# Market performance review of Spring 2018

## Market performance review

17 March 2020

# Executive summary

This paper covers specific issues that arose during the spring of 2018, but that were not covered in the undesirable trading situation (UTS) decision paper, which examined part of the same period. These issues are:

- The November HVDC outage
- Thermal generator offer behaviour when gas constrained
- The hedge disclosure database
- The availability of public information on gas production.

This paper concludes that:

1. While Transpower did not consider the Pohokura outage when assessing the risk of the HVDC outage, it has subsequently put effort into improving its processes
2. Thermal generation offers were an important source of information during the Pohokura outage. The situation could have been improved by a platform on which generators could outline their fuel constraints
3. Hedge disclosure data is increasingly important and needs to be improved
4. The publicly available information on gas production is useful, but takes some knowledge to interpret

The first conclusion is specific to Transpower's risk assessment and is of great interest given the upcoming gas outages over summer 2019/20. Authority staff have been in regular communication with Transpower regarding these outages and it is evident that Transpower is paying much closer attention to what it is assuming about thermal fuel leading up to the 2020 HVDC / Pohokura outage; indicating that it learned from the lessons of spring 2018.

There is a common theme of needing to improve information disclosure in conclusion 2, 3 and 4. It is clear that gas market information will continue to have a high value for the electricity industry and play an important determinant of spot and forward electricity prices. Partly as a result of the review, the Authority has commenced a project to review information disclosure needs and issues raised with thermal fuel related disclosure.

Gas market information disclosure is also being reviewed by the Gas Industry Company (GIC). The GIC finished consulting on an information disclosure problem assessment paper when cross submissions closed on March 11 2020. They are now considering the next steps for each of the information issues that were identified in the paper. Some issues are likely to be taken forward to a Statement of Proposal (SOP) where options for addressing identified information problems are reviewed. Other issues may be progressed through other avenues and some may be assessed as not requiring further work.

Petroleum Exploration and Production New Zealand (PEPANZ), along with major gas producers and Flex Gas (the owner/operator of the Ahuroa gas storage facility) are actively working to develop an industry-led Upstream Gas Outage Information Disclosure Code (Code) for gas production and storage outages. The GIC will assess this Code as one of the options for addressing information issues in the gas sector in its SOP process. As an interim step, GIC is currently hosting a voluntary information notifications page on its website for all industry participants.

# Contents


Executive summary ii

1 Overview 1

3 High prices in spring 2018 were the result of market conditions 2
There was a gas shortage at Pohokura 5
Hydro fuel had limited availability 6
Demand had increased 7
Outages were scheduled 9

4 The November HVDC outage 10
Transpower continued planning to proceed with the outage after Pohokura became public knowledge 10
There was ample time to reconsider the risks of this outage 11
During the outage, Transpower made the decision to bring the HVDC back into service during peak load (morning and evening) 11
An error in the system operators dispatch tools overstated security concerns on the 22nd and 23rd 12
There no evidence that there would have been a shortfall on the 25th or 26th of November 14

5 Thermal offers during the Pohokura outage 18

6 Hedge disclosure data needs to be improved 23
Data quality issues 23
Download speed 23
Option contracts 23

7 Publicly available gas production information 23
OATIS scheduled and metered quantity data 24


## Figures


Figure 1: Simple daily average spot prices 2
Figure 2: Timeline of events during spring 2018 3
Figure 3: Settlement price trends Otahuhu Monthly Contract October 2018 4
Figure 4: Settlement price trends Otahuhu Quarterly Contracts 4
Figure 5: Marginal price setter by fuel type and island 2018 5
Figure 6 Cumulative inflows in South Island for 2018 6
Figure 7: Controlled hydro storage and hydro risk curves 2018 7
Figure 8: Monthly consumption (including Tiwai) 8
Figure 9: Monthly consumption at Tiwai 8
Figure 10 Generation outages, according to POCP 9
Figure 11: Timeline of the HVDC outage with reserve over-procurement and spot prices 13
Figure 12: 26th November FIR Pre-dispatch as at 4pm 25th November 14
Figure 13: 26th November Energy Pre-dispatch as at 4pm 25th November 15
Figure 14: 26th November FIR Pre-dispatch as at 8am 25th November 16
Figure 15: 26th November FIR Pre-dispatch as at 8am 25th November 17
Figure 16: Prices for the 26th and 27th November, single pole vs bipole 18
Figure 17: e3p offers for week beginning 1 October 19
Figure 18 Sample of pre-dispatch offers for week beginning 1 October 20

Figure 19 e3p offers for week beginning 8 October 21
Figure 20 Sample of pre-dispatch offers for week beginning 8 October 21
Figure 21 e3p offers for week beginning 3 September—prior to the Pohokura outage 22
Figure 22 Sample of pre-dispatch offers for week beginning 3 September 22

# 1 Overview

1.1 Spring is usually an uneventful time in the electricity market; the high demand of winter is over, and snow melt and spring rains contribute to high inflows into the hydro lakes, providing plenty of spare capacity. However, spring 2018 was an outlier, with high wholesale prices, security of supply concerns and wide spreads for short-dated baseload contracts on the ASX market.

1.2 There was a UTS claimed on 8 November 2018 and the UTS decision paper was released in February 2019, investigating the period between 15 September 2018 up to the claim date. The decision paper found that a UTS did not occur during the investigation period.

1.3 This review will not cover concerns already addressed in the decision paper on the UTS or subsequent compliance processes. Instead it will take a wider view of the events of Spring 2018 and look into the following which have not been covered elsewhere:

(a) The market conditions which lead to high prices

(b) The November HVDC outage

(c) The nature of thermal offers while gas was in short supply

(d) How hedge disclosure information could be improved

(e) Where publicly available gas information can be found

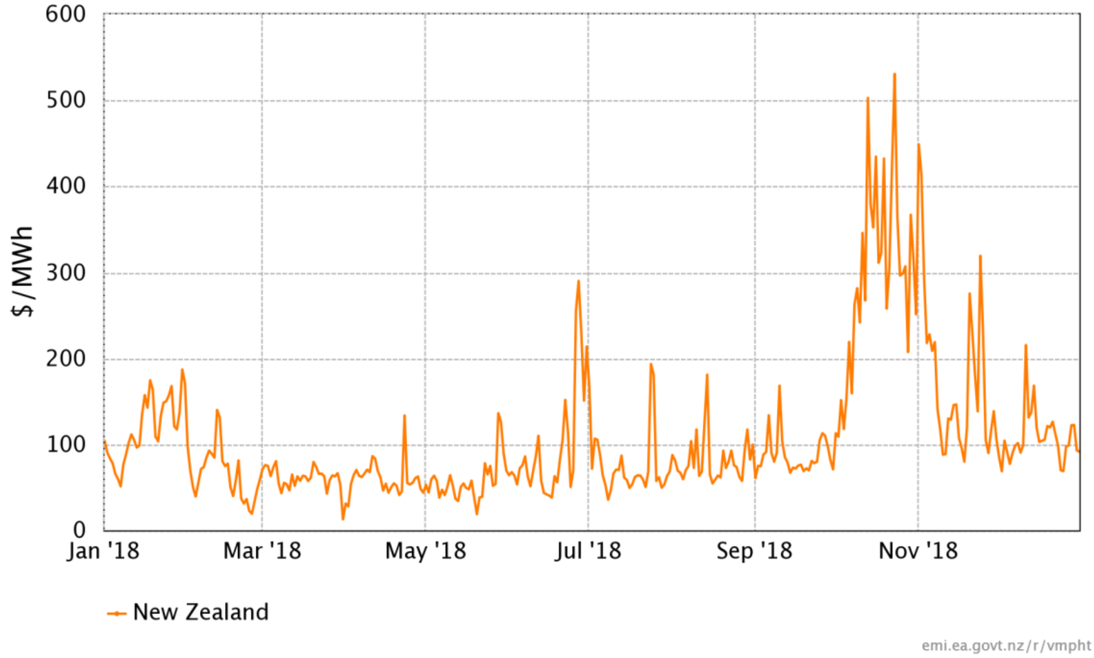
1.4 This review contains a number of images that are produced by various monitoring tools that the Authority uses to understand market conditions. These tools complement our real time monitoring tools and allow us to look back at market events in some detail.

# 3 High prices in spring 2018 were the result of market conditions

3.1 Spring 2018 was characterised by periods of unexpected high prices from September to November. Wholesale prices were especially high during the period of the 14th September to 2nd November.

3.2 The main cause of these high prices were market conditions; a gas shortage due to the Pohokura outage, a shortage of water in hydro schemes and increased demand. This was also exacerbated by planned outages that occurred during this period as there was not expected to be any supply concerns. Outages for maintenance are often planned to occur during spring or early summer.

**Figure 1: Simple daily average spot prices**




3.3 For most of 2018, the average spot price was below $100/MWh, with the daily average price peaking at $290/MWh in mid-winter. In October the average daily price was $293/MWh and peaked at $531/MWh. Spot prices in October 2018 were the fifth highest monthly average spot price on record.[1] Spot prices from the end of the investigation period until the end of 2018 dropped considerably and averaged $126.49/MWh.

[1] After adjusting all prices to 2018 dollars.

