Review of low residual and insufficient generation events

Executive summary

Transpower, as the system operator, communicates potential grid issues to electricity market participants through notices that are sent via email and published on its website. From 2021 to August 2023, there was a marked increase in the number of notices forecasting low residual and insufficient generation compared to previous years (CANs, WRNs, and GENs[1]). This report investigates how these periods of low residuals or insufficient generation were resolved by looking at participant reactions and the accuracy of forecasts. The review was motivated by the increase in such events, and it aims to provide insights for the future, in particular for winters when these events are more likely to occur.

There were 14 events in 2021, 12 in 2022, and so far in 2023 (until the end of August) there have been 12. We define an event as a continuous block of trading periods to which the notice (or notices) applied. As a comparison, in the years 2018-20 there were only 9 such events.

In 2021, events were usually resolved when demand did not meet forecasts. However, demand was usually higher than forecast in 2022 and 2023, which increases the potential for events to escalate. Most of the events had final residuals that were higher than forecast for all trading periods (12 out of 14 events).

Only five events in 2022 had final residuals that were higher than forecast for all trading periods within the event, and six events had lower than forecast residuals for some trading periods. None of those events escalated into insufficient generation apart from one when there was an extenuating circumstance such as an unplanned outage.

Similarly for 2023, only seven of the events had final residuals that were higher than forecast for all trading periods within the event. Again, none of the events with a decrease in residuals escalated into insufficient generation.

Both demand and wind were closer to forecast in 2022 and 2023, which also meant the residuals did not change as much after the notices were sent in these years. Sensitivities to changes in demand are now published on the WITS website, which should go some way towards mitigating the risk associated with forecast inaccuracies.

Since the grid emergency of 9 August 2021 Transpower has improved its notification of potential grid issues. Notices have been issued earlier, giving participants more time to react. Participants reacted by increasing reserve and energy offers where possible. There was no escalation of events in 2022 or 2023, except where there were extenuating circumstances such as equipment failures. Despite having near-record peak demand in 2023, there were neither any periods of insufficient generation, nor the need to cut any demand, discretionary or otherwise.

In addition to the earlier publication of the low-residual CANs in 2022 and 2023, the number of WRN notices issued reduced. Furthermore, in 2022 insufficient generation notices were only released due to extenuating circumstances, which was not always the case in 2021 (in five events WRNs or GENs were released even in the absence of such circumstances). In 2023 so far there have been no WRNs or GENs issued.

In summary, we found that the management of potential low-residual and insufficient generation situations have improved due to several factors including earlier issuing of the tight situation notices by the system operator and better wind and demand forecasting accuracy. However, in

[1] See para 1.1 for these defined terms.

2023 there were also some underlying factors that helped avoid tight situations – including warm temperatures while hydro storage remained high, a Methanex outage meaning more gas was available for generation, and the e3p outage simplifying other slow start thermal commitment issues. Next year Methanex do not have a planned outage, hydro storage trajectories are uncertain, peak demand is likely to be high, and more intermittent generation will come online. Therefore – despite the improvements observed – managing these tight situations remains a challenge.

Contents

Tables

Figures

1 Notices of low residual and insufficient generation forecasts

1.1 Transpower as the system operator issues notifications via email and publishes notices of potential grid issues to electricity participants on its website. In cases when forecast residuals are low the system operator issues a Customer Advice Notice (CAN) or if there is insufficient generation to cover demand the system operator can release Warning Notices (WRNs), or Grid Emergency Notices (GENs).

1.2 The notices inform electricity market participants about a tight situation, often requesting them to take action in order to rectify it (eg, the system operator can request generators to increase their offers during an insufficient generation event). The system operator introduced the Low Residual Situation CANs on 03 May 2019[2] to provide earlier notification to the market of when to expect tight situations. The system operator issues the low residual situation CANs when residual power quantities are expected to be less than 200MW.

1.3 The generation residual power quantities are calculated as the minimum between offered energy *(total energy offered - energy cleared)* and offered capacity *(maximum offered capacity - energy cleared - reserves (FIR or SIR – whatever is greater))*. Therefore, the residual calculation considers both generation needed to meet demand and generation needed to meet reserve requirements.[3]

1.4 Every notice has a start and end time, usually corresponding to a period after its release. We call this start-end interval an "event". If the event escalates (multiple notices associated with the same day and period of the day), we consider the start time as the earliest time among all notices for that event. Similarly, the end time becomes the latest among all notices. In 2022 there was one notice sent out for two separate time periods on the same day – 1pm and 3.30pm-5.30pm on 21 February. We have treated these as two separate events.

1.5 We have included in our analysis low residual or insufficient generation notices that apply to national or North Island residuals.

1.6 Low residual and insufficient generation notices have increased in frequency since 2021 compared to previous years. This review investigates how the events were resolved. We break down the residuals in order to determine what led to an improvement or decline in the residuals for each event:

(a) The amount of **generation offered** prior to the notice and after the notice was sent out.

(b) Forecast **demand** prior to the notice and the resulting demand during the event.

(c) **Wind generation offers** prior to the notice and resulting wind generation.

(d) **Generation outages** prior to the notice and during the event.

(e) The amount of **reserves offered** prior to the notice and after the notice was sent out.

1.7 It is worth noting that this investigation looks at how past events were treated. We are aware that the factors contributing to tight situations will continue and will likely become

2 See: CAN Industry Update Introduction of Low Residual Situation 3098623458.pdf (amazonaws.com)

3 For more information on the calculation refer to: https://www2.electricityinfo.co.nz/help/island_residual.html

more frequent (e.g., variability in generation and increase in peak demand). The Authority continually monitors those factors and publishes updates when applicable.

2 Factors influence the type of notice issued

2.1 The system operator monitors the energy capacity available to the electricity grid from around six months to weeks and hours ahead of the present time. The latter case includes information from market schedules, which becomes more accurate the closer it gets to real-time as participants adjust their offers to reflect updated conditions including demand forecasts.[4]

2.2 Between six months and one week ahead, the system operator relies on the New Zealand Generation Balance (NZGB) system for assessing the supply-demand balance, and if there are any shortfalls forecast it will list these dates in a CAN.[5]

2.3 During 2021 and 2022, if low residual situations were found between one week and four hours prior to real-time the system operator used two types of notices: a low residual CAN or a WRN, depending on the forecast level of generation. In 2023 the system operator updated this to up to one hour prior to real-time.[6] A CAN is issued if the residual is forecast to be less than 200MW but greater than zero, and a WRN is issued if there is insufficient generation forecast – that is, the residual is forecast to be less than zero.

2.4 In the case where insufficient generation to meet demand is expected to happen less than an hour from real-time (ie, after gate closure), the system operator will issue a GEN. Table 1 provides the precise definition of those notices as communicated in 2021-2023. Besides nationwide events, our analysis also includes the events specific to the North Island since it is where most of the population is located.

