2 February 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 23 to 29 January

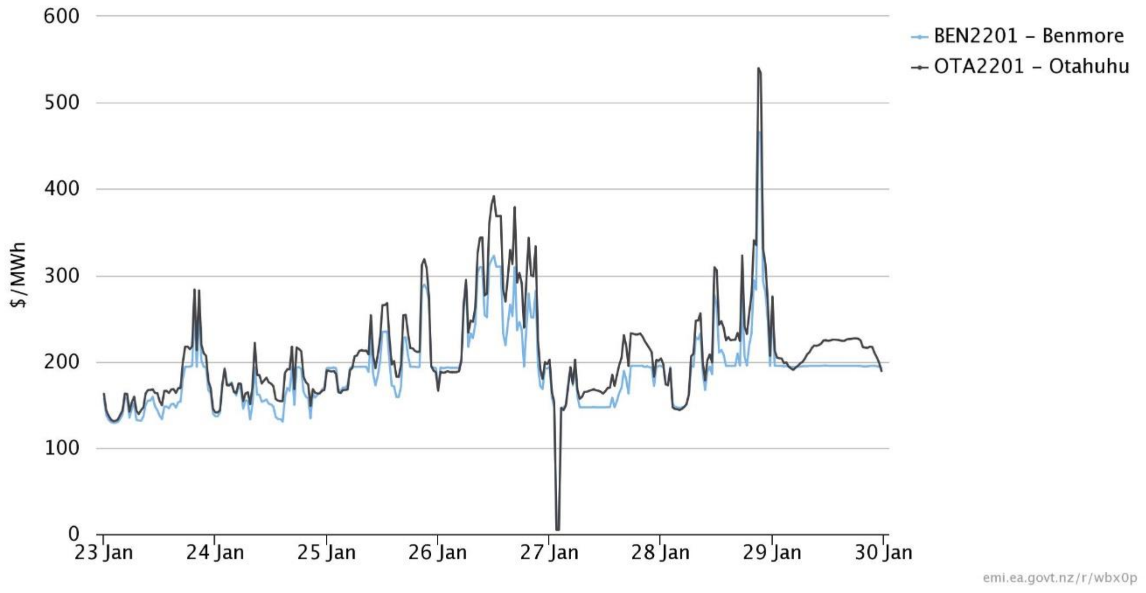
1.1. There is no evidence of unusual trading activity over the last week and high prices appear to have instead been driven by underlying supply and demand conditions, such as low wind generation, high demand and significant outages.

2. Prices

Energy prices

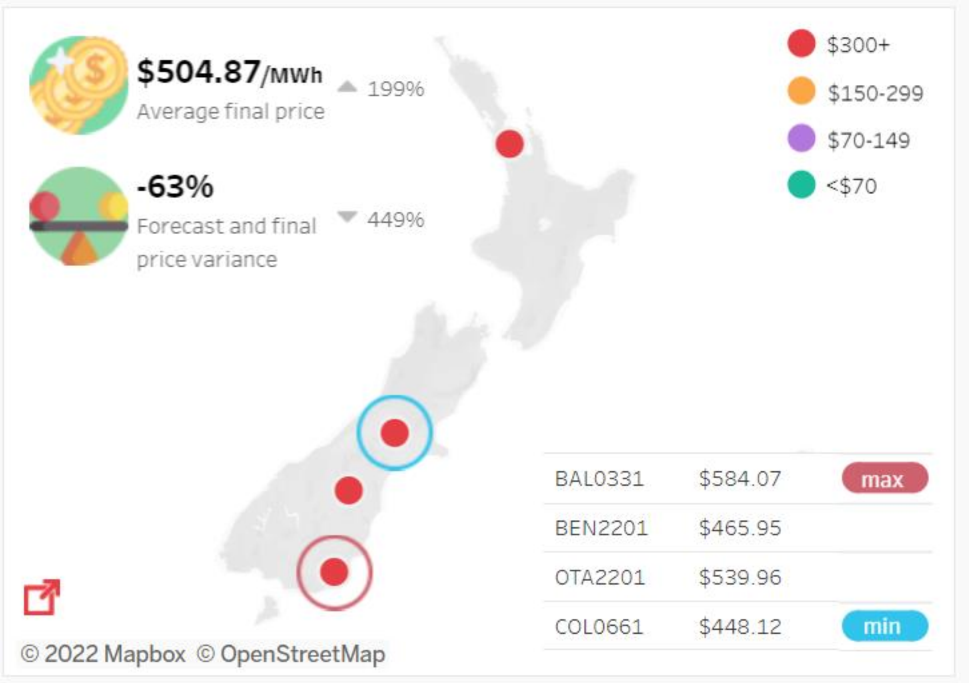
2.1. The average spot price this week was $202MWh[1], 6% higher than last week. This week prices rarely fell below $150/MWh. Prices were regularly between $300-$400/MWh on 26 January, though the highest price $540/MWh at Otahuhu occurred on TP43 on 28 January (see Figure 2).