**Figure 2: Timeline of events during spring 2018**

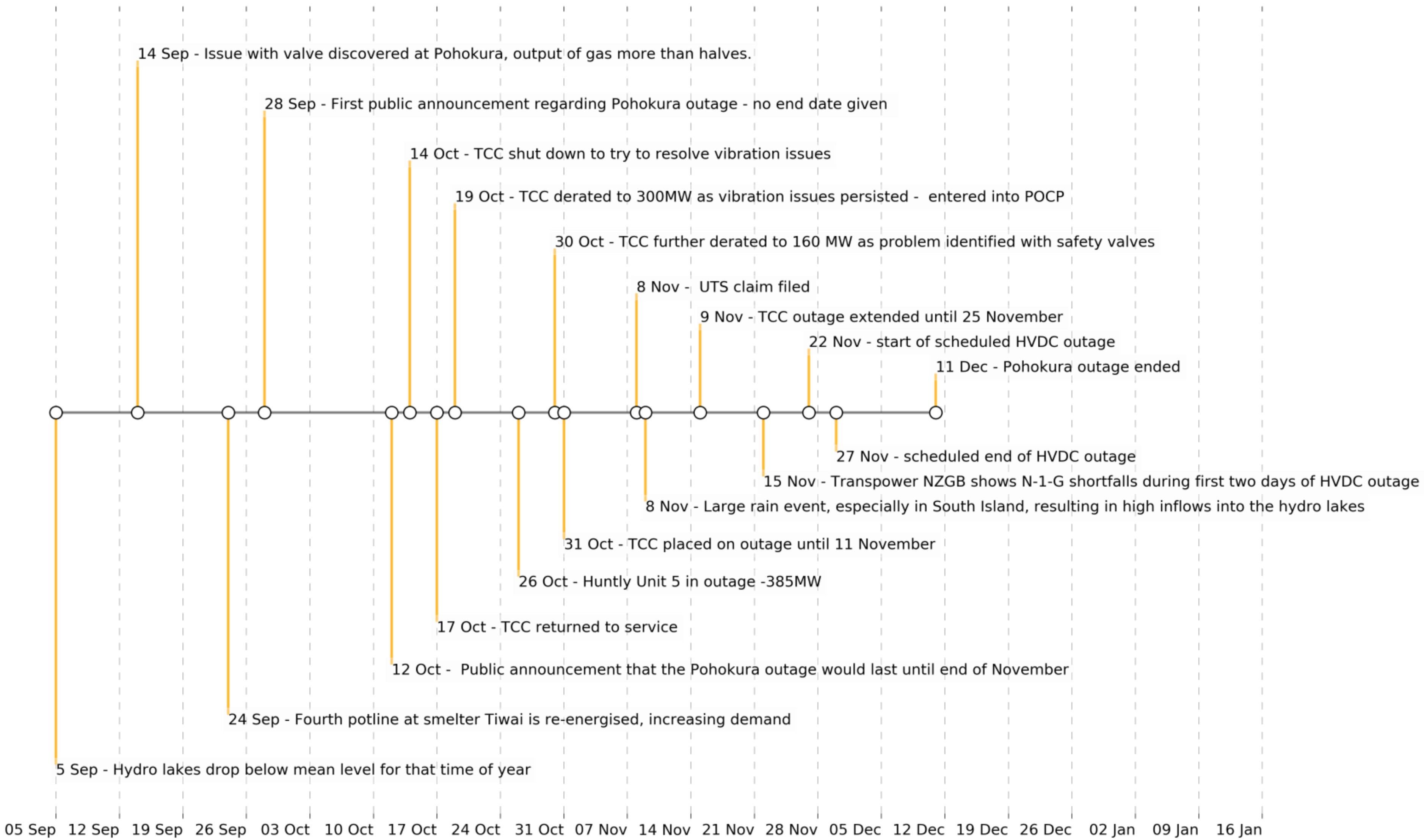
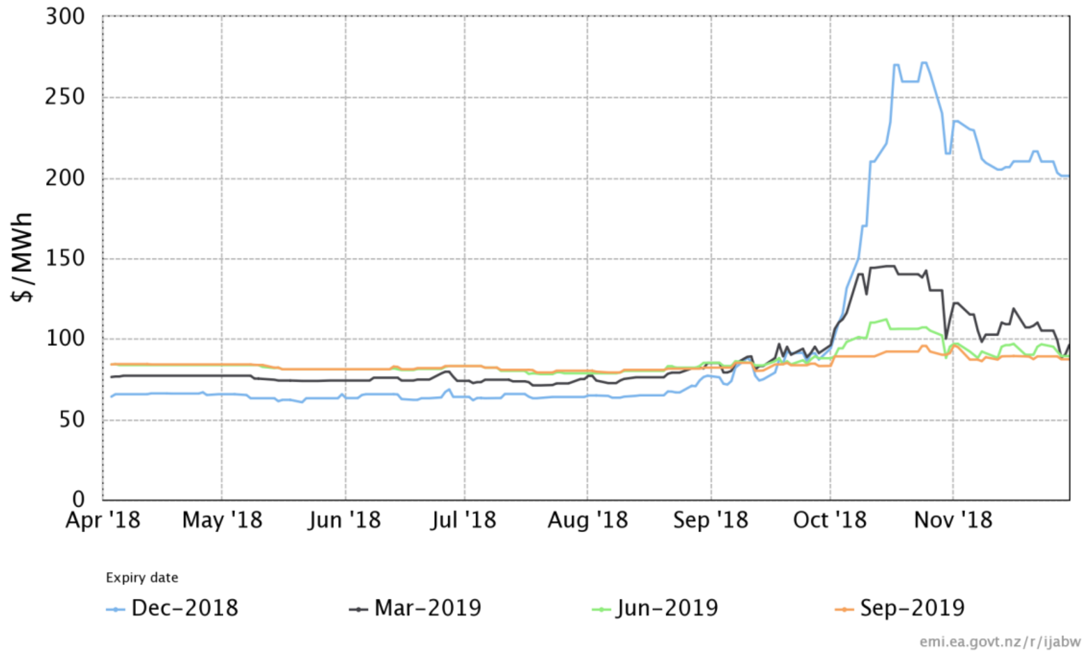


**Figure 3: Settlement price trends Otahuhu Monthly Contract October 2018**


3.4 The increase in the wholesale spot price led to an increase in the short term monthly and quarterly future prices, reconciling the difference between what had been expected to happen prior to the gas outage and what was happening as a result of the outage.

3.5 The price for October monthly was about $70/MWh until September 2018, when it increased slightly, potentially due to declining hydro storage. The prices increased dramatically to $300/MWh once the Pohokura shortage was announced publicly.

**Figure 4: Settlement price trends Otahuhu Quarterly Contracts**




3.6 Similar price changes can be seen for the quarter ending December prices, which also increased from around $65/MWh prior to the start of spring, up to $271/MWh after the outage was announced. The prices for the first quarter of 2019 also increased, likely due to uncertainty of how long the outage would last and the ongoing impact it could have. The outage had a declining impact on future prices for each subsequent quarter.

3.7 High prices can have a detrimental impact on retail businesses and large electricity consumers. However, prior to the start of Spring 2018 there was plenty of opportunity for retailers to hedge at $65/MWh for Spring up to $85/MWh during the following winter.

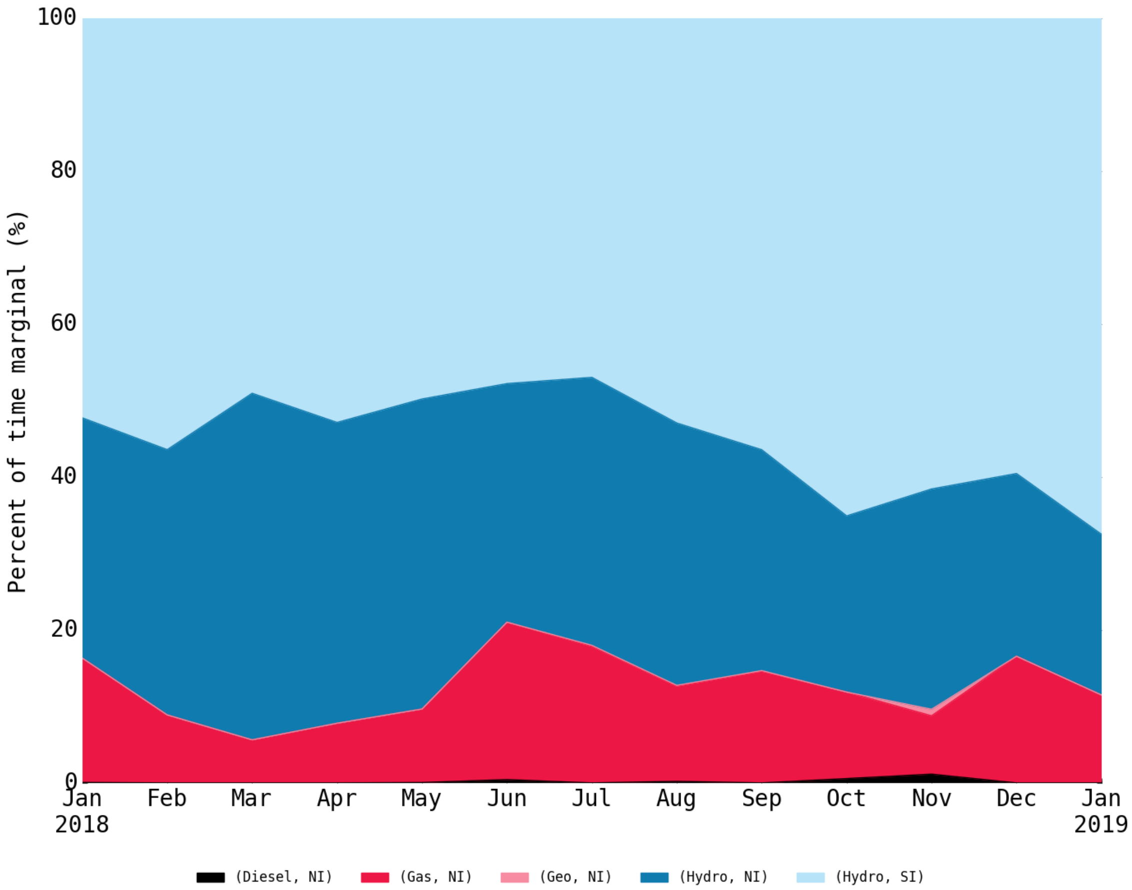
## There was a gas shortage at Pohokura

3.8 Pohokura is New Zealand's highest producing gas field. In 2017 it produced an average of 219,000GJ/day of gas. This is a significant amount of gas: a CCGT such as Huntly unit 5 (e3p) can consume approximately 65,000GJ/day at full capacity and produce approximately 8GWh or 8% of national daily demand.

3.9 An issue was discovered with a valve on the offshore platform, resulting in reduced output of 100,000GJ/day from 14 September 2018. Initially it was unclear how long the gas shortage would last, with those who purchased gas from Pohokura told they would have reduced access to gas for a few days. A public announcement that the outage would last until the end of November was made on the 12th of October[2].

3.10 The valve issue was resolved in early December 2018 and production returned to approximately 200,000GJ/day for the remainder of the 2018 calendar year.

**Figure 5: Marginal price setter by fuel type and island 2018**




3.11 The Pohokura outage saw a drop in the frequency of gas plants being the marginal price setter. Diesel and geothermal plants set the price more often during spring than

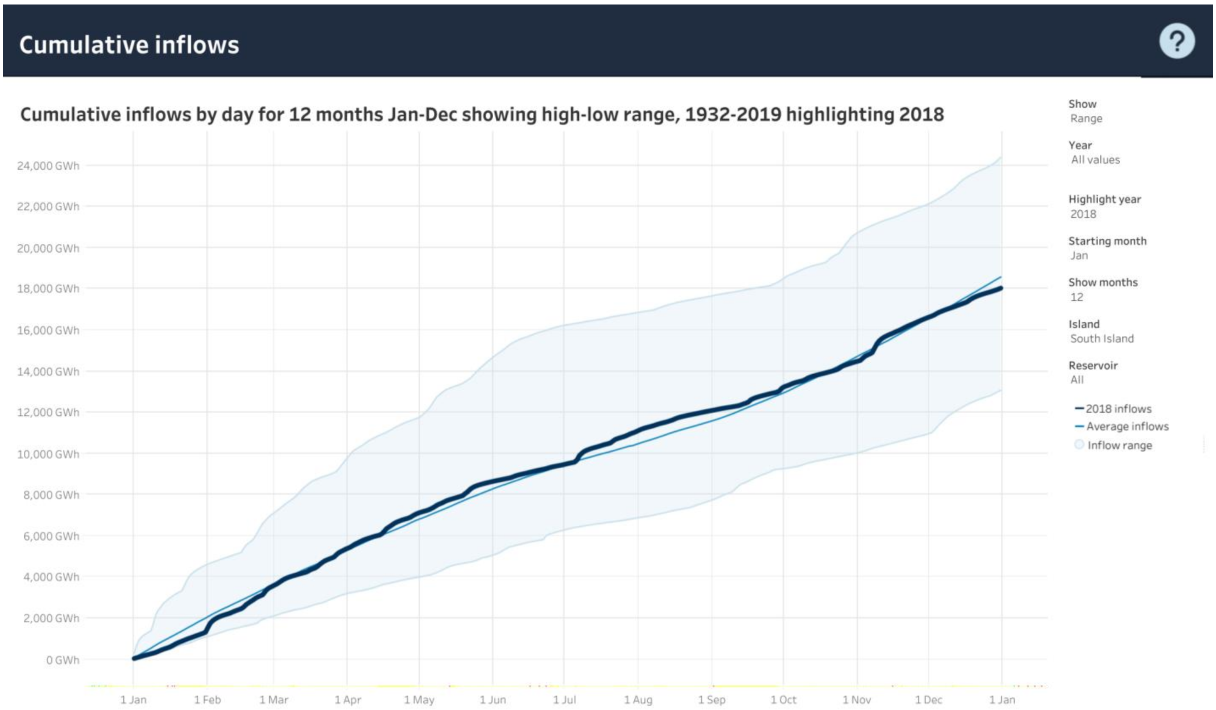
[2] For more details on what information was known about the Pohokura outage by participants see the UTS report

in any other time of the year, even winter during peak demand. However, they were still the marginal price setter only a fraction of the time, with North and South Island hydro setting the price the most frequently.

