12 January 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the period of 19 December to 8 January

1.1. Note, this report is covering the period of 19 December to 8 January, three weeks of data instead of one. 25 December to 28 December and 1 January to 4 January were public holidays. Standard weekly reporting will resume from next week.

1.2. It is unclear if all prices from the last three weeks reflect supply and demand conditions. Prices were low for the first two weeks due to low demand, but prices increased from 2 January. Further analysis will be done to ensure the price increase reflected demand and supply conditions and that offers were in line with the trading conduct provisions.

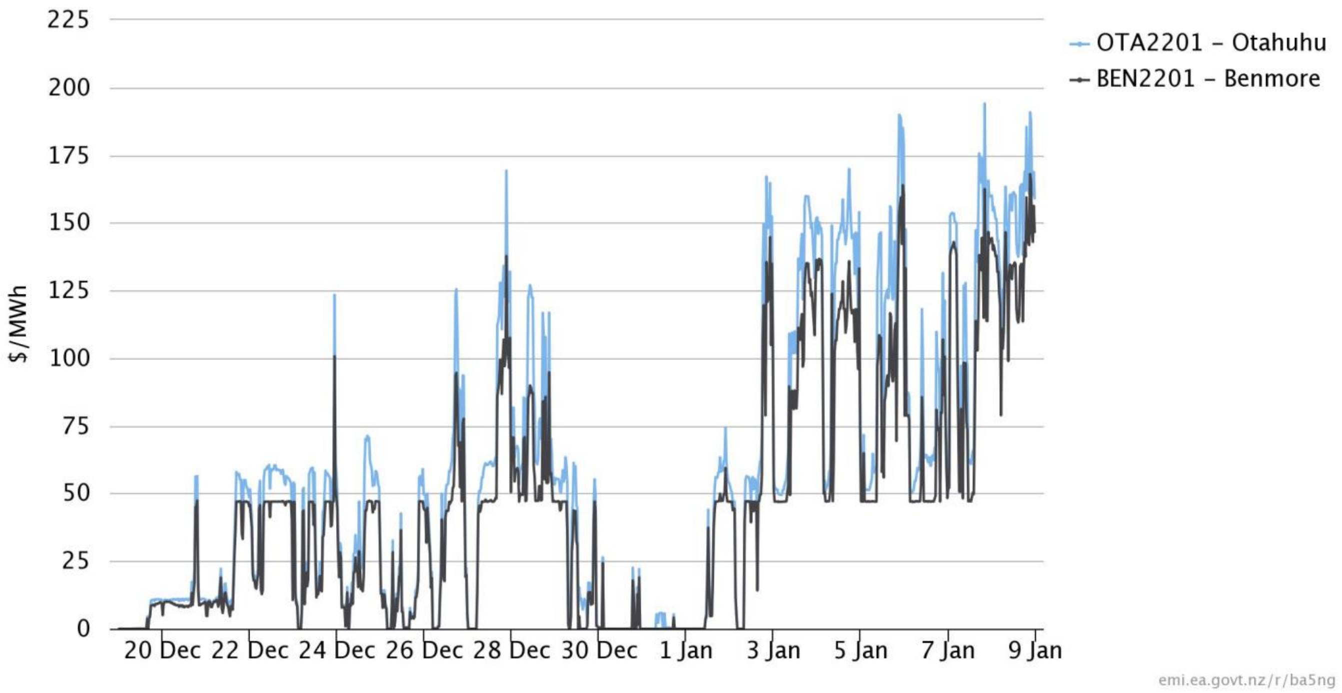
2. Prices

Energy prices

2.1. The average weekly spot price was $23/MWh[1] for the week starting 19 December, $31/MWH for the week starting 26 December, and $98/MWh for the week starting 2 January. Between 19 December and 2 January prices at Benmore were usually below $50/MWh. The highest price of $179/MWh at Otahuhu occurred at TP43 on 8 January, and almost all the high prices occurred in the week starting 2 January. The only price above $150/MWh that occurred in the first two weeks was TP43 on 27 December.

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

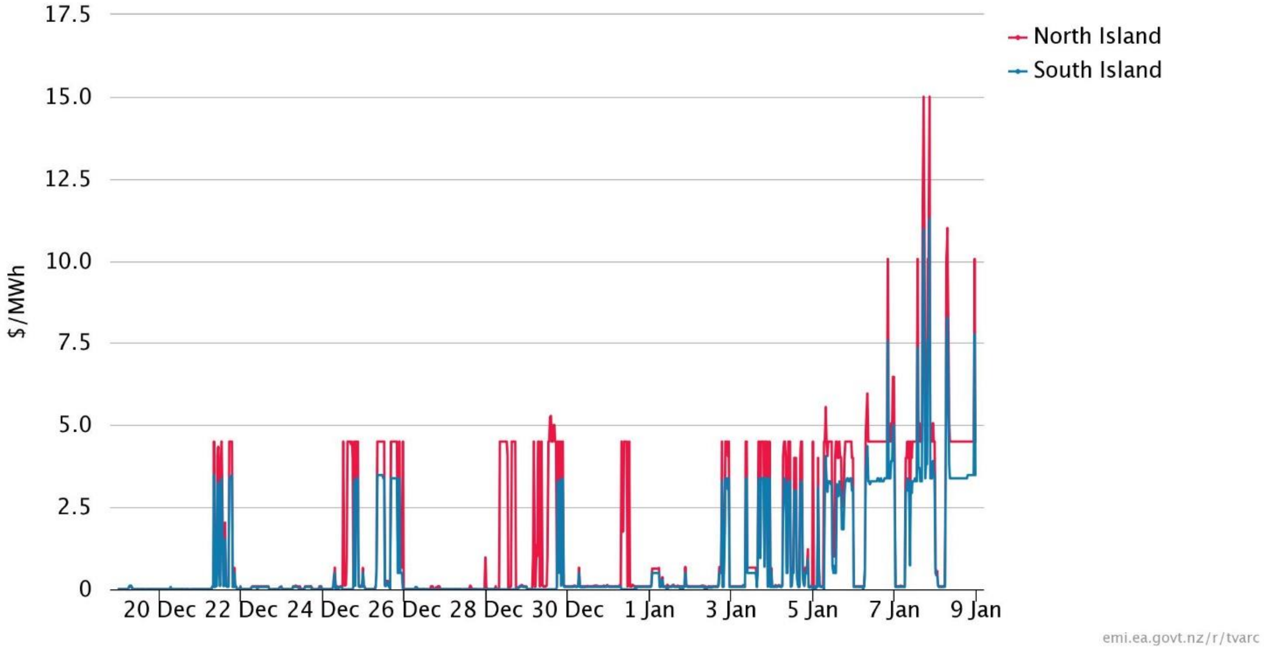
Figure 1: Spot prices by trading period at Otahuhu and Benmore