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

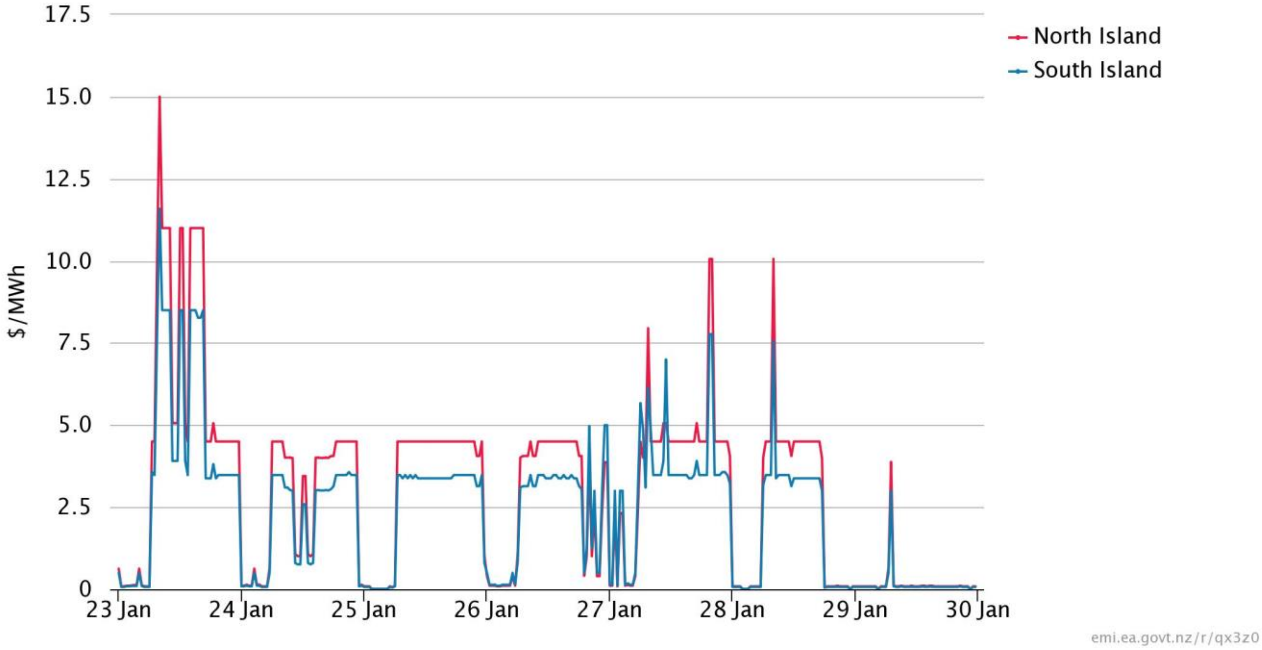
Figure 2: Spot prices for TP31 on 18 January compared to the previous week



Reserve Prices

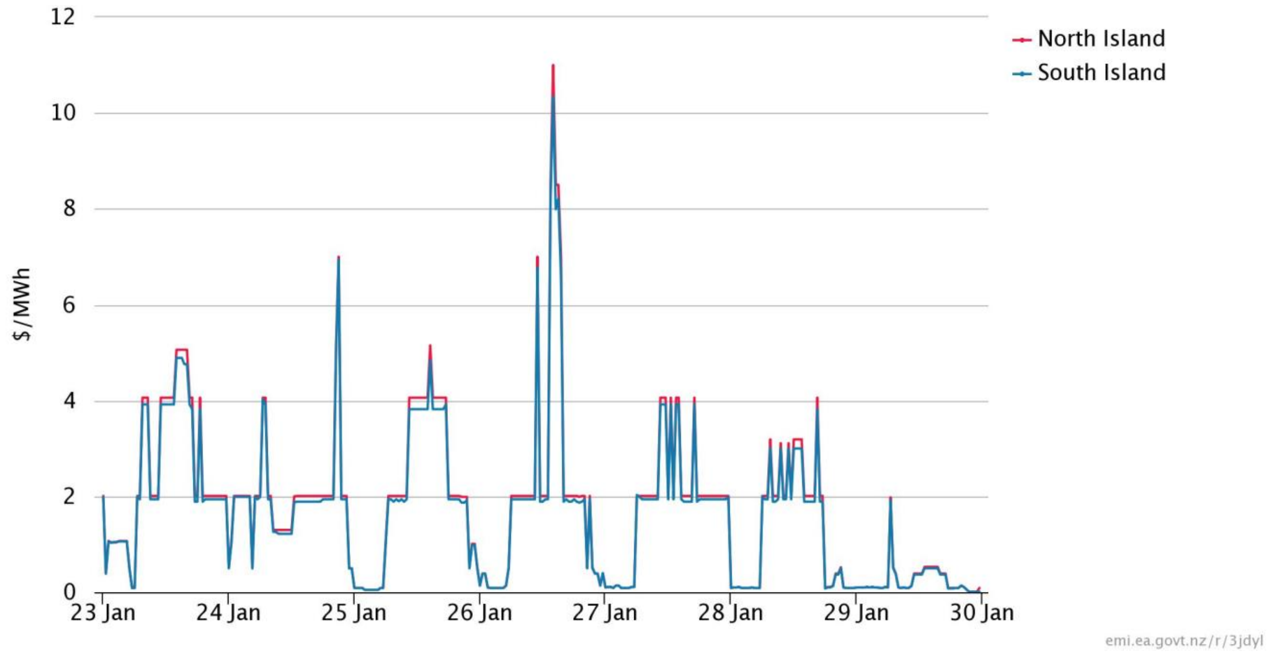
2.2. Fast instantaneous reserves (FIR) prices were below $15/MWh and usually below $5/MWh.

