9 March 2022

# Trading Conduct Report

## Market Monitoring Weekly Report

## 1. Overview for the week of 27 February to 5 March

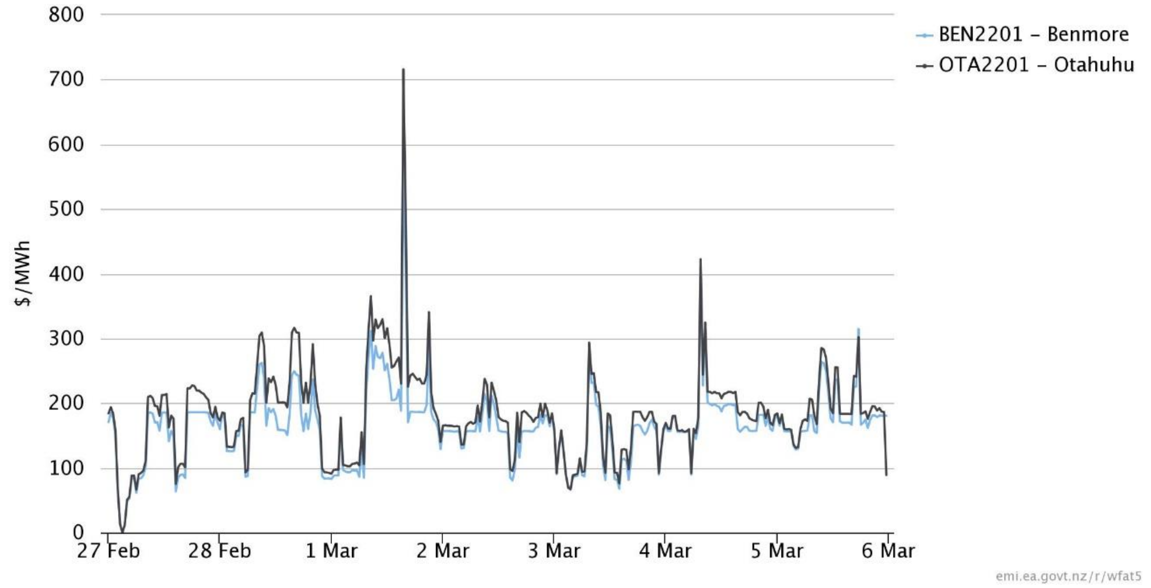
1.1. The majority of energy prices this week appear consistent with supply and demand conditions, with high prices on 1 March due to a trip at Huntly. Further analysis will be done to understand some other high prices observed this week.

## 2. Prices

### Energy prices

2.1. The average spot price this week was $175MWh[1], 32% higher than last week. The highest price this week occurred at TP32 on 1 March reaching $726/MWh at Otahuhu. This occurred shortly after a trip at Huntly which caused an under-frequency event (UFE). The next highest price was TP 16 on 4 March reaching $422/MWh at Otahuhu.

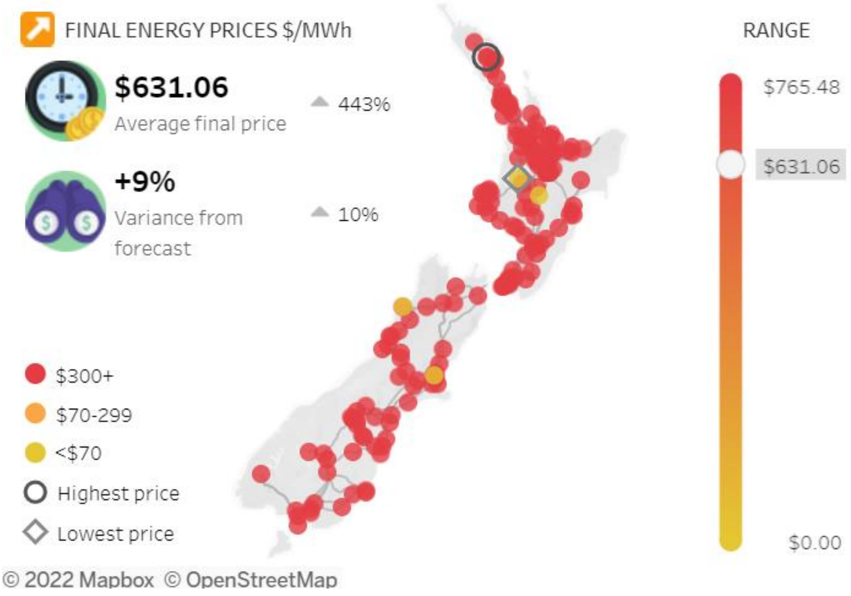
*Figure 1: Spot prices by trading period at Otahuhu and Benmore*




2.2. The simple average price for TP32 on 1 March was $631/MWh, with consistently high prices throughout New Zealand in response to loss of generation at Huntly

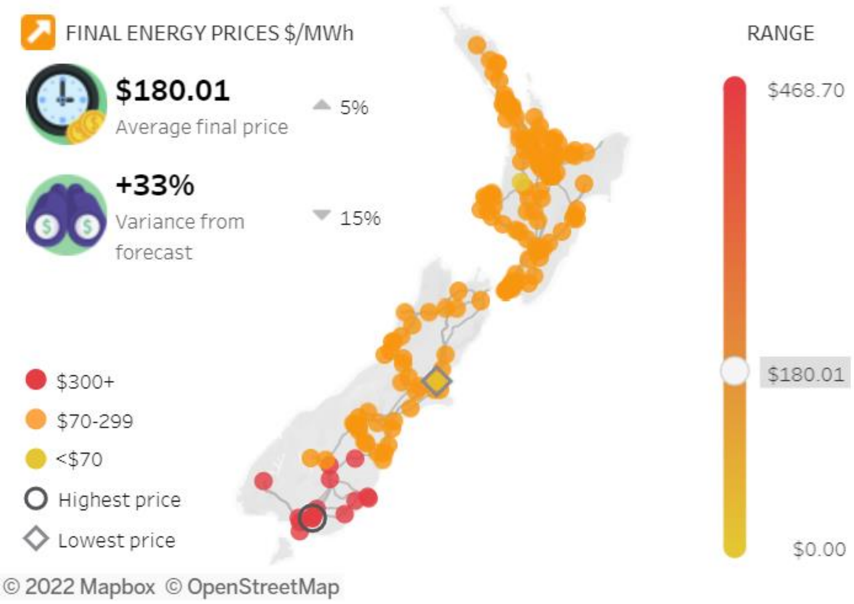
[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

*Figure 2: Nodal and average spot prices for TP32 on 1 March*




2.3. Figure 3 shows the prices for TP6 on 4 March. This was one of several trading periods in the early morning between 3 and 5 March when there was price separation between the lower South Island and the rest of New Zealand. During these trading periods there was a branch constraint for import stability, which reduced import into the lower South Island. High prices may reflect the impact of low lake levels at Manapouri, though demand was low.

