16 February 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 6 to 12 February

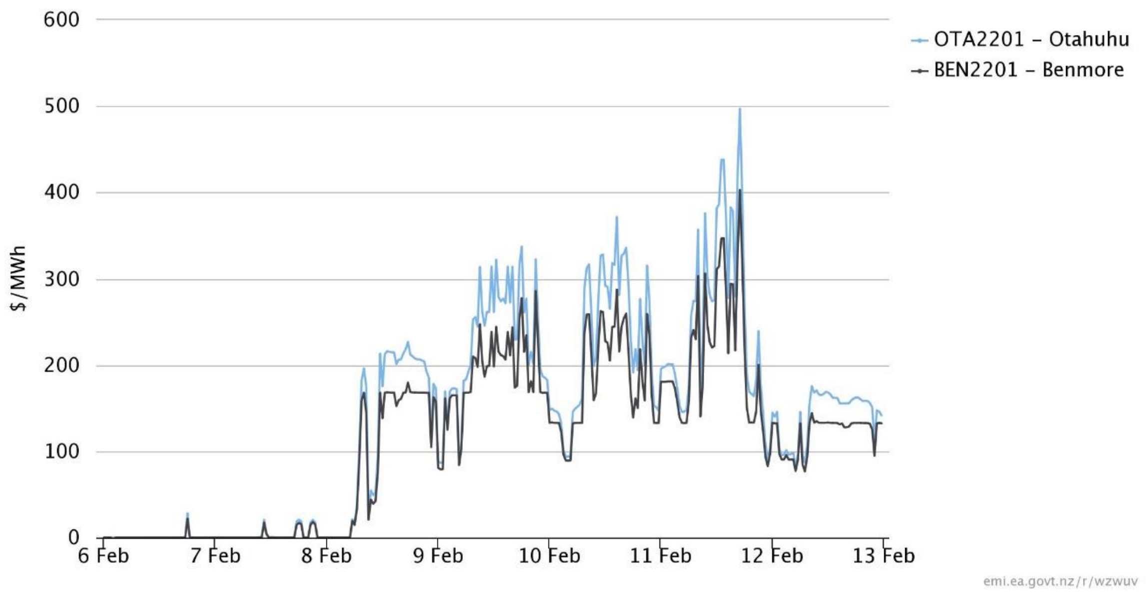
1.1. Low prices at the beginning of this week are consistent with the high supply and low demand conditions that occurred. However, while supply and demand conditions explain some of the price increase later in the week, further analysis will be done to understand why high prices persist considering recent hydro inflows.

2. Prices

Energy prices

2.1. The average spot price this week was $81MWh[1], 61% lower than last week. Prices were under $20/MWh on 6 and 7 February but increased to above $100/MWh for most of the rest of the week (see Figure 1). Prices were highest on 11 February, reaching $497/MWh at Otahuhu for TP35.

