2 March 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 20 to 26 February

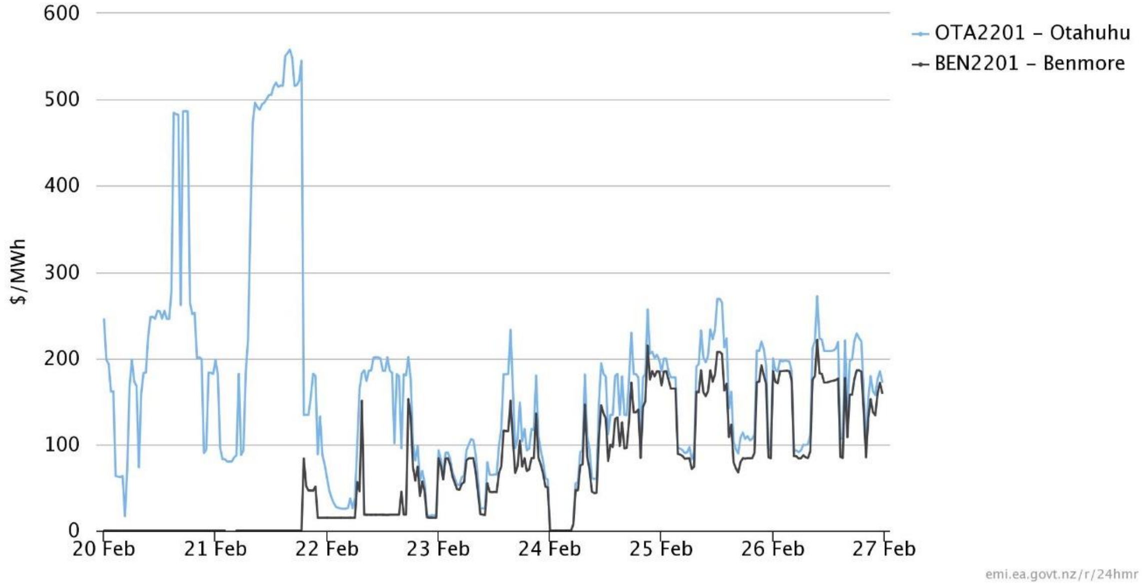
1.1. The majority of energy prices this week appear consistent with supply and demand conditions, with high prices in the North Island due to the extended bipole outage. However, some reserve prices and offer behaviour have been identified for further analysis.

2. Prices

Energy prices

2.1. The average spot price this week was $127MWh[1], 29% higher than last week. The week started with a bipole outage which caused high prices in the North Island, reaching $558/MWh at Otahuhu at TP33 on 21 February and low prices in the South Island, at around $0.03/MWh at Benmore for most of 20 and 21 February (see Figure 1). Some price separation continued on 22 February due to the monopole HVDC outage. After the bipole outage prices were between $0 and $272/MWh (see Figure 2).

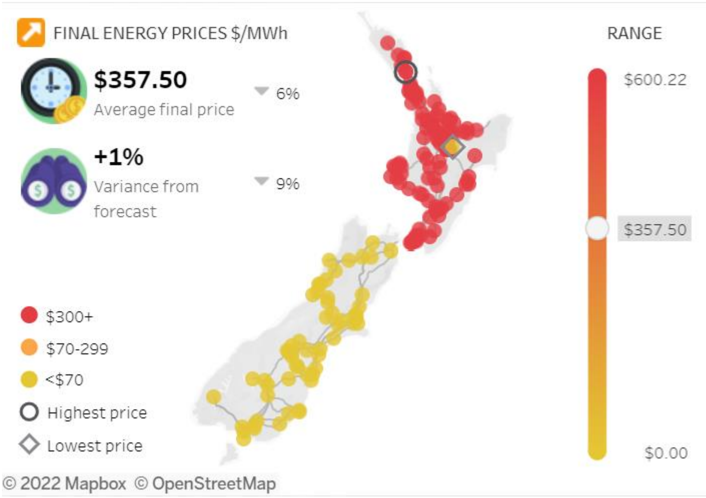
Figure 1: Spot prices by trading period at Otahuhu and Benmore



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

2.2. The simple average price for TP33 on 21 February was $357.50, but due to the bipole outage, prices in the South Island were $0.03/MWh while prices in the North Island were as high as $600/MWh. Figure 2 clearly shows that the two islands were separate markets during the bipole outage, with tight supply in the North Island and excess supply in the South Island. Note, the node at Ohaaki shows as the lowest price at $0.00/MWh, due to transmission outages that disconnected this node from the rest of the grid while Ohaaki station was on outage.

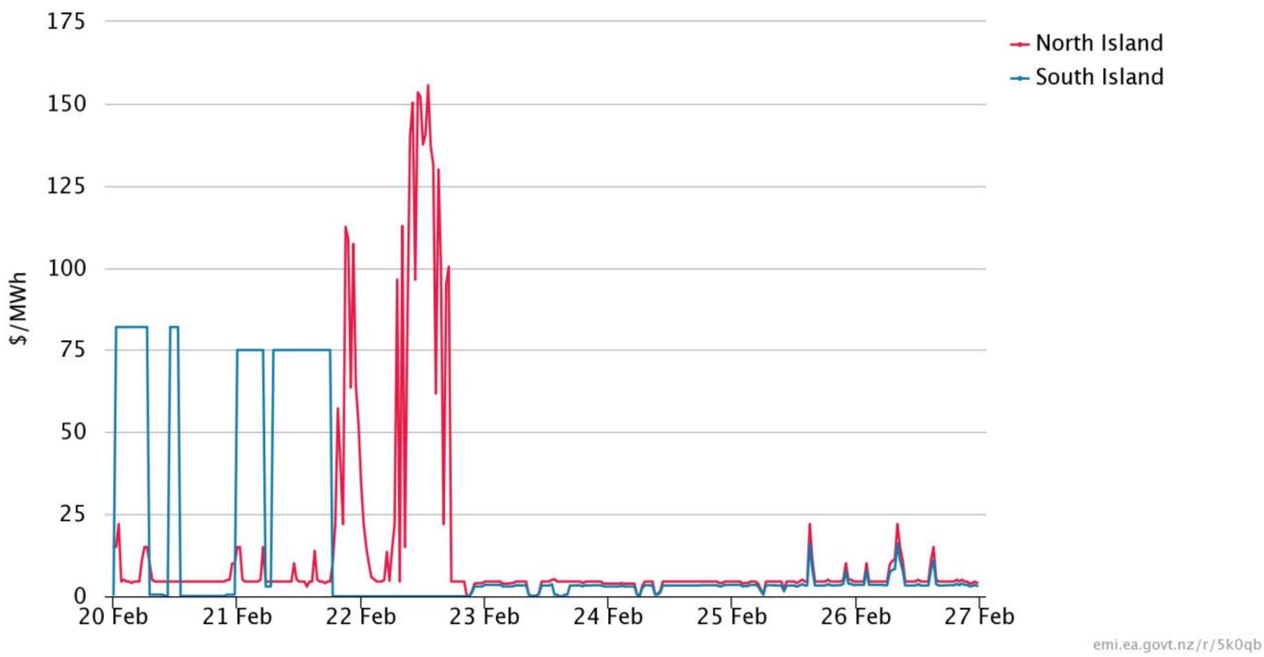
Figure 2: Nodal and average spot prices for TP33 on 21 February