## Hydro fuel had limited availability

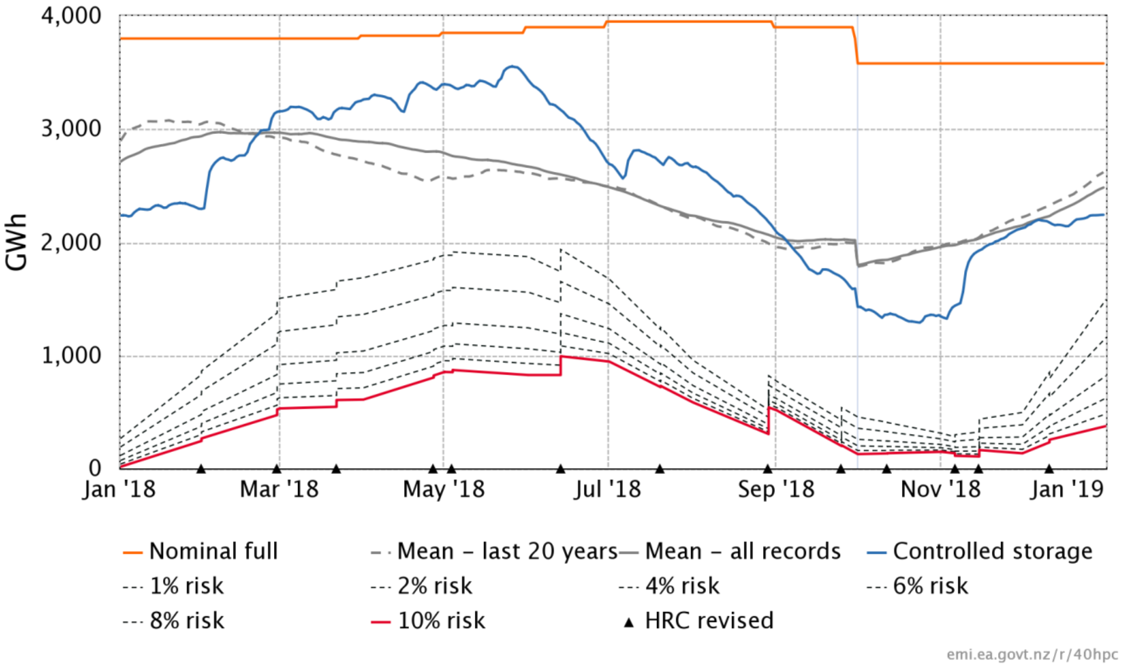
3.12 The availability of water to run hydro generators was another significant factor affecting spot prices in New Zealand. For most of the year South Island inflows were at or just above average inflows. However, inflows were low during spring 2018, bringing the cumulative inflows from above average to below average for that time of year.

**Figure 6 Cumulative inflows in South Island for 2018**




3.13 While hydro schemes' levels were above average for most of the year by the start of spring 2018, they were at about average levels and dropping rapidly. By the start of October 2018 controlled hydro storage for the whole of New Zealand was significantly lower than average and stayed about that level until large rainfall in November.

**Figure 7: Controlled hydro storage and hydro risk curves 2018**




3.14 Normal market behaviour is for prices to increase as storage decreases. The increased prices make it economic for thermal generation to operate, resulting in reduced hydro generation, which conserves water.

3.15 However, the gas outage also limited the degree to which thermal generation could run. This caused more hydro to be dispatched than expected, which reduced lake levels even further and pushed prices up higher than seen even during the winter peak period.

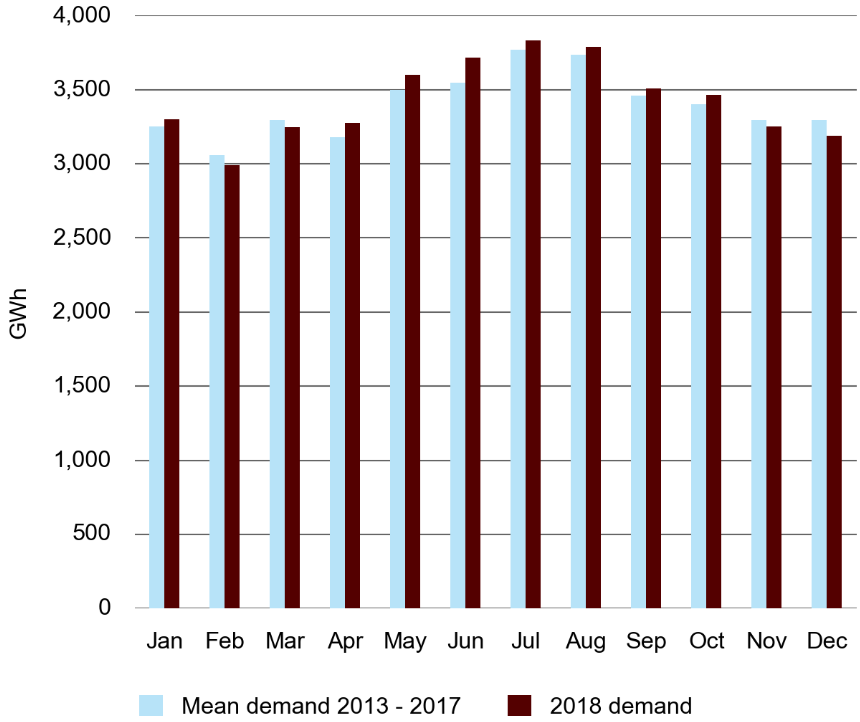
3.16 From 2013 to 2017 the correlation between thermal and hydro was -0.41. In September and October 2018, the correlation was -0.01. The negative correlation over the five years from 2013 to 2017 shows it is usual for thermal generation to increase when hydro storage is low. The correlation of approximately zero during September and October 2018 shows that thermal was unable to firm hydro. The most obvious explanation of this is lack of thermal fuel due to the gas outages.

3.17 This meant that spot prices increased more than they otherwise would in response to low hydro storage. This also resulted in hydro storage, which was already low, falling faster than normal because thermal generation was unable to play its usual role of firming hydro and therefore conserving hydro storage.

## Demand had increased

3.18 Electricity demand in September and October 2018 was higher than the average of the previous five years. Figure 8 below shows monthly consumption in 2018 compared to average monthly consumption for the previous five years. The chart includes demand at Tiwai.

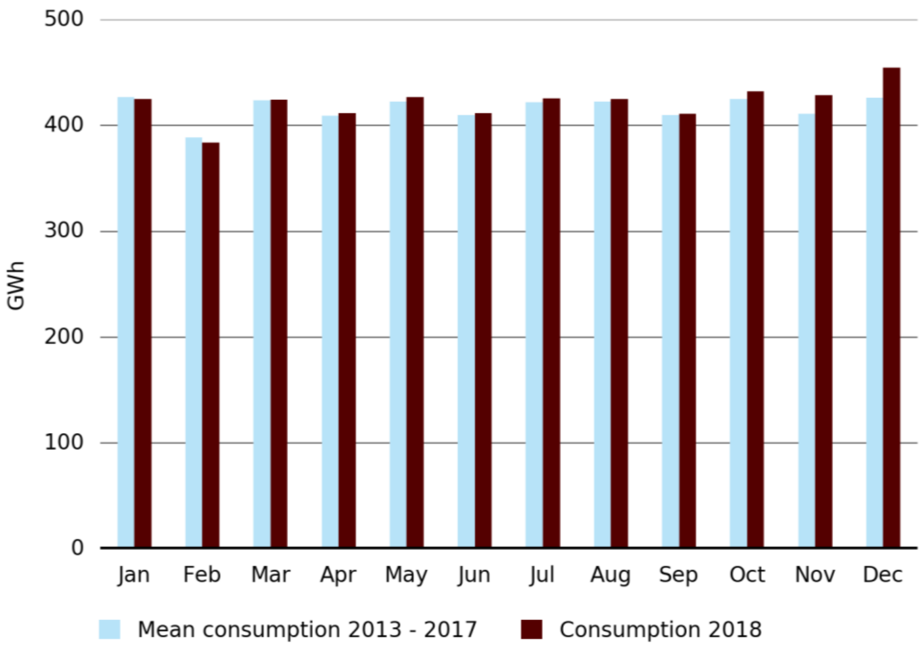
**Figure 8: Monthly consumption (including Tiwai)**




Source: Electricity Authority

3.19 There has been a general trend of higher demand in 2018 compared to previous years, which may indicate that demand has started to increase again. It was also relatively dry in the South Island from July to October, resulting in a higher irrigation use than usual for September and October.

**Figure 9: Monthly consumption at Tiwai**

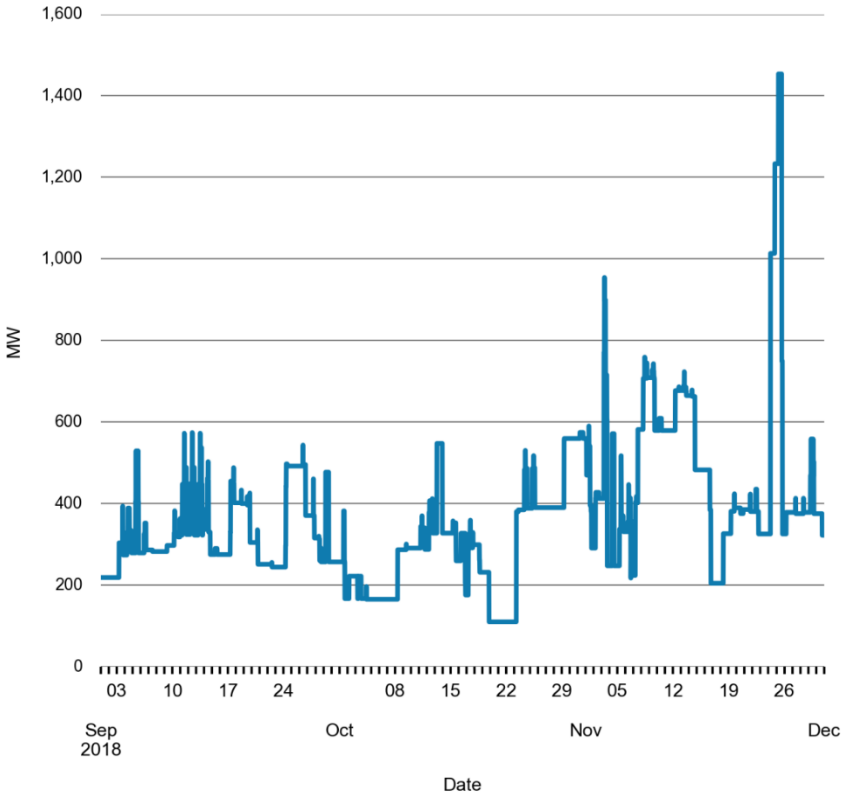


3.20 Figure 9 above shows demand at Tiwai which was also high in October 2018. The smelter increased production starting the week beginning 24 September 2018 as a fourth pot line was re-energised. Tiwai contracted an additional 50MW from Meridian in April to cover the energy use of the fourth pipeline. This further exacerbated the fuel shortages.

## Outages were scheduled

3.21 Springtime is usually a good time for generators to plan maintenance outages as there is usually a generation surplus at that time of year.

**Figure 10 Generation outages, according to POCP**




3.22 Huntly Unit 4 was brought back into operation on August 20th in order to replace Huntly Unit 2 which went out from the 7th of September. Huntly unit 4 was then out from the 23rd of September until the 7th of October for 240 MW. Huntly unit 1 had outages on the 19th September and 19th October which reduced generation by 240MW. Huntly unit 5 was taken out from the 26th of October until the 11th of December which reduced generation by 385MW.