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

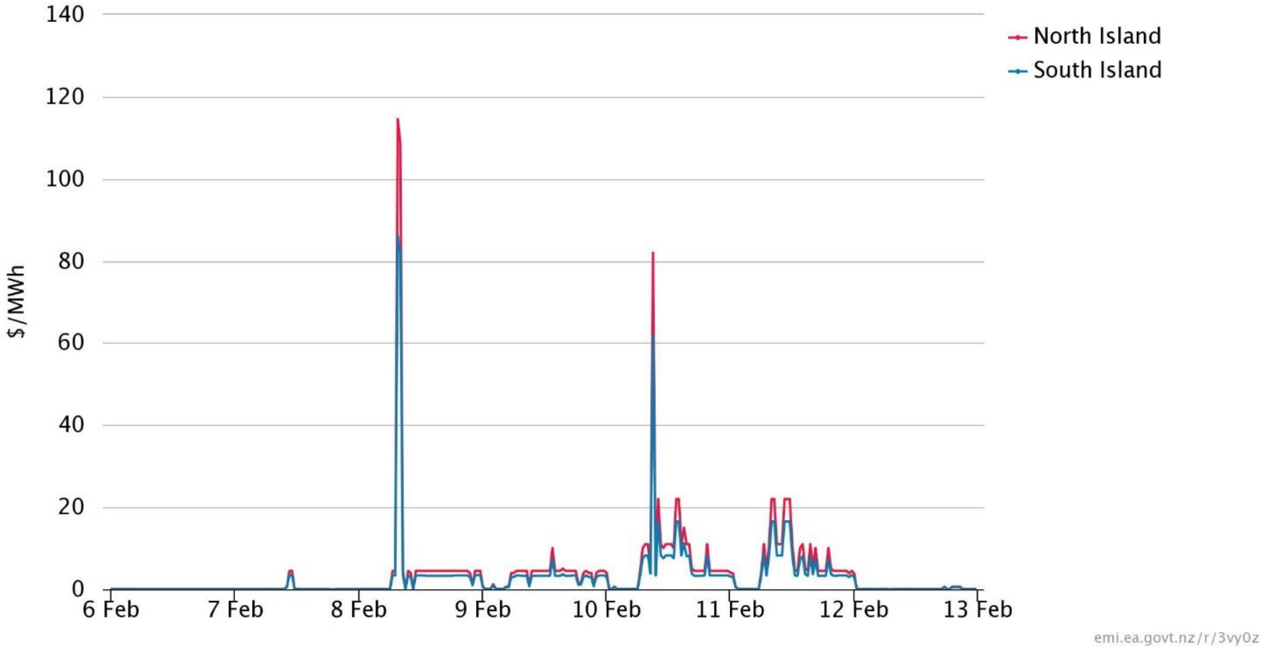


[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

Reserve Prices

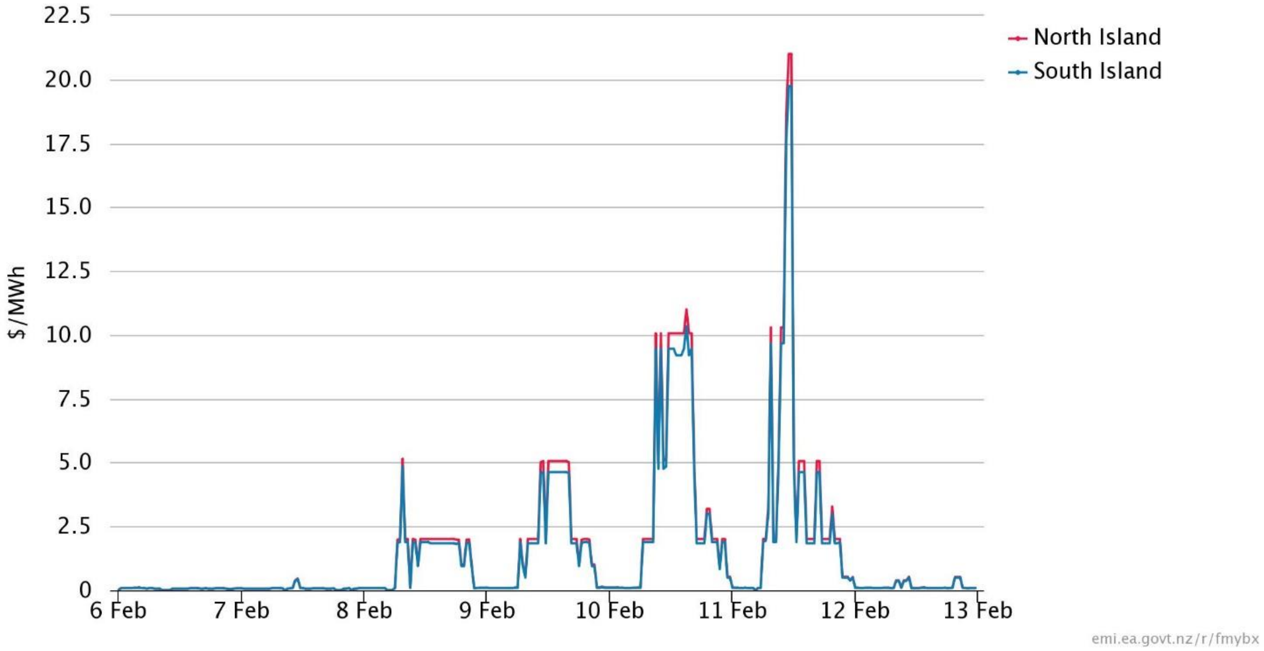
2.2. Fast instantaneous reserves (FIR) prices were usually below $20/MWh though prices did spike up to $114/MWh in the North Island for TP16 and 17 on 8 February and for TP 19 on 10 February (see Figure 2).

Figure 2: FIR prices by trading period and Island



2.3. Sustained instantaneous reserves (SIR) prices were below $21/MWh, with most prices at or below $5/MWh (see Figure 3).

Figure 3: SIR prices by trading period and Island

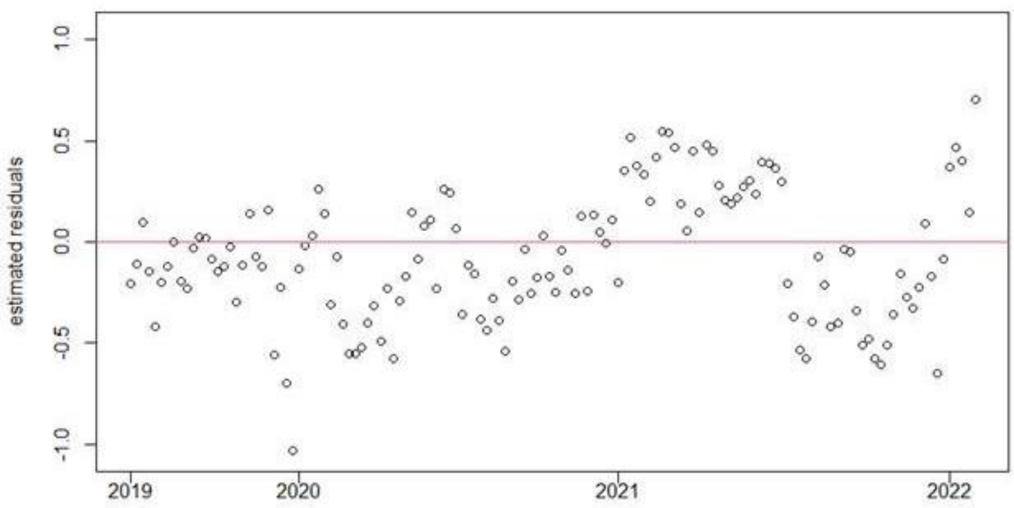


Residuals from regression models

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.