Reserve Prices

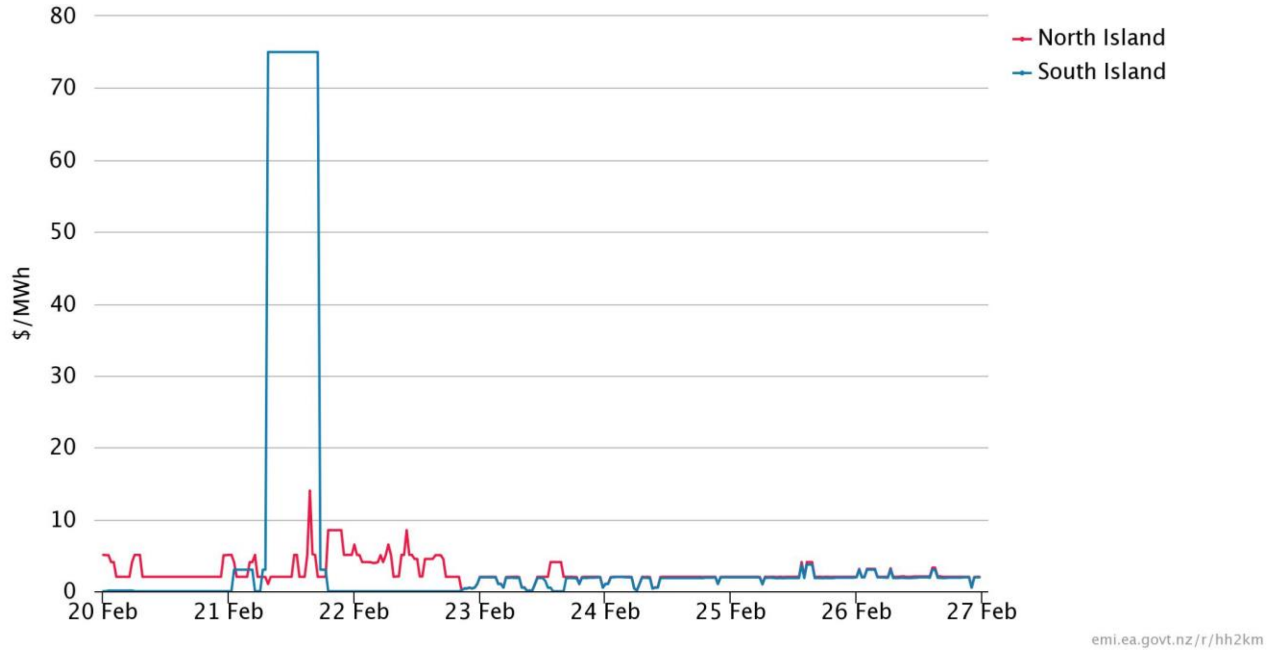
2.3. Fast instantaneous reserves (FIR) prices were usually below $25/MWh (see Figure 3). However, the South Island FIR prices were up to $75/MWh during the bipole outage and North Island FIR prices reached $156/MWh on 22 February during the monopole outage.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were usually below $10/MWh (see Figure 4). The HVDC outage did cause price separation between North and South Island though North Island prices were not significantly high. South Island SIR prices were also around $80/MWh on 21 February.

Figure 4: SIR prices by trading period and Island



2.5. North Island reserve prices were highest during the monopole outage when North Island reserve requirement (FIR and SIR) were about 200MW higher compared to later in the week, due to needing to cover risk of losing remaining pole and not being able to share reserve requirement with South Island.

2.6. The bipole outage prevented reserve sharing so the South Island reserve requirement on 20 and 21 February was slightly higher than earlier in the week. This may have been a factor in high South Island reserve prices. Further analysis will be done on offers to understand why South Island reserve prices were high on 20 and 21 February.

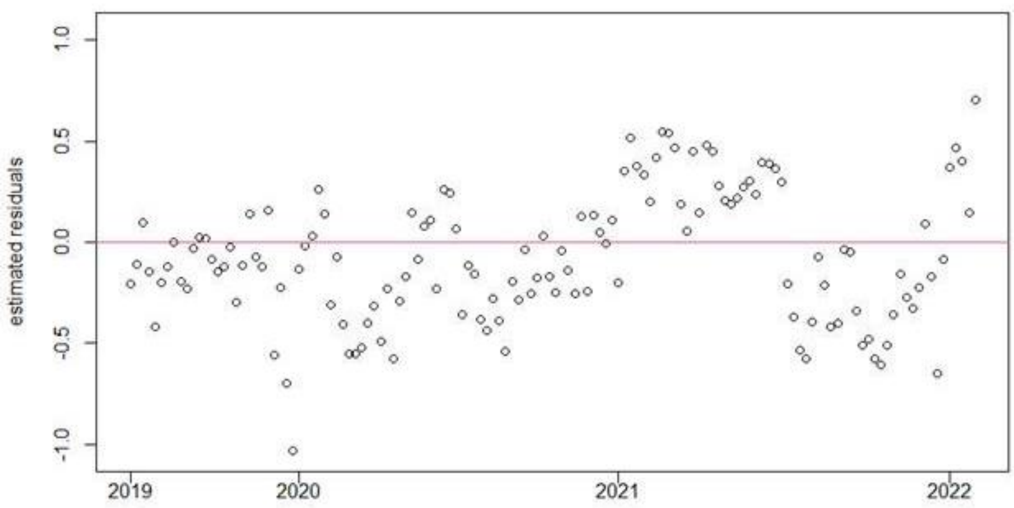
2.7. When pole 3 returned to service on 21 February, South Island reserve requirement dropped as North Island reserves were available to cover a contingent event in South Island (by reducing transfer across Pole 3). This resulted in low reserve prices in the South Island.