Reserve Prices

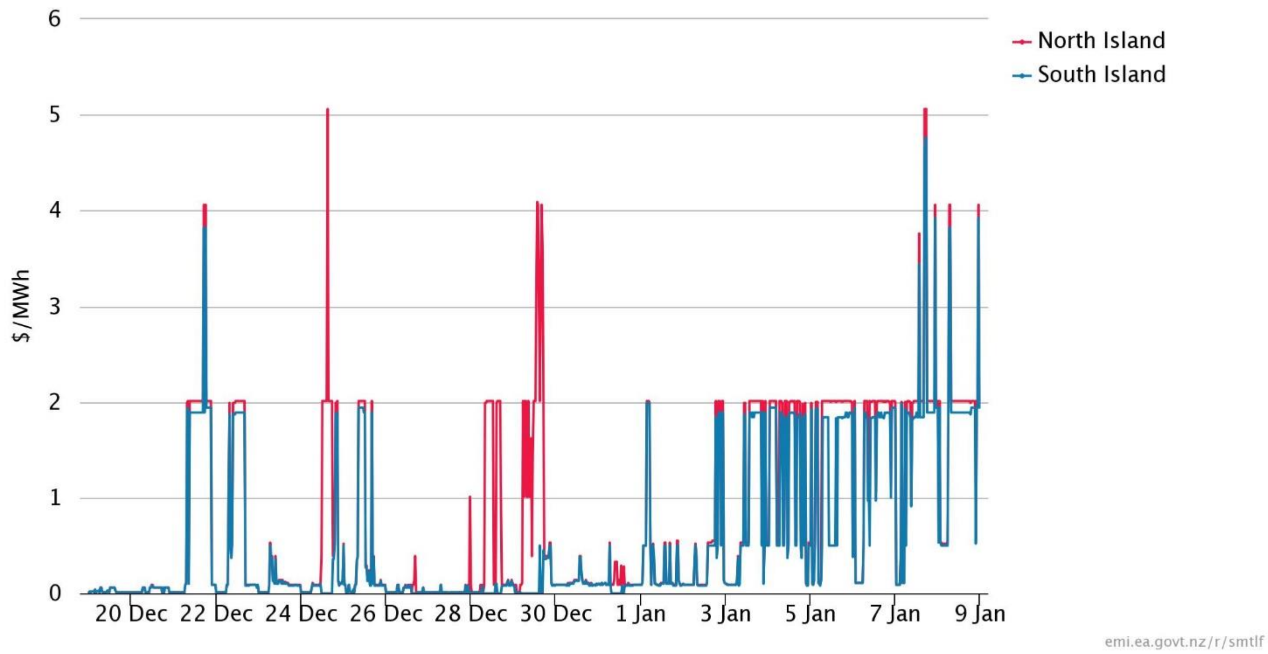
2.2. Fast instantaneous reserves (FIR) prices were usually below $5/MWh from 19 December to 5 January. Prices were higher from 6 to 8 January, but still below $15/MWh.

Figure 2: FIR prices by trading period and Island



2.3. Sustained instantaneous reserves (SIR) prices were below $6/MWh during the entire 3 weeks, with very low prices frequently occurring between 19 December and 2 January.

Figure 3: SIR prices by trading period and Island

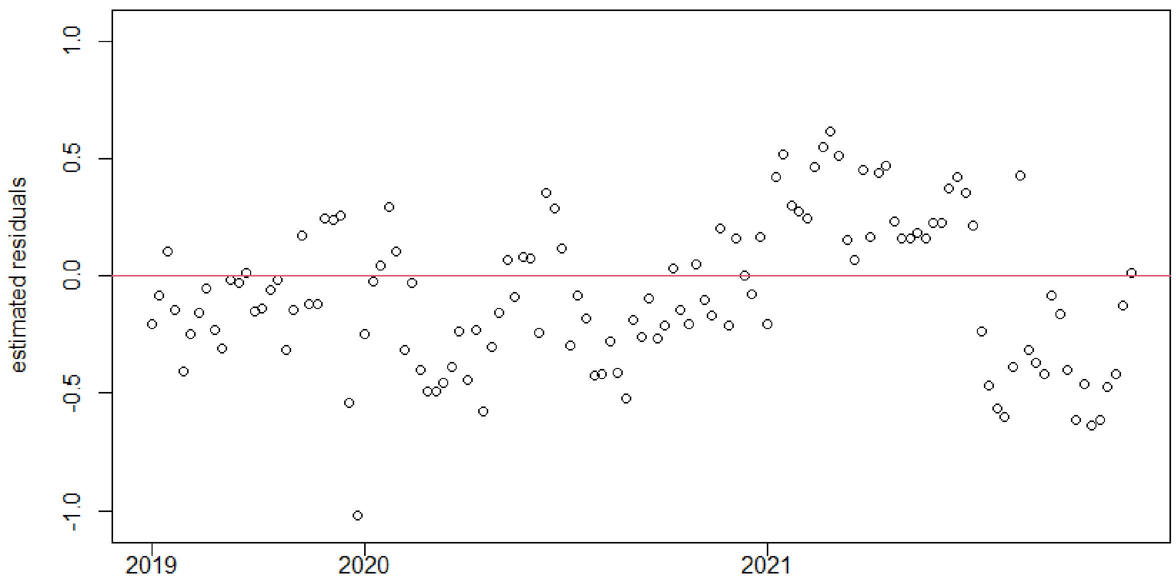


Residuals from regression models

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.

