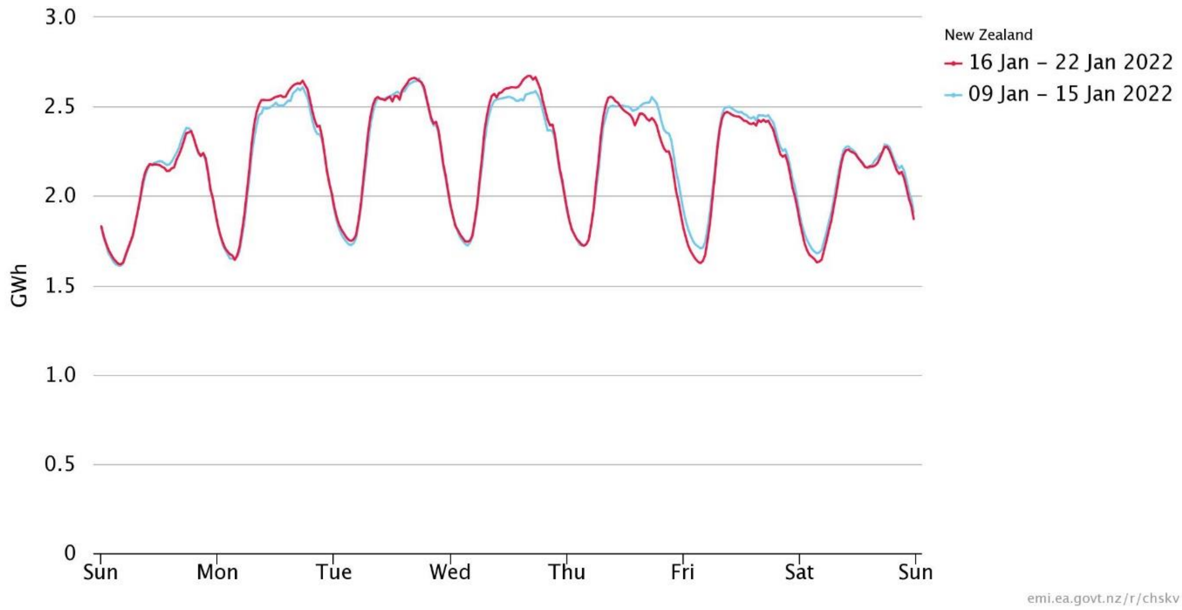
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 22 January 2022



3. Demand Conditions

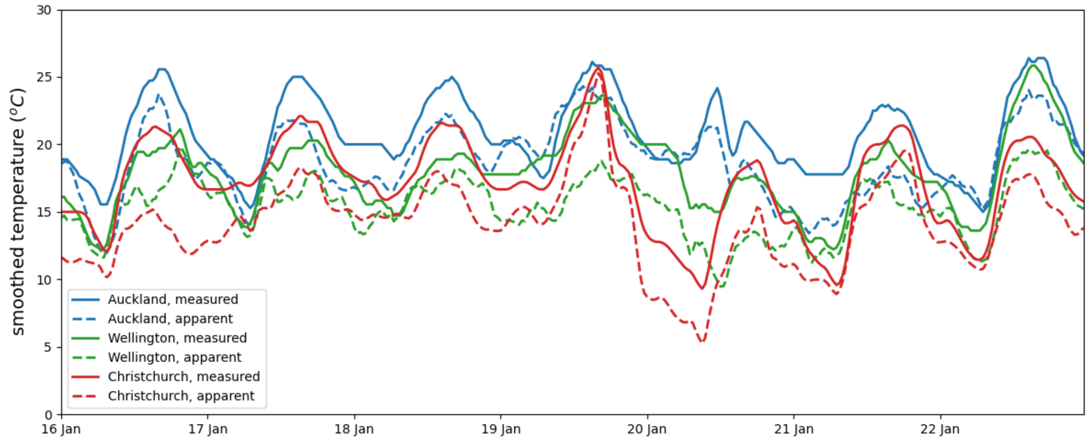
3.1. National demand was similar to the previous week (see Figure 7) and 2% higher than the same time last year. Demand was high from Monday to Wednesday, likely due to high temperatures in the main population centres (see Figure 8) and increased irrigation load. Demand dropped on Thursday as temperatures decreased.