Figure 3: FIR prices by trading period and Island



2.3. Sustained instantaneous reserves (SIR) prices were below $12/MWh, with prices frequently below $5/MWh.

Figure 4: SIR prices by trading period and Island

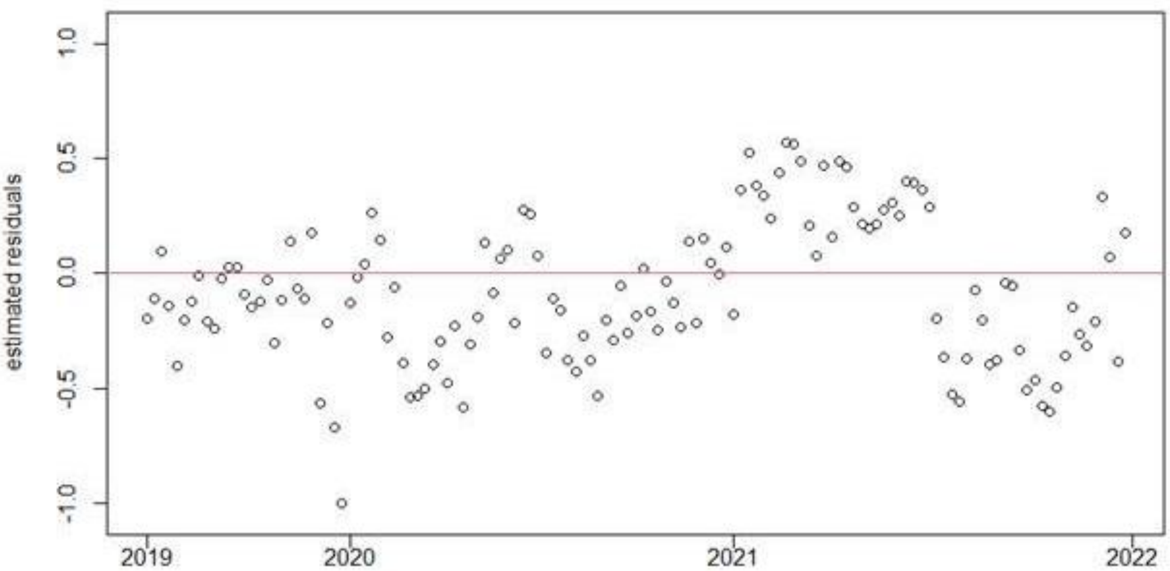


Residuals from regression models

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.

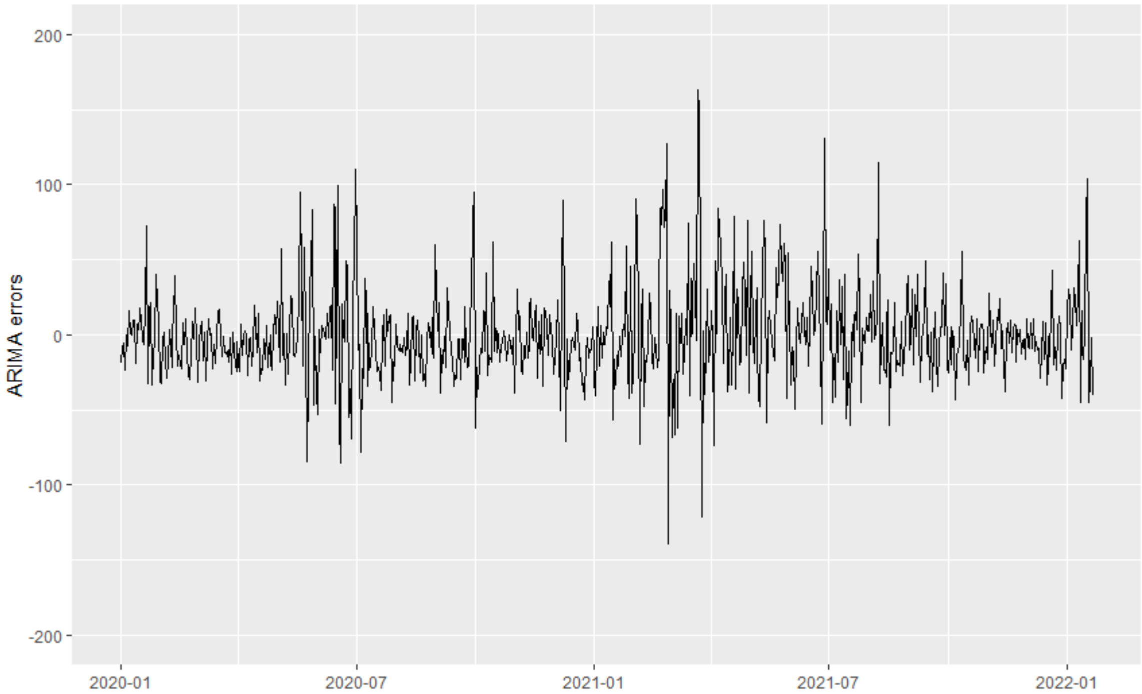
2.5. Figure 5 shows the residuals from the weekly model. During December 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

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.