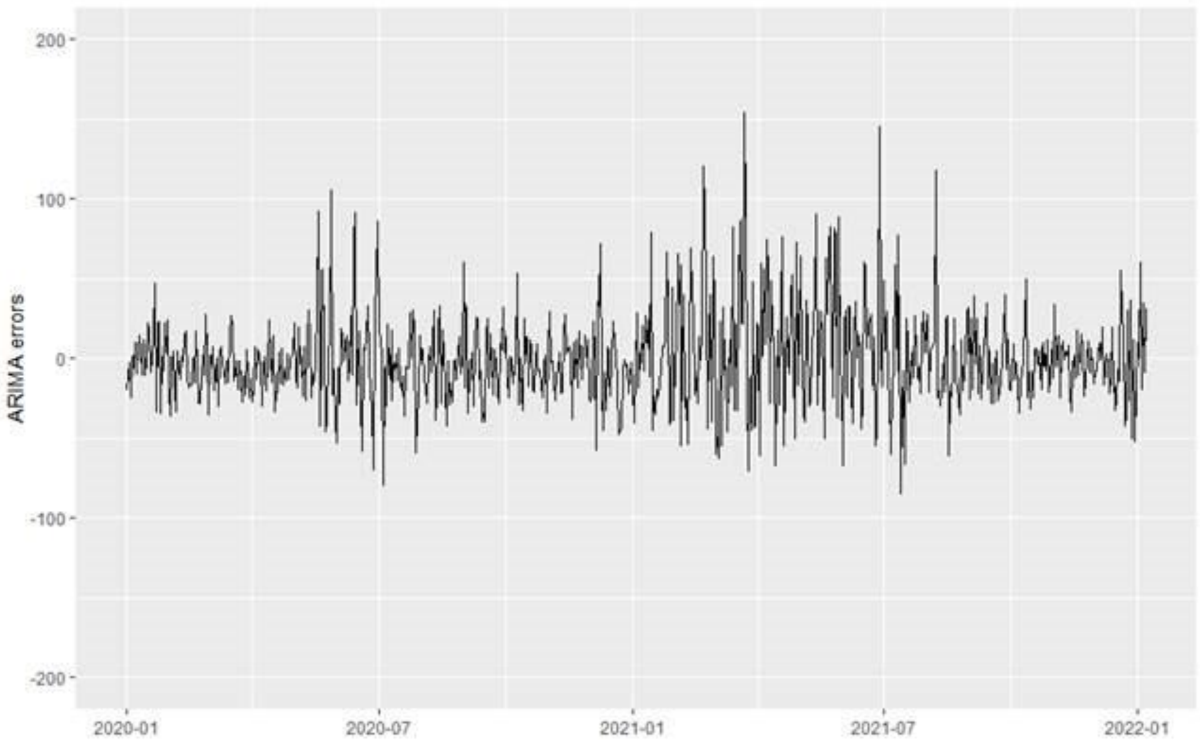
2.5. Figure 4 shows the residuals from the weekly model. During November 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 4: Residual plot of estimated weekly price from 2 July 2019 to 25 November 2021



2.6. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. The last 3 weeks the daily residuals were within the normal range but were larger than recent residuals. Historically residual values were low over this period so this may warrant further analysis.

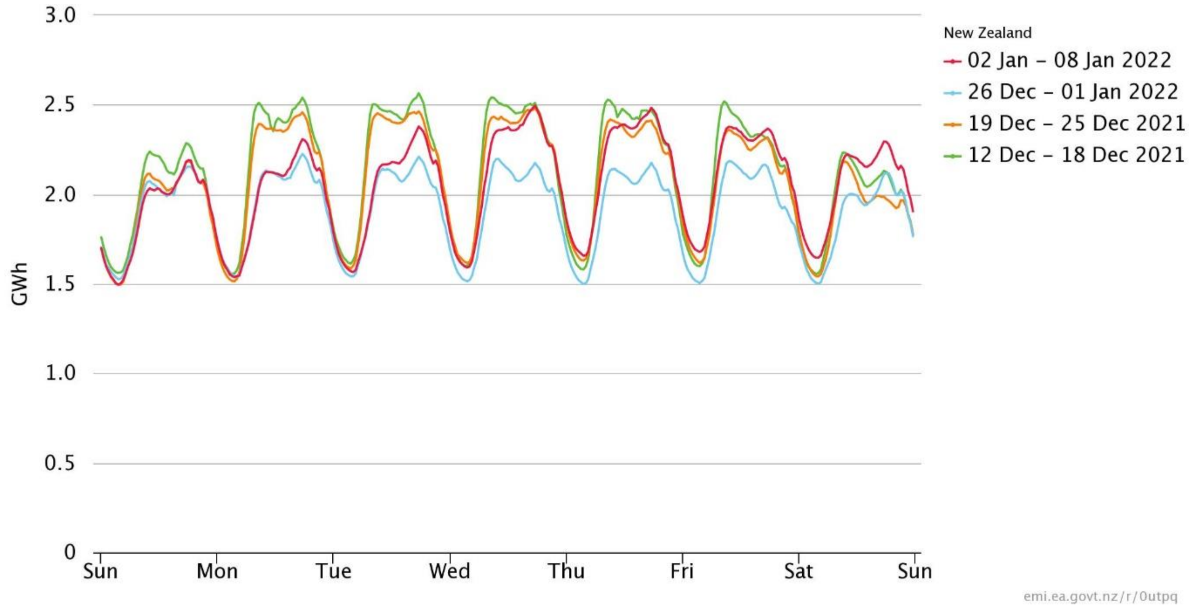
Figure 5: Residual plot of estimated daily average spot price from 1 January 2020 to 8 January 2022