Figure 7: National demand by trading period compared to the previous week



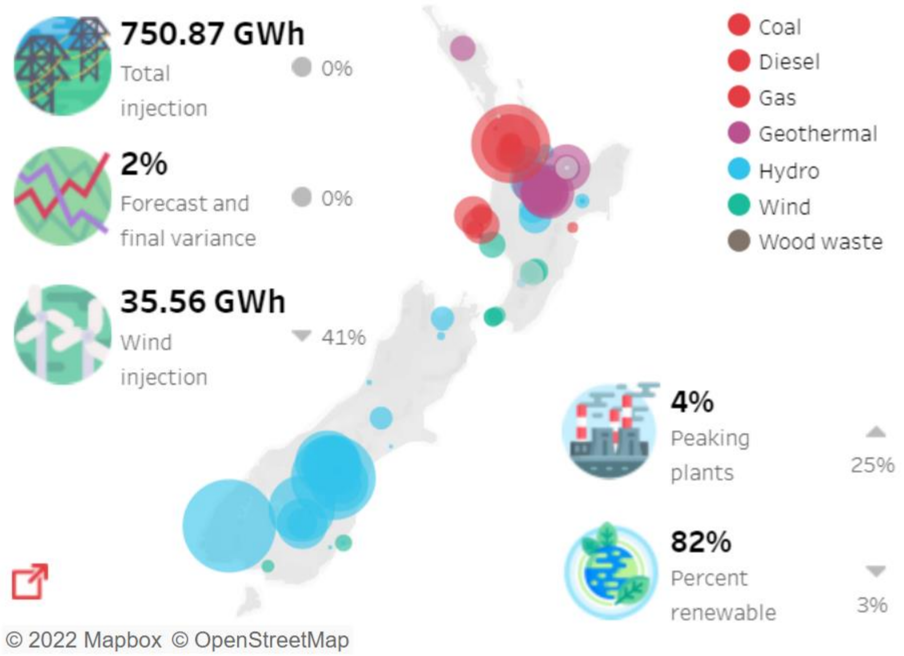
3.2. Figure 8 hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures were warmer during the first half of this week, particularly on Wednesday when temperatures reached 25°C in Christchurch and Auckland. Temperatures dropped on Thursday, particularly in Christchurch. Lower temperatures, as well as rainfall contributed to reduced irrigation load at the Ashburton GXP.

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



4. Supply Conditions

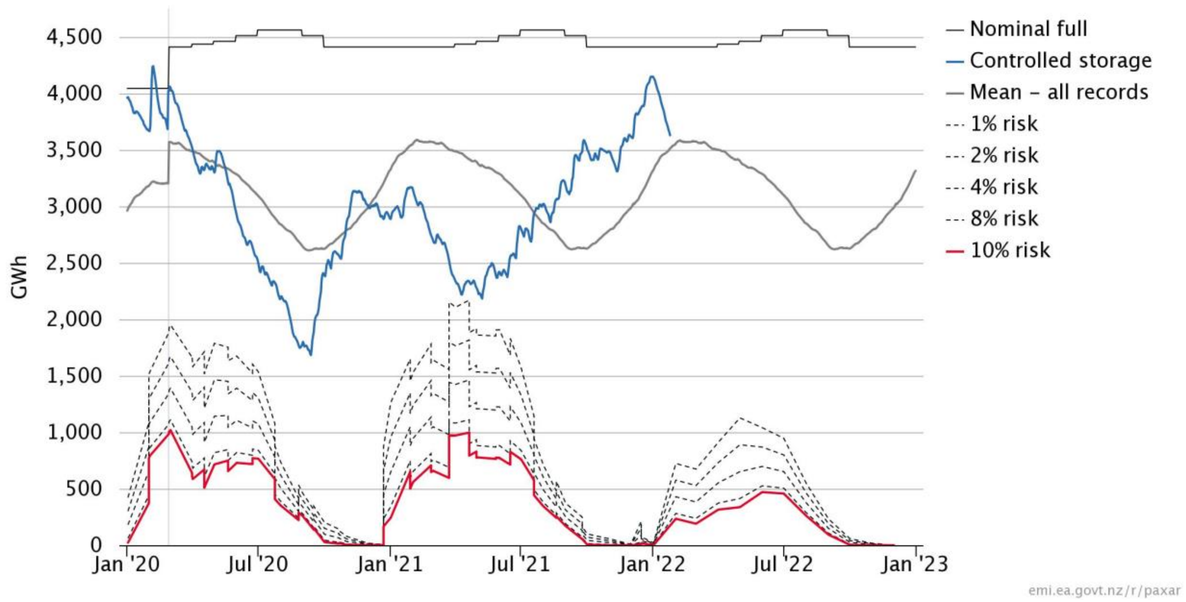
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage continued to decrease this week due to low inflows, shown in Figure 10. If inflows remain low, storage will likely fall below the average for this time of year within the next week.