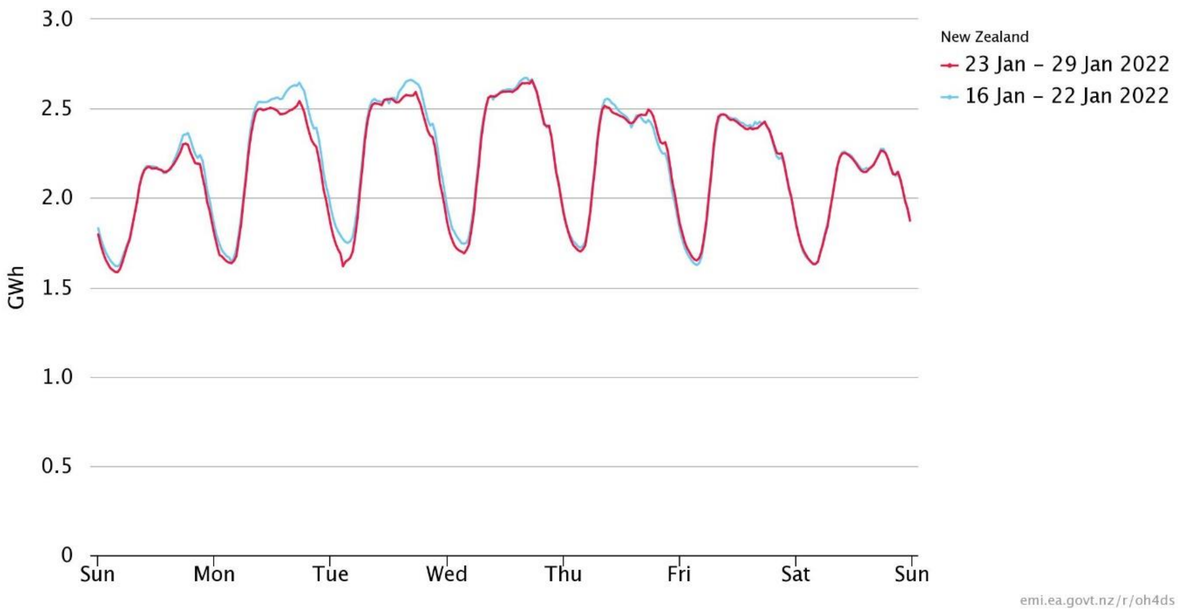
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 22 January 2022



3. Demand Conditions

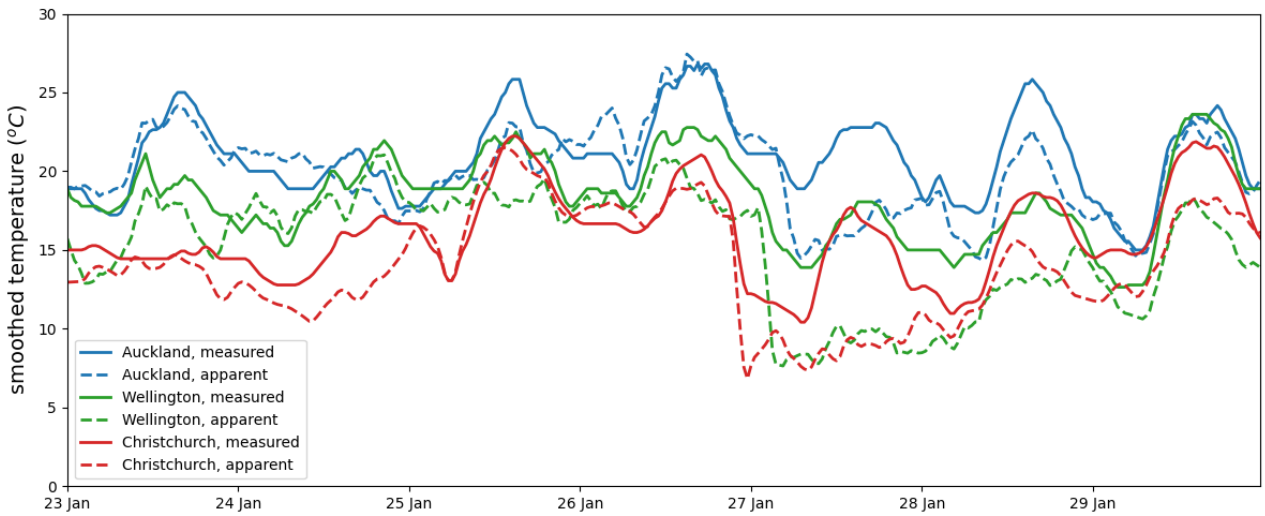
3.1. National demand was 1% lower than the previous week (see Figure 7). The drop in demand may have been due to moving to the red traffic light setting at 11:59pm on January 23 under the Covid-19 Protection Framework. Lower demand on Monday was also due to Wellington Anniversary Day, which impacted demand in lower North Island. Demand was highest on Wednesday due to high temperatures, similar to last week (see Figure 8).

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



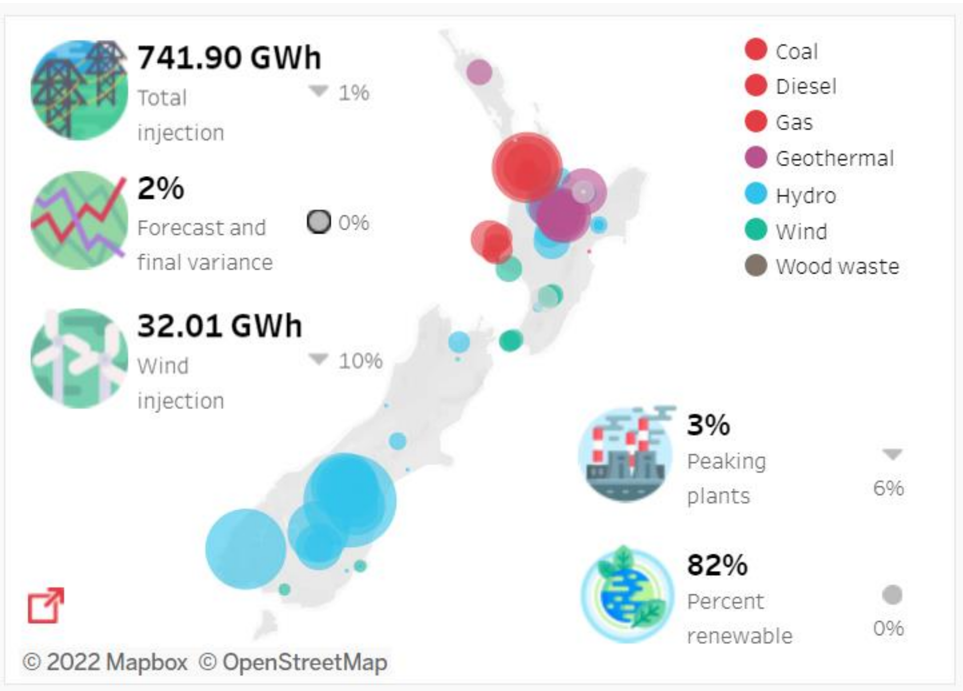
3.2. Figure 8 hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures were warmer during the first half of this week, particularly on Wednesday when temperatures reached over 25°C in Auckland. Temperatures dropped on Thursday, particularly in Christchurch. Rainfall and lower temperatures contributed to reduced irrigation load at the Ashburton GXP on 28 and 29 January.