3. Demand Conditions

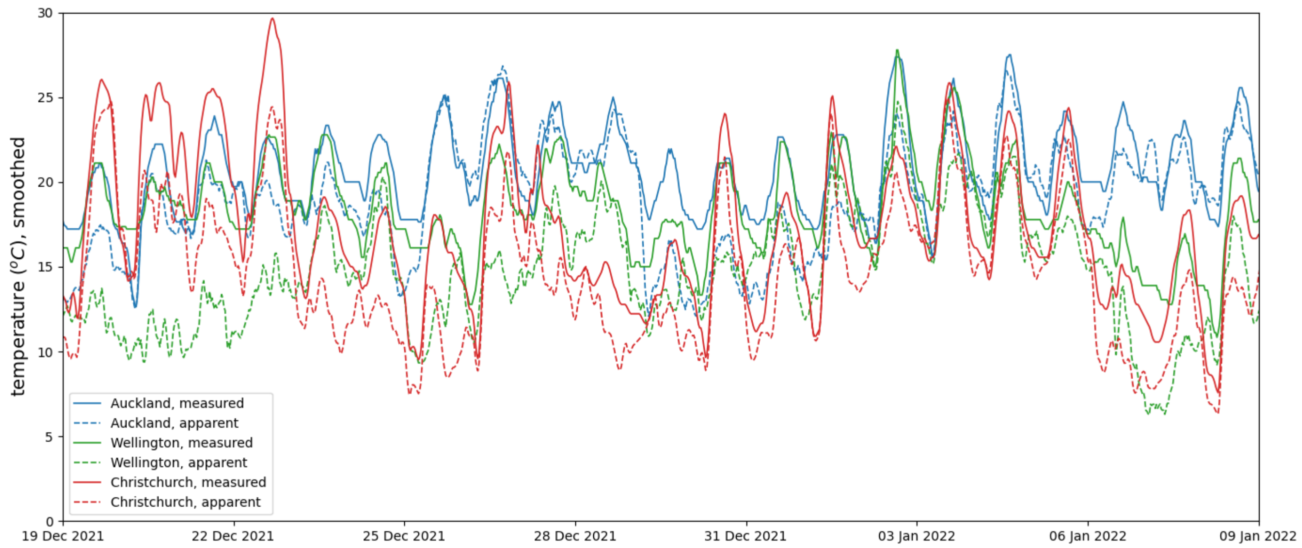
3.1. National demand was low over the 3 weeks, particularly between 25 December and 4 January (see Figure 6). Many businesses were closed for this period, including 29 to 31 December, which were not official public holidays. Demand started decreasing before 25 December with a noticeable decline each day between 22 and 25 December. There was also a noticeable increase in demand on 5 January - the first official business day of 2022, but demand was still lower than seen in the week 12 to 18 December especially in the morning.

Figure 6: National demand by trading period for each week from 12 December to 8 January



3.2. Figure 7 shows the 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 warm it feels. Temperatures were warm over this period, with almost all measured temperatures between 10° and 30°. From 1 to 5 January all the main centres had particularly warm temperatures (both measured and apparent). There was higher evening demand on these days likely due to increased load for cooling, such as for air conditioning and fans. This higher evening demand also occurred on 8 January which was also a warm day.