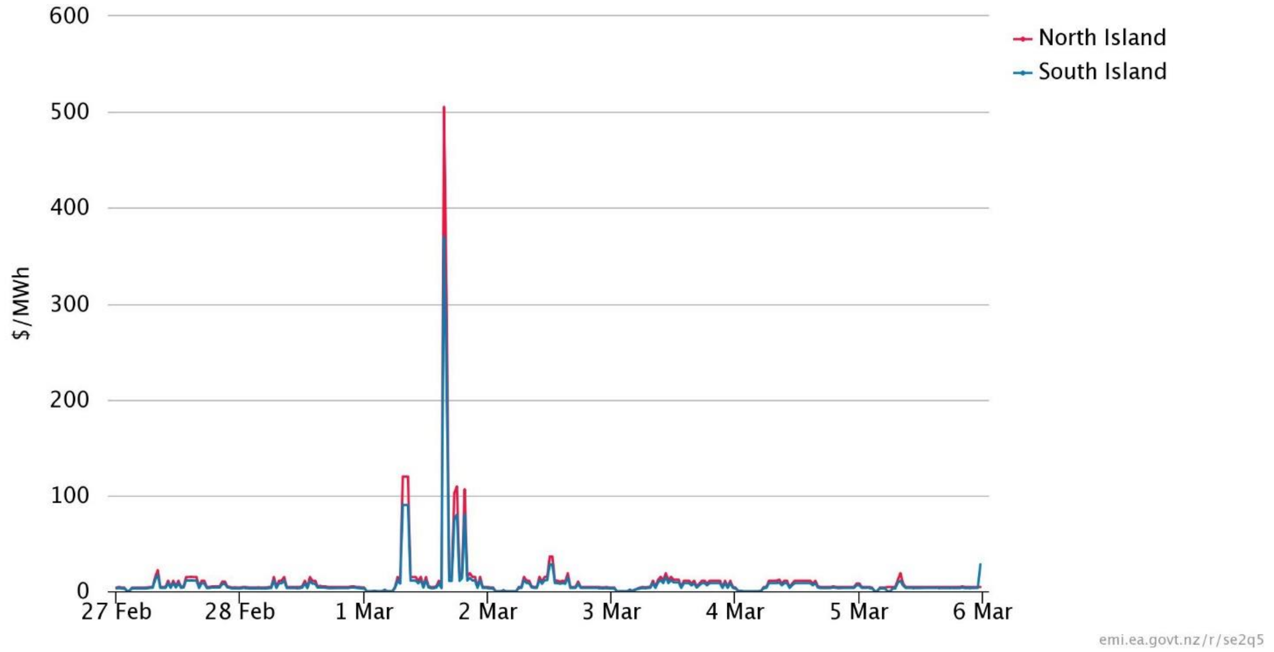
*Figure 3: Nodal and average spot prices for TP6 on 4 March*



## Reserve Prices

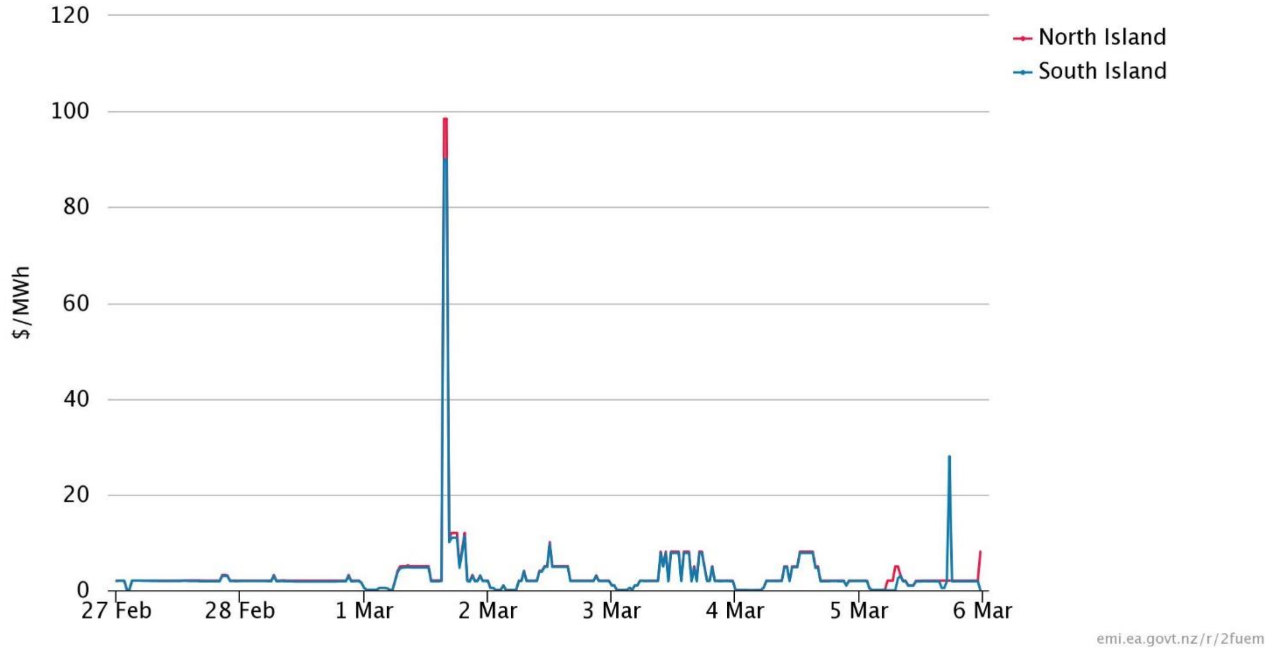
2.4. Fast instantaneous reserves (FIR) prices were usually below $20/MWh (see Figure 4). The exception is on 1 March when prices spiked over $100/MWh including to $500/MWh in the North Island shortly after the trip at Huntly

*Figure 4: FIR prices by trading period and Island*




2.5. Sustained instantaneous reserves (SIR) prices were usually below $10/MWh (see Figure 5). The trip caused SIR prices to reach $98/MWh for two trading periods afterwards.