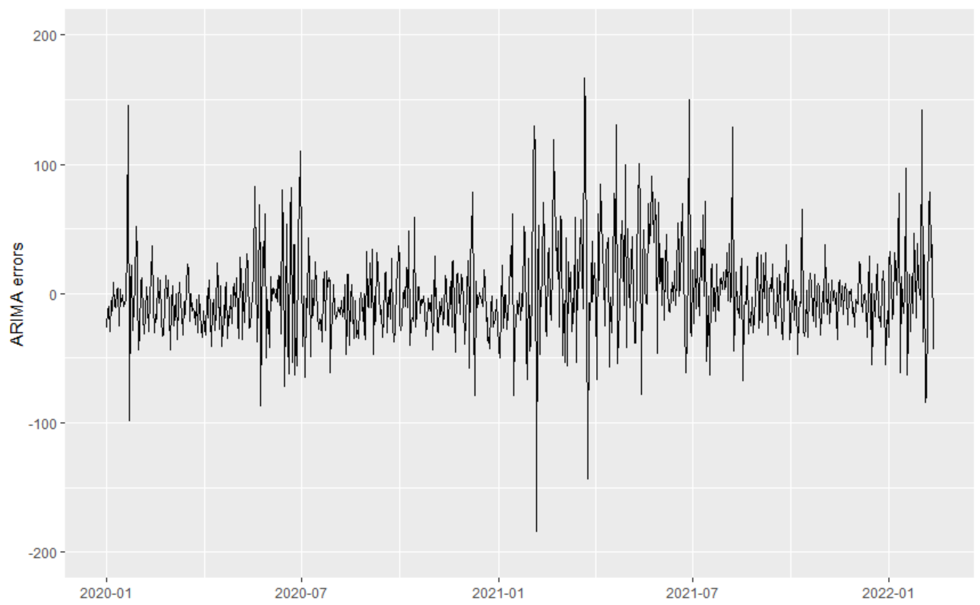
2.5. Figure 4 shows the residuals from the weekly model. During the first four weeks of January 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions. However, the residual of the last week was high. This may be due to factors not captured by the model, such as Manapouri entering its low operating range. A report has been published on high January prices.

Figure 4: Residual plot of estimated weekly price from 2 July 2019 to 4 February 2022



2.6. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were large on 6 and 9 February, indicating prices may warrant further analysis.

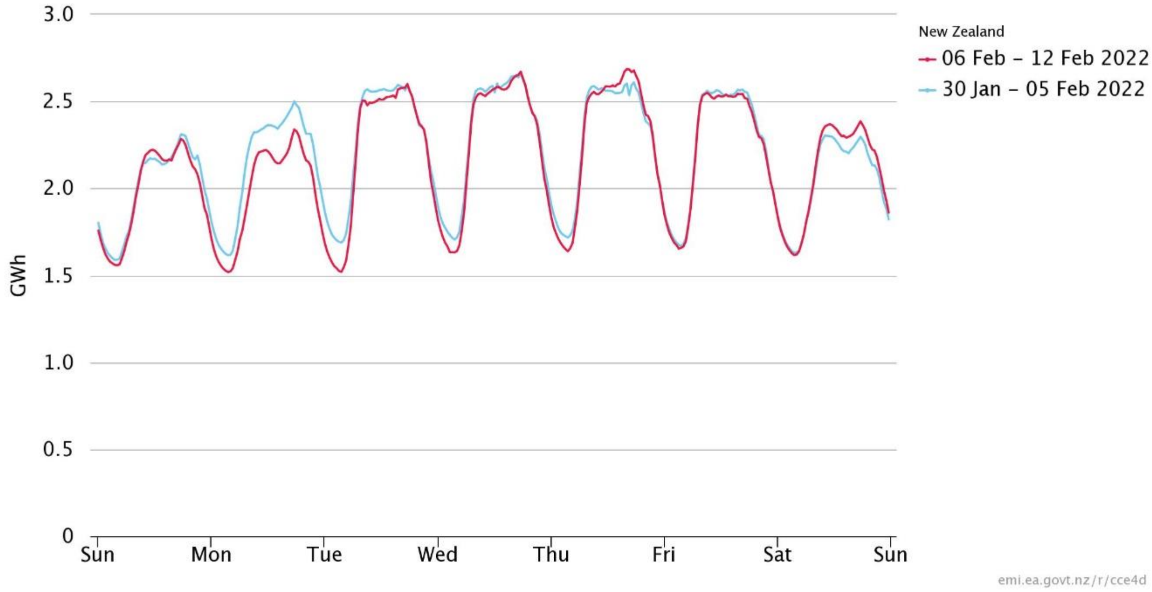
Figure 5: Residual plot of estimated daily average spot price from 1 July 2020 to 12 February 2022



3. Demand Conditions

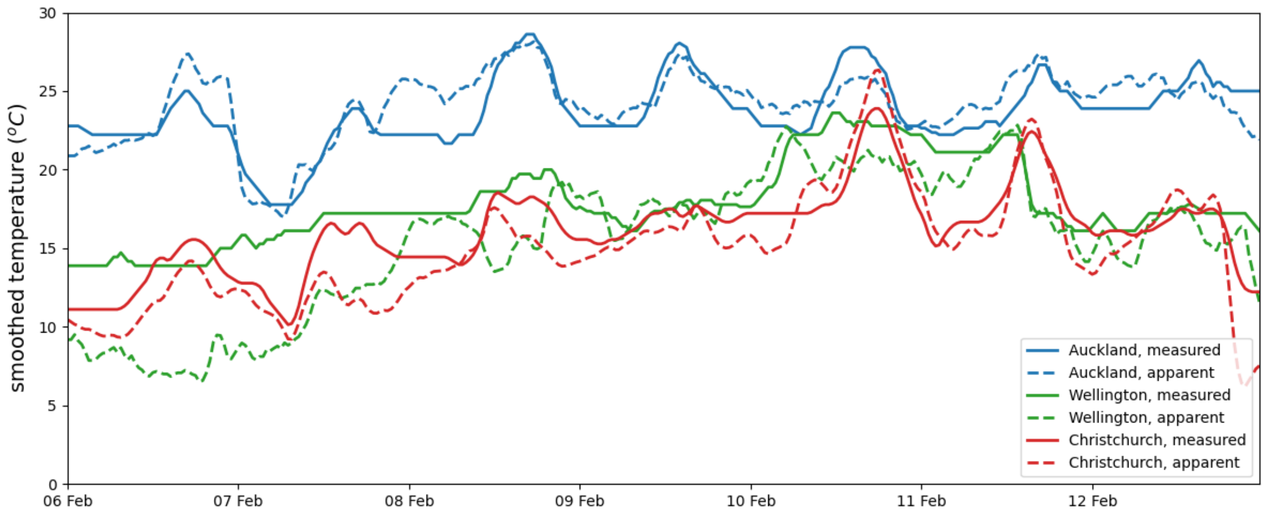
3.1. National demand was similar to the previous week (see Figure 6). Demand was low on Monday due to Waitangi Day. Demand was high the rest of the week, particularly on Thursday evening due to high temperatures (see Figure 7).