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



4. Supply Conditions

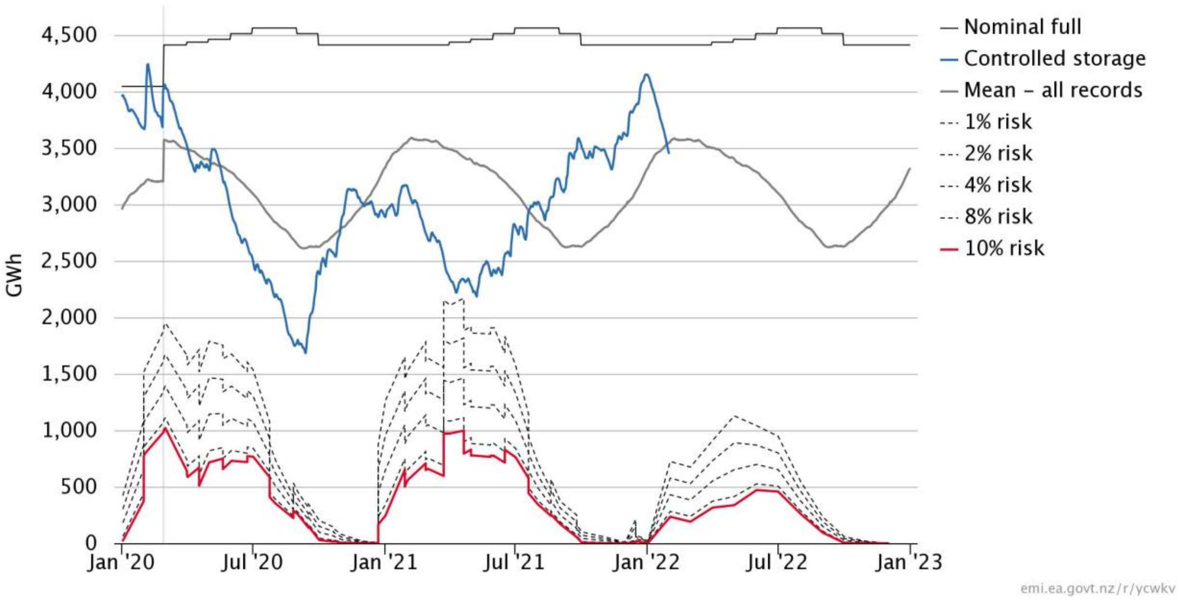
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage continued to decrease this week due to low inflows, shown in Figure 10, and is now below the mean for this time of year. While some lakes are still above their mean for this time of year, Meridian announced that Manapouri's lake level was close to its low operating range on 28 January[2].