*Figure 5: SIR prices by trading period and Island*

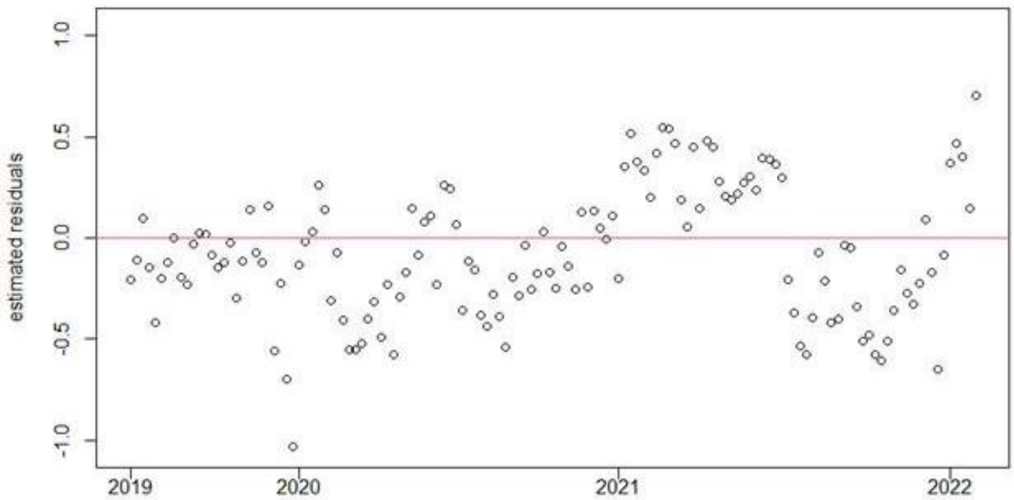


# 3. Residuals from regression models

3.1. 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.

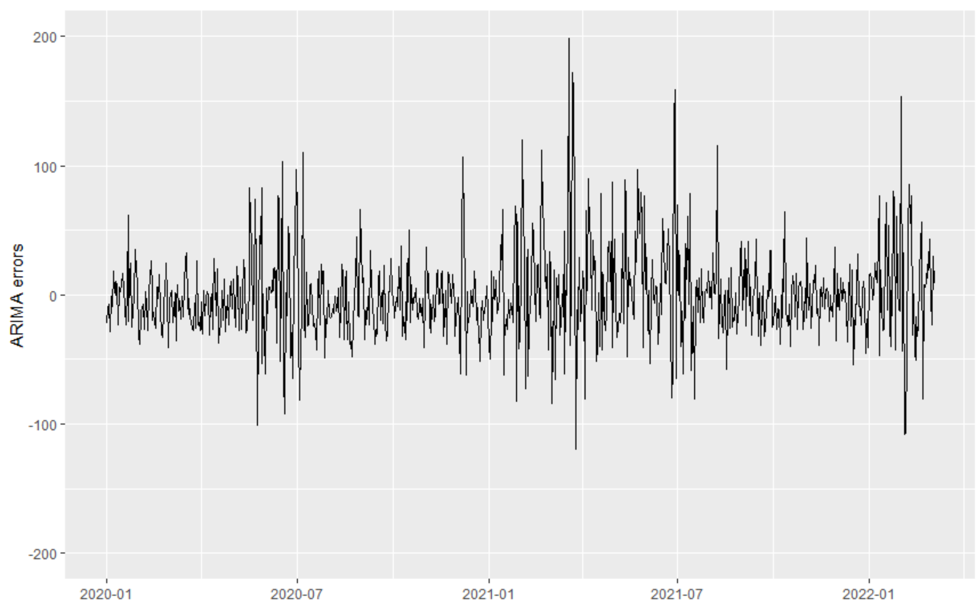
3.2. Figure 6 shows the residuals from the weekly model. During the first four weeks of January 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions. However, the residual of the last week was high. This may be due to factors not captured by the model, such as Manapouri entering its low operating range. A report has been published on high January prices.

*Figure 6: Residual plot of estimated weekly price from 2 July 2019 to 4 February 2022*




3.3. Figure 7 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. The residuals for this week were within the normal range.

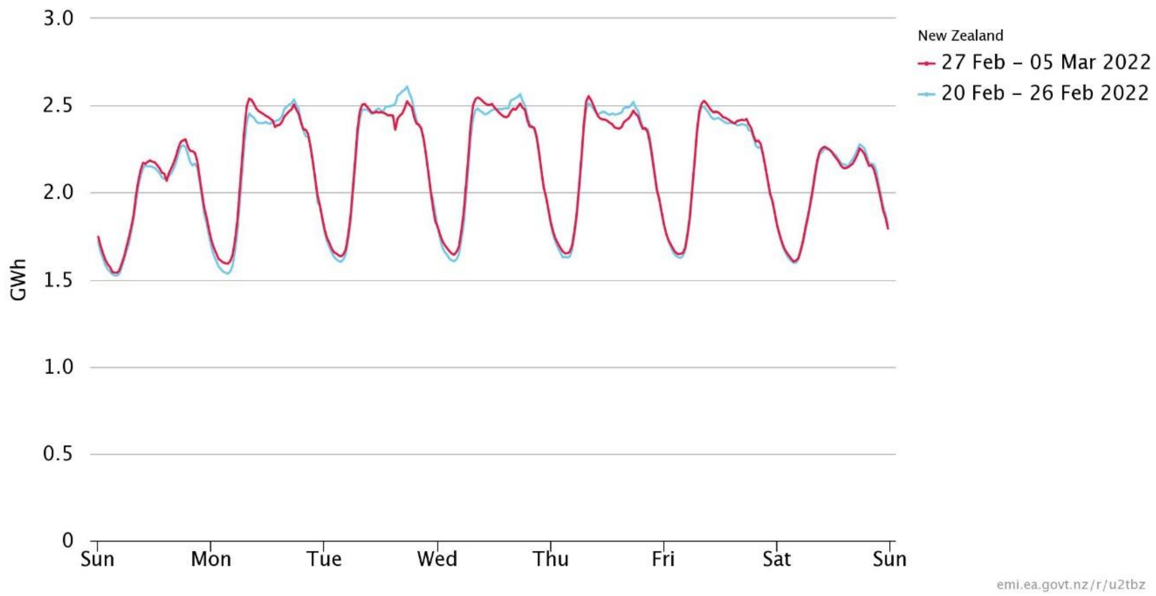
*Figure 7: Residual plot of estimated daily average spot price from 1 July 2020 to 5 March 2022*