3.23 Ohau A, B and C (264/240/240 MW each) had partial outages on the 3rd and 4th of November which reduced South Island generation by a total of 542 MW and 448 MW respectively. This was followed by a total outage on the 24th and 25th of November which reduced South Island generation by a combined 688MW during the total outage of the HVDC. This was likely planned to coincide with the HVDC outage as it would reduce demand for South Island generation.

3.24 There were outages at Benmore throughout the period, usually only 90MW, with 23 October to 1 November being the largest outage at 270MW. Two 540MW outages were planned for spring but they were cancelled on the 25th of September.

3.25 Tokaanu power station was on outage on the 6th of October reducing generation at 240MW (Genesis)

3.26 Aviemore station had several small outages (55MW) and two big outages on the 29 September and 13 October, with 220 MW in losses (Meridian)

3.27 Plus, other smaller planned outages which were less than 200MW each.

3.28 As well as outages that were planned in advance, the TCC had to go into outage due to vibration issues detected on the 14th of October. The TCC had a generation capacity of 340MW based in Taranaki. Initially the TCC was out until the 17th of October. From the 19th of October the TCC was downgraded to 160MW and then down to 160MW on the 30th October. Another outage began on the 31st of October and was initially scheduled to run until 12th.

# 4 The November HVDC outage

4.1 The annual HVDC outage is a relatively regular event scheduled in late spring or early summer each year to reduce the likelihood of disruptions to the power system. This section focuses on the time from when the unscheduled outage at Pohokura was public knowledge until the end of the scheduled HVDC outage. The focus is on the risk management of the outage and how the outage at Pohokura was accounted for by Transpower in its assessment of the HVDC outage.

## Transpower continued planning to proceed with the outage after Pohokura became public knowledge

4.2 Planning for the HVDC outage was finalised in November 2017 and the outage was entered into POCP. The outage was also included in Transpower's outage planning consultation. POCP is a tool used for to coordinate planned outages in the power system.

4.3 The planned outage was for pole 2 to be on outage from 22 November until 25 November and pole 3 to be on outage from 24 November until 27 November.

4.4 The system operator's risk assessment of major outages affecting generation supply uses the New Zealand Generation balance (NZGB) six months out and in the weeks leading up to an outage. The N-1-G scenario used by the NZGB is inherently conservative. The risk being assessed is the risk to system security.

4.5 The NZGB uses POCP as an indicator of plant availability (as well as for transmission outages which significantly constrain generation) to meet peak demand. This has worked well previously to the 2018 outages, but during the Pohokura outage it was a poor indicator of plant availability because of fuel constraints on thermal generators which were not on outage.

4.6 A complicating factor was the TCC outage, which was extended at relatively short notice, as new information became available to Contact Energy. Once this outage was included in POCP ,the NZGB, indicated potential shortfalls under the N-1-G scenario on the 22nd and 23rd of November. However, during the event, despite no further generation outages, shortages were indicated as possible if an N-1 event occurred.

4.7 In the week ahead of an outage the system operator uses the Week Ahead Schedule (WDS) which uses the schedules of generation and reserve offers, and demand forecasts, to assess risks of generation shortfall.

4.8 The WDS indicated that the first two days of the outage would be tight and on the 19th highlighted a potential reserve deficit during the peak of the 22nd. This prompted further assessment and escalation. On 21 November the system operator's assessment was that the N-1 security margin was tightest on the first two days of the outage (22 and 23 November) but manageable.

4.9 The decision was made (by Transpower as the grid owner) to go ahead with HVDC outage after considering advice from the system operator on system security. During the outage it appeared the power system was near its limits and pole 2 was brought back into service for the morning and afternoon peaks on the 22nd and 23rd. The pole 3 outage was then ended early on the evening of the 25th.

## There was ample time to reconsider the risks of this outage

4.10 The first public announcement of the Pohokura outage was on 28 September—55 days before the HVDC outage was due to start. The first public announcement of the likely duration of the Pohokura outage was on 12 October—41 days before the start of the HVDC outage (see Figure 2 for timeline).

4.11 This shows that there was ample time for Transpower to reconsider how it was assessing the capacity of the system in light of the Pohokura outage. The system operator relied on its systems without recognising that the Pohokura outage meant that these were misleading. In particular, thermal generators that were not on outage were also not able to run at full capacity because of gas constraints. This was a failure by the system operator to identify any heightened security risk associated with the Pohokura outage.

4.12 More careful consideration of the impact of the gas shortage on available generation, should have led to a more cautious approach to the outage. Transpower says "Our approach now, would be as system operator we would consider the impact of the gas shortage, notify participants and request further information, and request generators and grid owner to reconsider their outages."

4.13 Transpower has put considerable effort into improving its risk management of outages, in particular its understanding about the gas industry and its effect on generators. The NZGB included a worst-case scenario with reduced gas and no wind in their planning for the next HVDC outage in the first quarter of 2020. This has become a permanent feature of the NZGB. Transpower as the system operator also worked with generators to shift other outages outside of the period of the 2020 HVDC outage, and as the grid owner moved some its work to the weekends to minimise the impact. To date the 2020 outage has proceeded smoothly.

## During the outage, Transpower made the decision to bring the HVDC back into service during peak load (morning and evening)

4.14 On the morning of the 22 November, at around 5:00am the system operator noted a potential shortfall in North Island and informed participants. About 6:00am Transpower made the call to bring pole 2 back into service in time for the 7am to 9am peak, as the NRSS has identified potential shortfalls.

4.15 The reason for these shortfalls given by the system operator was that system conditions deviated significantly from the assumptions that Transpower made based on generation and reserve offers and load forecast the day before..

(a) 2 degrees drop in temperature forecast (effective 80MW load increase)

(b) North Island generation offers dropped 40MW

(c) Wind generation dropped 30MW

(d) Interruptible load dropped 80MW without a noticeable equivalent drop in load – requiring an additional 80MW of spinning reserve to cover DC transfer, removing 80MW of North Island generation from providing energy

(e) Net free reserves dropped 23 MW – Requiring an additional 23MW of spinning reserve to cover DC transfer, removing another 23MW of NI generation from providing energy.

4.16 Some of these risks are correlated—a drop in IL means less NFR and cold weather is often when wind is low. In addition, we would have expected that these assumptions would have been tested using sensitivity analysis

4.17 Later that day the grid owner also decided to bring the pole back into service for the evening peak and restart the outage after the morning peak on the 23rd had finished, again because the NRSL had identified potential shortfalls.

## An error in the system operators dispatch tools overstated security concerns on the 22nd and 23rd

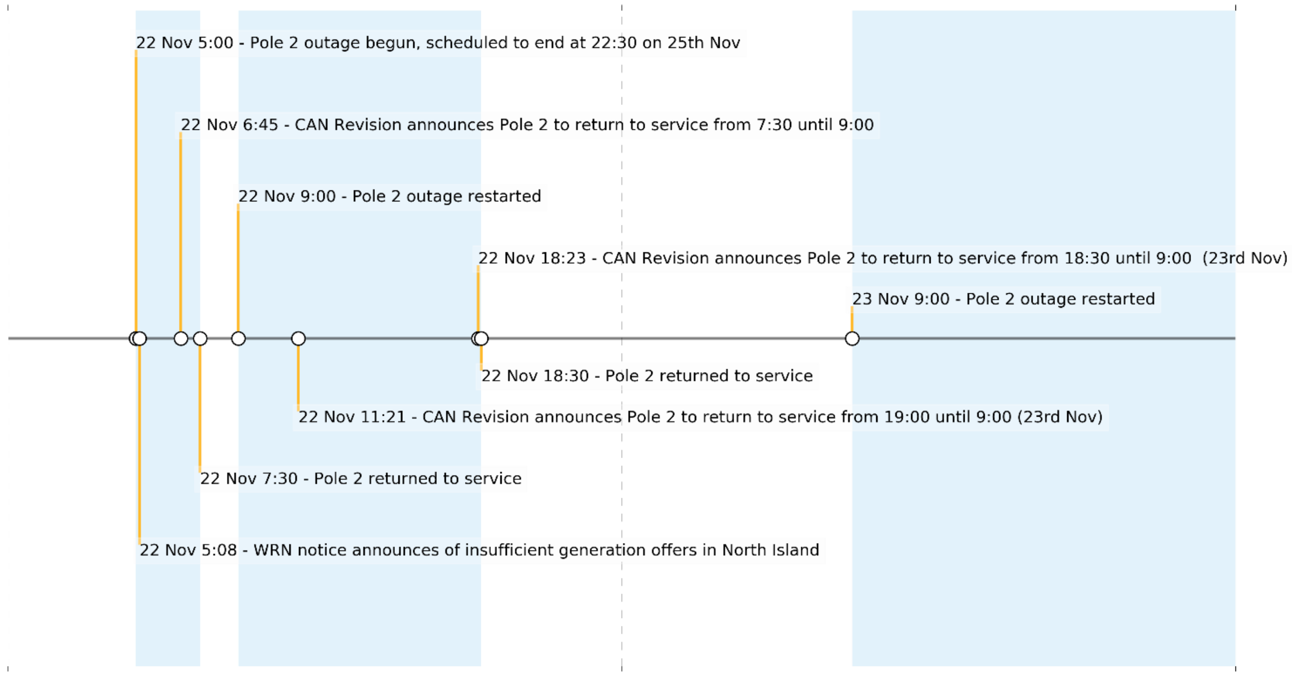
4.18 An error was found in the Reserve Management Tool (RMT) that fast instantaneous reserves (FIR) had been over-procured by an amount approximately equal to Whirinaki's dispatch from January 2018 until it was fixed on the 17 January 2019.

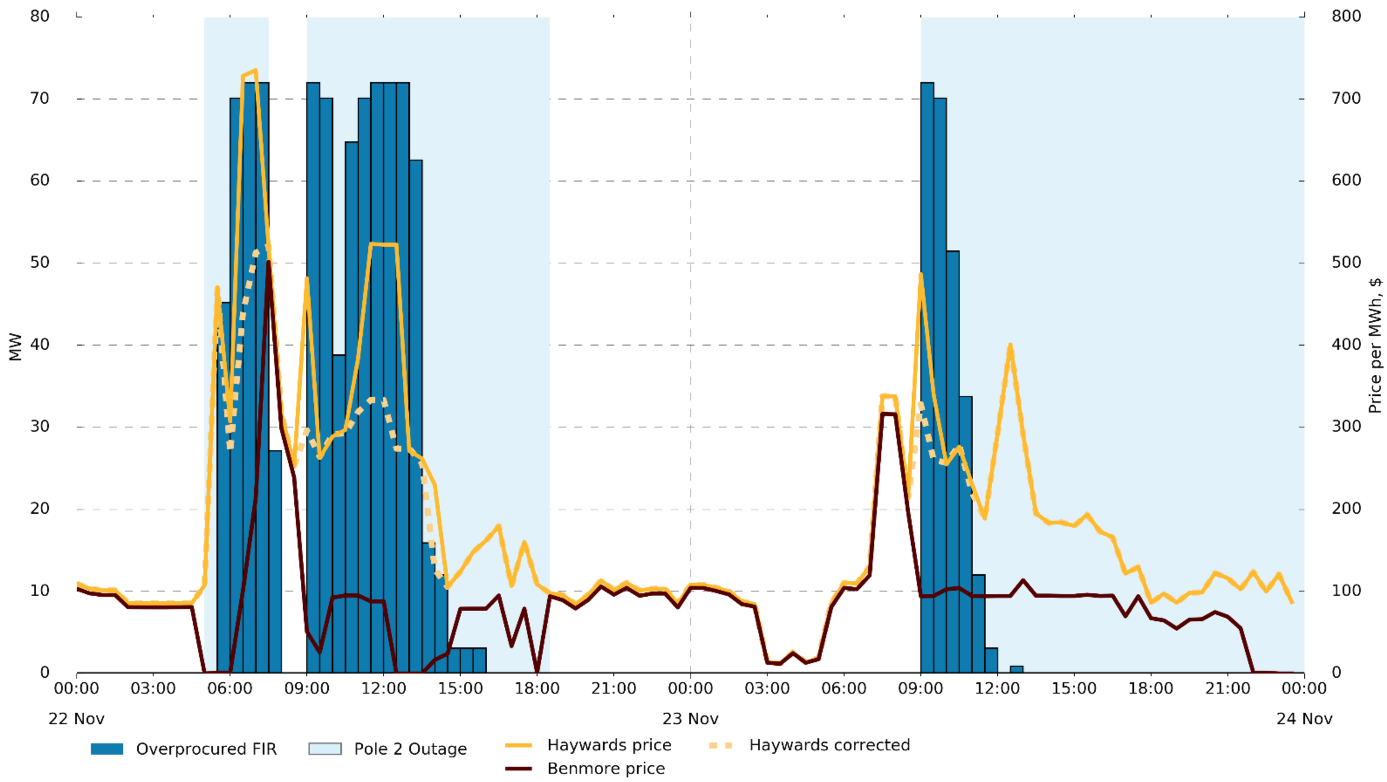
4.19 Whirinaki was dispatched for reserves on the 22nd and 23rd of November, during the HVDC outage. This effectively reduced North Island capacity by the amount of reserves procured from Whirinaki. This made the already acute North Island capacity situation worse and affected prices as shown in Figure 11.