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

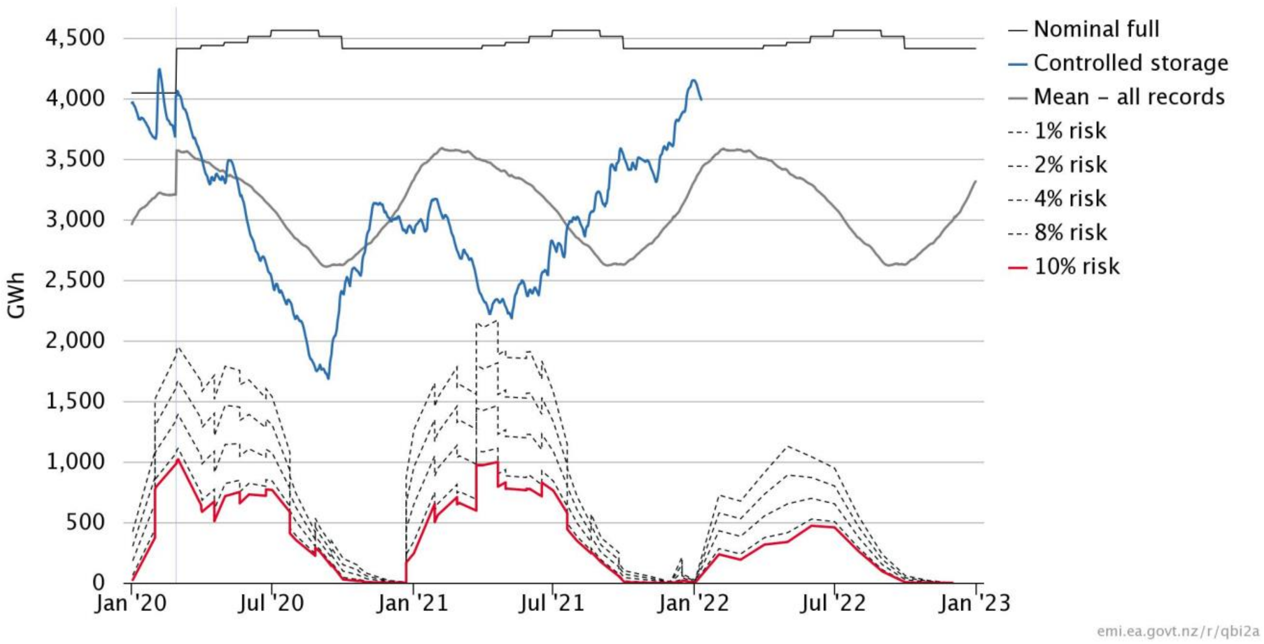


4. Supply Conditions

Hydro conditions

4.1. National hydro storage increased between 19 and 31 December, reaching 4,149 GWh, shown in Figure 8. However, low inflows caused storage to decline from 1 January and storage is currently just below 4,000 GWh.

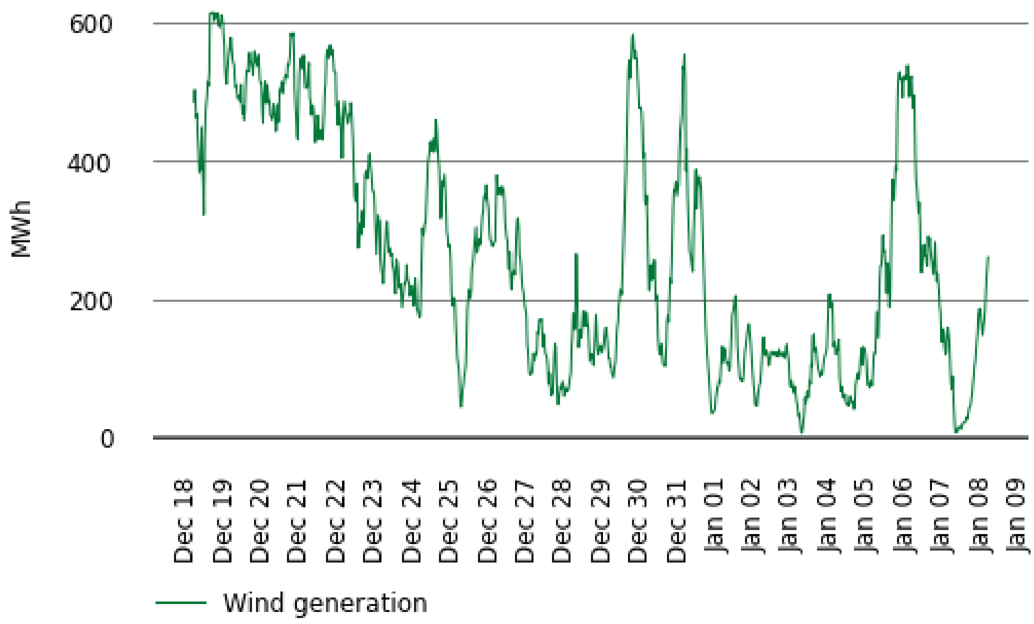
Figure 8: Electricity risk curves and hydro supply



Wind conditions

4.2. Wind generation was variable over the last three weeks, with a period of high wind generation between 18 and 22 December and another period of low wind generation between 1 and 5 January. Higher prices over the last three weeks tended to occur during periods of low wind generation.

Figure 9: Wind generation by trading period



Significant outages

Generation outages

4.3. Most of the generation outages over the last 3 weeks were long term outages with a few short-term outages that did not have a significant impact on prices.

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

(a) Clyde,

(i) 116MW (2021-29 April 2022)

(ii) 116MW (21-22 December 2021)

(b) Tekapo, 80MW (13 Sept 2021-16 January 2022)

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

(d) Benmore, 90MW (0730-1600 20 December 2021)

(e) Manapouri,

(i) 125MW (0700-1630 22 December 2021)

(ii) 125MW (0800-1100 30 December 2021)

(f) Ohau, 66MW (0600-1600 20 December 2021)

(g) Waikaremoana, 93MW (8-9 January 2022)

(h) Huntly, Rankine unit; 240MW (4 October – 26 January 2021)

(i) Junction Road, 50MW (2-22 December 2021)