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.

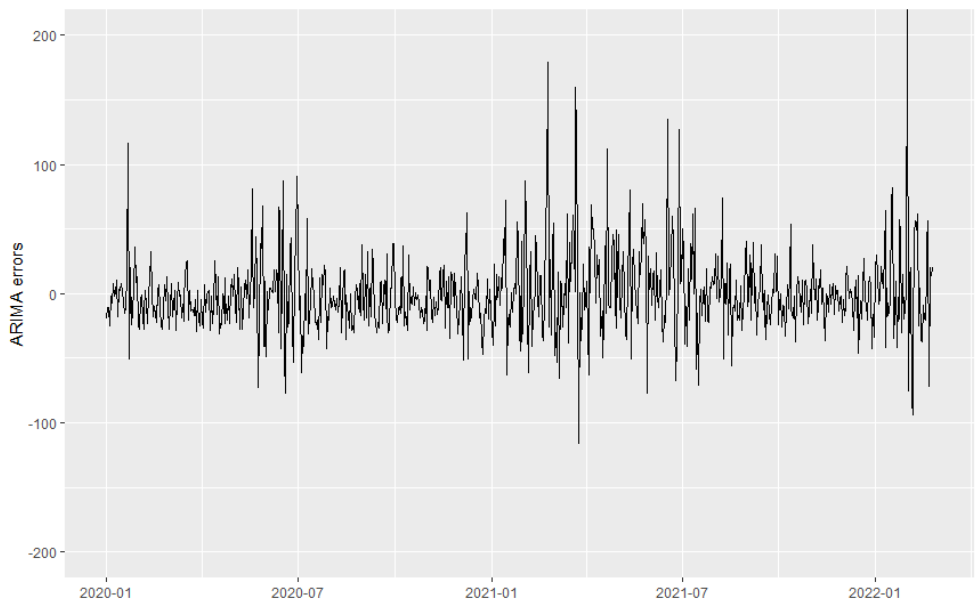
3.2. Figure 5 shows the residuals from the weekly model. During the first four weeks of January 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions. However, the residual of the last week was high. This may be due to factors not captured by the model, such as Manapouri entering its low operating range. A report has been published on high January prices.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 4 February 2022



3.3. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. The residuals were large for 21 and 22 February due to high prices on 21 February, but the daily residuals for the rest of the week were within the normal range.

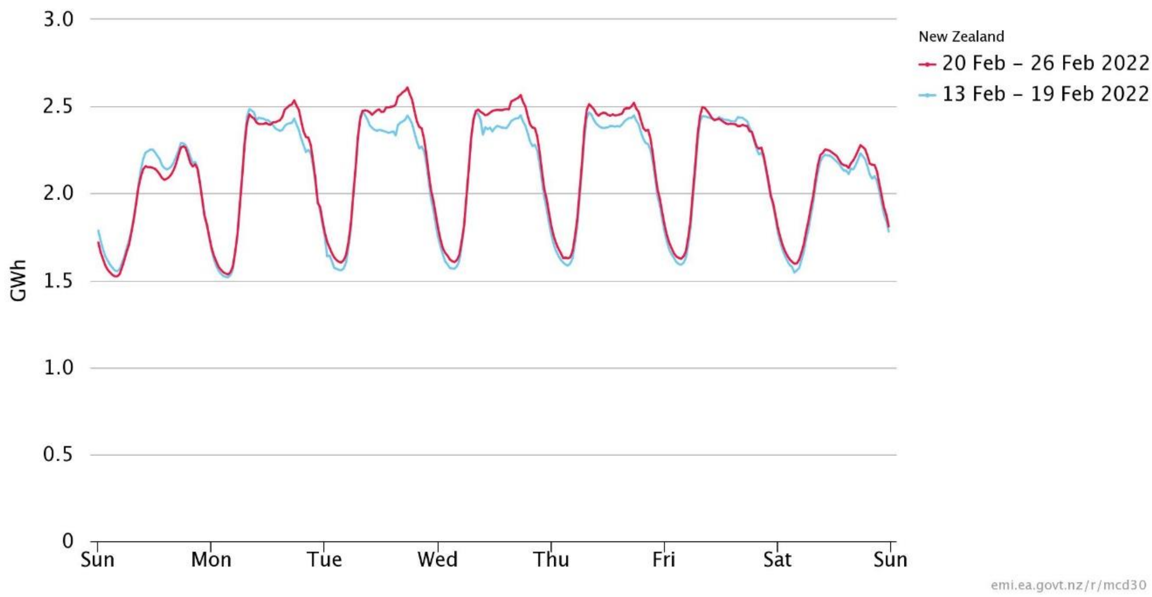
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 26 February 2022



4. Demand Conditions

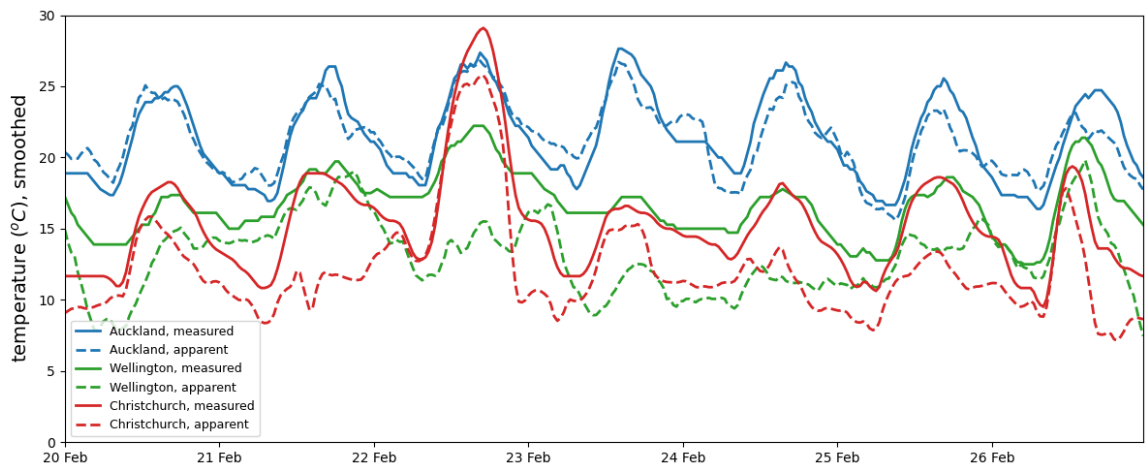
4.1. National demand was 2% higher than the previous week (see Figure 7). Demand was highest on Tuesday, 22 February, when temperatures were warm around the country (see Figure 8).