4 See: [Overview of notices for insufficient generation.pdf (amazonaws.com)] and [Security of supply and capacity | Transpower]

5 These forecasts are based on generation capacity, rather than offers.

6 WRNs were also updated to no longer be sent further than 36 hours prior to real-time. Instead, from 2023 a CAN sent out further than 36 hours prior to real-time can reflect either potential insufficient generation or residuals less than 200MW.

Table 1 - Overview of the system operator notices related to low residuals or insufficient generation during 2021 to 2023

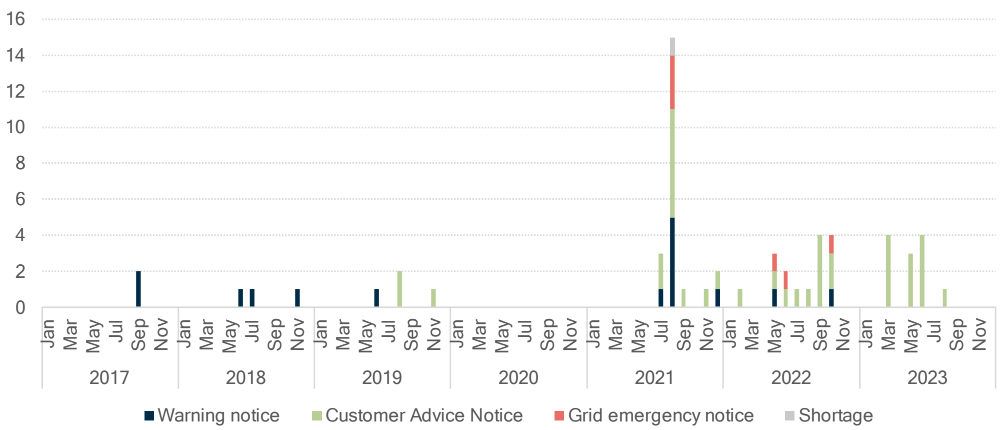
Notice	Timing	Trigger	Purpose	Requests made to
CAN	One week to one hour out	Residual generation at or lower than 200 MW for given times	Warn that a situation of low generation is expected and request preparations or actions from participants	Market participants, the Grid Owner, and to distributors, direct connects and retailers
WRN	One week to one hour ahead of real-time	A deficit in the forecast generation at given times	Request participants to act at given times and warn them of potential consequences if the situation is not alleviated	Market participants, the Grid Owner, and to distributors, direct connects and retailers
GEN	1 hour to real- time	Either a forecast deficit or a real-time deficit observed after gate closure	Requests participants to respond to actions in the GEN while allowing them to reoffer. It also warns the participants of the consequences if requirements are not met	Market participants, the Grid Owner, and to distributors, direct connects and retailers
GEN Report	At the end of the GEN event	End of the GEN event	Advise the market participants that the GEN has ended and inform them of the actions taken by the system operator	N/A

2.5 Depending on the severity of the event, the system operator can escalate the notices, usually beginning with a low residual CAN (released when certain trading periods look like they will have expected headroom of less than 200MW of supply) up to the level of a GEN, which requests quick actions due to insufficient generation to maintain standard reserve levels, with the potential need for load shedding in the system. It is worth noting that once residuals are below 200MW, there is little room to manage any unforeseen changes in generation or demand (eg, a decrease in generation from intermittent sources or an unexpected outage) whilst maintaining standard reserve levels.

3 Higher peak demand has contributed to the increase in notices

3.1 The number of low residual and insufficient generation notices has increased since 2021 (as shown in Figure 1).

Figure 1: Number of low residual and insufficient generation notices by month, 2017 to 2023



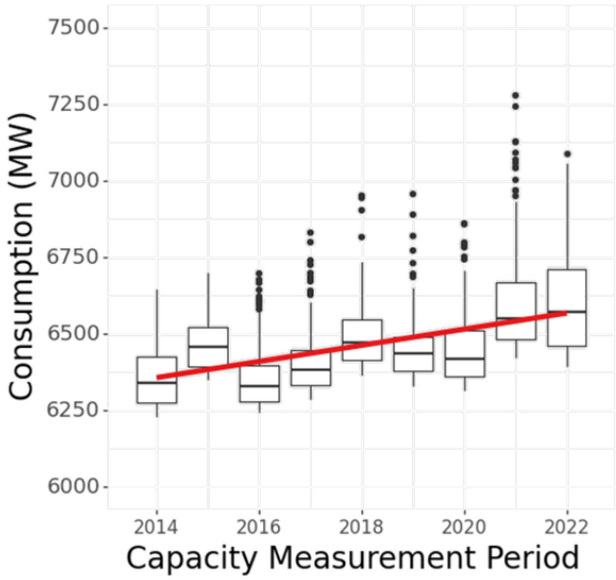
3.2 A study published by the Authority concludes that an increase in peak consumption contributed to the rise in the number of low residual situations in 2022.[7] Peak electricity consumption appears to have continued this trend in 2023, with six out of the top 10 highest peaks occurring during winter 2023.

3.3 Peak electricity consumption exhibited an upward trend from 2014 to 2022, as shown in Figure 2, taken from *The impact of the RCPD charge removal on peak demand.*[8] The figure shows electricity consumption in the trading periods with the top 300 highest consumption in the form of boxplots for each year. The study found that peak demand has been growing by around 0.4% per year.

3.4 The study also found that growth in 2022 electricity demand was above the average yearly growth rate and could not be explained by cold winter weather temperatures, since 2022 was a relatively warm year. It is estimated that the removal of the Regional Coincident Peak Demand (RCPD) charge[9] increased daily peak consumption by around 150MW during the top 300 consumption periods in 2022.

3.5 The findings also suggest structural changes reflected in the increase in peak demand, and we might see a higher growth rate in the upcoming years.

Figure 2: Plot of annual top 300 consumption trading periods between 2014 and 2022, with a trend line



3.6 As stated in section 1, we are aware that peak demand is not the only contributing factor for tight situations. For instance, the combination of higher demand peaks with high hydro storage levels and variability caused by renewable generation can lower thermal commitment, causing less firm generation to be available.