## 4. Demand Conditions

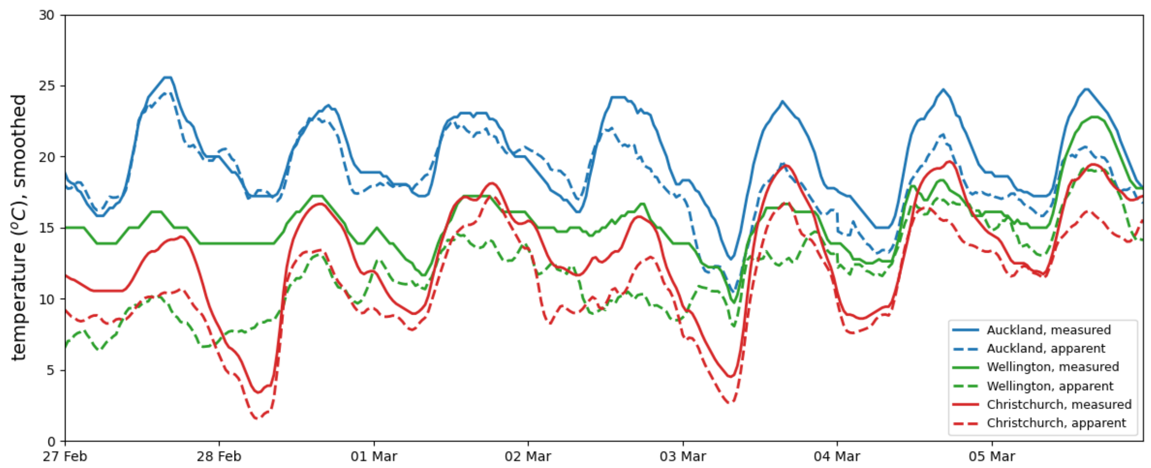
4.1. National demand was 2% higher than the previous week (see Figure 8) as temperatures were relatively mild (see Figure 9). There was a noticeable drop in demand on Tuesday which coincided with the UFE event caused by a trip at Huntly. This was likely due to interruptible load, a type of reserve where offtake is disconnected in the event of a UFE. It appears that most of this load was restored quickly, as more generation was dispatched.

*Figure 8: National demand by trading period compared to the previous week*



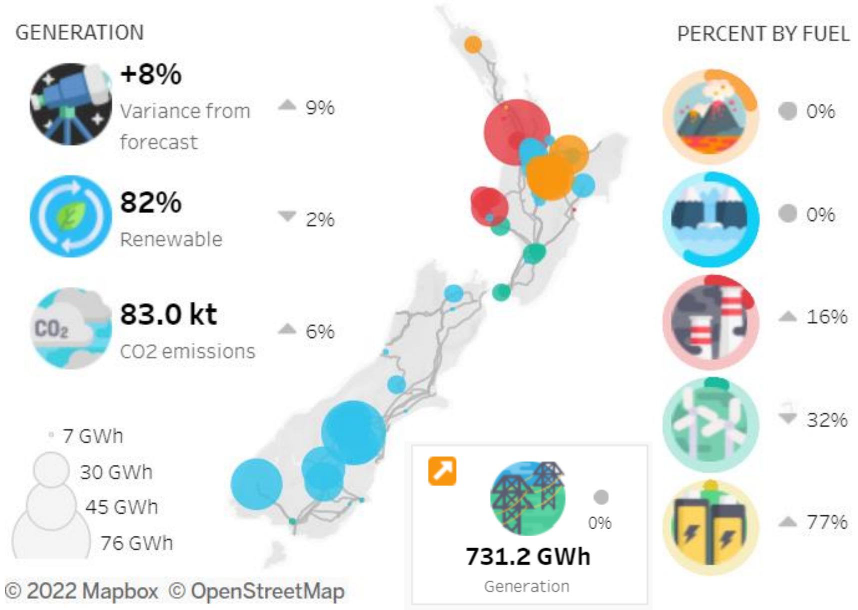

4.2. Figure 9 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures this week were relatively mild. Colder morning temperature in Christchurch on 28 February and 3 March may have contributed to higher morning peaks.

*Figure 9: Hourly temperature data (actual and apparent) and humidity data at main population centres*



# 5. Supply Conditions

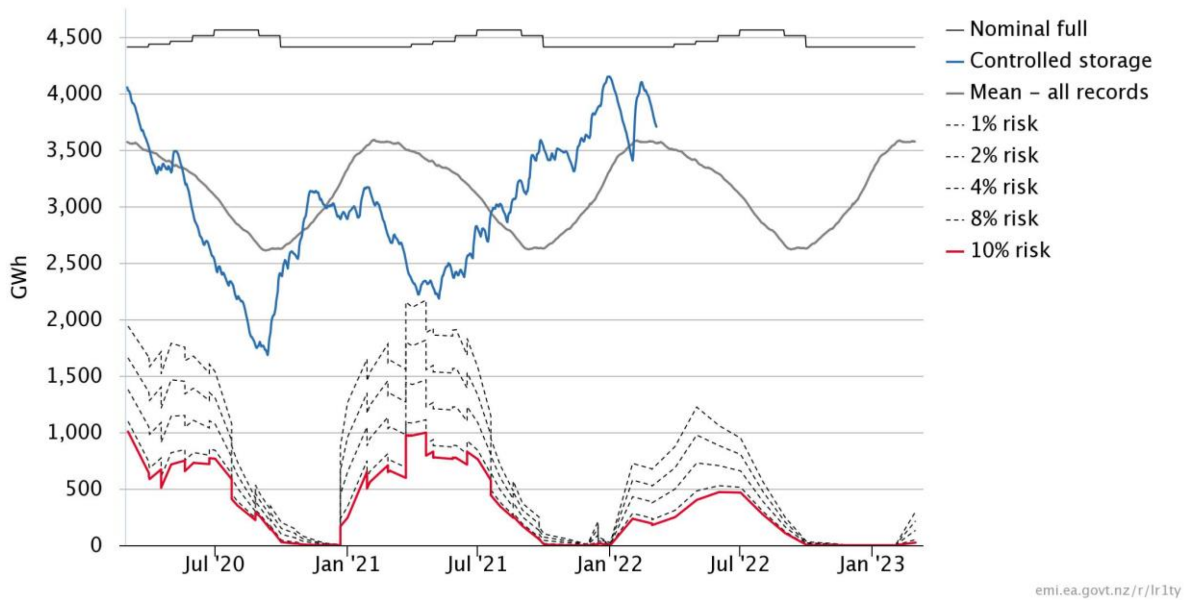
*Figure 10: Generation in the last week compared to previous week*




## Hydro conditions

5.1. National hydro storage decreased by about 150GWh over the week, shown in Figure 11, to 78% of nominal full storage. Storage is still above the historical means for this time of year. However, lake levels at Manapouri appear to be within the low operating range similar to end of January.