(j) Stratford peakers,

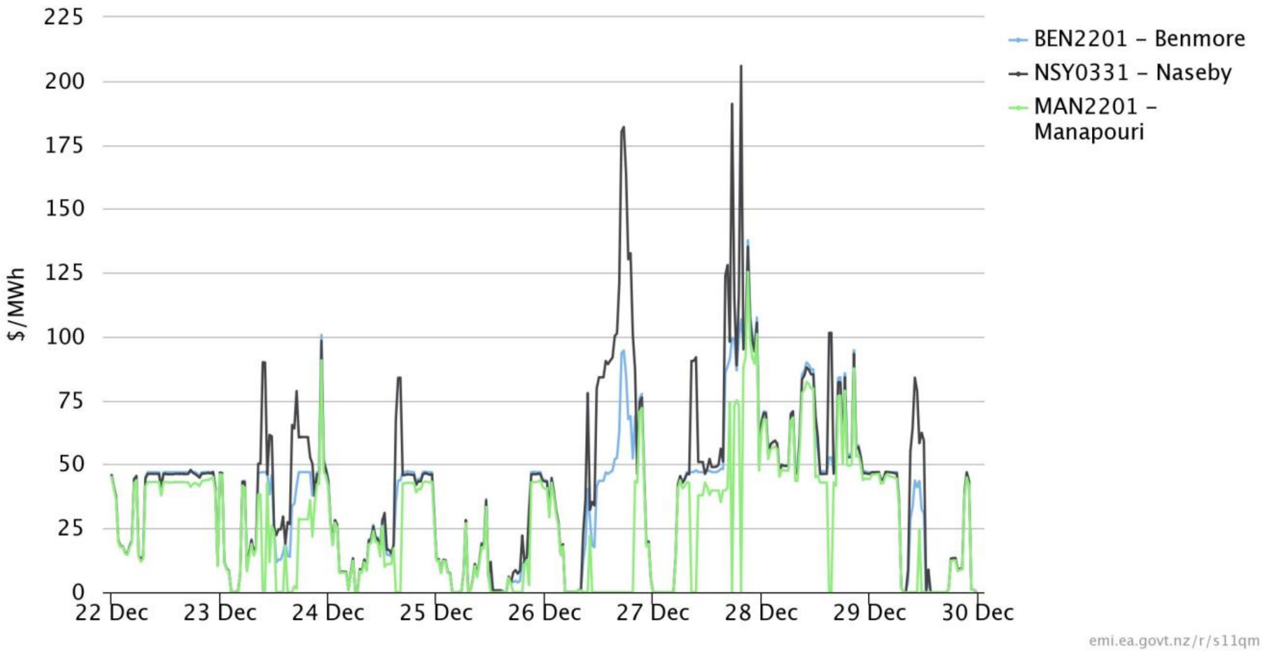
(i) 100MW, (31 October 2021 – 15 April 2022)

(ii) 100MW (1400-1500 21 December 2021)

Binding constraint

4.5. Between 22 and 29 December the branch between Naseby and Roxburgh constrained several times. This resulted in price separation between Manapouri and Naseby, shown in Figure 10. Generation from the lower South Island was constrained and this caused higher prices north of the constraint, especially on 27 December when wind generation was low.

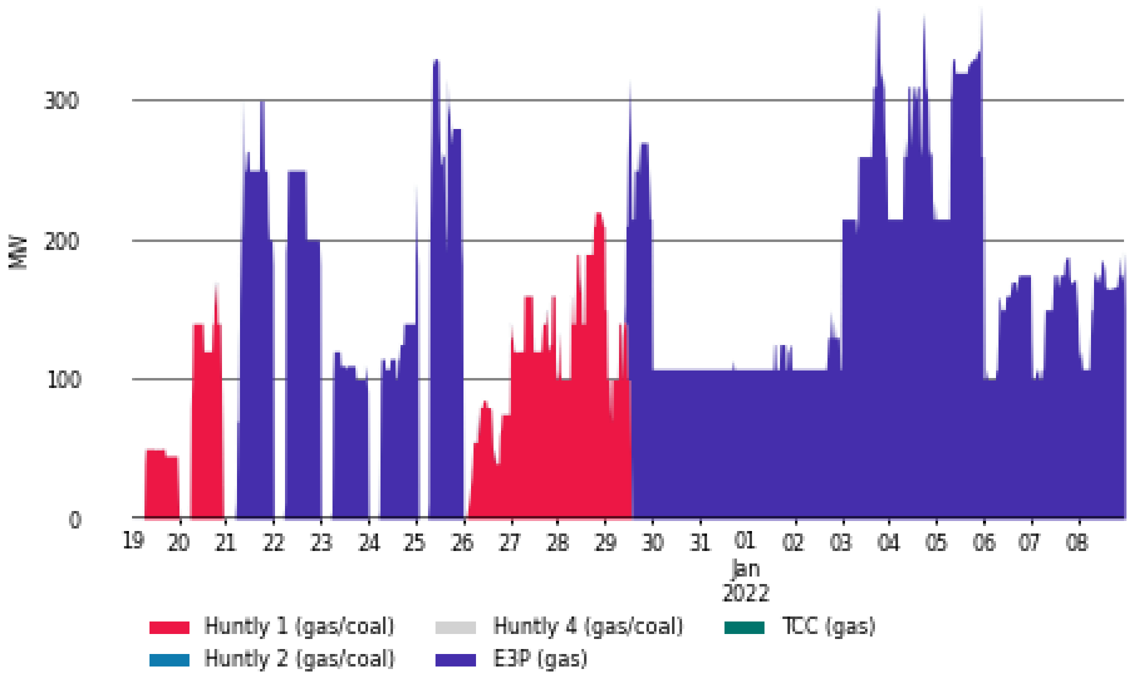
Figure 10: Prices in Lower South Island by trading period 22-29 December



Thermal conditions

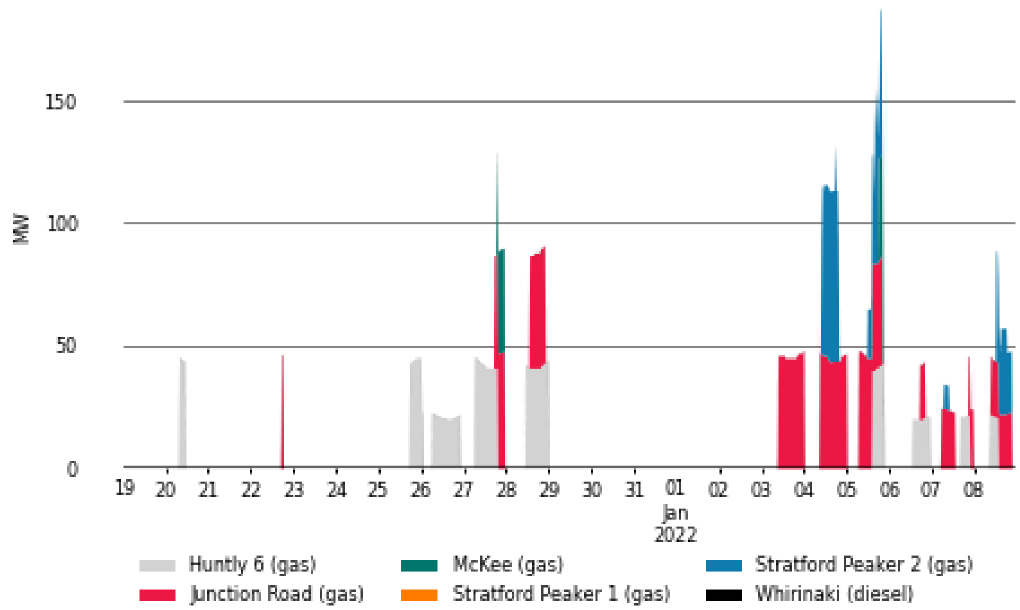
4.6. Genesis ran either E3P or Huntly 1 as baseload generation during the last three weeks.