Figure 6: National demand by trading period compared to the previous week



3.2. Figure 7 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. The week started cooler, especially in Wellington and Christchurch. Temperatures in these two centres increased until they reached over 20°C on Thursday (10 February), with apparent temperatures particularly high in Christchurch, possible due to high humidity.

Figure 7: Hourly temperature data (actual and apparent) and humidity data at main population centres

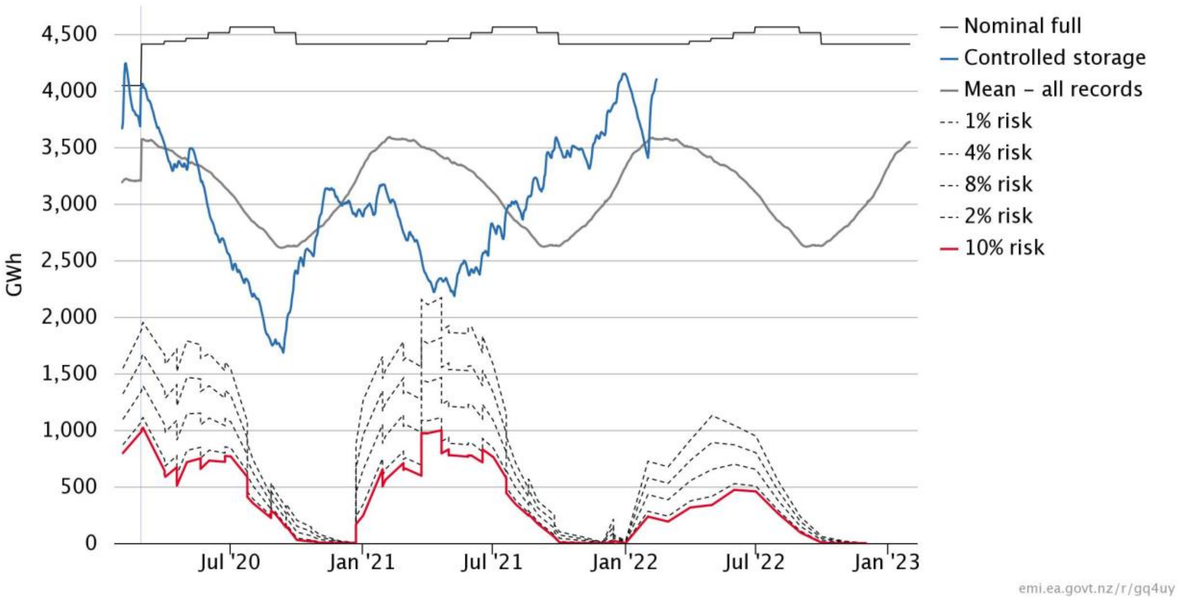


4. Supply Conditions

Hydro conditions

4.1. National hydro storage continued to increase this week reaching 4,086 GWh on Saturday, shown in Figure 8. Inflows in the South Island were high on 6 February due to rainfall which started on 3 February. This week there were also higher inflows in the North Island, particularly on 7 and 12 February. While most reservoirs are now above the mean for this time of year, Lake Manapouri and Lake Te Anau remain well below the mean.

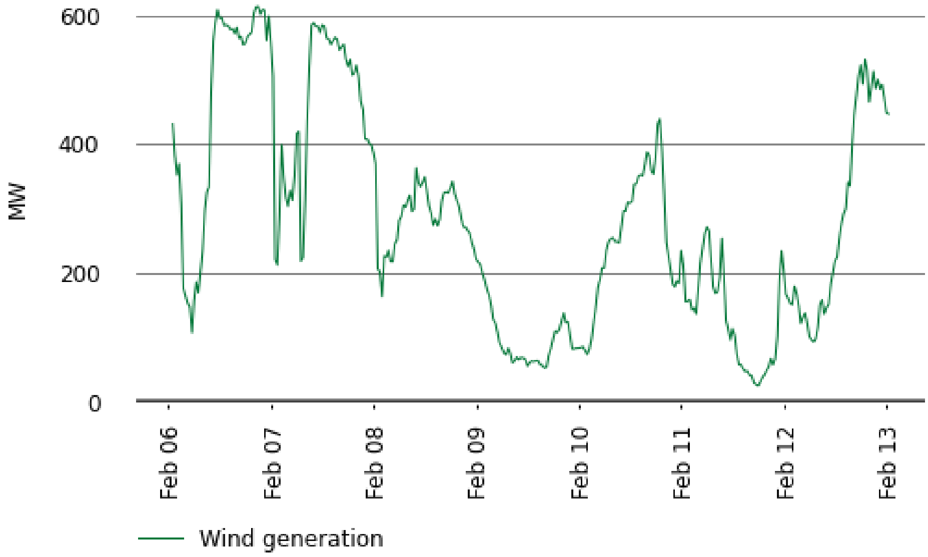
Figure 8: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 47GWh, similar to last week. Wind generation was variable throughout the week, with high wind generation of close to 600MW seen on 6 and 7 February, and generation under 100MW seen on 9 and 11 February. High wind on 6 and 7 February would have contributed to low prices and low wind generation on evening of 11 February likely contributed to particularly high prices that occurred.