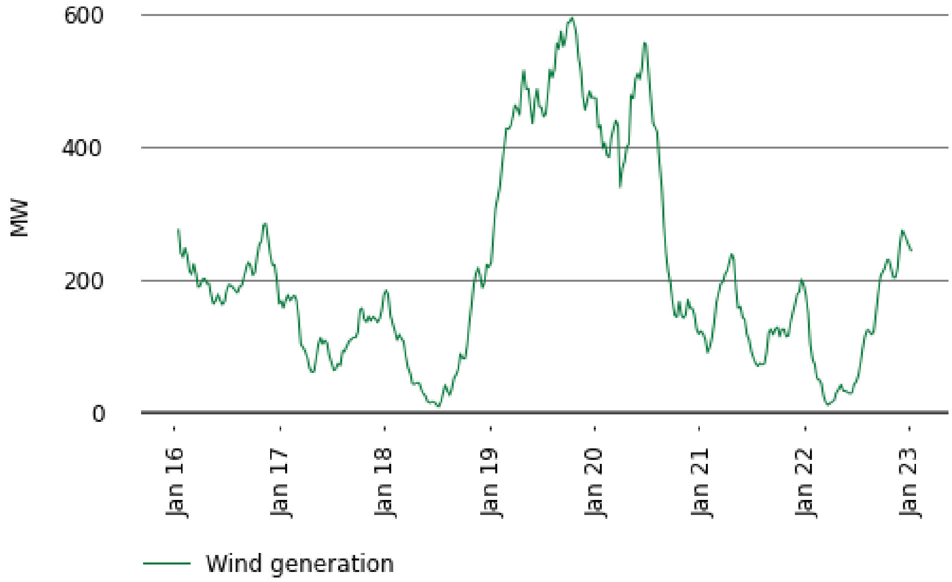
Figure 10: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 35.5GWh, 41% lower than last week. For most of the week wind generation was close to or below 200MW. However, wind generation was much higher on 19 and 20 January reaching up to 600MWH. The high prices which occurred on 17 and 18 January coincided with very low wind generation.

Figure 11: Wind generation by trading period



Significant outages

Generation outages

4.3. There was a high number of generation outages this week, especially in the lower South Island, where up to a quarter of hydro generation capacity was on outage. Some of the outages were likely coordinated to coincide with nearby transmission outages.