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



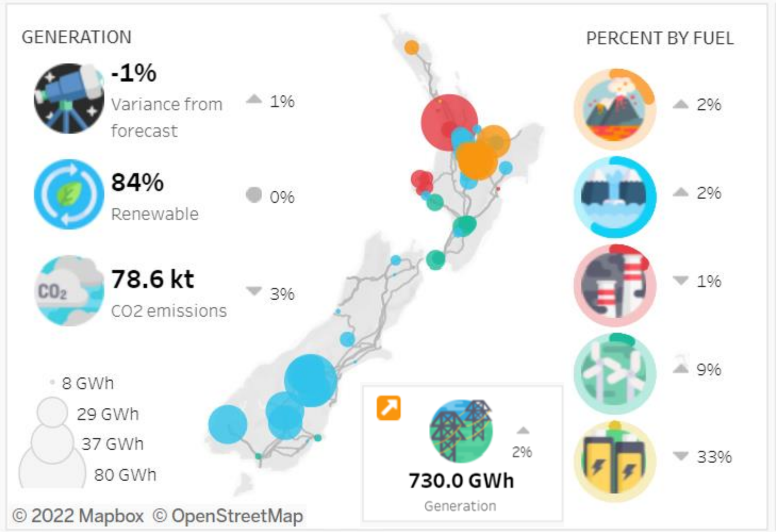
4.2. Figure 8 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures in Auckland were warm throughout the week, but temperatures in Wellington and Christchurch started cooler and rose on 22 February before dropping again.

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



5. Supply Conditions

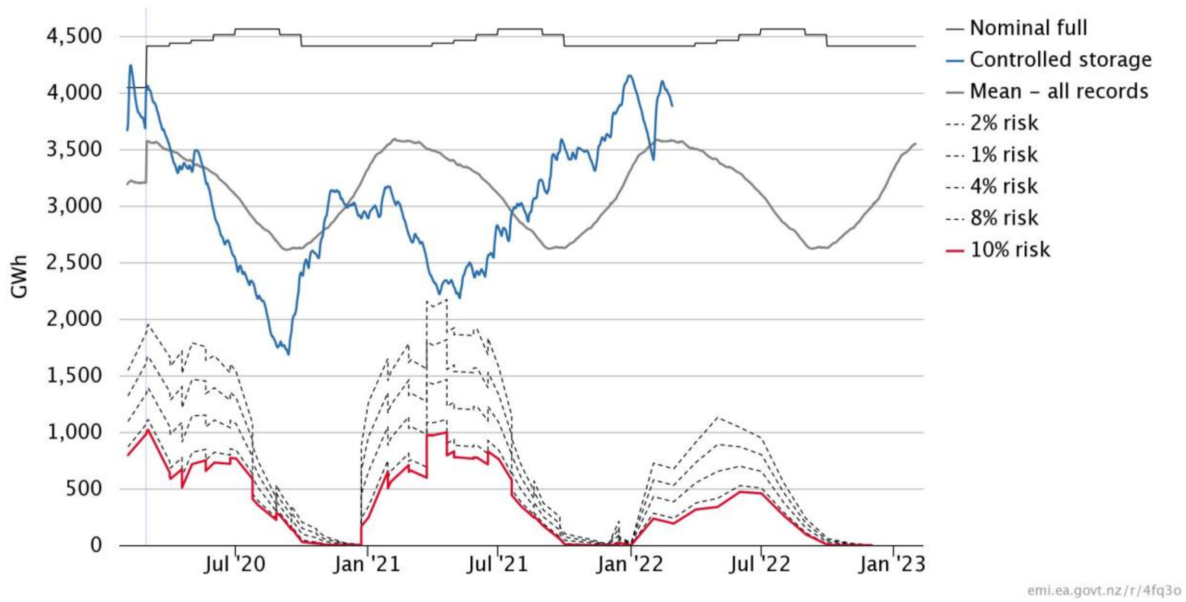
Figure 9: Generation in the last week compared to previous week



Hydro conditions

5.1. National hydro storage decreased by about 100GWh over the week, shown in Figure 10, to 81% of nominal full storage. Storage is currently about 300GWh above historical means for this time of year. Inflows were below average in both islands this week. Hydro generation contributed 59% of total generation.

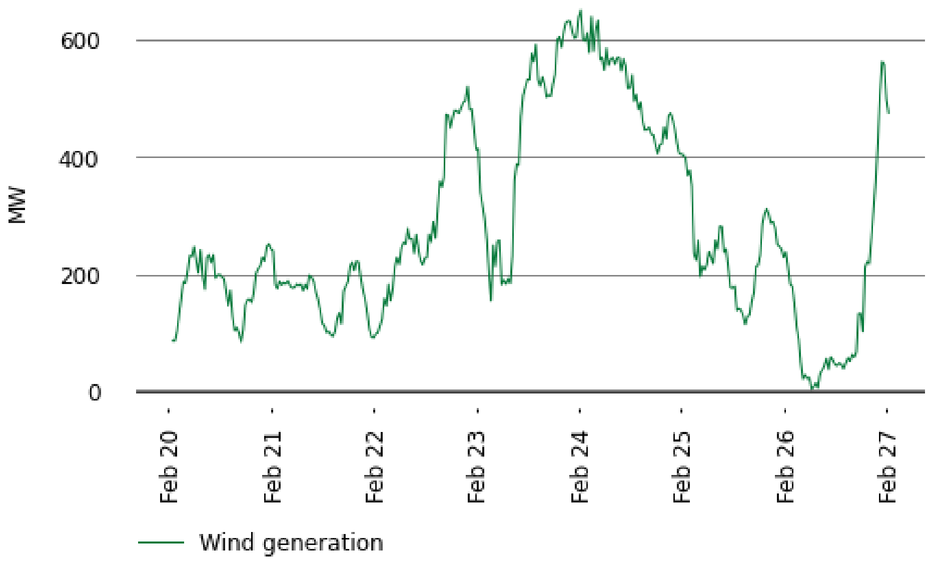
Figure 10: Electricity risk curves and hydro supply



Wind conditions

5.2. Total wind generation was 48GWh, similar to last week, and contributed about 7% of total generation. Wind generation was low, frequently below 200MW, at the start of the week, which contributed to high North Island prices during the HVDC outage. Wind generation generally increased on 22 and 23 February and reached over 600MW on 24 February, at which point prices dropped below $1/MWh. Wind generation dropped later in day on 24 February, decreasing to 0MW on 26 February before rising again.