Figure 9: Wind generation by trading period

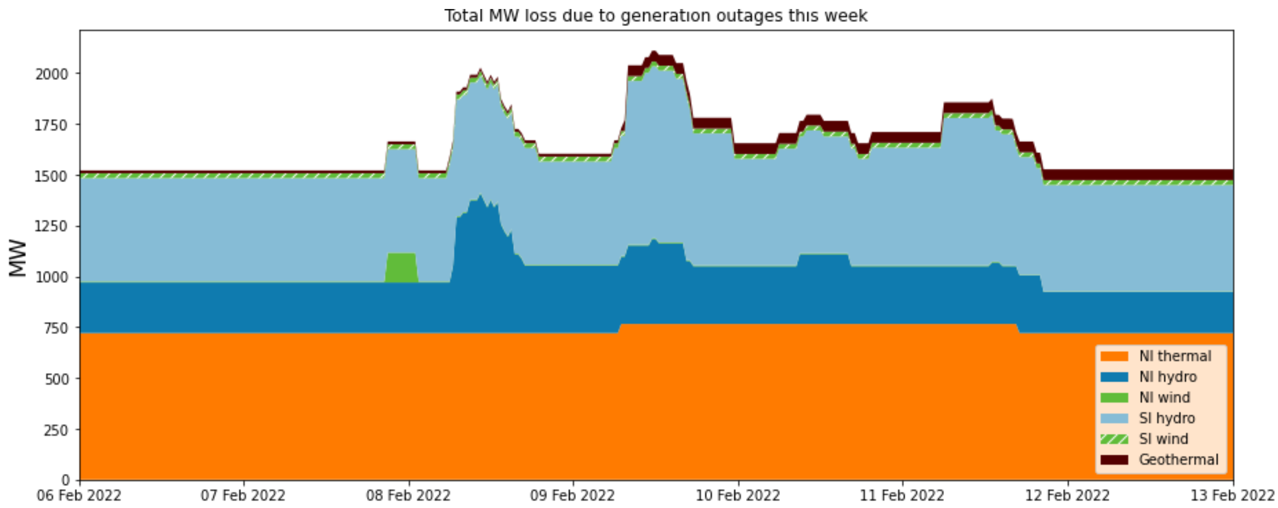


Significant outages

Generation outages

4.3. Over 1500MW of generation was on outage this week, with periods of particularly high outages on 8 and 9 February (see Figure 10). This was due to a high number of hydro units being on outage, including at Ohau, Tokaanu, Manapouri and Benmore. There was also an increase in the amount of geothermal generation on outage from 9 February. Geothermal outages decrease baseload generation which can contribute to higher prices. The peaker at Huntly was also on outage from 9 to 11 February.

Figure 10: Total MW loss due to generation outages



4.4. These are the more significant ongoing outages[2]:

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

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

(b) Berwick, 80MW (8 November 2021– 16 March 2022)

(c) Stratford peaker, 100MW, (31 October 2021 - 30 April 2022)

(d) Manapouri, 125MW (23 January - 11 February)

(e) Tekapo, 80MW (17 January -13 February)

(f) TCC, 350MW, (22 January - 28 February)

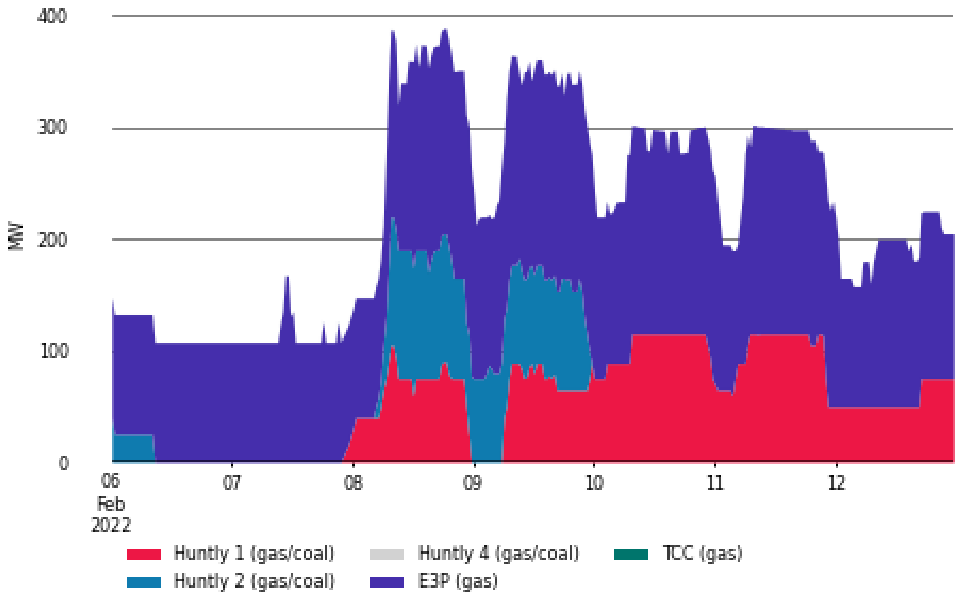
(g) Huntly, Rankine 4, 240MW (5-16 February)