Figure 11: Generation from baseload thermal by trading period



4.7. Thermal peakers ran between the 25 and 28 December, when generation out of the lower South Island was constrained and wind generation was lower, especially on 27 December. Thermal peakers were also running between 3 and 8 January, with output highest on 5 January which was the first business day of the year, as well as a day with low wind generation and warm temperatures.

Figure 12: Generation from thermal peakers by trading period



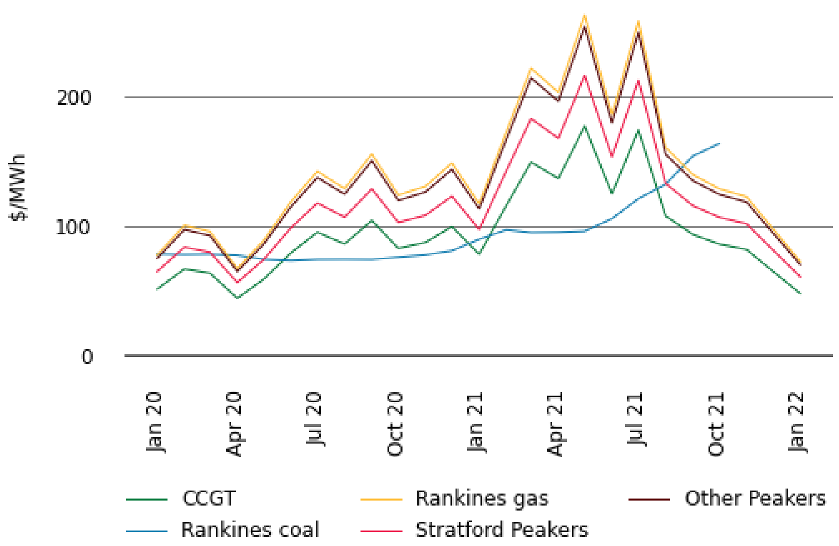
5. Price versus estimated costs

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 12 shows estimates of thermal SRMCs as a monthly average. The thermal SRMC of gas (to 9 January) has decreased while the SRMC of coal has increased over the last few months. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.

Figure 13: Estimated monthly SRMC for thermal fuels



DOASA Water values

5.3. The DOASA[2] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 14 shows the national water values[3] obtained from DOASA up to end of October 2021. The outputs from DOASA closest to actual storage levels are shown as the yellow water value range. These values are used to estimate marginal water value at the actual storage level, indicated by the blue line[4]. Figure 14 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased.

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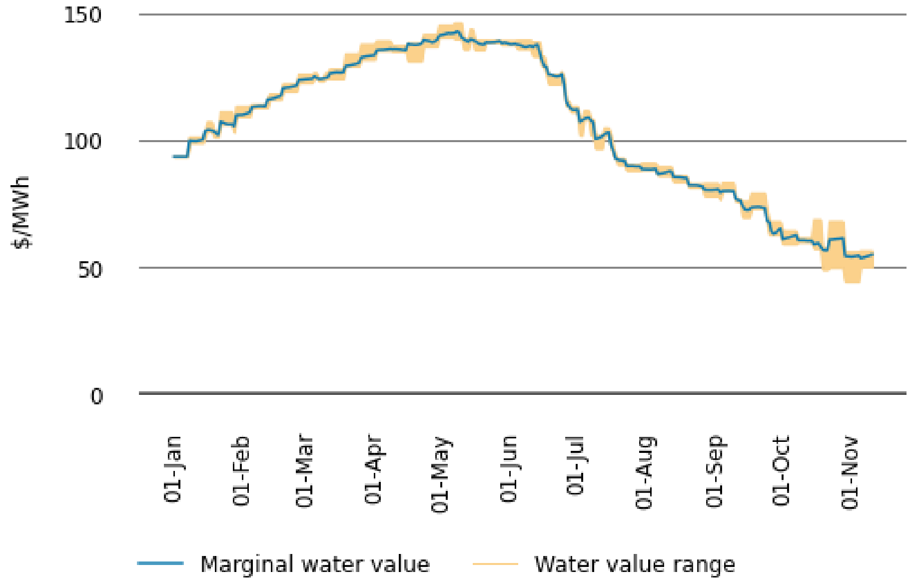
[2] DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market. (More details in Appendix B)
[3] The national water values are estimated assuming all hydro storage reservoirs are equally full.
[4] See Appendix B, 2 for more details