Figure 11: Wind generation by trading period



Significant outages

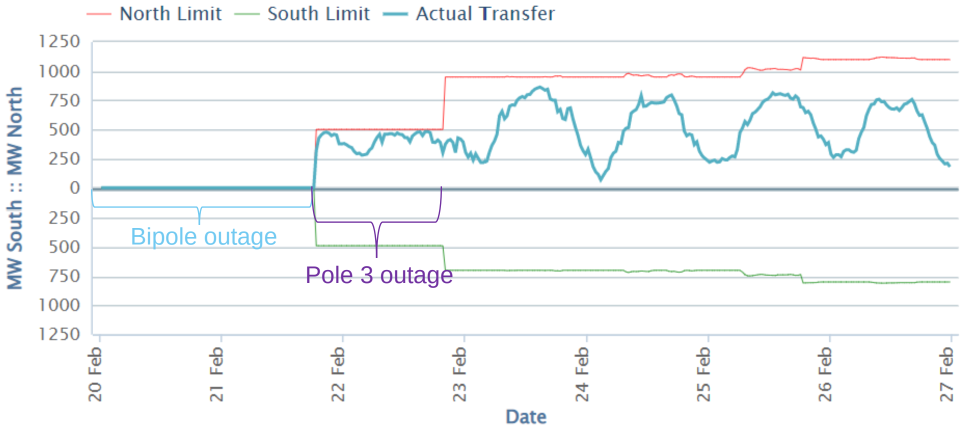
HVDC outage

5.3. There was a planned outage of the HVDC this week, which started on 17 February. Pole 2 was on outage from 17 February at 5am, expected back on 20 February[2] at 10pm, and Pole 3 was on outage from 19 February at 5am. However, on 20 February the Grid Owner identified urgent work on Pole 2 and extended the outage by one day. This resulted in an extension of the bipole outage until 6:30pm on 21 February.

5.4. Figure 12 shows that the HVDC transfer each day, as well as the transfer limits and outages. On 20 February and until 6:30pm on 21 February there was a full bipole outage which separated the market into two. North Island generation was needed to meet North Island demand, which was higher on 21 February as it was a weekday, driving up the price. Conversely prices were very low in the South Island due to excess supply. From 6:30pm on 21 February until 6:30pm 22 February pole 2 was back in service, with a transfer limit of 500MW. Transfer North was frequently at or close to the limit, which caused price separation between the two islands.

[2] This outage was extended and instead pole 2 returned to service after 6:30pm on 21 February. This will be covered in more detail in next week's Trading Conduct Report.

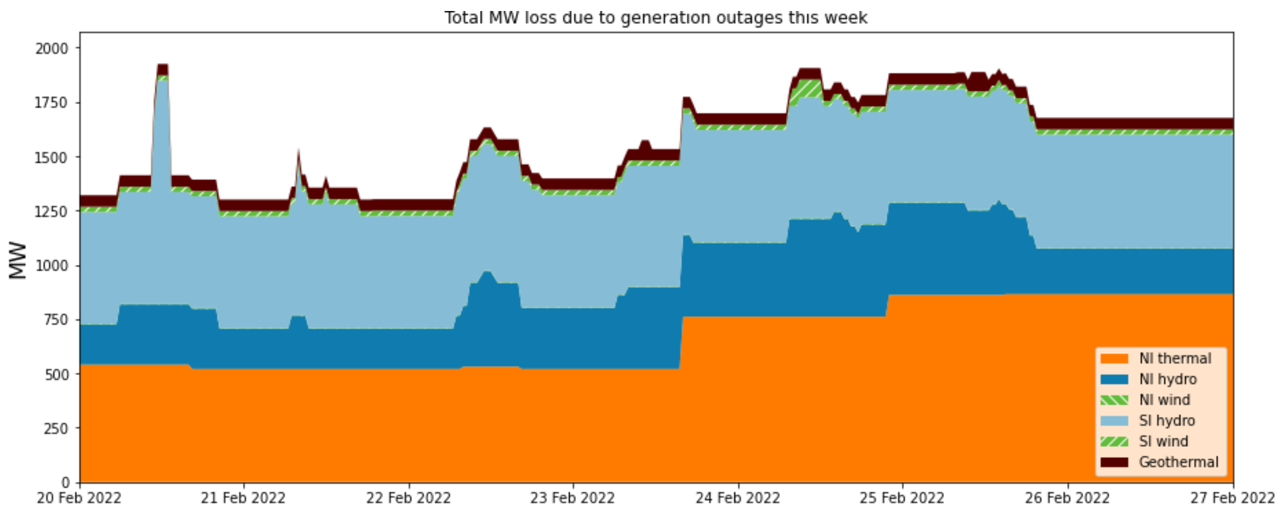
Figure 12: HVDC transfer, HVDC limits and HVDC outage



Generation outages

5.5. At the start of the week just over 1250MW of generation was on outage, which increased to over 1750MW on 24 February. Huntly unit 4 went on outage on 23 February, reducing Rankines back to two units, though Genesis has yet to be able to run all 3 Rankines so far this year. Stratford Peaker 2 also went on outage at 10pm on 24 February, meaning both peakers are now on outage. Several hydro units in both the North and South Island were on outage at various times this week, including a large but brief outage at Ohau on 20 February.