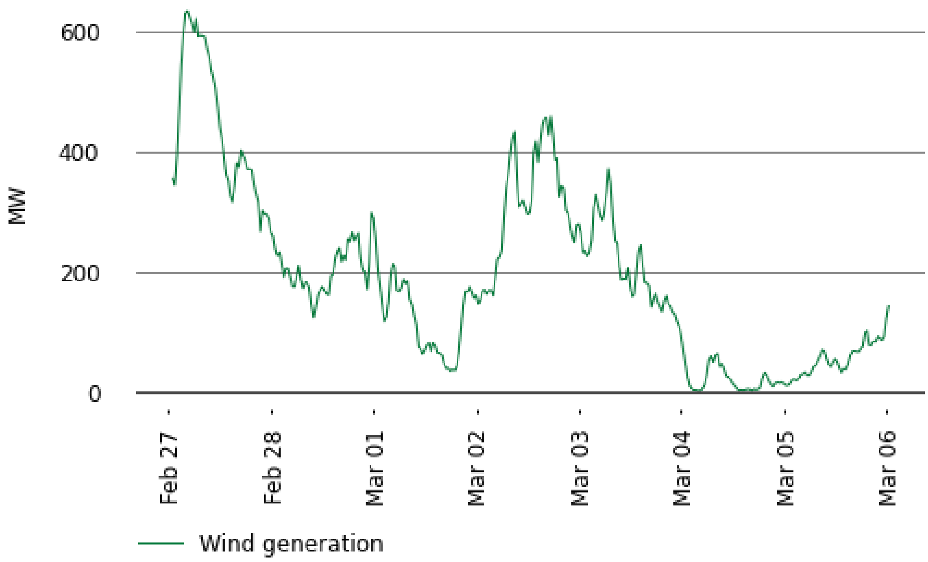
*Figure 11: Electricity risk curves and hydro supply*



## Wind conditions

5.2. Total wind generation was 33GWh, down 32% from last week, and contributed about 4% of total generation. Wind generation was high at the start of the week, with 600MW of generation, but this dropped below 200MW on 1 March Wind generation then increased to 400MW on 2 March, before again declining to 0MW on 4 March. Outages may have contributed to low wind generation.

*Figure 12: Wind generation by trading period*

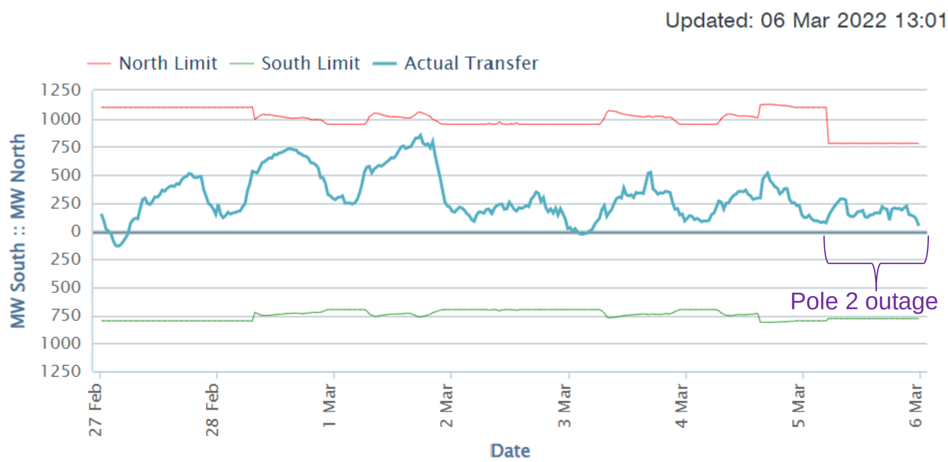



## Significant outages

### HVDC outage

5.3. There was a planned outage of the HVDC this weekend. Pole 2 was on outage from 5 March 5:30 to 6 March 17:30. As northward transfer was low, impact to the market was minimal. Figure 13 shows that the HVDC transfer each day, as well as the transfer limits and outages.

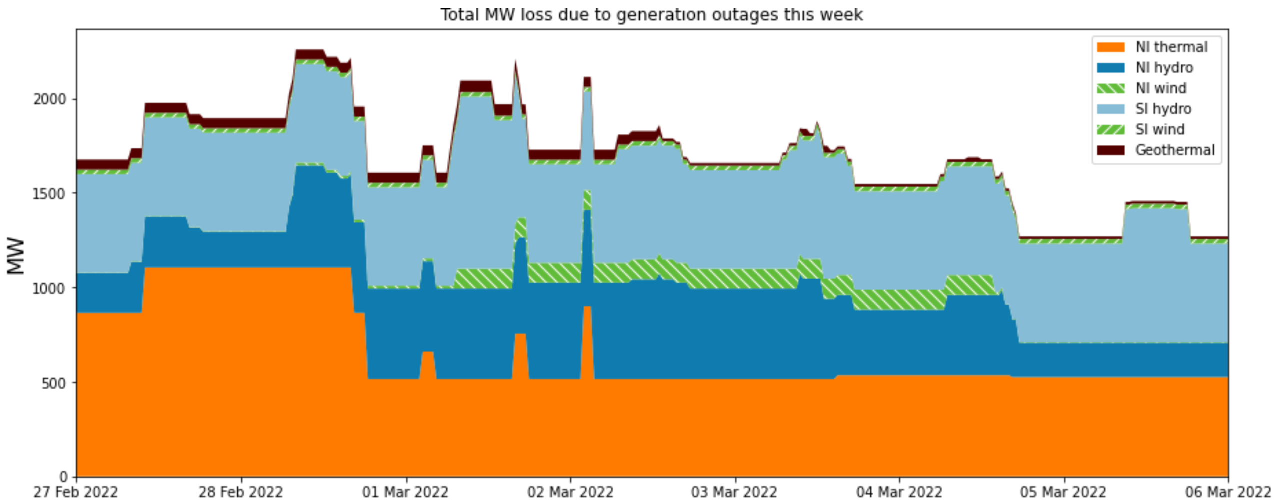
*Figure 13: HVDC transfer, HVDC limits and HVDC outage*



### Generation outages

5.4. The amount of generation on outage has declined this week. This is predominantly due to TCC returning from outage. There was a 90MW outage at Te Apiti, a North Island windfarm from 1 March to 4 March. There were also several outages of South Island hydro on 1 March, some of these were ended early in response to Huntly 2 tripping. Likewise, Huntly 4 was due to come back at midnight on 01 March but was returned early at 5:30pm due to Huntly 2 tripping. Huntly 2 was entered as on outage from 4pm, which is shortly after it tripped, and is not expected back until 15 March.