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

(a) Clyde,
- (i) 116MW (15 Feb 2021 – 20 May 2022)
- (ii) 116MW (10:00-17:00 18 January)
- (iii) 116MW (12:00-17:00 19 January)
- (iv) 116MW (12:00-16:00 20 January)

(b) Benmore,
- (i) 90MW (10-24 January)
- (ii) 90MW (15-16 January)
- (iii) 90MW (09:00-11:00 21 January)
- (iv) 90MW (08:00-14:00 22 January)

(c) Manapouri,
- (i) 125MW (17-18 January)
- (ii) 125MW (19-21 January)
- (iii) 125MW (13:00-15:30 19 January)
- (iv) 125MW (21-22 January)

(d) Tekapo,
- (i) 80MW (13 September 2021 – 16 January 2022)
- (ii) 80MW (17 January – 7 February)

(e) Tuai,
- (i) 40MW (8 November – 4 March)
- (ii) 71MW (16-28 January)
- (iii) 18MW (17 January – 11 February)

(f) Waipori, 80MW (8 November 2021– 11 February 2022)

(g) Aviemore, 55MW (08:00-16:00 20 January)

(h) Ohau,
- (i) 66MW (6am-3pm 18 January)
- (ii) 66MW (18-19 January)
- (iii) 55MW (11:00-13:30 21 January)

(i) McKee,
- (i) 50MW (18-20 January)
- (ii) 50MW (06:00-18:00 21 January)
- (iii) 50MW (06:00 – 19:00 22 January)

(j) Roxburgh,

   (i) 40MW (11-17 January)

   (ii) 50MW (11-20 January)

   (iii) 40MW (17-18 January)

   (iv) 40MW (17-28 January)

   (v) 40MW (19-20 January)

(k) TCC, 350MW, (22 January – 28 February)

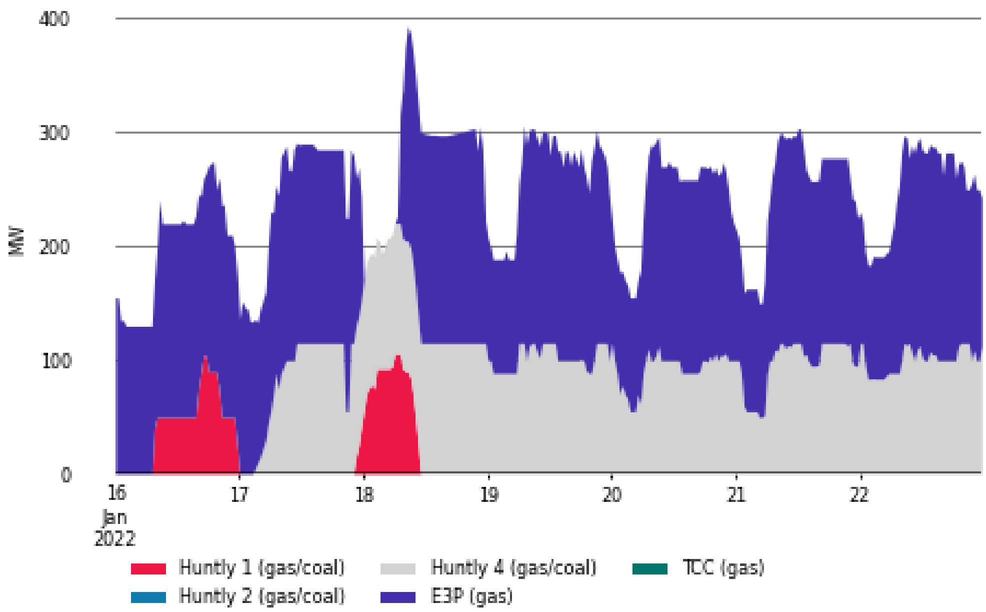
(l) Huntly, Rankine, 240MW (20 December 2021 – 31 January 2022)

(m) Stratford peakers, 100MW, (31 October 2021 – 30 April 2022)