4 Notices were issued earlier in 2022 and 2023

4.1 The system operator seems to have improved the use of the CANs for low residual situations in 2023 and 2022 compared to 2021, releasing the notices earlier on average and releasing CANs as the first notice in all cases except where there were extenuating

7 See: https://www.ea.govt.nz/documents/2338/The_impact_of_the_RCPD_charge_removal_on_peak.pdf

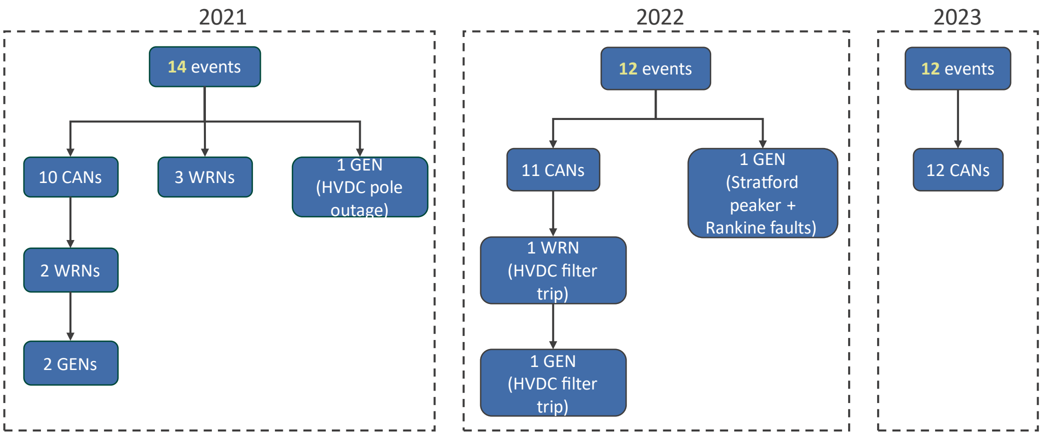
8 See above reference

9 For a definition of the RCPD charge, please refer to the link in footnote 10.

circumstances. Note that this finding is aimed at contributing to the evidence on how these events were resolved and does not constitute an investigation into the system operator's compliance with its service provider obligations.

4.2 Figure 3 illustrates the number of events between 2021 and 2023 and the type of notices sent out. There was a decrease in the number of events in 2022 and 2023 compared to 2021 – there were 14 such events in 2021 and 12 each in 2022 and 2023. In 2021 there were cases when a WRN notice was released without any prior CAN notice, which did not happen in the following years. During 2021 and 2022, GEN notices were released due to extenuating circumstances (one in 2021 and two in 2022), aligned with the intended use of such notices (grid emergency due to insufficient generation). For two events in 2021, the notices escalated to a GEN without any extenuating circumstances indicating the supply/demand balance deteriorated from a low residual to insufficient generation available. The events that escalated in 2022 were all related to extenuating circumstances. None of the events in 2023 escalated.

Figure 3 - Number of events that triggered notices released by the system operator between 2021 and 2023



4.3 Table 2 further details the events that happened in 2021. Most events occurred in July and August, and most of them applied to evening periods – 11 evening events compared to only three events in the morning peak period. On average the CAN notices were sent out 8.9 hours before the events. As discussed above, we identified two situations in 2021 where the events escalated without extenuating circumstances. Such situations are tied to the 9 and 10 August events[10], discussed further in the document. Finally, an unplanned outage on the HVDC pole caused the release of a GEN notice, without any other prior notice. Notices relating to residuals in the North Island only are highlighted in bold.

10 See: https://www.energynews.co.nz/news/energy-security/102930/record-demand-triggers-blackouts

Table 2 - 2021 System operator notices

Month	Period the notice(s) applied to		Initial notice	Sent	Extenuating circumstances
July	12 July 5:30pm-7:00pm	Evening	CAN	5hrs before	-
	13 July 5:30pm-7:00pm	Evening	CAN	8hrs before	-
	14 July 7:30am-10:00am	Morning	WRN	1.5hrs before	-
August	03 August 6:00pm-7:00pm	Evening	WRN	2.5hrs before	-
	05 August 5:30pm-7:00pm	Evening	CAN	2.5hrs before	-
	08 August 6:00pm-7:00pm	Evening	WRN	1.5hrs before	-
	09 August 5:30pm-9:00pm	Evening	CAN	11hrs before	None (1 WRN sent 4.5 hrs before 1 GEN sent 1 hr before)
	10 August 7:30am-9:00am	Morning	CAN	9hrs before	None (1 WRN sent 3 hrs before 1 GEN sent 1hr before)
	10 August 5:30pm-7:30pm	Evening	CAN	8hrs before	-
	17 August 5:00pm-7:30pm	**Evening**	**GEN**	**0.5hrs before**	**HVDC pole outage**
	18 August 8:00am-8:30am	**Morning**	**CAN**	**14.5hrs before**	**HVDC pole outage**
	20 August 6:00pm-6:30pm	**Evening**	**CAN**	**22.5hrs before**	**HVDC pole outage**
September	**1 September 6:00pm-6:30pm**	**Evening**	**CAN**	**4.5hrs before**	**-**
November	**22 November 3:30pm-7:00pm**	**Evening**	**CAN**	**4.5hrs before**	**-**

4.4 Table 3 shows the events that happened in 2022 (notices relating to North Island residuals only are in bold). Unlike 2021, the notices in 2022 tended to be spread over winter and autumn months (June to October) and distributed more equally between morning and evening periods - five notices in the evening, six in the morning, and one around midday. The 2022 CAN notices were sent out 19 hours before the events, on average (10.1 hours ahead of 2021, on average). This value is significantly influenced by a single event on 12 August when a CAN notice was released 65 hours before the event. If this event is excluded, the average time drops to 14.2 hours, although this is still 5.3 hours ahead of 2021. Also, only one event escalated in 2022, caused by a fault in the HVDC filter 4B at Haywards station. Finally, a double fault in generating units (Stratford peaker and Huntly unit 4) [11] caused the release of a GEN notice.

[11] See: https://www.energynews.co.nz/news/energy-security/122908/peaker-rankine-faults-trigger-emergency-notice

Table 3 - 2022 System operator notices

Month	Period the notice(s) applied to		Initial notice	Sent	Extenuating circumstances
February	**21 February 1:00pm**	**Midday**	**CAN**	**17.5hrs before**	**HVDC bipole outage**
	21 February 3:30pm-5:30pm	**Evening**	**CAN**	**20hrs before**	**HVDC bipole outage**
June	23 June 7:54am-9:30am	Morning	GEN	4mins into period	A mechanical fault on Stratford peaker and an electrical fault on Huntly 4 (coincident)
	28 June 5:00pm-7:30pm	Evening	CAN	1.5hrs before	-
July	5 July 5:00pm-7:00pm	Evening	CAN	4hrs before	-
August	12 August 7:30am-9:00am	Morning	CAN	65hrs before	-
September	6 September 6:00pm-7:30pm	Evening	CAN	31hrs before	-
	7 September 7:30am-8:30am	Morning	CAN	1.5hrs before	-
	14 September 5:30pm-7:30pm	Evening	CAN	24hrs before	-
	15 September 7:30am-9:00am	Morning	CAN	22hrs before	-
October	4 October 8:00am-9:30am	Morning	CAN	4.5hrs before	-
	7 October 7:30am-9:30am	Morning	CAN	16.5hrs before	HVDC filter trip (WRN sent 2hrs before GEN sent at the time of the event)

4.5 In 2023 most of the events occurred during morning periods over the winter months as shown in Table 4. The overall number of events so far in 2023 is comparable to the other years but several factors indicate an improvement in the handling of these tight situations:

- none of the notices published in 2023 escalated into insufficient generation.
- there was more warning time than in previous years (in 2023 the CAN notices were published 18 hours on average before the events).
- there were only eight events that did not have extenuating circumstances (compared to 11 in 2021 and eight in 2022).
- peak demand continues to increase, with six of the 10 highest demands recorded occurring in 2023[12].
- E3P went on outage on 30 June, and there has been only one low residual CAN issued since then.
- The new discretionary demand rule seems to be working well. An average of 167MW of discretionary demand was available for the five events since the new rule came into effect, but none of this demand needed to be reduced to resolve the events.