4.20 Whirinaki was scheduled to be dispatched as reserve during the trading periods that showed a shortfall of reserves on the 22nd and 23rd of November. This means there was just enough reserve to cover the risks, but the system operator thought that there was a shortage of reserve. The system operator and grid owner's decisions were justified by the information they had at the time, but if they had had the correct information, they may have made different decisions about how to manage the risk that day.

4.21 Figure 11 shows events during the first two days of the outage—22 November and 23 November. It shows the CAN notices that were issued to notify the market of last minute changes to the HVDC outage, and the quantity of reserves that were being over-procured during the HVDC outage, as well as, the effect that this had on the spot price.

**Figure 11: Timeline of the HVDC outage with reserve over-procurement and spot prices**



## There no evidence that there would have been a shortfall on the 25th or 26th of November

4.22 The grid owner decided to end the Pole 3 outage on the evening of the 25th November, instead of the 27th of November as planned. The decision was based on risk assessments of the likelihood of security of supply issues, the ability to complete critical work and the health and safety of work crews.

4.23 At the time the CAN notice was issued (5:35pm on the 25th November) there was no indication that there would be any shortfalls on the 26th or the 27th.

4.24 Figure 12 and Figure 13 shows the forecast load and offers for FIR and energy for the 26th November that was predicted by the pre-dispatch at 4pm on the 25th November. There was no security of supply concerns seen at this point; shortly before the CAN notice was released.

**Figure 12: 26th November FIR Pre-dispatch as at 4pm 25th November**

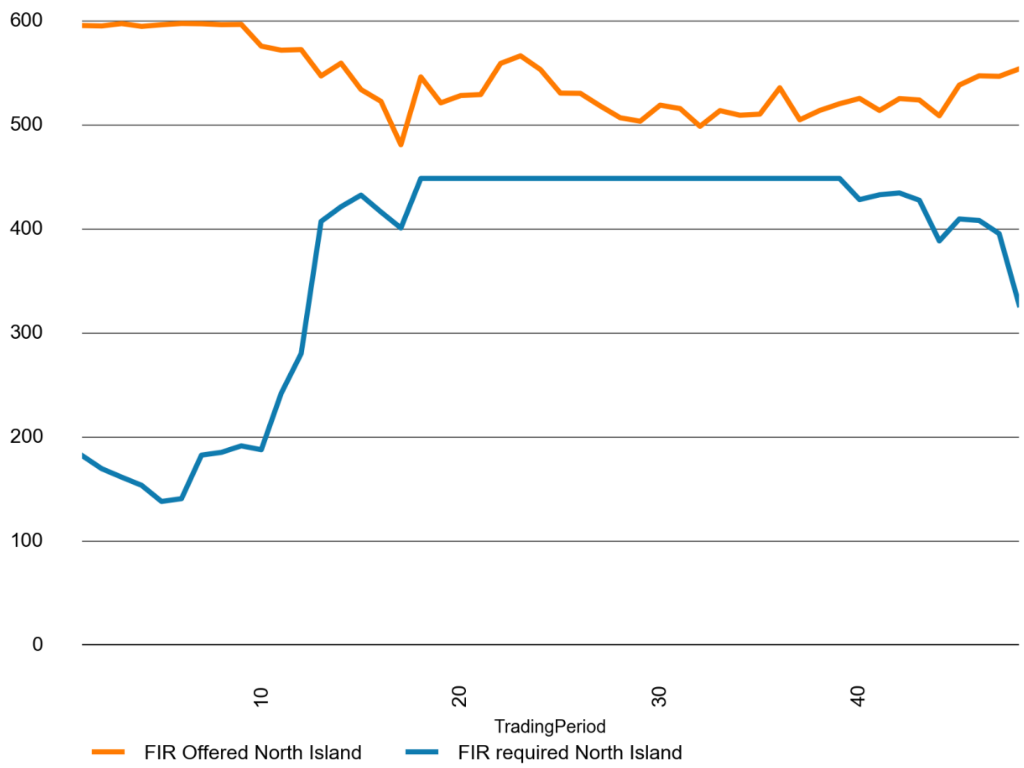
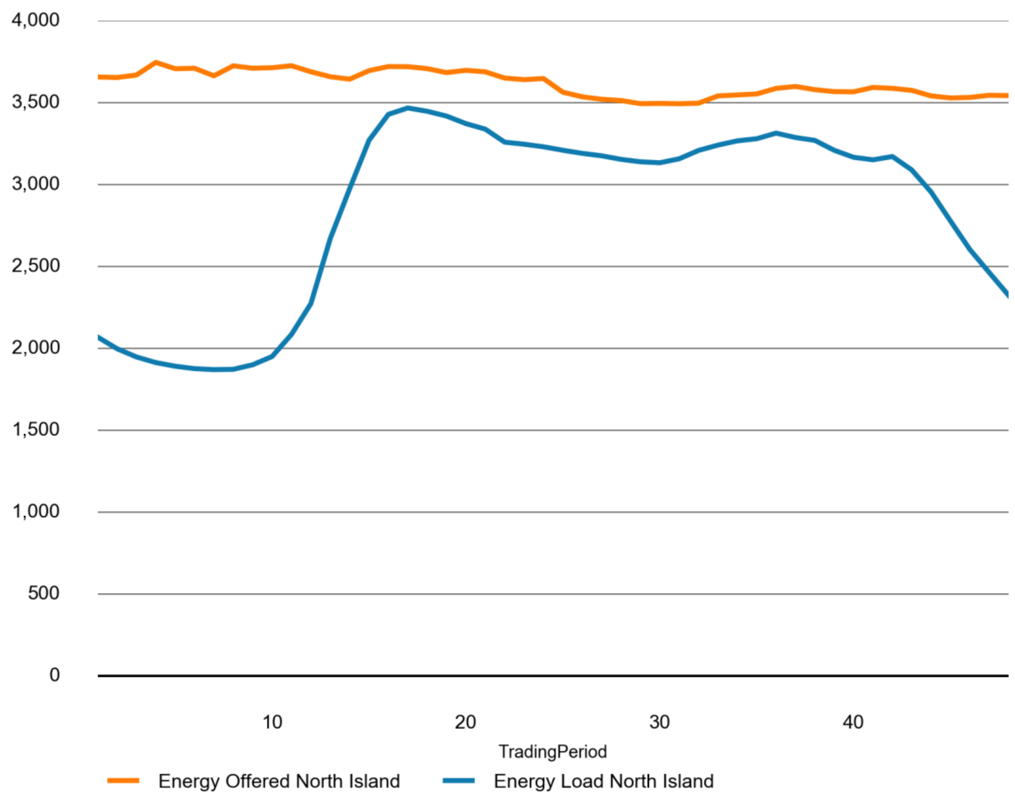


**Figure 13: 26th November Energy Pre-dispatch as at 4pm 25th November**




4.25 According to Transpower, the grid owner and the system operator had conference calls at 2:30pm on the 23rd of November and at 9:30am on the 25th of November. The system operator advised that the situation would be tight during the morning peaks and they could not guarantee that there would not be a shortfall during the morning peaks.

4.26 The system operator forecast 24 hours ahead showed that there were at least 270MW of surplus capacity for the morning peak of the 26th. They also modelled the forecast as if there was a repeat of events from the 22nd, with a loss of interruptible load (IL), net free reserves (NFR) and wind generation, which indicated that there would be 100MW of surplus capacity. Under this scenario a 3% increase in load would have resulted in a shortfall.

4.27 On Friday the Grid Owner made the decision to re-prioritise work over the weekend, so that the pole could be brought back on Monday if needed. On Sunday morning they decided to attempt to finish the critical Pole 3 work by the end of Sunday. This required work crew to work longer hours than expected over the weekend so the grid owner did not want to ask crew to continue working on Monday, and decided to cancel the rest of the outage.. They state that the market was not immediately advised of the outage cancellation (that is, on Sunday morning) as it was not possible to confirm the change in the work plan could be achieved until later on the Sunday afternoon.

4.28 Figure 14 and Figure 15 show the forecast load and offers for FIR and energy for the 26th November that was predicted by the pre-dispatch at 8am on the 25th November, the latest information available prior to the 9:30am conference call. It shows that during the morning trading period there was 51MW more FIR offered than required. Had there been a repeat of events from the 22nd November (see 4.15) there is a chance that there would have been a shortage of FIR. However, there does not seem to be any suggestion of an energy shortfall.

4.29 Note that Whirinaki was not dispatched on the 26th and 27th, so the issue of over-procurement of reserves did not occur on the 26th and 27th.