Figure 13: Total MW loss due to generation outages



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

(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 – 21 March)

(e) Manapouri, 125MW (23 January – 4 March)

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

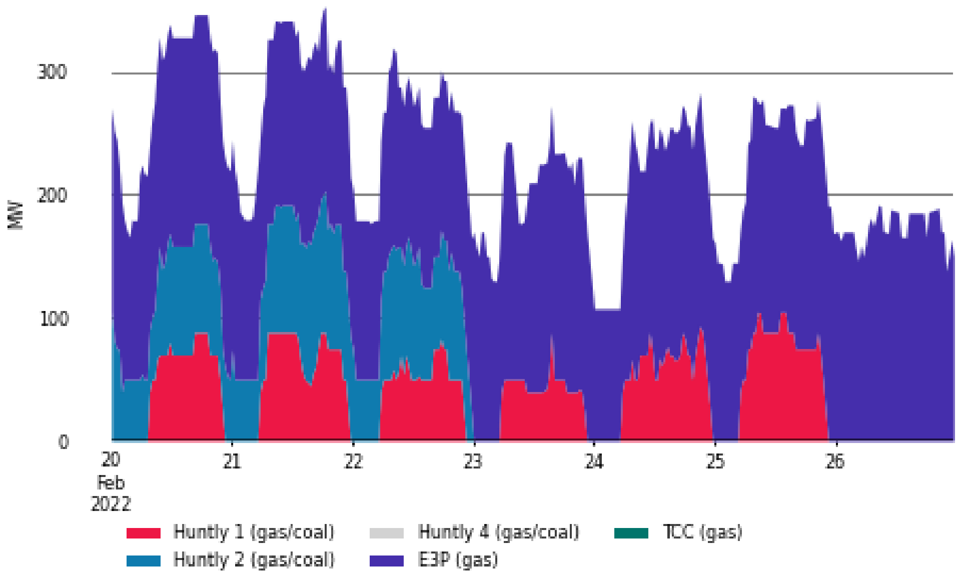
(g) TCC, 350MW, (22 January - 28 February)

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

Thermal conditions

5.7. Overall, thermal generation contributed 15% of total generation this week. The E3P continued to run as baseload. Two Rankines units ran during the HVDC outage, with one running on the weekdays since. The third Rankine unit was available during the HVDC outage but did not run due to high river temperatures and has returned to outage.

Figure 14: Generation from baseload thermal by trading period

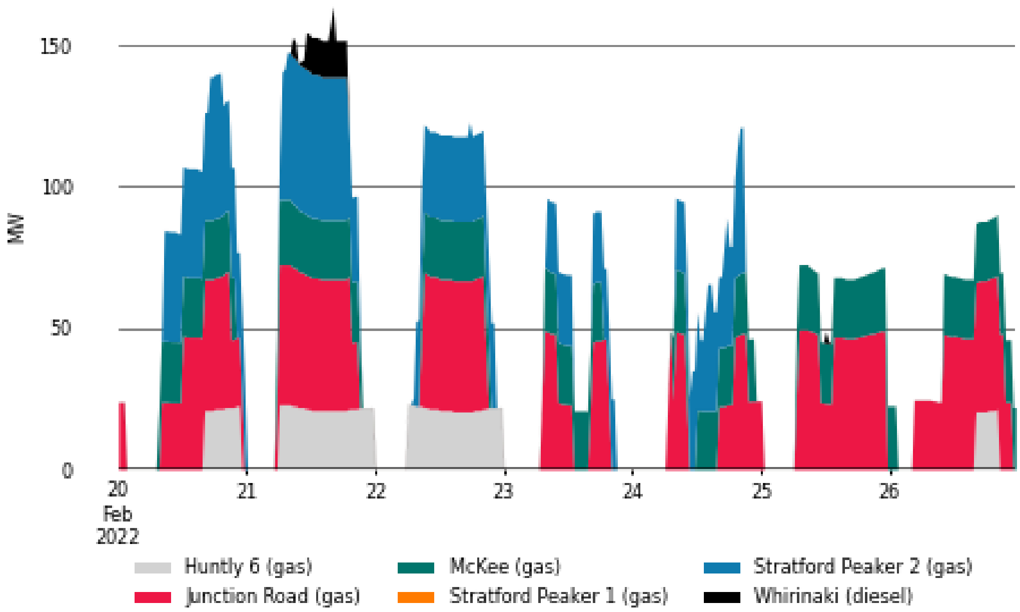


5.8. Generation from thermal peakers was highest during the HVDC outage. The unexpected extension of the bipole outage on 21 February resulted in Whirinaki being dispatched for a significant portion of the day when prices were above $500/MWh. Output from Whirinaki was highest at TP33 when the price was highest. During this trading period thermal generation made up a quarter of total generation, double its output at the same time the previous week.

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

5.9. Stratford Peaker 2 went on outage on 24 February, while Stratford Peaker1 remains on outage. On 25 February for a short period Whirinaki was dispatched while generation from other peakers was below 50MW. While Whirinaki was offered at a price below estimated SRMC, likely to cover the loss of both Stratford Peakers, it is unusual for Whirinaki to be dispatched before other available thermal peakers, with both Junction Road and Huntly 6 available to the market at the time. Further analysis of these trading periods will be done.

Figure 15: Generation from thermal peakers by trading period



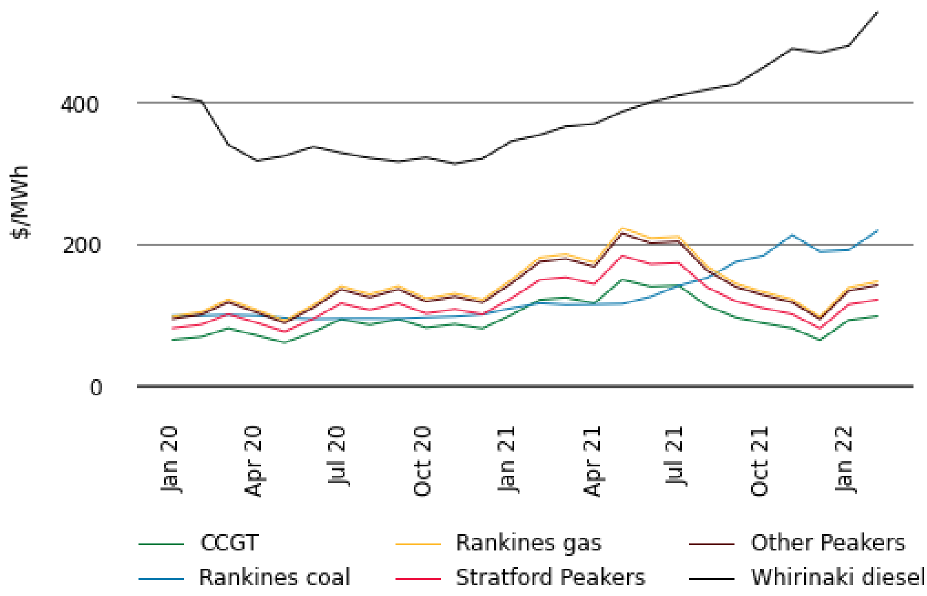
6. Price versus estimated costs

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 16 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January and February (to 20 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 continued to increase this year, recently reaching $85/tonne.