Thermal conditions

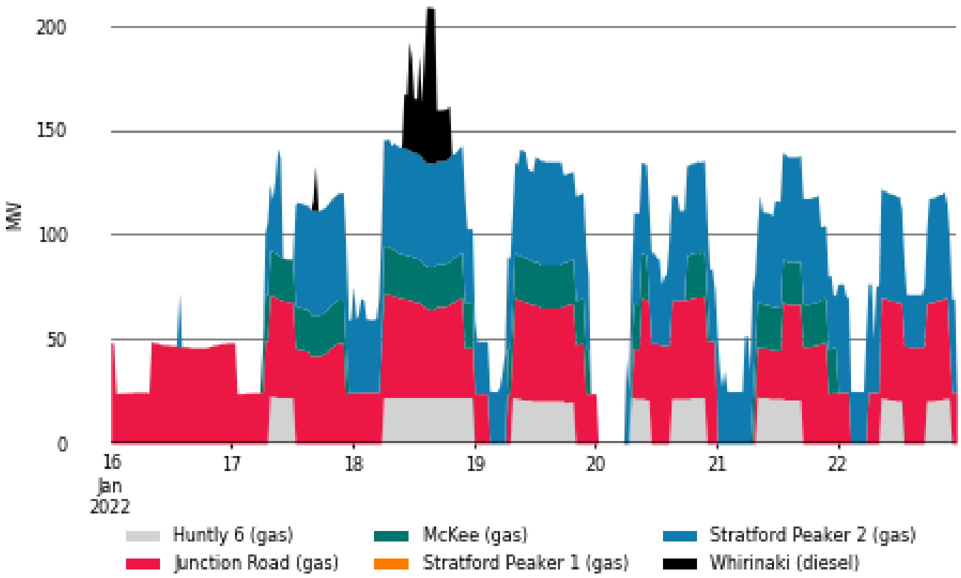
4.5. This week the E3P and Huntly 1 ran for most of the week as thermal baseload, with Huntly 1 running when one of the other two was not dispatched. There was a brief period in the morning of 18 January when all three were running.

Figure 12: Generation from baseload thermal by trading period



4.6. Thermal peakers were running for most of this week, especially Junction Road and Stratford Peaker 2. All the available thermal peakers were running on 18 January, with Whirinaki, a high-cost generator, running for a significant portion of the day. There was less use of thermal peakers later in the week due to increased wind and lower demand (from 20 January).

Figure 13: Generation from thermal peakers by trading period



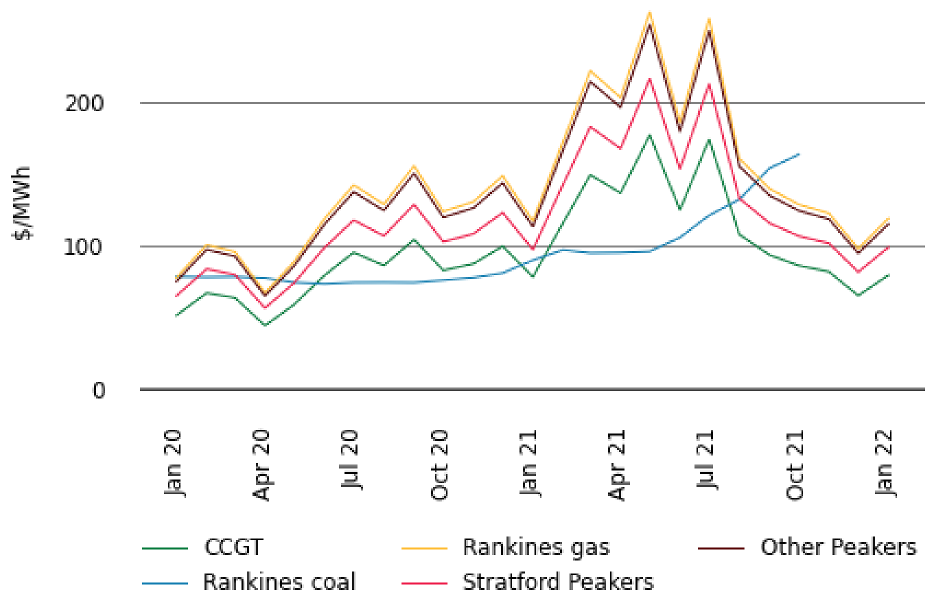
5. Price versus estimated costs

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 14 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January (to 22 January), likely due to a recent increase in gas consumption. The SRMC of coal has been increasing due to global supply and demand conditions. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal. The carbon price has continued to increase this year, reaching $75/tonne on 21 January.