**Figure 14: 26th November FIR Pre-dispatch as at 8am 25th November**

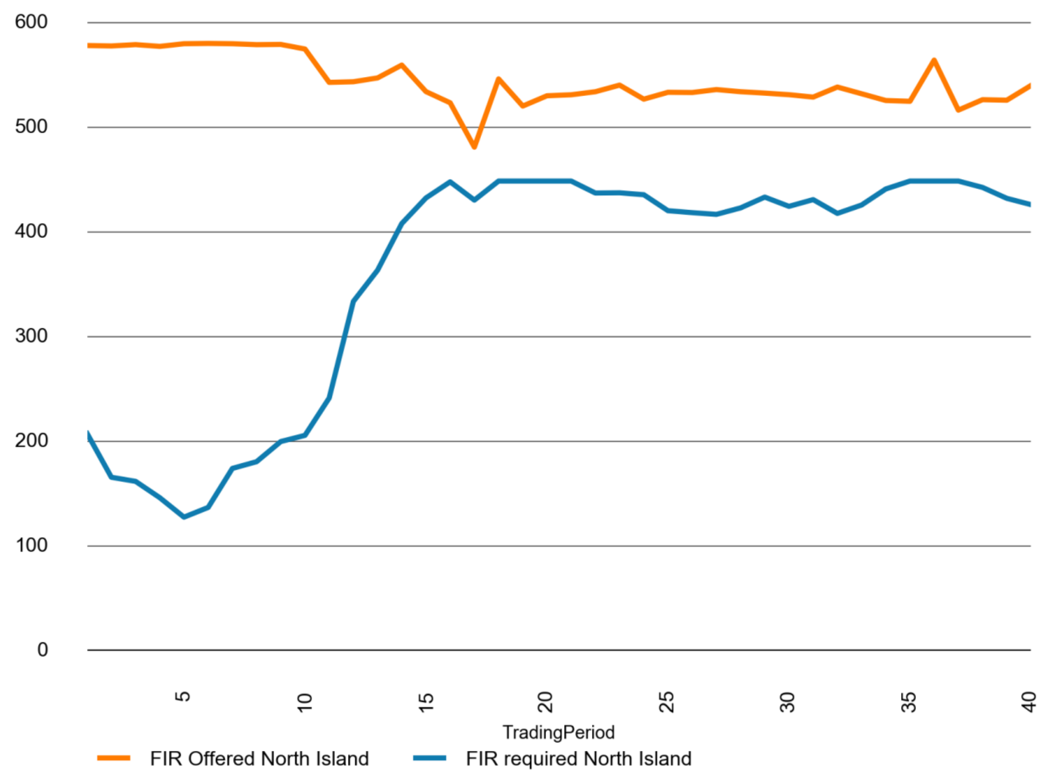
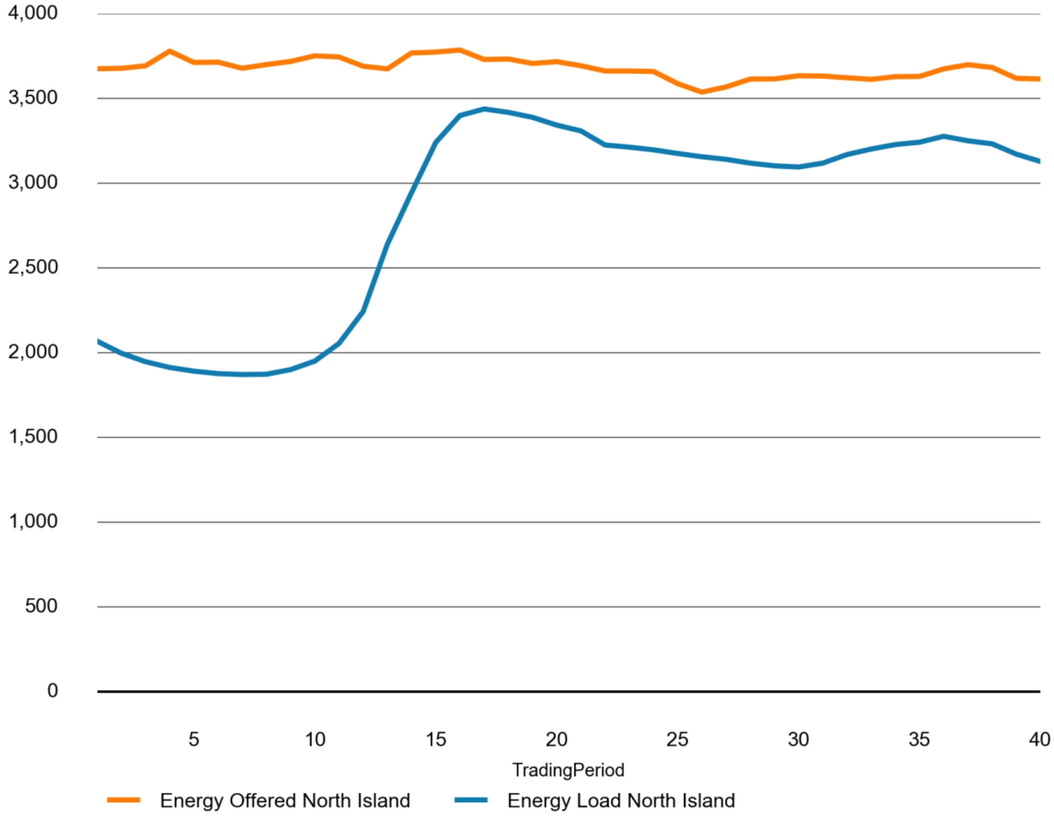
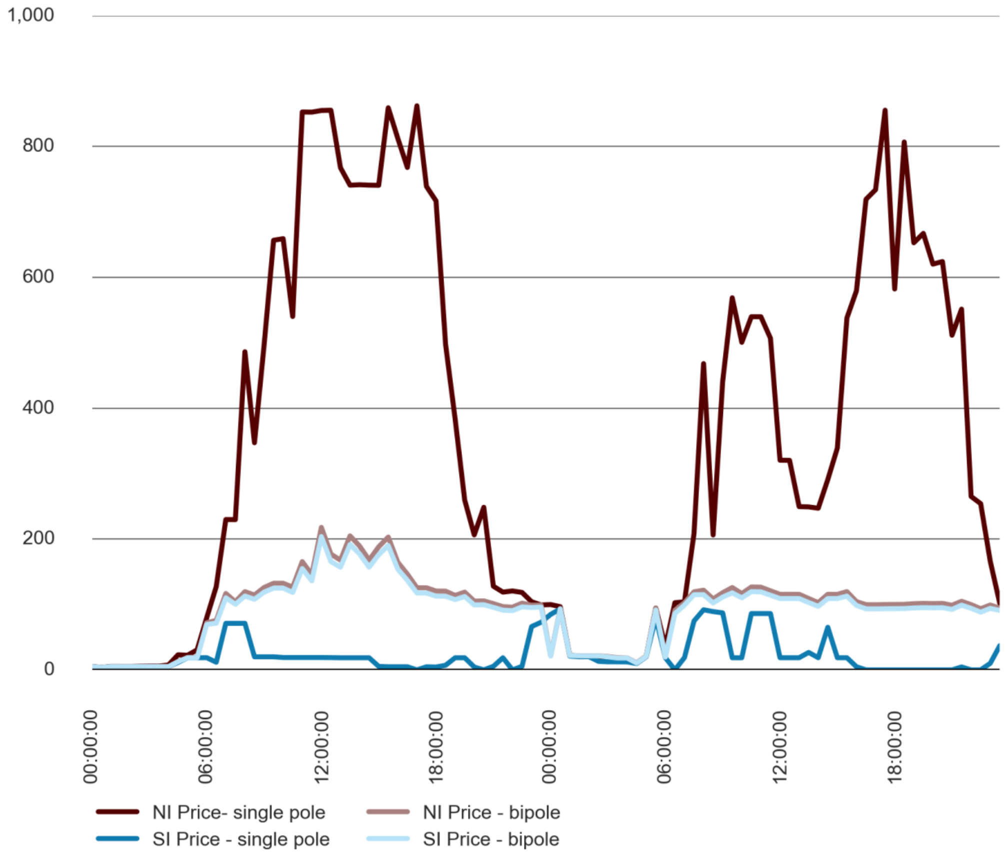


**Figure 15: 26th November FIR Pre-dispatch as at 8am 25th November**




4.30 Figure 16 shows the actual final price, with the HVDC in bipole mode, that was seen on the 26th and 27th of November and what the prices would have been (assuming the same final offers) if the HVDC had been in single pole on the 26th and 27th. If the HVDC had been in single pole there would likely have been a large price separation between the North and South Island during the day.

**Figure 16: Prices for the 26th and 27th November, single pole vs bipole**




4.31 Parties that were hedged for the anticipated price separation shown in Figure 16 would have lost money because of the decision to cancel the outage. In addition, these same parties will have to purchase the same sort of hedge cover the rescheduled work.

# 5 Thermal offers during the Pohokura outage

5.1 During the Pohokura outage, some thermal plant was neither on outage nor able to generate at full capacity for long periods. This meant that there were times when plant was not entered into POCP so appeared to be fully available, but would not have been able to sustain full capacity if needed

5.2 The way thermal generators offered their plant tended to be in one of two ways:

(a) Offering capacity at higher than usual prices with a plan that if required to generate early in the day, offers would be withdrawn later in the day to ensure that they didn't burn gas they didn't have.

(b) Offering reduced capacity.

5.3 The following charts show how Genesis's was offering e3p. This sort of offering was indicative of other thermal generators and we are using e3p as it demonstrates a variety of different offer behaviours. This is not meant as a criticism of how e3p or any thermal plant was offered during the Pohokura outage.

5.4 These charts are generated from monitoring tools that are used by Electricity Authority to monitor actual market outcomes in each trading period and to investigate changes to pre-dispatch offers prior to gate-closure. The trading periods chosen for the pre-dispatch offers are intended to be representative of trends and are not highlighting those particular trading periods.

5.5 Figure 17 shows Genesis's offers for e3p for the week beginning 1 October. It shows that during the working week 200MW was offered throughout the week—around 180MW less than e3p's capacity.

**Figure 17: e3p offers for week beginning 1 October**

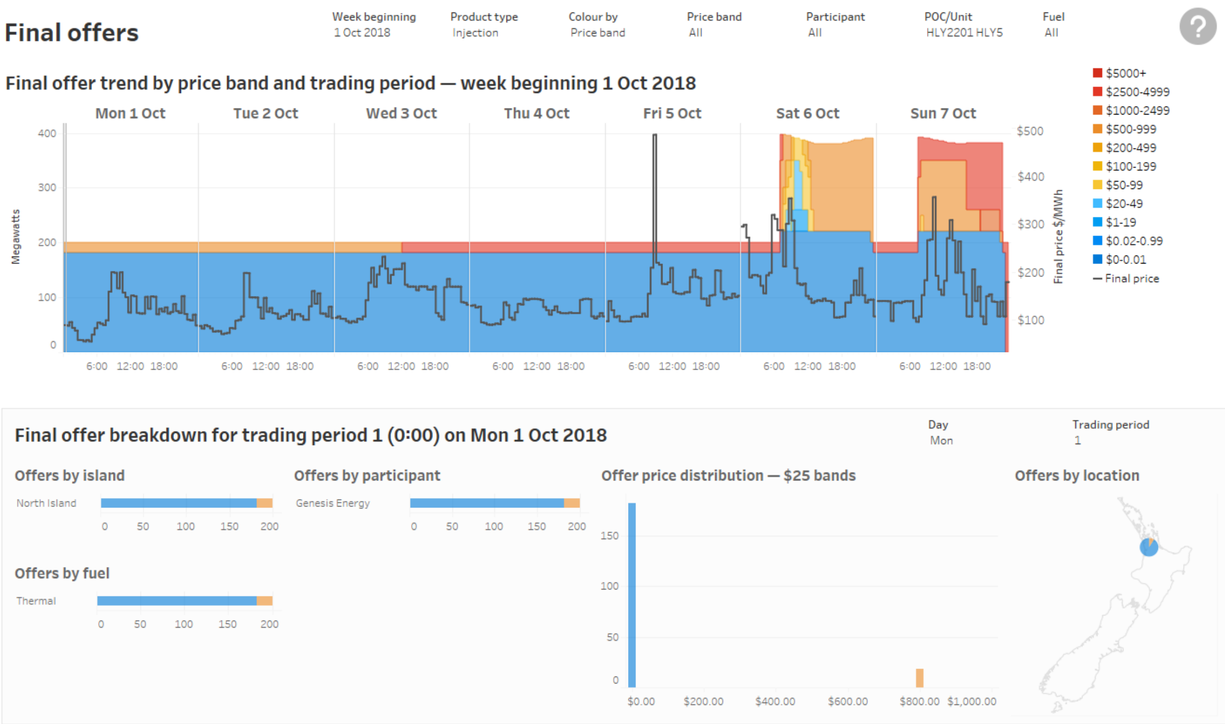
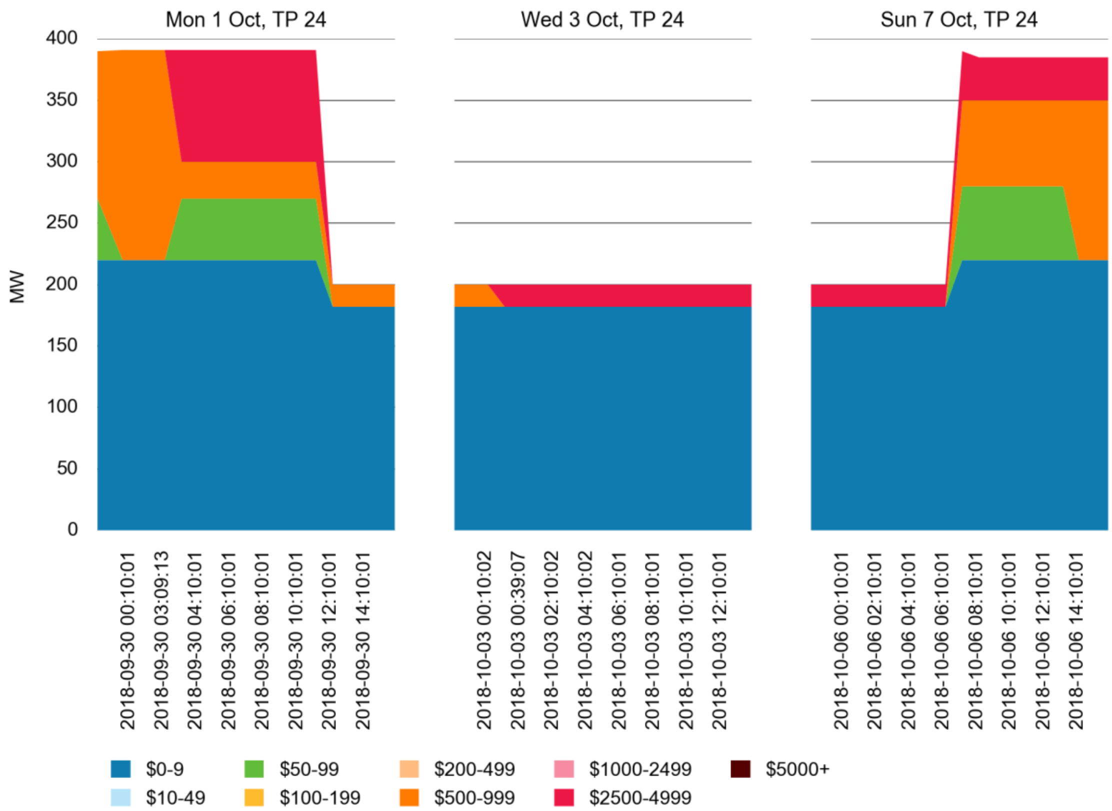