Figure 10: Electricity risk curves and hydro supply

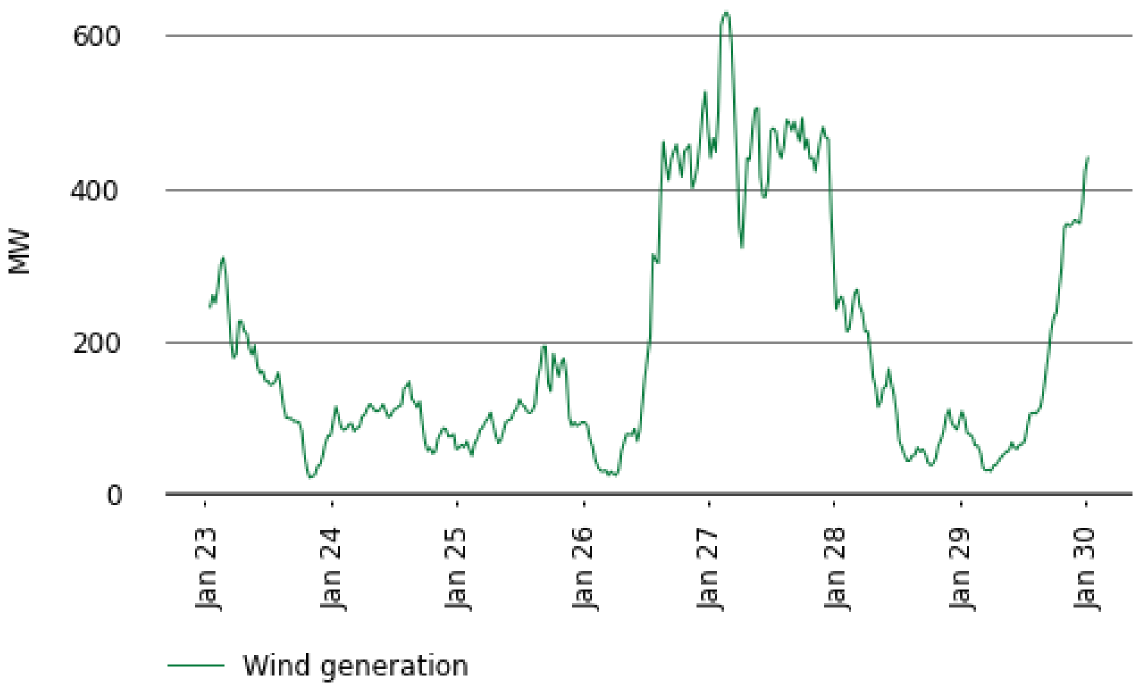


Wind conditions

4.2. Total wind generation was 32GWh, 10% lower than last week. Wind generation was below 200MW for much of the week and was particularly low on the morning of 26 January, contributing to high prices. Wind generation picked up later in the day and stayed high before falling on morning on 28 January, with low wind contributing to the high prices on the evening on 28 January.

[2] See announcement with details of restrictions here Lake Manapouri levels update | Meridian Energy

Figure 11: Wind generation by trading period

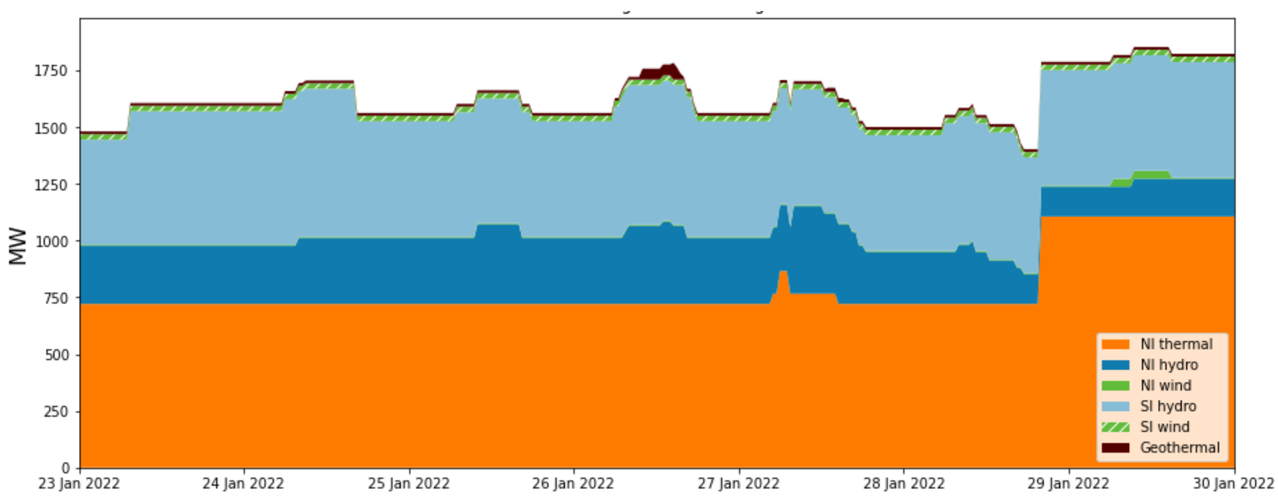


Significant outages

Generation outages

4.3. There is a high amount of generation on outage this week at over 1500MW (see Figure 12). This is due to significant hydro and thermal generation outages. The amount of MWs on outage was particularly high on 26 January when Kawerau geothermal outages reduced baseload generation by up to 90MW. The E3P at Huntly also went on outage on evening of 28 January until morning of 31 January, due to the Maui pipeline outage, which reduced available thermal generation by a further 385MW over the weekend.

Figure 12: Total MW loss due to generation outages



4.4. These are the more significant ongoing outages[3]:

(a) Clyde, 116MW (15 Feb 2021 – 20 May 2022)

[3] Detailed outage information is available from https://pocp.redspider.co.nz/

(b) Manapouri, 125MW (23 January – 4 February)

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

(d) Huntly, Rankine 2, 240MW (20 December 2021 – 2 February 2022)

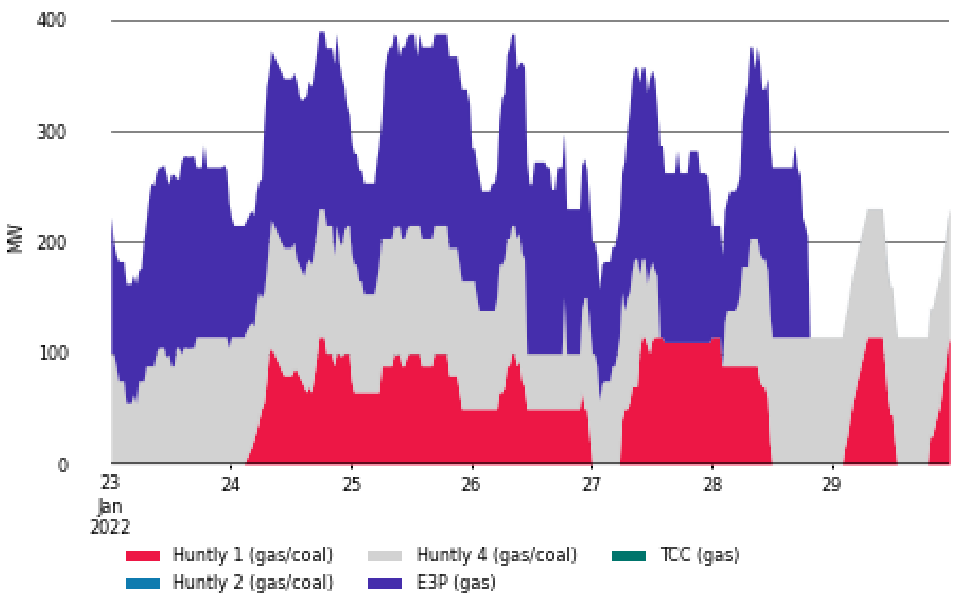
(e) Huntly. E3P, 385MW (28-31 January)