(h) Huntly, Unit 6, 45MW (9-11 February)

Thermal conditions

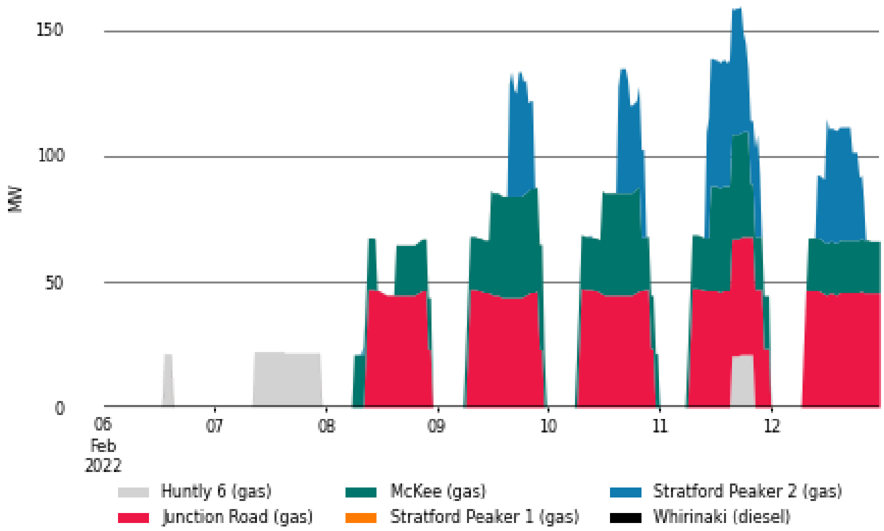
4.5. This week the E3P ran as baseload throughout this week, with lower output on 6 and 7 February when prices were down. Two Rankine units were running on 8 and 9 February but only one unit ran for the rest of the week. This was likely due to the warmer weather (shown on Figure 7) causing high river temperatures, which have been curtailing the Rankines' output since January. Genesis has indicated this could continue until March. This likely contributed to higher prices.

Figure 11: Generation from baseload thermal by trading period



4.6. Generation from thermal peakers was low at the start of the week, as demand was low and generation from wind and hydro was high. However, this increased as demand increased and wind generation decreased, with Junction Road, McKee and Stratford Peaker running each day. Huntly 6 was on outage from 9 to 11 February but did run on afternoon of 11 February when prices were highest after its outage ended.

Figure 12: Generation from thermal peakers by trading period



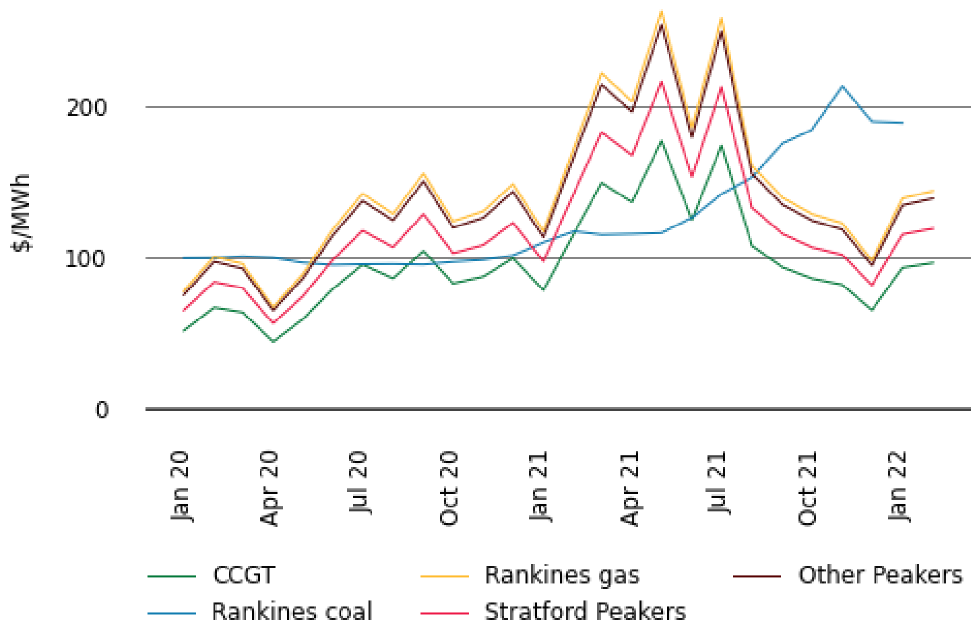
5. Price versus estimated costs

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 13 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January and February (to 12 February), likely due to a recent increase in gas consumption. The SRMC of coal 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. The carbon price has continued to increase this year, reaching $75/tonne on 21 January.

Figure 13: Estimated monthly SRMC for thermal fuels



DOASA Water values

5.3. The DOASA[3] 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 14 shows the national water values[4] to first week of February 2022 using values obtained from DOASA in November 2021. This means the water values shown since November do not show impact from other changes in the market besides hydro storage, such as the recent increase in gas prices. 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[5].

5.4. Figure 14 shows that the marginal water value declined from June to December as hydro storage levels increased and gas costs decreased. In January, the water values increased as hydro storage decreased, with a small decrease in the last week as rainfall increased inflows. While the increase in hydro storage did cause a decline in the water value it was still higher than the water values at the end of last year, likely due to being closer to winter when water values are usually highest.