*Figure 14: Total MW loss due to generation outages*




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

(a) Clyde, 116MW (15 Feb 2021 – 1 July 2022)

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

(c) Stratford peaker 1, 100MW, (31 October 2021 - 30 April 2022)

(d) Stratford peaker 2, 100MW (24 February – 1 September)

(e) Manapouri, 125MW (23 January – 15 March)

(f) Manapouri, 125MW (21 February – 11 March)

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

(h) Huntly, Rankine 4, 240MW (23 February – 1 March)

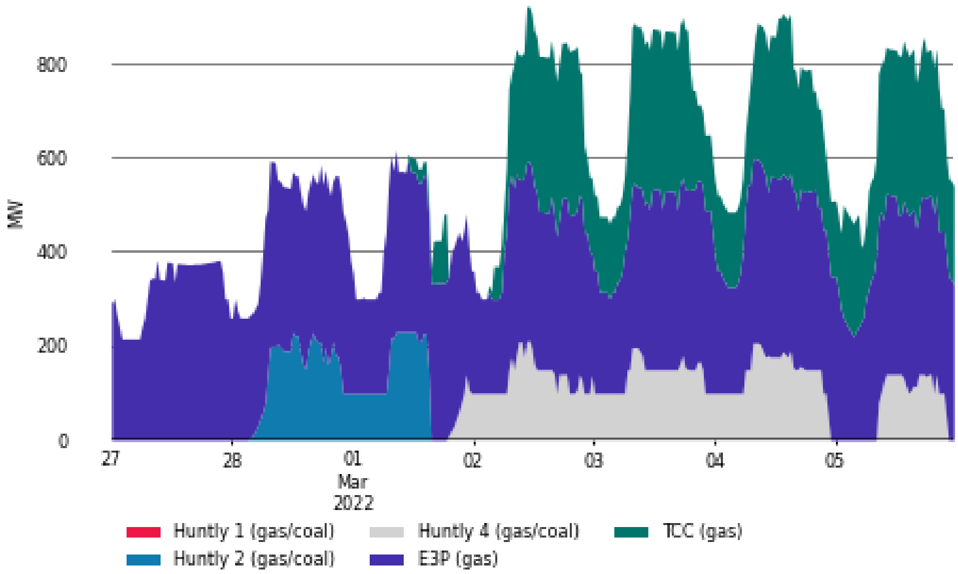
(i) Huntly, Rankine 2, 240MW (1 March – 15 March)

## Thermal conditions

5.6. Overall, thermal generation contributed 17% of total generation this week. The E3P continued to run as baseload. Huntly 2 was running from 28 February but tripped at 2:57pm and caused an under-frequency event (UFE). Huntly 4 was on outage but was undergoing testing as it expected to be returned at midnight. This enabled Genesis to end the outage early and for Huntly 4 to cover the loss of Huntly 2. TCC's outage ended up 28 February, though output was low on 1 March as it was only starting to ramp up from cold, it was able to briefly increase generation to help cover the loss of Huntly 2. The return of TCC increased baseload thermal generation for the rest of the week and reduced northward transfer across the HVDC.

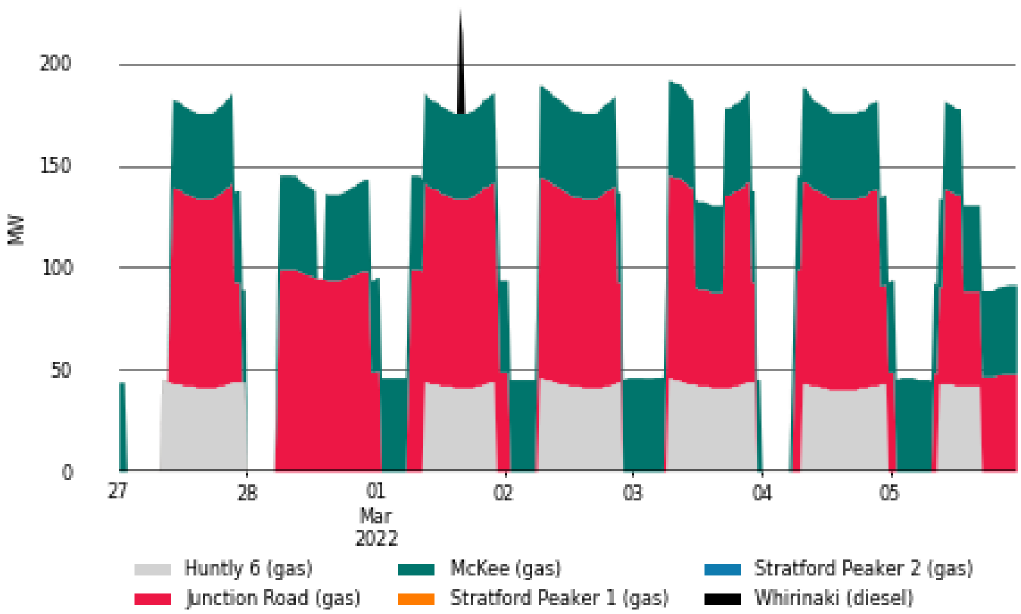
[2] Detailed outage information is available from https://pocp.redspider.co.nz/

*Figure 15: Generation from baseload thermal by trading period*




5.7. For most of the week Huntly 6, Junction Road and McKee have all been running for the majority of the day. Both the Stratford Peakers are currently on outage, reducing the total capacity of peakers. When the trip occurred at Huntly, only Whirinaki was available for additional dispatch, resulting in high prices.

*Figure 16: Generation from thermal peakers by trading period*



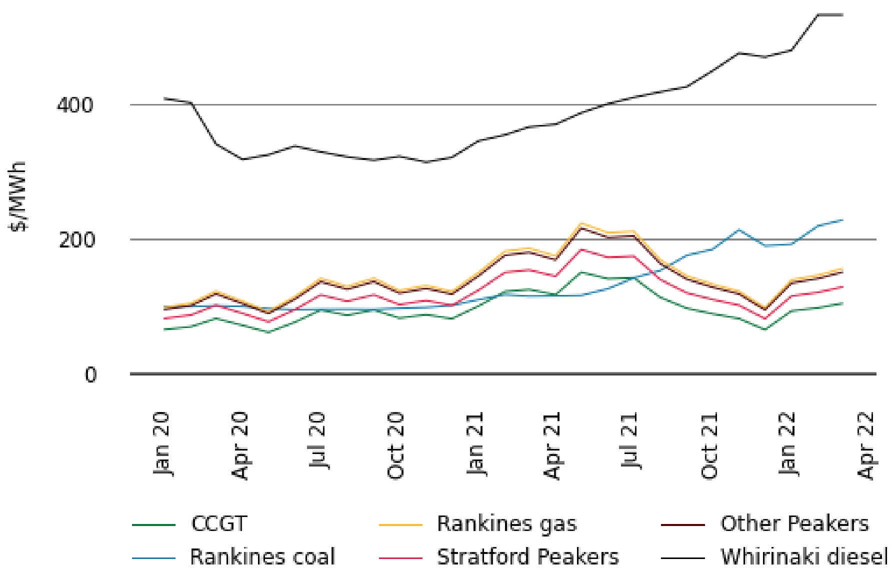
# 6. Price versus estimated costs

6.1. 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

6.2. 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 17 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January and February, likely due to the increase in gas consumption. The SRMC of coal and diesel both increased due to global supply and demand conditions and remain high. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal. The carbon price has significantly increased in the last year, reaching a high of $85/tonne though has recently dropped to $75/tonne.