(f) Stratford peaker, 100MW, (31 October 2021 – 30 April 2022)

Thermal conditions

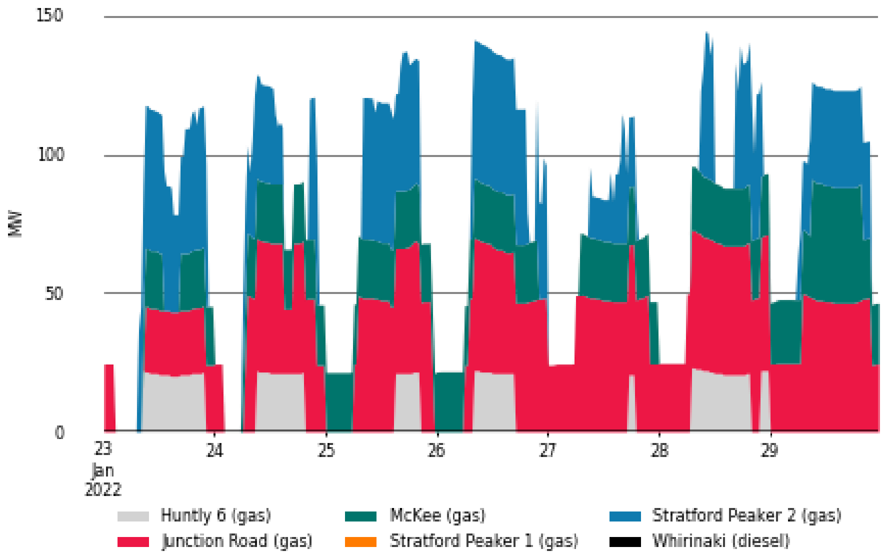
4.5. This week the E3P continued running as baseload but shut down around 9pm on Friday evening due to an outage of the Maui Pipeline to undertake repairs. The outage reduced available gas in the upper North Island, and other large gas users also shut down for the duration, including the Te Rapa co-generator plant. The highest price this week coincided with E3P turning off, with higher cost generation, mostly North Island hydro, dispatched to make up for the shortfall. The Rankine units did not shut down as they can be fuelled by coal, however their output continues to be subject to river temperatures.

Figure 13: Generation from baseload thermal by trading period



4.6. Thermal peakers were running for most of this week, especially Junction Road, McKee and Stratford Peaker 2.

Figure 14: Generation from thermal peakers by trading period



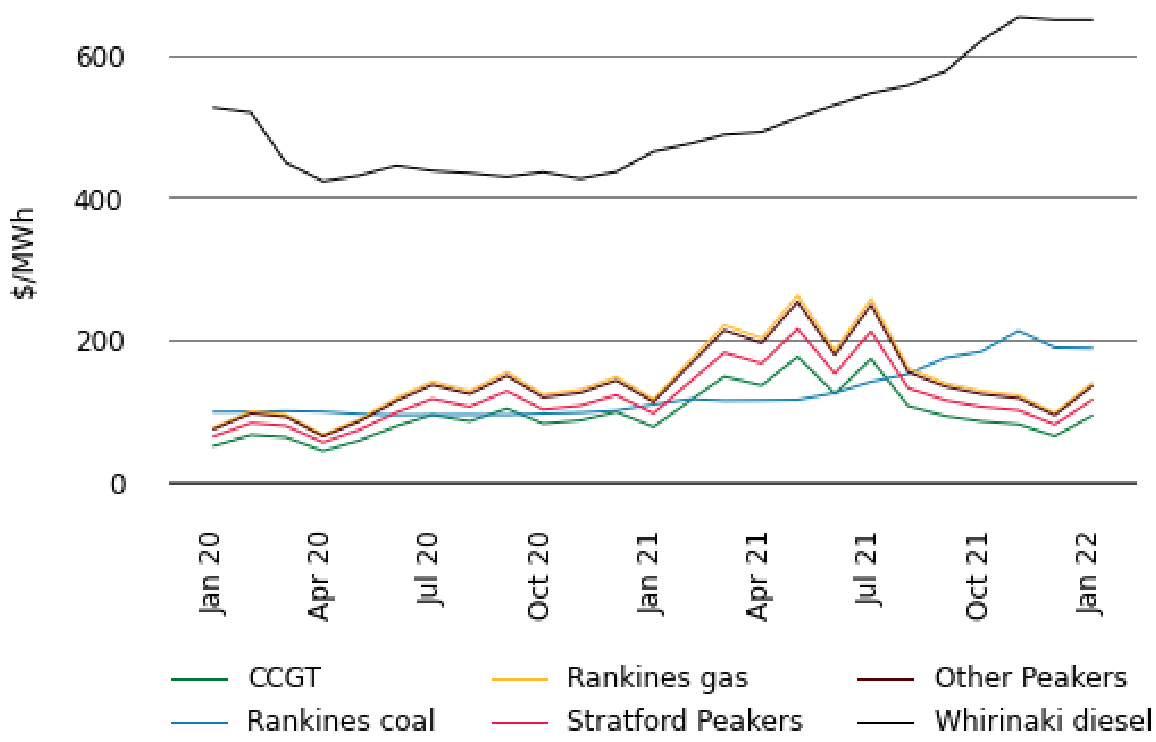
5. Price versus estimated costs

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 15 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January (to 30 January), likely due to a recent increase in gas consumption. The SRMC of coal and diesel both increased to a recent high in November 2021 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 and diesel. The carbon price has continued to increase this year, reaching $75/tonne on 21 January.