12 See: New peak records point to overall demand increases | Energy News

Table 4 - 2023 System operator notices

Month	Period the notice(s) applied to		Initial notice	Sent	Extenuating circumstances
March	22 March 8:00am-8:30am	Morning	CAN	21hrs before	HVDC Pole 2 outage
	23 March 8:00am-8:30am	Morning	CAN	23hrs before	HVDC Pole 2 outage
	24 March 8:00am-8:30am	Morning	CAN	23hrs before	HVDC Pole 2 outage
	29 March 7:30am-9:00am	Morning	CAN	15hrs before	HVDC Pole 2 outage
May	11 May 5:30pm-7:30pm	Evening	CAN	30.5hrs before	-
	12 May 7:30am-8:30am	Morning	CAN	25hrs before	-
	16 May 5:30pm-6:30pm	Evening	CAN	12.5hrs before	-
June	12 June 8:00am-8:30am	Morning	CAN	23hrs before	-
	14 June 7:30am-8:30am	Morning	CAN	22.5hrs before	-
	14 June 5:30pm-6:30pm	Evening	CAN	2.5hrs before	-
	15 June 7:30am-8:30am	Morning	CAN	16.5hrs before	-
August	11 August 7:30am-9:00am	Morning	CAN	17hrs before	-

5 Residuals were closer to forecast in 2022 and 2023

5.1 Figure 4 shows that the final residuals for the events have been much closer to the forecast residuals in 2022 and 2023. Both the average difference between final and forecast residuals[13] and the range of such differences decreased in 2022 compared to 2021, and further decreased in 2023.

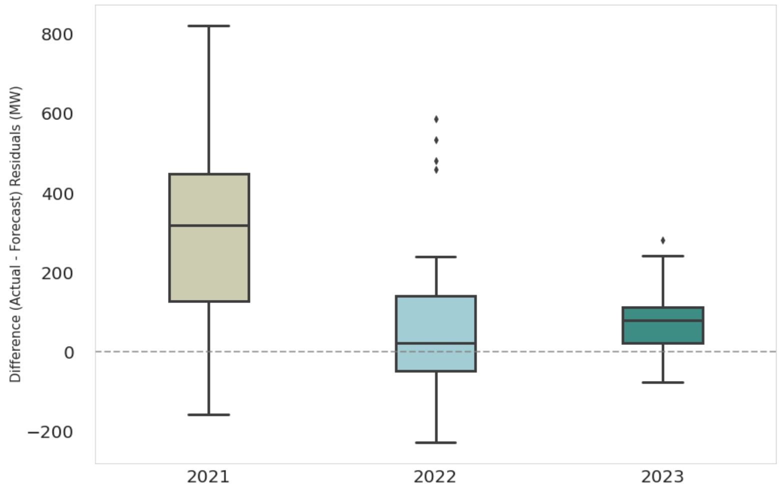
5.2 In 2021 there was, on average, a large increase in residual generation available for the events compared to the forecast. The mean difference between the final and forecast residuals was 296MW (with a median of 318MW). In eight events all trading periods within the events had differences between final and forecast residuals above 300MW. That is, the headroom ended up being much larger than expected for most events, except for the 9 and 10 August events, when the residual generation available ended up being lower than forecast.

5.3 In 2022, the final residual generation was much closer to forecast, on average (with a mean of 64MW and a median of 21MW). The differences between final and forecast residuals were greater than 200MW for only one event in 2022 (14 September). Four events in 2022 had average final residuals lower than forecast.

5.4 Similar to 2022, in 2023 there was a slight increase on average in residual generation available compared to forecast, with a mean difference between final and forecast residuals of 78MW and median of 81MW. Only two events in 2023 had a difference between final and forecast residuals above 200MW. Four events in 2023 had average final residuals lower than forecast.

13 The differences are calculated as the forecast values at the trading period immediately before the system operator issued a notice and the actual values during the trading periods the notices applied.

Figure 4 - Boxplot showing the difference between actual and forecast residuals[14]



6 Different factors affected how the events were resolved

6.1 This section discusses the factors that contributed to the change in residuals, and how the events were resolved, such as demand and offers, before and after the notices were issued.[15] We aim at understanding how underlying conditions and generator offers contributed to an improvement or decline in the residual generation available.

6.2 Table 5 show the differences in these factors before and after the notices were issued. When the notice applied to the North Island only, values for the North Island are shown in parentheses.

6.3 As discussed in the previous section, all events in 2021, except for 9 and 10 August had final residuals that were higher than forecast. This was mainly due to demand being lower than forecast. For five events the system operator requested demand to be cut. However, even in events where this request was not made, demand was usually lower than forecast – usually by more than 100MW (and up to 670MW). The lowest residual level for all events happened on 9 August 2021 and was 6MW.

6.4 The largest increase in residuals in 2022 occurred for the event on 14 September, where resulting residuals were significantly higher than forecast due to a combination of an extra Rankine unit being offered, demand being lower than forecast, and wind generation being above forecast.

6.5 For the event with the largest increase in residuals during 2023 (11 August), milder than expected temperatures drove down demand, and wind generation was slightly higher than forecast.

6.6 For the events in 2022 and 2023 where residuals were lower than forecast, demand was usually higher than forecast. For the 15 June 2023 event however, the main reason for

14 This boxplot and subsequent boxplots show the difference in nationwide values for the nationwide events, and the difference in North Island values for the North Island events. The boxplots present data for all trading periods within the events.

15 The differences are calculated as the forecast values at the trading period immediately before the system operator issued a notice and the actual values during the trading periods the notices applied.

lower residuals was a decrease in reserve and thermal offers – the reasons for which are discussed more later. This was also the event with the lowest residuals in 2023.

6.7 Despite more events in 2022 and 2023 having lower residuals than forecast compared to 2021, the minimum residuals over all events were higher than in 2021, at 106MW (on 6 September 2022 at 6.30pm) and 160MW (on 15 June 2023 at 7.30am).[16]

6.8 Other factors that contributed to the resolution of the events include an increase in reserve and hydro offers after the notices were issued (for most events), and the addition of a Rankine unit when possible. Wind generation was also higher than forecast for seven events in 2021, five in 2022, and eight in 2023.