*Figure 17: Estimated monthly SRMC for thermal fuels*



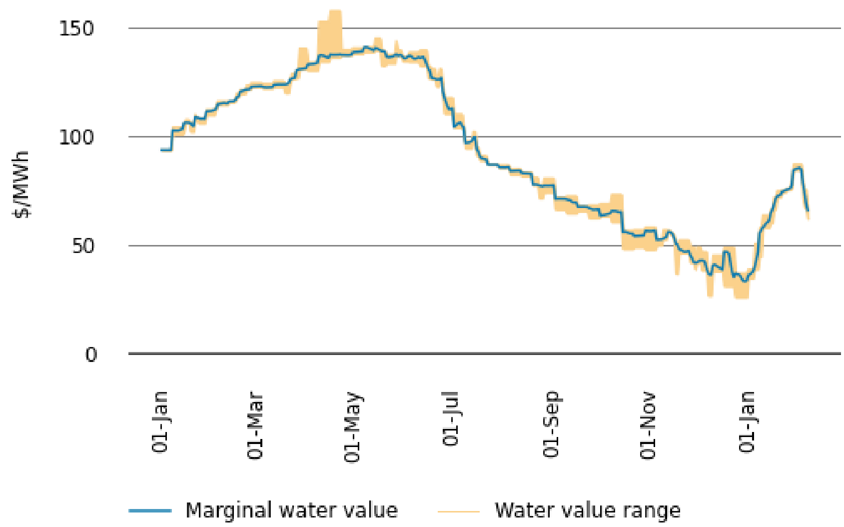

## JADE Water values

6.3. The JADE[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 18 shows the national water values[4] to 20 February 2022 using values obtained from JADE. The outputs from JADE 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].

[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE 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, 3 for more details

6.4. Figure 18 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 and gas costs increased. 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.

*Figure 18: JADE water values for January 2021 to February 2022*




## Monthly prices

6.5. Figure 19 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. Prices increased in January, as hydro storage declined, and thermal generation increased. February prices were lower than January, especially at Benmore, which is in line with lower water values but high thermal fuel costs.

*Figure 19: Average monthly prices at Otahuhu and Benmore last 12 months*

# 7. Offer Behaviour

## Daily Offer Stacks

7.1. Figure 20 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. Note that the HVDC outage may result in the black line not indicating actual prices observed on 5 March.

7.2. Total generation offered reduced as a result of Huntly 2's trip on 1 March for the two following trading periods (which were past gate closure at the time of the trip) however, generators responded to the trip by increasing the generation offered, including by ending generation outages early, including at Huntly 4.

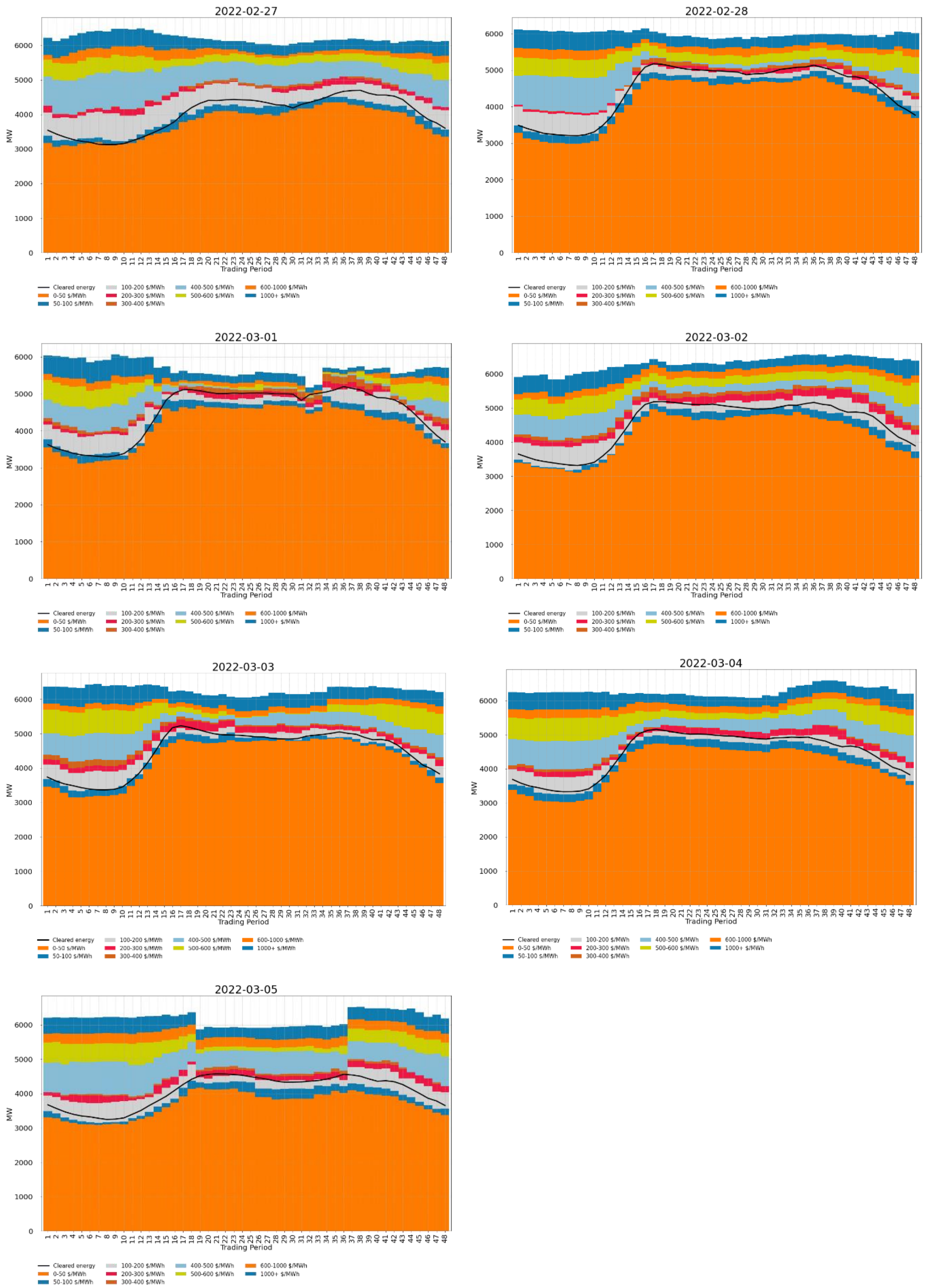
7.3. The total generation offered increased from 2 March due to TCC being returned to the market. TCC usually runs as baseload thermal generation over the winter months. This appears to have caused the quantity weighted offer price to have dropped. There was also a noticeable increase in generation offered on 4 March as generation outages ended, including North Island hydro and wind.