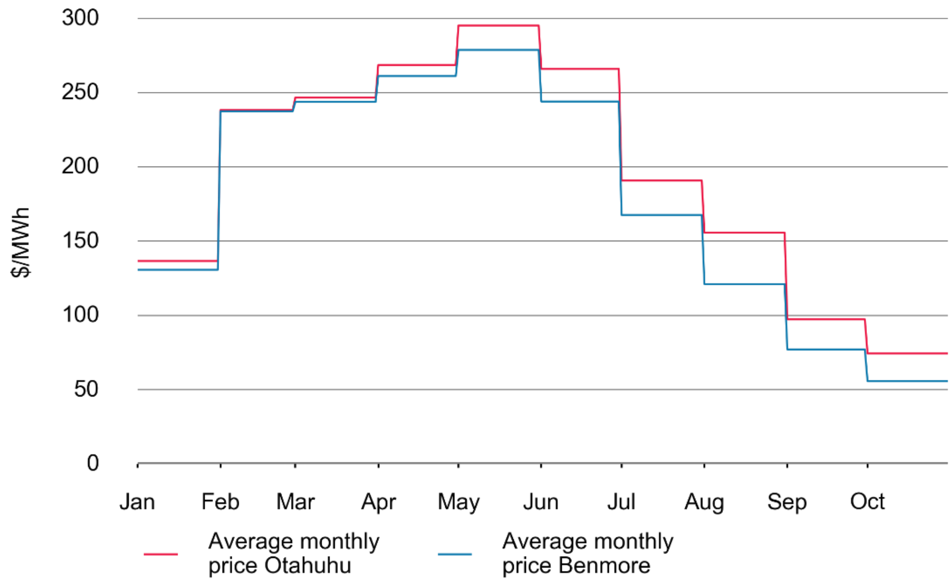
Figure 14: DOASA water values for January to November 2021



Monthly prices

5.4. 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.

Figure 15: Average monthly prices at Otahuhu and Benmore January-October 2021



Ongoing Work in Trading Conduct

5.5. Further analysis will be done to understand why prices increased from 2 January and if offers were in line with the trading conduct provisions.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
02/01-08/01	Several	Further Analysis	High energy prices, low wind, low demand
30/06-20/08	Several	Compliance: review	High energy prices in shoulder periods
30/06-21/08	Several	Compliance: review	Withdrawn reserve offers

Appendix A Regression Analysis

1. The Authority's monitoring team has developed two regression price models. The purpose of these models is to understand the drivers of the wholesale spot price and if outcomes are indicative of effective competition.

Weekly Model

2. The weekly model is an updated version of the model published in https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf, Section 8, pg. 21-25

3. The regression equation is

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

where P_t is the PPI and trend adjusted weekly average spot prices; t =week 1,…,52 for each year; i = spring, summer, autumn, and winter

Daily Model

4. The daily model estimates the daily average spot price based on daily storage, demand, gas price, wind generation, the HHI for generation (as a measure of competition in generation), the ratio of offers to generation (a measure of excess capacity in the market), a dummy variable for the period since the 2018 unplanned Pohokura outage started, and the weekly carbon price (mapped to daily). The units for the raw data are as following: storage and demand are GWh, spot price is $/MWh, gas price is $/PJ, and wind generation is MW, carbon price is in New Zealand Units traded under NZ ETS, $/tonne.

5. We used the Augmented Dicky-Fuller (ADF) to test all variables to see if they are stationary. If not, we tested the first difference and then the second difference using the ADF test until the variable was stationary. The first difference of a time series is the series of changes from one period to the next. For example, if the storage is not stationary, we use $storage_t - storage_{t-1}$.

6. We fitted the data using a dynamic regression model with Autoregressive with five lags (AR(5)). Dynamic regression is a method to transform ARIMAX (Autoregressive Integrated Moving Average with covariates model) and make the coefficients of covariates interpretable.

7. Once we dropped the insignificant variables; the ratio of offers to generation, the dummy variable for 2018 and carbon price, we got the following model[5], where diff is the first difference:

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

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

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.

[5] 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.[6] DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[7] A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well-known and widely accepted modelling tool for hydro-thermal optimisation in electricity systems. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load.

2. The DOASA model outputs the marginal water value for a range of storage levels. The marginal water value, y, at the actual storage level, x, is estimated using the outputs closest to actual storage level (x_1, y_1) and (x_2, y_2) using the equation

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

3. The following are some of the limitations of the assumptions in the DOASA model:

    a. Load is based on forecasts for future periods and recent periods where reconciled data was not yet available.

    b. Forecast plant and HVDC outages based on current POCP data

    c. The estimated thermal fuel costs used in DOASA may not accurately represent what hydro generators face, in terms of thermal generator offers. Hydro generators must manage their storage levels within the context of volatile thermal fuel prices and availability, and the thermal fuel cost estimates may not perfectly represent these.

    d. Non-dispatchable plant, such as wind, is modelled as having constant power output instead of stochastic power output

    e. Some hydro station head ponds and major reservoirs are governed by complex resource consent rules. The model limits used in DOASA are necessarily somewhat simplified and may not accurately reflect the actual flexibility of these limits.

    f. Inflow probability distributions are based on past inflow sequences.

    g. DOASA does not directly model stagewise dependence (i.e., from week to week) of inflows, e.g., if it was wet last week, it's more likely to be wetter this week as well. However, DOASA approximates this effect by an approach called Dependent Inflow Adjustment (DIA), which artificially increases the variance of historical inflows when generating the cutting planes.[7]

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

    a. DOASA does a forward solve (linear programming), so as long as the objective values are the same, it is likely to use all water from one reservoir first until it hits some constraint, before moving to the next reservoir. This leads to the likely extreme usage of small reservoirs (i.e., not using water proportional to total national storage by either holding back or letting it all go).

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

[7] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

b. Therefore, small (constrained) reservoirs in DOASA are expectedly more likely to hit maximum or minimum levels or constraints, and this will be reflected in the water values (high price if likely to hit minimum level and low price if likely to hit maximum level).

c. National water values are calculated based on absolute total national storage, not absolute individual reservoir storage, which tends to make the water values less volatile. That is, if we had two reservoirs with the same capacity and one had storage at 10 percent of capacity and the other at 90 percent, the national water value is based on total storage of 50 percent of total capacity