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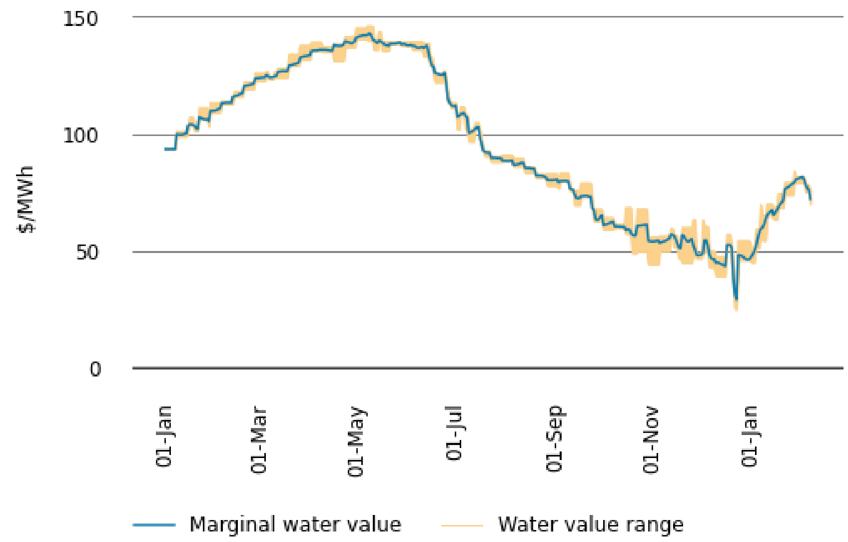
[3] DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market. (More details in Appendix B)

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

[5] See Appendix B, 2 for more details

Figure 14: DOASA water values for January 2021 to February 2022



Monthly prices

5.5. Figure 15 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. Prices increased in January, as hydro storage declined, and thermal generation increased.

Figure 15: Average monthly prices at Otahuhu and Benmore last 12 months

6. Offer Behaviour

Daily Offer Stacks

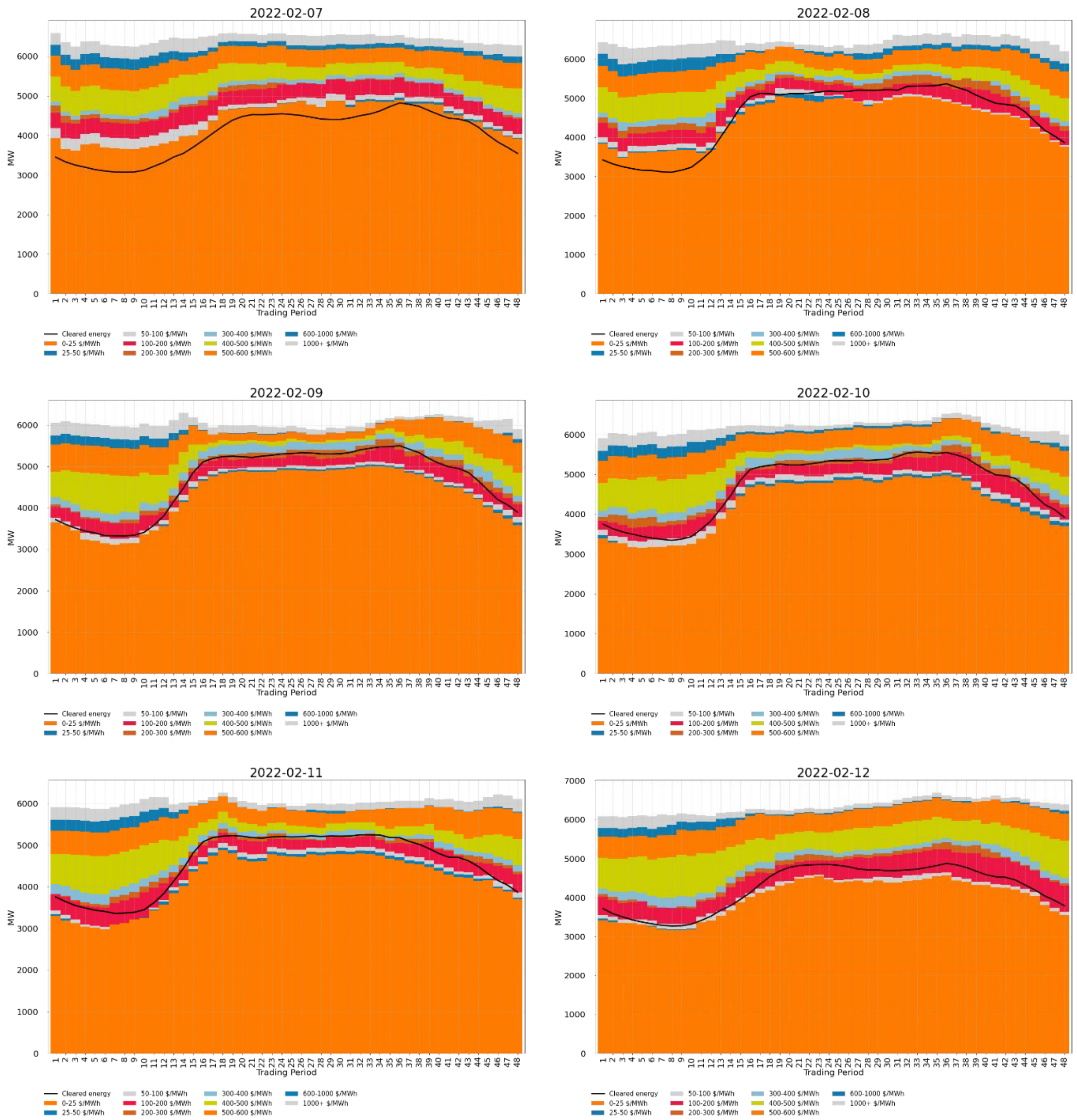
6.1. Figure 16 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[6] The black line shows the cleared energy, indicating the range of the average final price.