Figure 16: Estimated monthly SRMC for thermal fuels



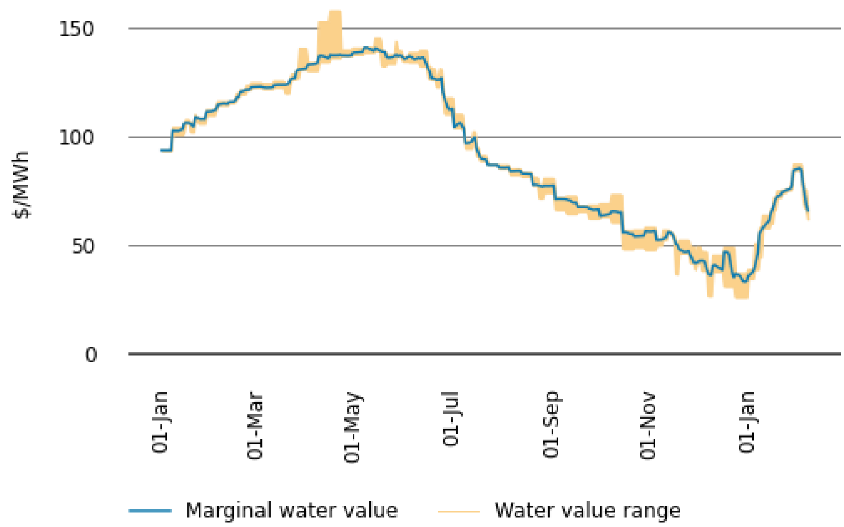
JADE Water values

6.3. The JADE[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 17 shows the national water values[5] 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[6].

6.4. Figure 17 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.

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

Figure 17: JADE water values for January 2021 to February 2022



Monthly prices

6.5. Figure 18 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 18: Average monthly prices at Otahuhu and Benmore last 12 months

7. Offer Behaviour

Daily Offer Stacks

7.1. Figure 19 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[7] The black line shows the cleared energy, indicating the range of the average final price. Note that the black line does not indicate actual prices observed from 20 to 22 February due to the HVDC outage which caused price separation between the North and South Island.

7.2. The Ohau outage made a noticeable difference to generation offered on 20 February. However, due to the HVDC outage this did not impact the North Island and energy prices remained low in South Island.

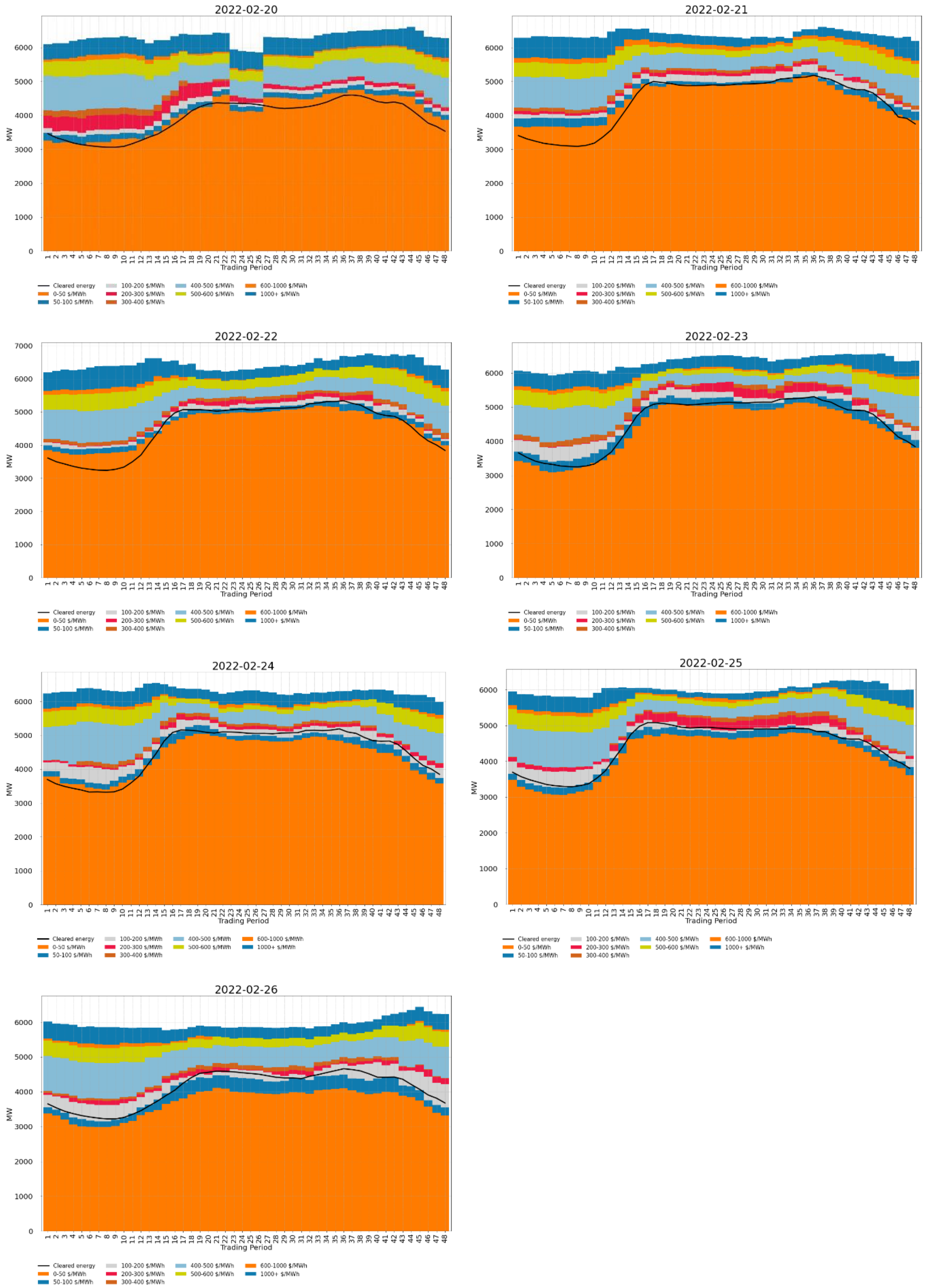
7.3. More generation was offered at low prices on 21 February, despite low wind, as higher levels of generation were required in the North Island due to the bipole outage. While the figure for cleared generation looks like prices would have cleared at below $100/MWh for most of the day, prices in the North Island were actually upwards of $500/MWh.