Figure 14: Estimated monthly SRMC for thermal fuels

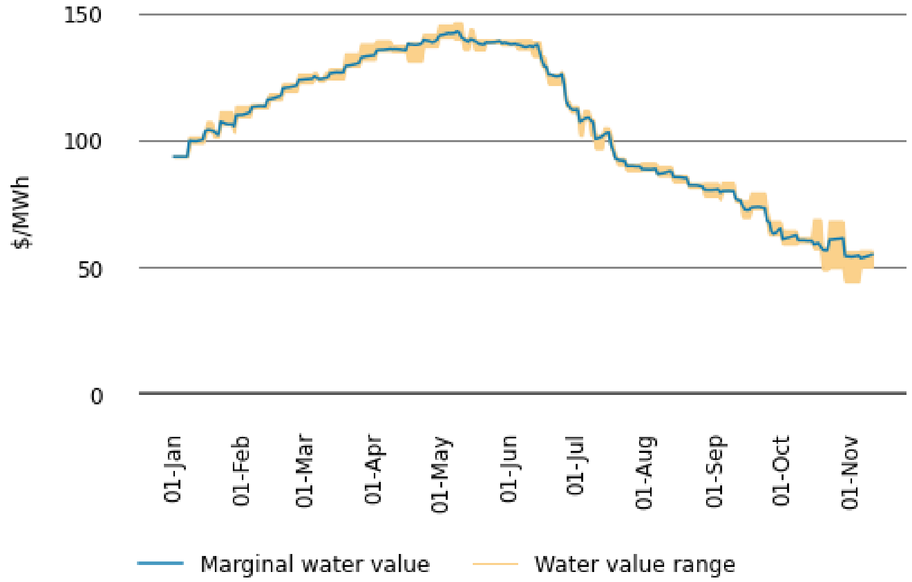


DOASA Water values

5.3. The DOASA[2] 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 values[3] 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[4]. Figure 15 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased. We expect that the marginal water value has increased recently due to decline storage levels and increase gas costs.

[2] 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)
[3] The national water values are estimated assuming all hydro storage reservoirs are equally full.
[4] See Appendix B, 2 for more details

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.