**Figure 18 Sample of pre-dispatch offers for week beginning 1 October**




5.6 When investigating the pre-dispatch offers, it appears that originally almost 400MW was offered for this week, but on the 30th September and 1st October, offers were pulled to only offer 200MW for all trading periods, likely in response to an increased understanding on the impact on gas supply after the announcement on the 28th. For the rest of the week 200MW was offered in at pre dispatch though on 6 and 7th Oct, this amount was increased in some trading periods.

5.7 Figure 19 shows e3p offers for the following week. It shows that e3p was not offered at all overnight during the week and then offered up to 400MW during the day.

**Figure 19 e3p offers for week beginning 8 October**

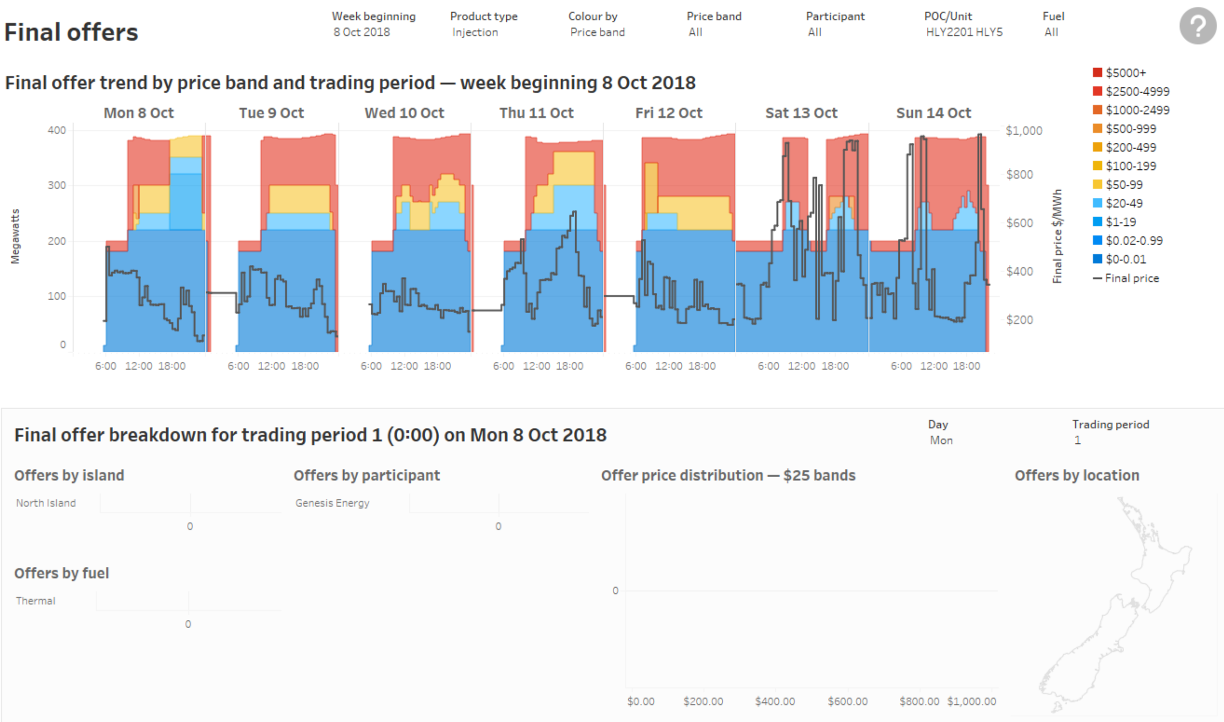
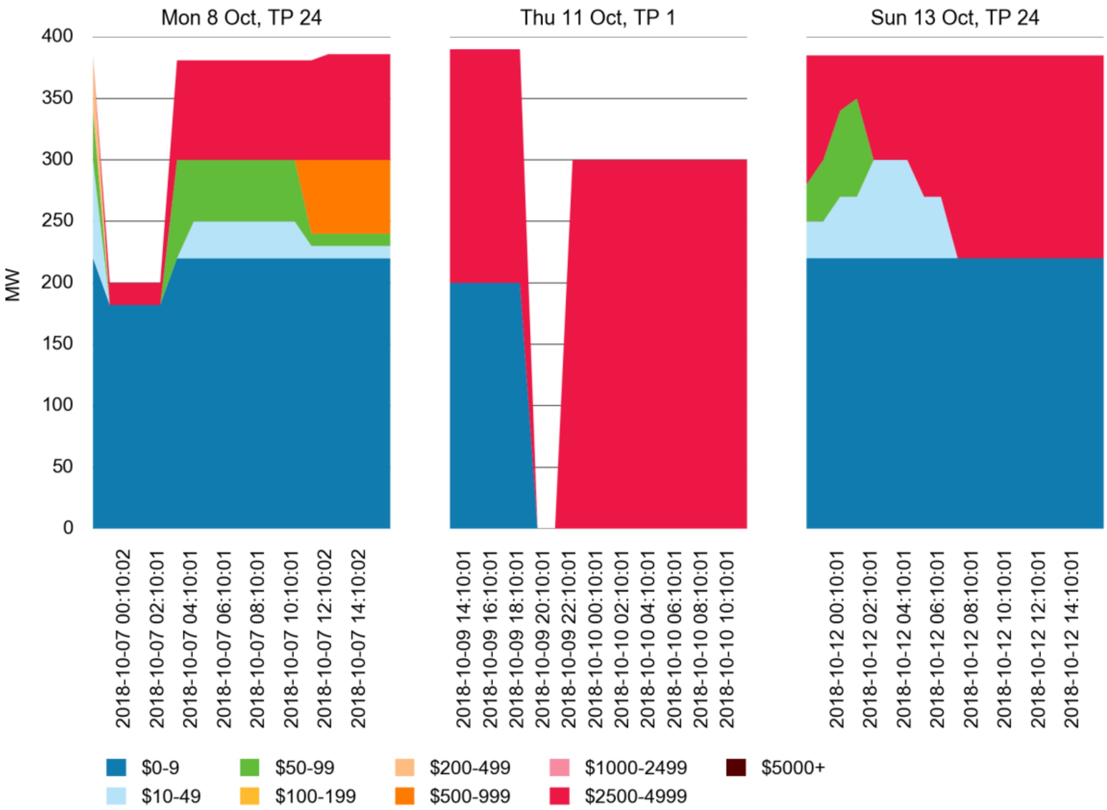



**Figure 20 Sample of pre-dispatch offers for week beginning 8 October**




5.8 Figure 20 shows a sample of pre-dispatch offers for the week beginning 8th of October. There does not appear to be a consistent bidding pattern, with large changes being made to price and quantity of generation. These changes likely reflect the knowledge of availability of gas.

5.9 Figure 21 shows e3p offers prior to the Pohokura outage. It shows that the highest price offer band was $500/MWh to $999/MWh. This contrasts to Figure 17 and Figure 19 where offer prices in the highest priced band were in the $2500MWh to $4999/MWh range.