Table 5 – Summary of the findings - 2021

2021	Period the notice(s) applied to	Difference in Residuals (MW)*	Any trading periods in the event with a decrease in residuals?	Difference in Demand (MW)	Demand Cut (Y/N)	Change in Rankine Offers (MW)	Change in Thermal Offers (MW)	Change in Reserve Offers (MW)	Change in Wind Offers (MW)	Change in Hydro Offers (MW)
July	12 July 5.30pm-7pm	273	N	-219	N	0	0	120	7	36
	13 July 5.30pm-7pm	344	N	-436	N	0	1	12	-93	9
	14 July 7:30am-10am	605	N	-87	Y	2	-2	13	149	9
August	03 August 6pm-7pm	130	N	-154	Y	2	0	-58	-35	0
	05 August 5.30pm-7pm	378	N	-460	N	0	-3	72	-54	-7
	08 August 6pm-7pm	436	N	-361	Y	0	-1	16	6	-2
	09 August 5:30pm-9pm	-12	Y	-164	Y	0	3	-105	-88	-123
	10 August 07:30am-8.30am	-95	Y	177	N	0	0	26	-50	131
	10 August 5:30pm-7:30pm	330	N	-190	N	0	2	192	81	62
	17 August 5pm-7:30pm	293 (241)	N	-279 (-224)	Y	2	0	-6 (-6)	-54	33 (31)
	18 August 8am-9am	1141 (816)	N	-972 (-678)	N	266	4	146 (146)	-29	-9 (-9)
	20 August 6pm-7pm	305 (514)	N	-74 (-114)	N	236	0	191 (191)	186	13 (13)
September	1 September 6pm-7pm	351 (315)	N	-295 (-303)	N	30	0	49 (49)	22	0 (0)
November	22 November 3:30pm-7pm	274 (380)	N	104 (90)	N	0	0	80 (80)	18	104 (11)

Table 6 - Summary of the findings - 2022

2022	Period the notice(s) applied to	Difference in Residuals (MW) *	Any trading periods in the event with a decrease in residuals?	Difference in Demand (MW)	Demand Cut (Y/N)	Change in Rankine Offers (MW)	Change in Thermal Offers (MW)	Change in Reserve Offers (MW)	Change in Wind Offers (MW)	Change in Hydro Offers (MW)
February	21 February 1pm	83 (64)	N	114 (132)	N	-63	-1	191 (19)	35	114 (114)
	21 February 3.30pm-5.30pm	-32 (-35)	Y	160 (170)	N	-113	-5	158 (-18)	118	63 (63)
June	23 June 7.54am-9.30am	-82	Y	97	Y	0	-1	0	-7	5
	28 June 5pm-7.30pm	-111	Y	106	N	0	0	25	-11	-2
July	5 July 5pm-7pm	160	N	48	N	0	-1	51	115	51
August	12 August 7.30am-9am	N/A	N/A	N/A	N	-70	N/A	-204	-22	324
September	6 September 6pm-7.30pm	-72	Y	159	N	0	3	105	-30	19
	7 September 7.30am-8.30am	88	N	-43	N	0	0	40	-7	0
	14 September 5.30pm-7.30pm	516	N	-115	N	230	-4	137	62	20
	15 September 7.30am-9am	70	N	-1	N	0	-2	37	-15	-14
October	4 October 8am-9.30am	112	Y	-2	N	0	0	-67	11	12
	7 October 7.30am-9am	30	Y	190	Y	230	-27	5	5	-40

16 Note: this is the minimum average within a trading period, not the minimum of the RTD schedules.

Table 7 - Summary of the findings - 2023

2023	Period the notice(s) applied to	Difference in Residuals (MW) *	Any trading periods in the event with a decrease in residuals?	Difference in Demand (MW)	Demand Cut (Y/N)	Change in Rankine Offers (MW)	Change in Thermal Offers (MW)	Change in Reserve Offers (MW)	Change in Wind Offers (MW)	Change in Hydro Offers (MW)
March	22 March 8:00am-8:30am	**-168 (-14)**	**Y**	**128 (23)**	N	**0**	**-51**	**116 (126)**	**6**	**52 (62)**
	23 March 8:00am-8:30am	**-145 (-76)**	**Y**	**188 (110)**	N	**0**	**19**	**-13 (67)**	**6**	**17 (24)**
	24 March 8:00am-8:30am	**-94 (-55)**	**Y**	**122 (88)**	N	**0**	**-6**	**-88 (-29)**	**-27**	**34 (34)**
	29 March 7:30am-9:00am	**48 (70)**	**N**	**-27 (-89)**	N	**0**	**0**	**62 (62)**	**-7**	**-25 (-25)**
May	11 May 5:30pm-7:30pm	82	N	258	N	180	10	-62	14	45
	12 May 7:30am-8:30am	190	N	250	N	240	-42	90	25	105
	16 May 5:30pm-6:30pm	134	N	44	N	100	25	77	-19	15
June	12 June 8:00am-8:30am	31	N	153	N	0	-6	65	49	192
	14 June 7:30am-8:30am	93	N	144	N	240	2	47	-14	7
	14 June 5:30pm-6:30pm	15	Y	41	N	0	0	-3	8	13
	15 June 7:30am-8:30am	-58	Y	9	N	0	-54	-109	9	14
August	**11 August 7:30am-9:00am**	**304 (230)**	**N**	**-140 (-172)**	N	**0**	**0**	**-41 (-55)**	**70**	**20 (20)**

* Difference between actual values observed at the time when the notices apply minus forecast values before the notice was released (using average values within a trading period once real-time pricing was introduced to be consistent with previous years). The mean difference between pre-dispatch and final over the trading periods within an event is presented.
** Values in parentheses: North Island values.

Demand was cut for more events in 2021 and none in 2023

6.9 During five out of the 14 events in 2021 participants were asked to cut demand (14 July, 3, 8, 9, and 17 August). Figure 17 in section 8 shows the effect of the demand cut request for 8 August 2021. There was a sudden drop in actual demand (blue line) during the time of the event (shaded region), changing the shape of the curve (compared to the expected response represented by the 1-hour and 12-hour ahead forecasts).

6.10 In 2022, the system operator requested demand cuts in only two events (23 June and 7 October), caused by extenuating circumstances (see section 8 for more details on the 7 October event).The decrease in the number of events that participants were asked to cut demand in 2022 compared to 2021 might be related to the lower spread of inaccuracies in the demand forecast observed in 2022 and to the increase in the average time CANs were released before the events.

6.11 No demand shedding was needed during the 2023 events. From 3 May 2023 the urgent Code amendment clarifying the availability and use of discretionary demand came into effect.[17] This meant that starting from the 12 June event, the system operator has included in the low residual notices the request for difference bids to be submitted for discretionary demand. Over the five events where this request was made, an average of 167MW was bid in as discretionary demand. However, the system operator did not have to instruct any participants to reduce any of this discretionary demand. That is, these events were resolved without the need to use this discretionary demand.

Demand was closer to forecast in 2022 and 2023

6.12 Figure 5 shows the accuracy of the demand forecasts, excluding events when demand was cut. The spread in forecasting errors decreased in 2022 and 2023 compared to

17 See: https://www.ea.govt.nz/documents/2942/Decision_paper_-_Clarify_the_availability_and_use_of_discretionary_demand_control.pdf

2021. However, there was a tendency for demand to be higher than forecast for the events in 2022 and 2023.[18]

6.13 For the 2021 events, demand was 108MW lower on average than forecast, with a median of -113MW, indicating there were a few events where demand was lower than forecast. For the event on 18 August, demand reached 630MW lower than forecast over the North Island. For the events on 13 July and 5 August, demand reached 412MW and 419MW lower than forecast, respectively.