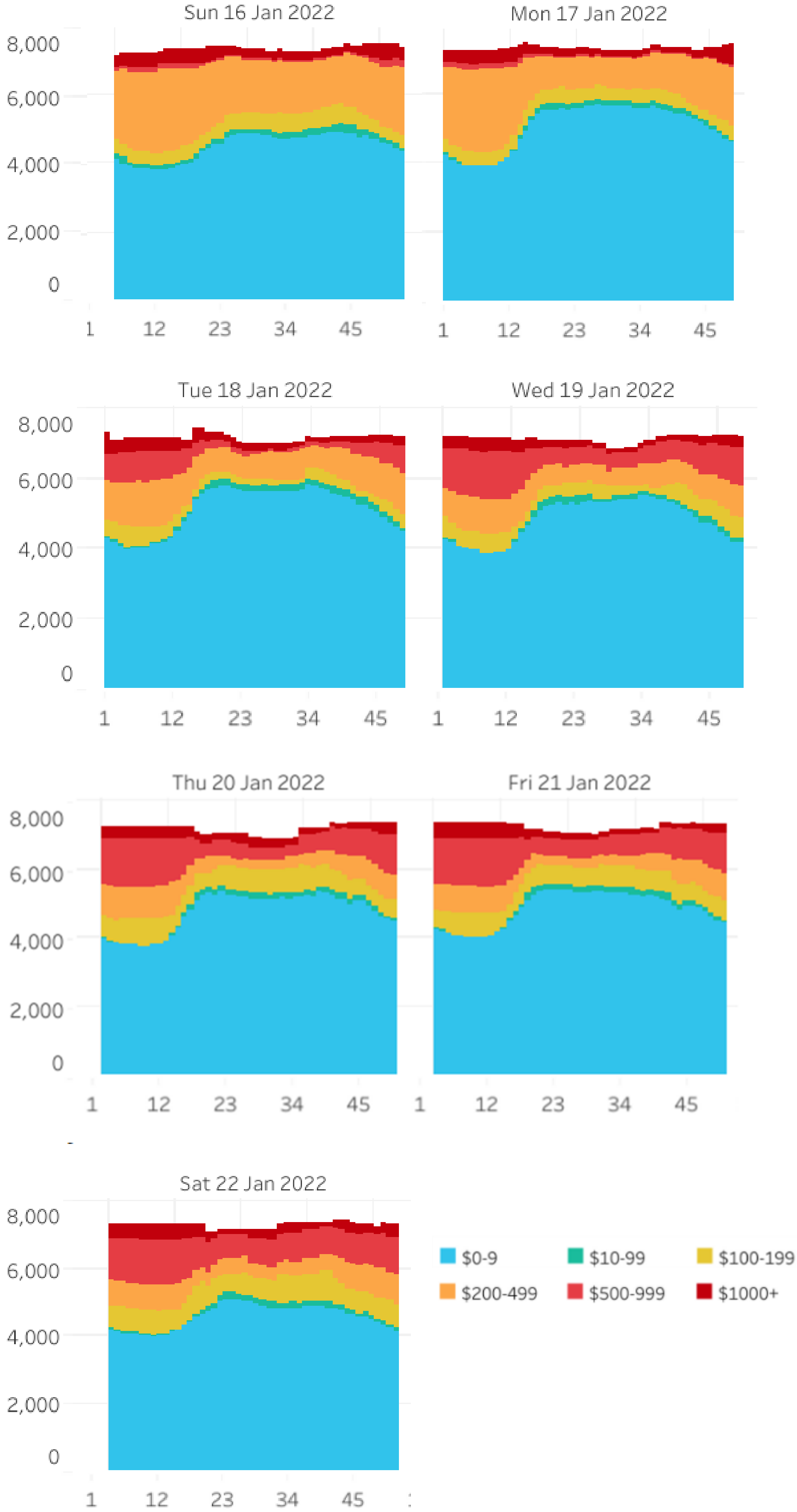
Figure 16: Average monthly prices at Otahuhu and Benmore 2021

Offer Behaviour

Final daily offer stacks

5.5. Figure 17 shows this week's raw daily final offer stacks. The offer stacks show all offers bid into the market in price bands. Note that these offer stacks have not been adjusted to account for actual wind generation or for capacity dispatched as reserve.

Figure 17: Daily offer stack



5.7. The shape of the offer stack has changed this week, more generation was offered between $100-199/MWh and above $500/MWh with less generation offered between $200-499/MWh. This has likely been due to the combined impact of falling hydro storage and increased availability of thermal generation. This resulted in prices between $100-$199/MWh with large price jumps when demand has been high and wind generation low.

Ongoing Work in Trading Conduct

5.8. Some trading periods have been identified for further analysis, particularly to understand high energy prices on 17 and 18 January and high FIR prices on 19 and 20 January.

5.9. The Authority's market monitoring team has received additional information regarding recent high energy prices. This information is currently being reviewed.

5.10. The Authority's compliance team has obtained information regarding withdrawn reserve offers and high energy prices. Further clarification and analysis is under way to consider compliance with the Code.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
19/01-20/01	Several	Further Analysis	High FIR prices
17/01-18/01	Several	Further Analysis	High energy prices
10/01-11/01	Several	Further Analysis	Prices over $300/MWh, increase in outages – further information being reviewed
02/01-08/01	Several	Further Analysis	High energy prices, low wind, low demand
30/06-20/08	Several	Compliance enquiries in progress	High energy prices in shoulder periods
30/06-21/08	Several	Compliance enquiries in progress	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[5], where diff is the first difference:

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

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

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 $(storage_t - 20.year.mean.storage_{dayofyear})$

Appendix B DOASA water value model

1. DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[6] DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[7] 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

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

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.[7]

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 (i.e., not using water proportional to total national storage by either holding back or letting it all go).

---

[6] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.
[7] 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