7.4. Tekapo B unit 3 was returned from outage on 19 February at 5pm but was offered at prices above $1500/MWh despite high storage at Lake Tekapo until the end of the HVDC outages. Prices in the South Island were only $0.03/MWh during the bipole outage but were as high as $150/MWh on 22 February when only pole 3 was on outage. Information received from Genesis about these offers is being reviewed.

7.5. Observable on February 25, the outage of Stratford Peaker 2 resulted in a reduction of offers between $100-$200/MWh where Contact was usually offering its available generation, but an increase in generation offered between $200-$300/MWh as Contact reduced the offer price of Whirinaki.

[7] The offer stacks show all offers bid into the market (where wind offers are truncated at their actual generation and excluding generation capacity cleared for reserves) in price bands and plots the cleared quantity against these.

Figure 19: Daily offer stack



Offers by trading period

7.6. The offer stacks of TP25 on 21 February is shown on Figure 20 along with the generation weighted average price (GWAP) and cleared generation. This is the trading period when Whirinaki was briefly dispatched. The same trading period from the day before is shown in Figure 21.

7.7. Cleared generation was higher on 24 February than 25 February, but the resulting GWAP was similar. This was partly due to lower wind generation, which reduced the quantity offered at a very low price. There was also less generation offered just below $200/MWh on 25 February as the Stratford Peakers were on outage and more generation offered between $200 and $300/MWh.

Figure 20: Offer Stack for trading period 25 on 25 February

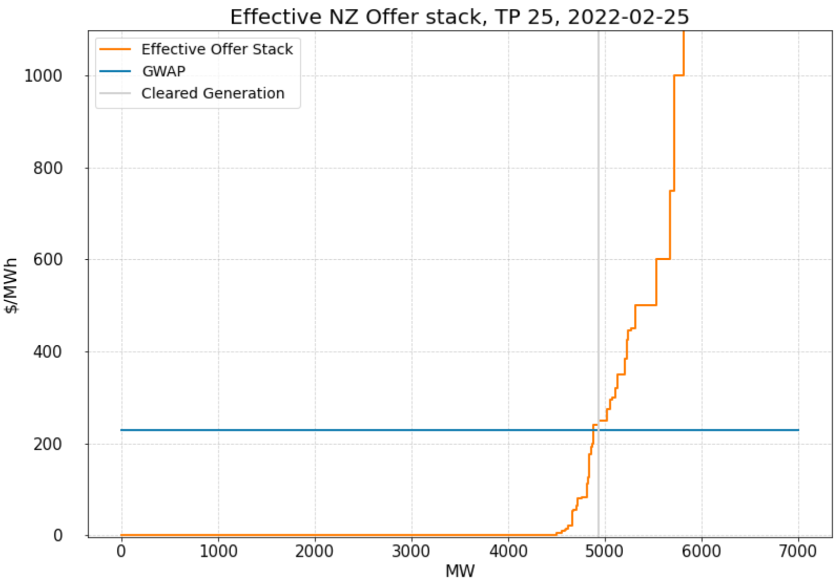
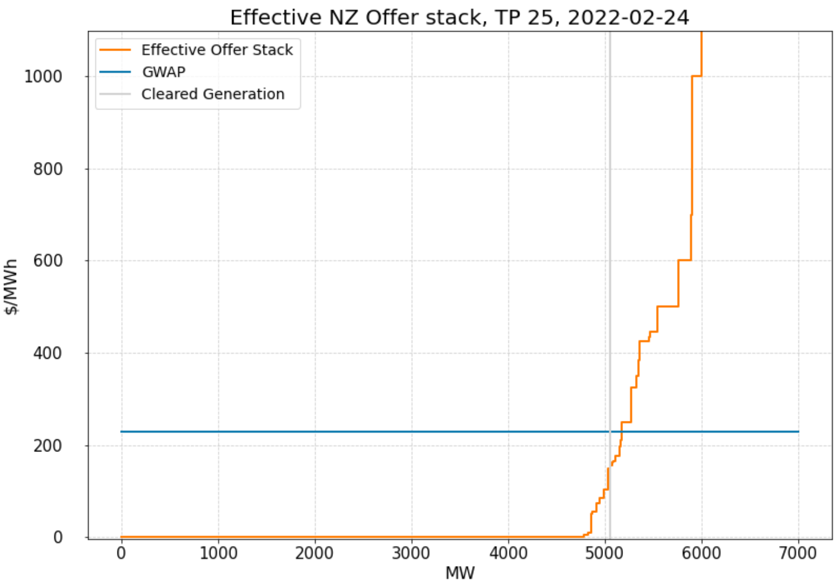


Figure 21: Offer Stack for trading period 25 on 24 February



8. Ongoing Work in Trading Conduct

8.1. Further analysis will be done of energy offers on 25 February and of reserve offers in the South Island during the bipole outage.

8.2. The Authority is reviewing information received from Genesis regarding offers from Tekapo B while Lake Tekapo was spilling.

8.3. Further analysis of high FIR prices identified in previous reports found that they were due to SPD co-optimisation of the energy and reserve markets. In these cases, the energy market cleared at a point on the offer curve where the next highest offer price was substantially higher than the marginal offer price. Clearing higher priced reserves prevented higher energy prices and resulted in overall lower costs to the market. Also, on 8 February reserve requirements increased and interruptible load decreased. This created a tighter FIR market, increasing the chance of higher priced FIR. Evidence does not suggest that reserve offers were changed to increase either reserve or energy prices. These trading periods have been noted as 'Resolved' on the Table 1.

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
25/02	23-27	Further analysis	Whirinaki dispatched while other thermal peakers had capacity
19/02-24/02		Further Analysis	High priced offers at Tekapo-further information received
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
08/02, 10/02	16-17, 19	Resolved	High FIR prices were due to co-optimisation with energy market, high reserve dispatch and drop in IL
03/02	32	Resolved	High FIR prices were due to co-optimisation with energy market.
19/01-20/01	Several	Resolved	High FIR prices were due to co-optimisation with energy market.
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[8], where diff is the first difference:

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

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

8. ε_t, the residuals of ARMA errors (from AR(5)), should not significantly different from white noise. Ideally, we expect the ARIMA errors are purely random, and are not correlated with each other (show no systematic pattern). ARIMA errors equals y_t minus the estimate $\hat{y}$ with their five time lags.

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

Appendix B 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.[9] 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.[10] A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well-known and widely accepted modelling tool for hydro-thermal optimisation in electricity systems. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load.

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.[10]

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

[9] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.
[10] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

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 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