6.14 For the 2022 events, demand was 130MW *higher* on average than forecast, with a similar median difference of 140MW. Only the 14 September event had consistently lower demand than forecast for all the trading periods within the event, with demand ranging from 6MW to 65MW lower than forecast. In two other events (15 September and 4 October) there were some trading periods with demand lower than forecast but other trading periods where demand was higher than forecast. In all the other six events demand was higher than forecast for all trading periods. The results exclude 12 August since it was not possible to calculate the difference between final and forecasted demand due to the notice being released exceptionally early.

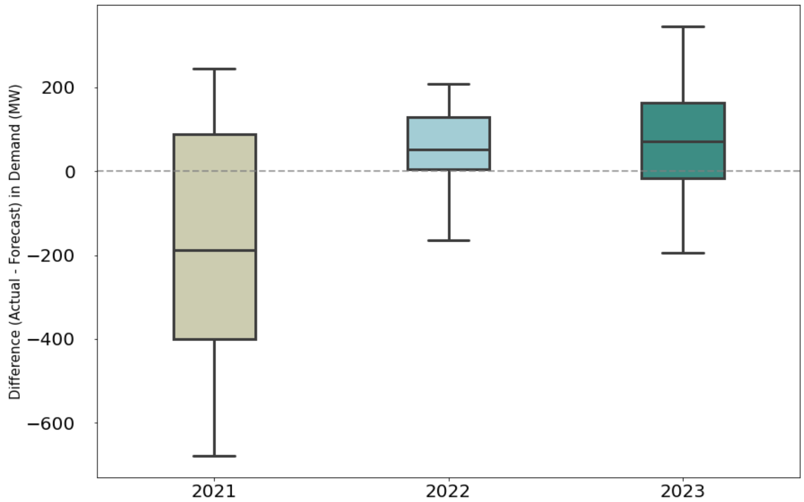
6.15 In 2023 demand was again higher than forecast on average during the events (mean 109MW, median 122MW). There were only two events in 2023 where demand was lower than forecast: 11 August, where demand was more than 100MW below forecast levels for all trading periods, and 29 March, where demand was lower than forecast but by less than 100MW.

6.16 Despite the tendency to underpredict demand, there was a decrease in the distribution of errors in the demand forecasts in 2022 and 2023 compared to 2021, possibly due to the adoption of the TESLA load forecast tool on 03 March 2022 by the system operator.[19]

18 Differences between demand actual demand and demand forecast are calculated to incorporate the maximum differences within the trading periods the notices apply.

19 TESLA have stated that they corrected for the removal of the RCPD charge after the first cold day of winter 2022 (see comment below this energy news article). The underpredicting of demand for the 2022 events may therefore be due to other (uncontrolled for) factors, and/or the RCPD charge removal increased demand by more than the TESLA correction.

Figure 5 - Evolution of demand forecast from 2021 to 2023. The results exclude events where participants were requested to decrease demand



A Rankine was usually added when there was enough warning time[20]

6.17 In this subsection we look at thermal generation from the Genesis Rankine units separately to other thermal plants because they are slow to start[21] and have a large capacity (250MW each). We do not include the Taranaki Combined Cycle (TCC - another large-capacity slow-start thermal generator) as it was on outage or had restricted running for most of the events. Huntly Unit 5 (also called E3P) is not included either as it is mainly used as baseload generation (ie, runs continuously most of the time) and was on outage during many of the 2023 events.

6.18 Six events had all available (ie, not on outage) Rankine units already offered prior to the notice being sent out. For an additional 15 events, the warning time given was less than 10 hours, so a cold Rankine unit could not have been added.[22] For five more events, another Rankine was added to the offers after the notice was sent out.

6.19 That leaves 12 events where all available Rankine units were not offered, another unit was not added, and the warning time given for the events was greater than 10 hours. Six of these events were in February/March when demand is lower and therefore at least one Rankine would probably have been in storage (ie, not being used over this time as unlikely to be needed and therefore uneconomic to run). When in storage, a Rankine unit takes at least one day to start up.

6.20 Of the remaining six events, one was the 9 August event in 2021 (details of which are discussed elsewhere).[23] Two of these events were in September 2022, and three were in 2023 (16 May, 12 June, and 11 August). In September 2022, hydro storage was high (well above the historical average for that time of year). This meant prices were low – most likely lower most of the time than the cost of turning a Rankine on for a short period

---

20 It is worth noting that besides enough warning time, other factors such as forward prices, wind generation and demand forecasting affect thermal unit commitment decisions.

21 The Rankine units can take up to 10 hours to start if they are cold, see https://www.genesisenergy.co.nz/about/generation/huntly-power-station for more information.

22 The Rankine units need 10 hours to start if they are cold, see https://www.genesisenergy.co.nz/about/generation/huntly-power-station for more information.

23 See: 9-August-2021-demand-management-event-Phase-2-Report.pdf (ea.govt.nz)

of time. Genesis did not offer the third Rankine at all from 18 August to 1 November, while two Rankines were offered for all except one event in September. This suggests that one Rankine was in storage for the events in September 2022 so could not have been added. However, for the event on 15 September, we are unsure why Genesis did not add another Rankine to the offers. It added a Rankine for the event on the previous day and had just about 22 hours of warning for the event.

6.21 For the three events in 2023, hydro storage was again high. However, all three Rankines were offered at various times from 10 May (before this Huntly 4 had not been offered all year). This suggests that all three units were not in storage at this time, so could have been brought on with around 10 hours of warning. All three events had a warning time greater than 10 hours.

6.22 Some events also had a small change in Rankine offered quantity (for the units that were already offered). Four events in 2021 had small increases in offered quantity, up to a maximum increase of 30MW, three events in 2022 had decreases in offered quantity, and one event in 2023 had an increase of 100MW.

6.23 For the three events in 2022 with a decrease in the Rankines offered quantity (two of which occurred on the same day), there were no Rankine outages listed on Transpower's Planned Outage Coordination Process (POCP) website for these days.