Figure 15: Estimated monthly SRMC for thermal fuels



DOASA Water values

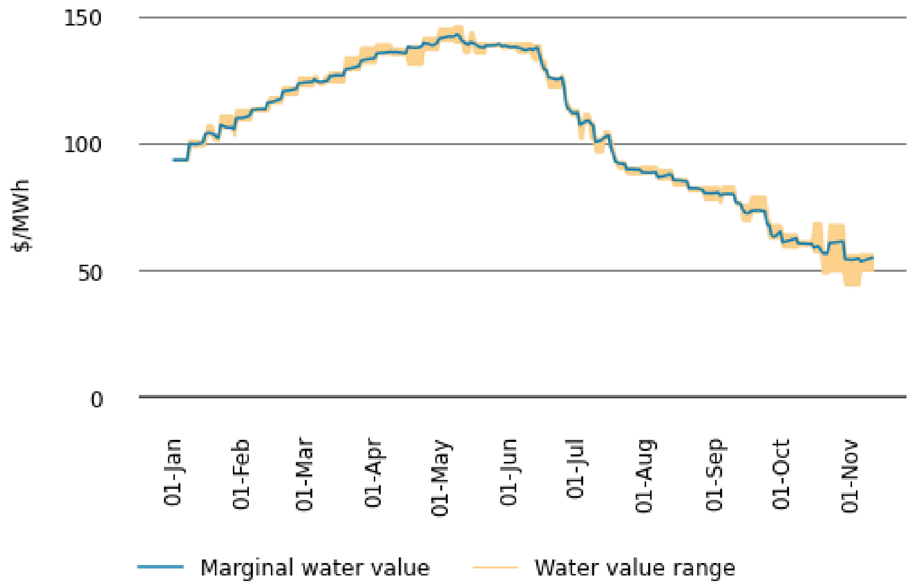
5.3. The DOASA[4] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 16 shows the national water values[5] obtained 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. We expect that the marginal water value has increased recently due to decline storage levels and increase gas costs.

[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

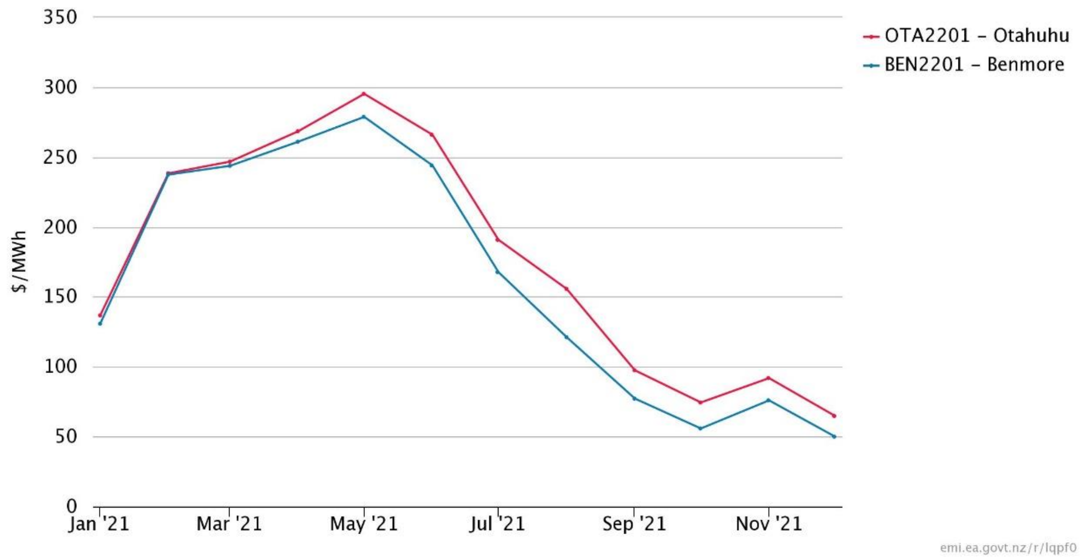
Figure 16: DOASA water values for January- to November 2021



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.

Figure 17: Average monthly prices at Otahuhu and Benmore 2021



Offer Behaviour

Final daily offer stacks

5.5. Figure 18 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 18: Daily offer stack

5.6. The offer stack at the start of the week was similar to last week with high more generation offered between $100-$199/MWh. There was a noticeable decrease in total generation offered on 26 January due to outages, with less generation offered under $10/MWh to above $500/MWh. From Thursday onwards there was a decline in generation offered at low prices and total generation offered over $350/MWh increased from 15% on Monday and Tuesday to 22-23% on Thursday and Friday. Total generation offered also dropped on Friday evening due to the E3P outage.

5.7. The change in offers this week was due to declining hydro storage, particularly at Manapouri, where Meridian shifted offered generation into higher offer tranches to reduce drawdown of the lake to within their operating guidelines.

Ongoing Work in Trading Conduct

5.8. No trading periods have been identified for further analysis this week.

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[7], 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.

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[7] 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.[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 (i.e., 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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[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.

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