6.2. Generation offered at very low prices was high at the beginning of the week but noticeable decreased from 10 February and there was an increase in generation offered between $100-$200/MWh. While some of the changes may be due to wind generation and outages further analysis will be done to understand offers in the later part of the week.

6.3. On 11 February there was a drop in generation offered below $200/MWh around TP35 which caused higher prices. Further analysis is required to understand why offers changed at this time.

[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 16: Daily offer stack



Offers by trading period

6.4. The offer stacks of the trading periods (TP) with the highest prices are TP35 on 11 February is shown on Figure 17 along with the generation weighted average price (GWAP) and cleared generation. A similar trading period from earlier in the week is shown in Figure 18

6.5. While demand was similar on the two days shown (slightly higher on 8 February) the offer stack on 11 February was steeper which caused higher prices. While low wind generation may be a contributing factor further analysis is needed to understand the change in the offer stack on 11 February.

Figure 17: Offer Stack for trading period 35 on 11 February

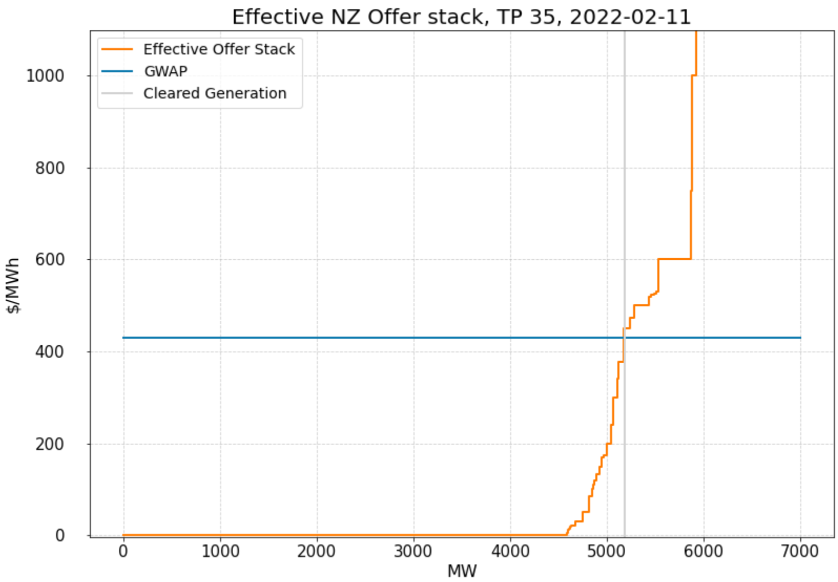
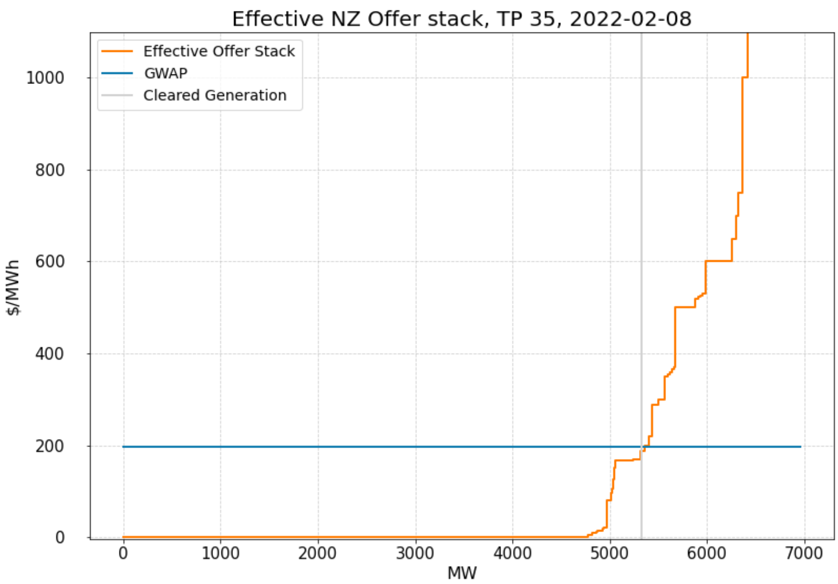


Figure 18: Offer Stack for trading period 35 on 8 February



Ongoing Work in Trading Conduct

6.6. Further analysis will be done of offers this week to understand persistent high prices, particularly TP35 on 11 February.

6.7. The Authority's market monitoring team has received additional information regarding offers on 5 February. This information is currently being reviewed.

6.8. The Authority has published a report on the drivers of high prices in January, https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/january-prices-were-high-due-to-high-demand-and-constrained-generation/

6.9. 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
08/02-12/02	Several	Further Analysis	High inflows but continued high prices
08/02, 10/02	16-17, 19	Further Analysis	High FIR prices
05/02	Several	Further Analysis	Checking offers in Waitaki scheme after high inflows- additional information received
03/02	32	Further Analysis	High FIR price
19/01-20/01	Several	Further Analysis	High FIR prices
17/01-18/01	Several	Analysis published	High energy prices
10/01-11/01	Several	Analysis published	Prices over $300/MWh, increase in outages
02/01-08/01	Several	Analysis published	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

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

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:

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

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

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.

[7] 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.[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

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

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.[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).

[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