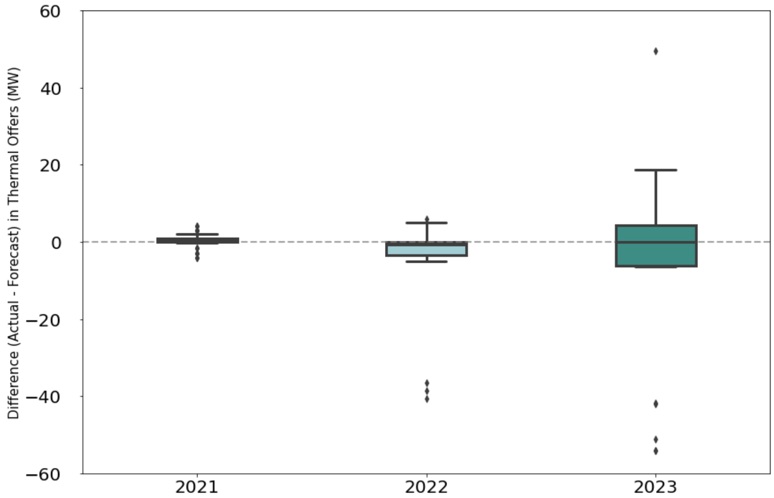
Most available thermal capacity was already offered

6.24 In 2021, all thermal units that were not on outage were already offered, although sometimes not at maximum capacity. This meant that sometimes there were minor changes in offered quantity (maximum of 4 MW for one event), as illustrated in Figure 6. Three events coincided with planned outages for the thermal plants. Stratford unit 2 (SFD2 – 100MW) was on outage during the 17 and 18 August events. On 22 November, three plants were on outage: Stratford (units 1 and 2 – 100 MW each) and McKee (50 MW). TCC was running on restricted capacity during many/all/number events due to gas supply issues. Section 9 presents a detailed discussion with respect to outages.

6.25 As in 2021, in 2022 all thermal units that were not on outage were already offered prior to the release of the notices, except for the 12 August event where the notice was published almost three days before the event. For this event, two extra units were added to the offer stack after the release of the notice. As shown in Figure 6, in 2022 there was little change in offered quantity due to most capacity already being offered. Some events in 2022 had outages that impacted offers. For instance, one Stratford peaker had an outage event initially planned to take place on 11 August (start and end) which had to be extended until 14 August. On 7 October, McKee was withdrawn (46MW) due to a planned outage. TCC was again on outage during five events in 2022 and had limited running capacity over winter. Whilst thermal outages (excluding Rankines) coincided with only three events in 2021, all 12 events in 2022 coincided with thermal outages.

6.26 In 2023 there was a wider range of offered quantity changes by thermal generators for the events, but these changes were due to outages. Changes ranged from an increase of 25MW on 16 May, to a decrease of 54MW on 15 June. For the event on 15 June, Contact decreased offers for Whirinaki by 52MW. Contact entered an outage for Whirinaki on POCP after the notice was sent out. The other two events with large decreases in thermal offers were 22 March and 12 May. For the 22 March event, Nova decreased offers for McKee by 42MW. Nova have told us that McKee tripped on start-up that morning, remaining out of action for three hours while the fault was investigated. For the 12 May event, Genesis decreased offers for Huntly Unit 6 by 47MW. This was due to Huntly Unit 6 being on outage over this time.

Figure 6 - Differences in thermal offers for 2021 to 2023 (excluding Rankine units)



Reserve offers usually increased when possible

6.27 There was usually an increase in offered reserves for events in 2021 and 2022 (11 events in 2021, eight events in 2022), but for only half of the events in 2023, as shown in Figure 7. Generators may need to decrease the quantity of reserves offered if the forecast dispatch of energy for the same unit increases, as this capacity is no longer available to be dispatched as reserves.

6.28 The average change in offered reserves for the 2021 events was 38MW (with a similar median change of 40MW). The 9 August event had the largest decrease of offered reserves of up to 149MW.[24]

6.29 The average change in offered reserves for the 2022 events was 14MW (with a median change of 24MW). The event with the largest decrease of reserve offered quantity was 12 August with up to 216MW, though, again, the notice for this event was released exceptionally early, at which time forecasts would have been quite uncertain.[25].

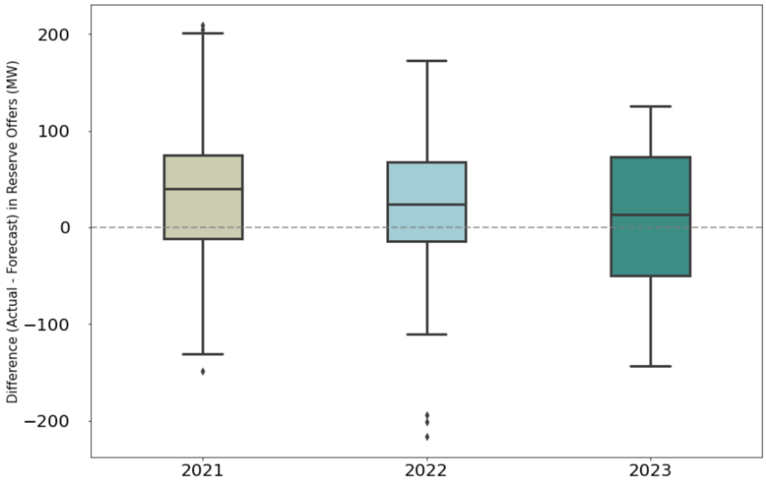
---

24 The decrease in offers by Mercury for this event were considered by the Compliance Committee. Mercury provided information that changes in reserves offered are impacted by expected energy dispatch. The higher the expected energy dispatch on the Waikato, the less reserves that are available. They also provided information that the relationship between Mercury's expected energy dispatch and available reserve is non-linear, and therefore not adequately modelled by the system operator's Scheduling Pricing and Dispatch tool (SPD). The Compliance Committee formed the view that a prima facie case had not been established and declined to take action under regulation 11(1)(b) of the Electricity Industry (Enforcement) Regulations 2010. This is detailed in: https://www.ea.govt.nz/documents/2157/Information-paper-Post-implementation-review-of-the-trading-conduct-provisions.pdf.

25 Both Mercury (for Maraetai) and Contact (for Roxburgh and Clyde) decreased reserve offers after the notice was sent out. For Mercury this was due to an increase in expected dispatch of energy, reducing the quantity of reserves available (the same as for 9 August 2021). Contact decreased reserve offers for Clyde by 80MW, due to reduced capacity as one unit was on outage. They also decreased reserve offers for Roxburgh from 48MW to 10MW after realizing more reserves were offered than was physically possible with the corresponding energy being offered at Roxburgh.

6.30 The average change in offered reserves for the 2023 events was 9MW (with a median of 14MW). The event with the largest decrease of reserve offered quantity was 15 June (143MW), which is also the event with the lowest residual levels for the year.[26]

Figure 7 - Differences in reserve offers for 2021 and 2022



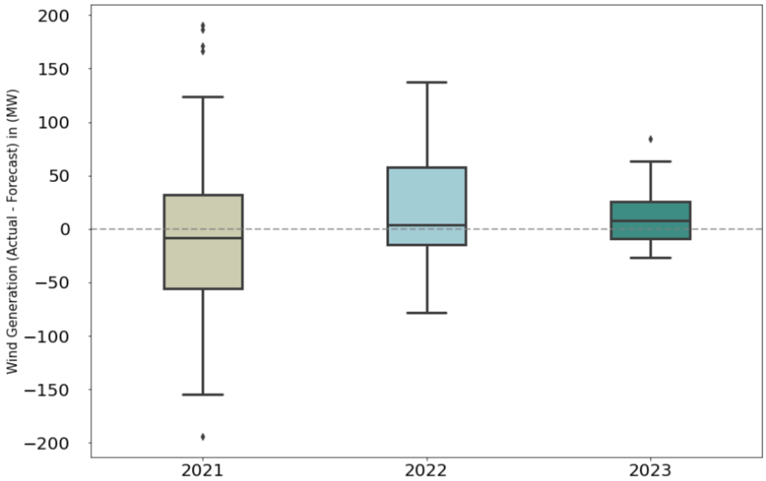
Wind forecasts have improved

6.31 Wind generation was closer to forecast for the events in 2023 compared to the events in 2021 and 2022 (as shown in Figure 8). The spread in inaccuracies decreased from 385MW in 2021 to 216MW in 2022 and 112MW in 2023. This decrease occurred despite average wind generation during the events being higher in 2023 compared to in 2022 (178MW compared to 163MW). This decrease in the spread of inaccuracies indicates an improvement in wind generation forecasting. While forecasts will never be completely accurate, improved accuracy helps generators and consumers in making decisions, for example whether to bring on slow-starting thermal units in advance of forecast tight situations.