**Figure 21 e3p offers for week beginning 3 September—prior to the Pohokura outage**

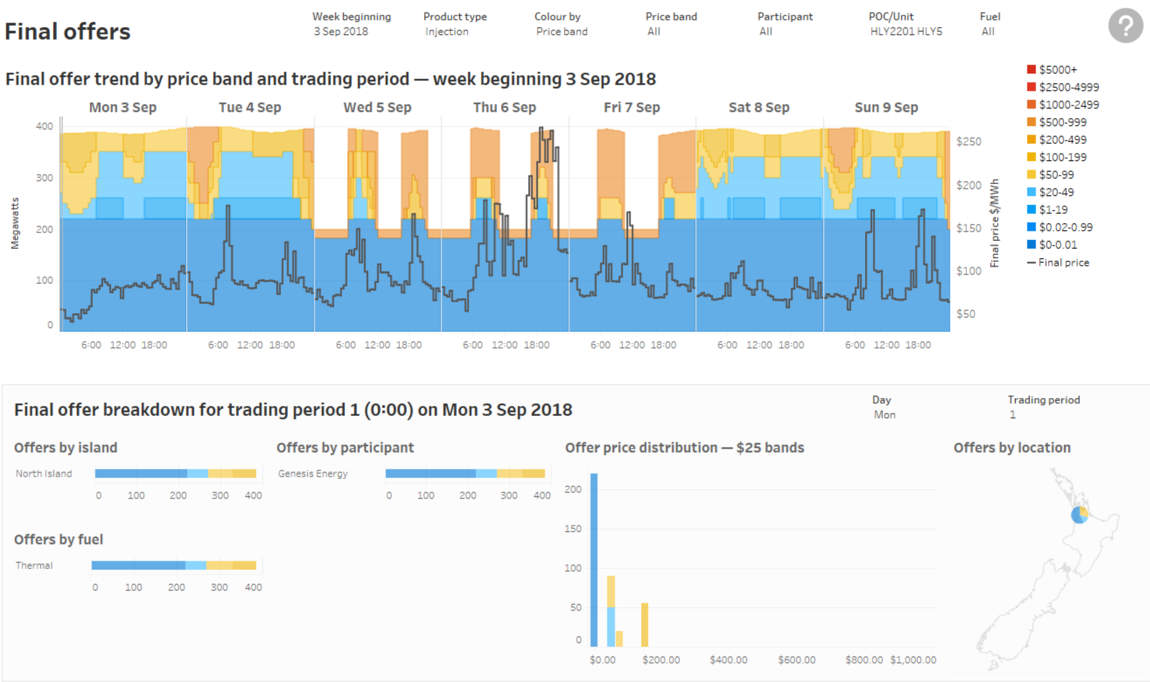
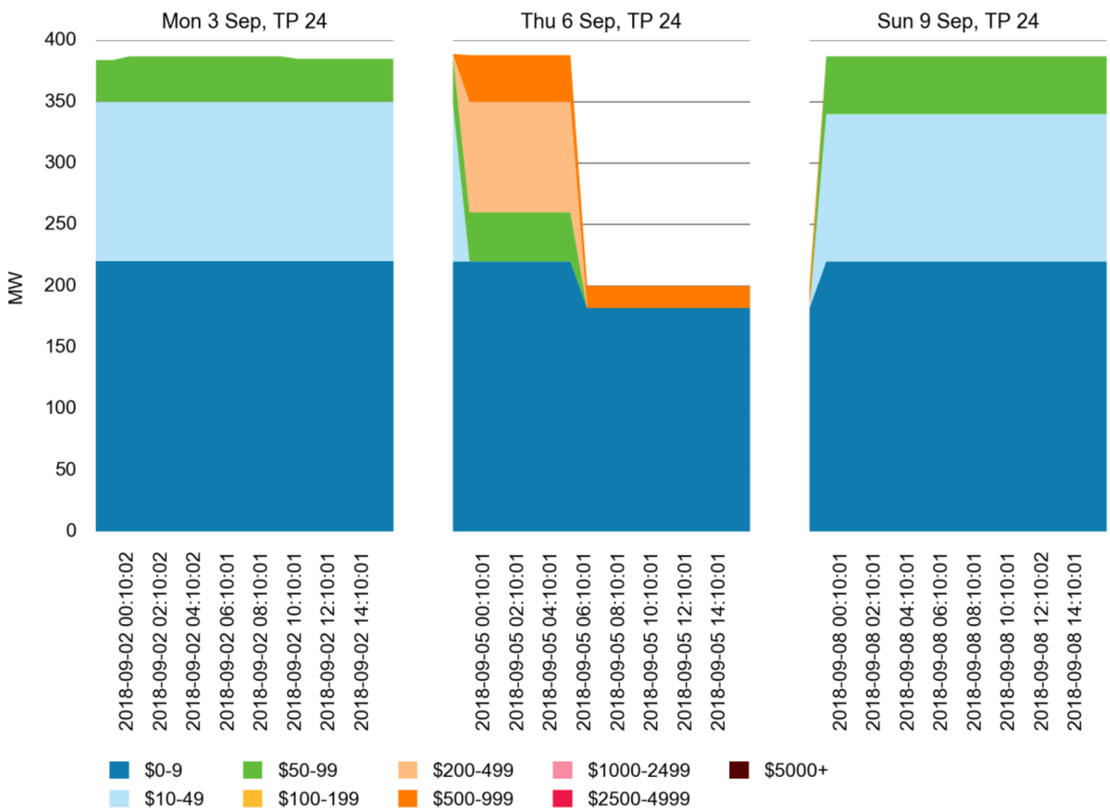



**Figure 22 Sample of pre-dispatch offers for week beginning 3 September**



5.10 We see no problem with the way e3p or any thermal generator was offered during the Pohokura outage. Given the lack of clear information about the Pohokura outage, generator offers were one of the best sources of information about gas availability. However, while offer data is public, it is only made available the following day, so it is more useful for explaining what happened than predicting what will happen.

5.11 There are instances when generation is able to run, but not at peak output. There are also instances when it is not clear whether generation can run. These can include times when a generator is unable to access all the fuel it has contracted for, but may be able to get short term fuel depending on the outcome of negotiations. A specific case brought to our attention by Genesis Energy is when cooling water for Huntly is near to its upper threshold which it could breach depending on the weather.

5.12 Ideally, generators would have a mechanism to signal when their plant was unable to run at full capacity despite not being on outage. This mechanism could be anything from an online notice board or publishing overall generating capacity on a rolling basis.

# 6 Hedge disclosure data needs to be improved

6.1 Hedge traders are required under part 13 of the Code to lodge their contracts on the hedge disclosure database. Generally, the disclosure of future contracts appears good. But the database itself could be improved, and there are insufficient details around Option contracts. Improving this database is important for tasks such as assessing the recent UTS claim.

## Data quality issues

6.2 There are data quality issues related to manual disclosure fields. For example, contract party names can and do vary—ASX can be referred to as; ASX, Australian Stock Exchange or ASX limited. These sort of naming issues are reasonably easy to deal with, but the data could be improved by constraining what goes into each field.

## Download speed

6.3 The total hedge disclosure data volume is small in comparison with other databases in the industry. Despite this, downloading the data is cumbersome and slow for any reasonable time period. To get around this, Authority staff download quarterly blocks, process the data to address the data quality issues set out above and append it to previous data.

6.4 This process is ad-hoc, complex and prone to error. A better solution would be to have database access, for example in EMI, to all of this data.

## Option contracts

6.5 Option trading has increased in the last few years and so analysis of option positions is gaining in importance. However, the disclosed option data is currently not sufficient. The main issue is that there is no field to determine if an Option contract is a Put or Call option.

# 7 Publicly available gas production information

7.1 The Pohokura outage highlighted the fact that while gas production information is publicly available, it is not obviously accessible. This was evident in the UTS claim—and other subsequent claims regarding information disclosure—the wording of which suggested that the claimants did not know how to access this information. However, there is a substantial amount of information publicly available. This section outlines the information that the Authority found most useful for monitoring gas production and consumption.

## OATIS scheduled and metered quantity data

7.2 The Maui section of the Open Access Transmission Information System (OATIS) website has scheduled and metered quantity reports under the publication tab. These reports are in spreadsheets that can be downloaded. They show the scheduled and metered quantities at various welded points in the network.

7.3 The data takes some knowledge of the gas network to interpret, but the following is useful:

(a) Oanui is Maui production

(b) The sum of Tikorangi#2 and Ngatimaru (receipt) is Pohokura's production

(c) Ngatimaru Road (Delivery) is Methanex consumption

(d) The sum of Tikorangi Mixing Station and Tikorangi #3 (Receipt) is McKee/Mangahewa production

(e) Kowhai Mixing Station is Kowhai production

(f) Turangi Mixing Station is Turangi production

(g) Huntly power station is consumption at Huntly power station

7.4 This data is updated daily, but hourly data is available with an approximately 90-minute lag by going to the "Station metering graph and details" page from the Maui section of OATIS.

7.5 Together this data allows monitoring of gas output from fields, as well as consumption by large users. For example, the data for Huntly can be used to determine when Genesis starts to burn coal at Huntly by calculating a gas efficiency factor using Huntly's generation output. This efficiency factor will jump when Huntly generates electricity using fuel other than gas.

7.6 In addition, the gas industry company (GIC) now has an industry notification site https://www.gasindustry.co.nz/industry-notifications/. Gas industry participants can post notifications, such as planned and unplanned outages, to the site to be publicly released.

7.7 Table 1 is an overview of other sources of gas information which are publicly available. Most of these were available during the Pohokura outage.

**Table 1 Publicly available gas information**

| | Information source | Form of information | Information available | Specification | Units | Notes |
|---|---|---|---|---|---|---|
| Contact | Monthly operating report | Monthly data tables | Gas storage | Monthly gas storage net movement | PJ | Published monthly approximately two weeks after end of month (available from Jan 2015) |
| | | | Gas used | Monthly gas used in internal generation | PJ | Published monthly approximately two weeks after end of month (available from Jan 2015) |
| Genesis | Historical quarterly and annual operating data 2010-2017[3] | Quarterly and annual data tables | Generation | Quarterly generation by fuel type (gas, coal) | GWh | Available quarterly from Sep 2009 |
| | | | Fuel purchases | Quarterly gas purchases, quarterly coal purchases | PJ | Available quarterly from Sep 2009 |
| | | | Fuel used | Quarterly gas used in internal generation; quarterly coal used in internal generation | PJ | Available quarterly from Sep 2009 |
| | | | Coal stockpile | Quarterly coal stockpile – closing balance | Kt | Available quarterly from Sep 2009 |
| | Quarterly report | Table including latest quarter, previous quarter, and year to date | Fuel cost | Quarterly weighted average fuel cost | $/MWh | First reported for Dec 2016 quarter |

3 At time of writing the last two quarters were not included in this data table but were available in the most recent quarterly reports.

| | Information source | Form of information | Information available | Specification | Units | Notes |
|---|---|---|---|---|---|---|
| **EMS Tradepoint** | Market results | Graph of physical natural gas market data | Price | Daily high price, low price, volume-weighted average price (VWAP) | $/GJ | Only available graphically. Updated each Monday (ex-post). |
| | | | Volume | Daily traded volume | GJ | Only available graphically. Updated each Monday (ex-post). |
| | | Table of physical natural gas market data | Price | Price of each trade | $/GJ | Updated each Monday (ex-post). |
| | | | Quantity | Quantity of each trade | GJ/day | Updated each Monday (ex-post). |
| | Natural gas indices | Table and graph of natural gas indices | Price indexes | Daily Frankley Road Natural Gas Monthly Index (FRMI) and Daily Frankley Road Natural Gas Quarterly Index (FRQI) | VWAP $/GJ | Calculated daily at market close and published next business day. Uses rolling months and quarters. |
| **Oatis** | First Gas information exchange | Display tables and downloadable files | Metering data | Historical daily and hourly injection data | GJ | |
| | | Display tables | Operational information | Linepack, gas composition, pressure and injection data on an hourly basis for the previous 48 hours | Various | |
| | | Downloadable files | Calculated quantities | Historical accumulated excess and operational imbalance | GJ | |

| | Information source | Form of information | Information available | Specification | Units | Notes |
|---|---|---|---|---|---|---|
| | Maui information exchange | Display tables | Metering data | Scheduled quantity and actual hourly flow for the previous 48 hours | GJ | |
| | | | Pipeline notices/ operational information | Pipeline conditions, critical/ other notices, operational information – pressure, capacity, linepack, contingency volume etc. | Various | |
| | | Downloadable files | Metering data | Historical daily scheduled and metered quantities | GJ | |
| **Ministry of Business, Innovation and Employment (MBIE)** | Energy Data Files | Quarterly data on supply, production, consumption and prices | Gas production | Quarterly gas production, including reinjection, LPG extracted, gas flared | PJ | Updated quarterly nearly three months after the end of the latest quarter[4] |
| | | | Gas energy transformation | Quarterly gas energy transformation, including electricity generation, cogeneration | PJ | Updated quarterly nearly three months after the end of the latest quarter |
| | | | Coal supply | Quarterly coal supply by coal type – production, imports, exports | tonnes | Updated quarterly nearly three months after the end of the latest quarter |
| | | | Coal transformation | Quarterly coal transformation by coal type – electricity generation, cogeneration | tonnes | Updated quarterly nearly three months after the end of the latest quarter |

4 For example, the March 2017 data became available on 22 June 2017.

| | Information source | Form of information | Information available | Specification | Units | Notes |
|---|---|---|---|---|---|---|
| | | | Oil supply | Quarterly oil supply – production, imports, exports | PJ | Updated quarterly nearly three months after the end of the latest quarter |
| | | | Oil used | Quarterly oil used for electricity generation | PJ | Updated quarterly nearly three months after the end of the latest quarter |
| | | | Natural gas prices | Quarterly natural gas prices – residential, commercial, industrial, and wholesale | $/GJ | Updated quarterly nearly three months after the end of the latest quarter |
| | | | Electricity generation | Quarterly electricity generation by type, including gas, coal, oil | GWh | Updated quarterly nearly three months after the end of the latest quarter |
| **Statistics New Zealand** | Energy Statistics | Historic data in downloadable excel and csv format updated quarterly | Price indexes | Quarterly by energy type, including commercial natural gas | Dec 1996 base | Updated quarterly about seven weeks after end of quarter |