7.4. There was also a drop in generation available due to the Ohau outage on 5 March. This also likely resulted in less transfer northwards across the HVDC. As a result, prices were higher than they likely would have been if Ohau station had been available to the market.

7.5. Besides the high price following the UFE on 1 March, the highest prices occurred on TP16 and TP 18 on 4 March. This occurred during the morning peak and wind generation was low. Price variance from forecast was over 40%, much higher than the other trading periods during this peak, which also had lower prices. This may mean that high prices were due to the forecast for demand or wind being incorrect. Further analysis will be done to understand the cause of both the high variance and high price.

[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 20: Daily offer stack*



## Offers by trading period

7.6. The offer stacks of TP30 and TP32 on 1 March are shown on Figure 21 and Figure 22 along with the generation weighted average price (GWAP) and cleared generation. The trip at Huntly occurred during TP31, so this is a good representation of the impact of the loss of Huntly 2.

7.7. Cleared generation during these two periods were similar, at about 5000MW. The trip at Huntly caused the offer curve to shift to the left as Huntly 2 had been offering about 150MW at a very low price and an additional 80MW offered at prices up to $250/MWh. As the offer curve was steep above $250/MWh the loss of 200MW at Huntly caused a large increase in the GWAP, with more expensive generation, including Whirinaki dispatched to cover the shortfall.

*Figure 21: Offer Stack for trading period 30 on 1 March*

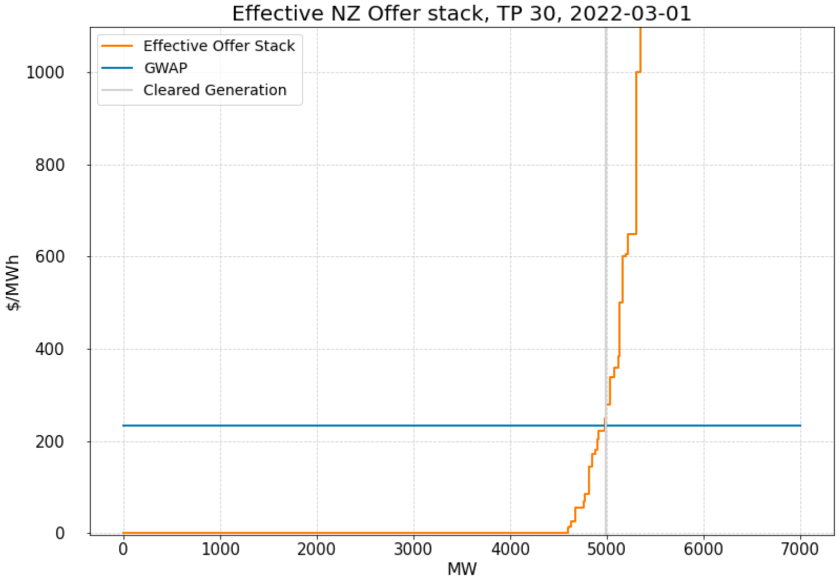
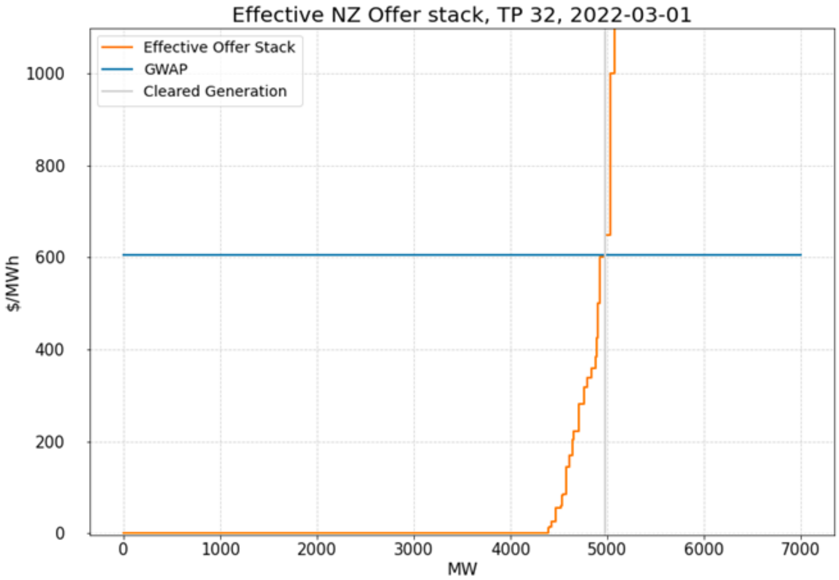



*Figure 22: Offer Stack for trading period 31 on 1 March*



# 8. Ongoing Work in Trading Conduct

8.1. Further analysis will be done of the high price on TP16 on 3 March to understand what caused the high price and high variance from forecast.

8.2. Further analysis will be done on the high prices in the lower South Island during the early morning this week.

8.3. After reviewing information received from Genesis regarding offers from Tekapo B while Lake Tekapo was spilling, this case has been passed to compliance to assess if the offers were compliant with trading conduct rules.

8.4. 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 |
|---|---|---|---|
| **03/03-05/03** | 4-10 | Further analysis | Branch constraint, high prices in lower South Island |
| **04/03** | 16, 18 | Further analysis | High price- dashboard indicates high variance from forecast |
| **25/02** | 23-27 | Further analysis | Whirinaki dispatched while other thermal peakers had capacity |
| **19/02-24/02** | | Compliance enquiries in progress | High priced offers at Tekapo-passed to compliance |
| **19/02-21/02** | Several | Further Analysis | High South Island reserve prices |
| **08/02-12/02** | Several | Further Analysis | High inflows but continued high prices |
| **30/06/21-20/08/21** | Several | Compliance enquiries in progress | High energy prices in shoulder periods |
| **30/06/21-21/08/21** | 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:

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

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

8. $\varepsilon_t$, 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 JADE water value model

1. JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[8] JADE is identical to DOASA in terms of model inputs and outputs but is written using the Julia modelling language JuMP.

2. 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.

3. The JADE 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

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

4. The following are some of the limitations of the assumptions in the JADE 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 JADE 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 JADE 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. JADE 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, JADE 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]

5. We use the average water value over all of New Zealand from JADE rather than the water values for individual reservoirs because the individual reservoir water values are very volatile. This is due to the following.
   a. JADE 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 JADE 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