6.32 In 2023 wind generation was 12MW higher than forecast on average (with a median of 7.5MW), compared to 24MW higher on average in 2022 (with a median of 4MW) and 1MW lower on average in 2021 (with a median of -8MW).

[26] Both Mercury (for Maraetai) and Contact (for Roxburgh) decreased reserve offers after the notice was sent out. For both parties this was due to an increase in expected dispatch of energy, reducing the quantity of reserves available.

Figure 8 - Evolution of wind generation offers from 2021 to 2022



Most available hydro capacity was already offered

6.33 There was usually little change in hydro offers, as shown in Figure 9. As with thermal offers, this was because all available capacity (ie, not on outage) was mostly already offered prior to the release of the notices. Any small changes were generally to increase the offered quantity.

6.34 For the 2021 events, there was an average increase of 6MW in hydro offers. A few exceptions are worth mentioning. On 9 August there was a 200MW decrease in North Island hydro offers after the notice was released.[27] On 10 August, there was an increase in hydro offers of 139MW (most from North Island generators).[28] On 22 November there was an increase in hydro offers of 194MW (26MW in the North Island and 168MW in the South Island).[29]

6.35 For the 2022 events again little change was observed in hydro offers, despite the average change in offers being higher compared to 2021 (38MW versus 6MW in 2021). This is because the average is heavily influenced by the addition of 324MW for the 12 August event. As previously mentioned, the notice for this event was published 65 hours in advance. When the notice was published, for instance, Trustpower did not have offers for its hydro generators uploaded into the system yet. The median values for 2021 and 2022 are also different (18 MW versus 1 MW in 2021). Apart from 12 August, the maximum increase in hydro offers for 2022 happened on 21 February (114MW)[30] and the maximum decrease in offers happened on 7 October (40MW).[31]

6.36 There was little difference in 2023 compared to previous years, with only a small change in hydro offers. The average change for events in this year was 33MW. The maximum

---

27 For more information on what happened for this event refer to https://www.ea.govt.nz/projects/all/review-of-9-august-2021-event/. There was only one other event in 2021 with an overall decrease in hydro offers but this event only had very minor changes in quantity.

28 Genesis increased offers at one of its Tongariro generators despite one unit being on outage from 8am that day.

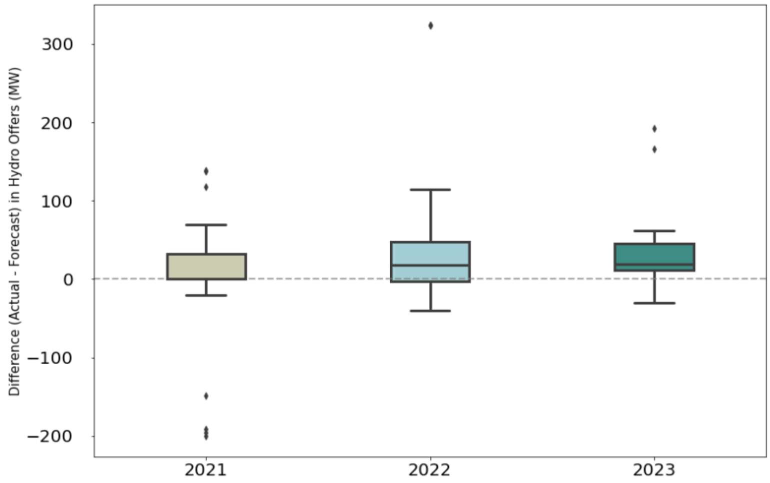
29 Meridian completed outages at Benmore and Ohau C early which allowed it to increase offers for these generators (and Ohau B) for some trading periods in the event.

30 Genesis bought a Tongariro unit back from outage early, allowing it to increase offers.

31 This decrease in offers was for two of Mercury's plants on the Waikato River – both of which (Maraetai and Waipapa) Mercury entered outages for on POCP after the notice was sent out.

increase in hydro offers in 2023 happened on 12 June (192MW)[32] and the maximum decrease in offers happened on 29 March (30MW).[33]

Figure 9 - Differences between hydro offers for 2021 and 2022



There were more events in 2023 where outages were cancelled or finished early

6.37 Using data from Transpower's POCP website, we found only one case in 2021 and one in 2022 of cancelled outages after the system operator released a notice, but five in 2023. The maximum available capacity added due to a cancelled outage during the events was 35MW.

6.38 We also investigated planned outages that changed (ie, were delayed or completed early) after the release of the system operator notices (and before the beginning of the events) and found only two events where an outage completion date was changed in 2021 and 2022.[34] During 2023, we found three instances where an outage was finished earlier than originally posted, with the change to the end time made after the notice was sent out.[35]

6.39 This indicates improved flexibility by participants to manage outages when a tight situation is forecast. It also indicates that more warning time helps for such changes to be possible.

6.40 This does not definitively show that there were no more events where generators delayed or cancelled outages, as they may have done so before the notice was sent out or removed the outage from POCP (this should not be the case but might occur

---

32 This increase mainly came from an increase of 116MW at Contact's Clyde station, but also a small increase (35MW) at Mercury's Maraetai station, despite an outage at this station beginning at 8am that day.

33 This decrease in offers was for Mercury's Whakamaru station on the Waikato River. Mercury changed the end time of an outage for this station during the event.

34 One was for the 22 November 2021 event, where Meridian brought forward the completion date of an outage at Benmore 12 minutes before the start time of the event, and the completion time for an outage at Ohau C during the event. The other was for the 21 February 2022 where Genesis brought forward the completion date for an outage at Tongariro after the CAN was sent out.

35 For the 11 May event, Mercury changed the end time of an outage for Maraetai, bringing the end time back from 12 May at 4pm to 10 May at 1.30pm. For the 12 June event, Genesis changed the end time of an outage for one of its dams at Waikaremoana from 14 June 11.59pm to 11 June 4.59pm. And for the 14 June event, Top Energy changed the end time for an outage of its Ngāwhā geothermal generation from 14 June 6pm to 13 June 6.30pm.

erroneously). We may have also missed some instances as we are currently unable to automate the searching of changes to outages.

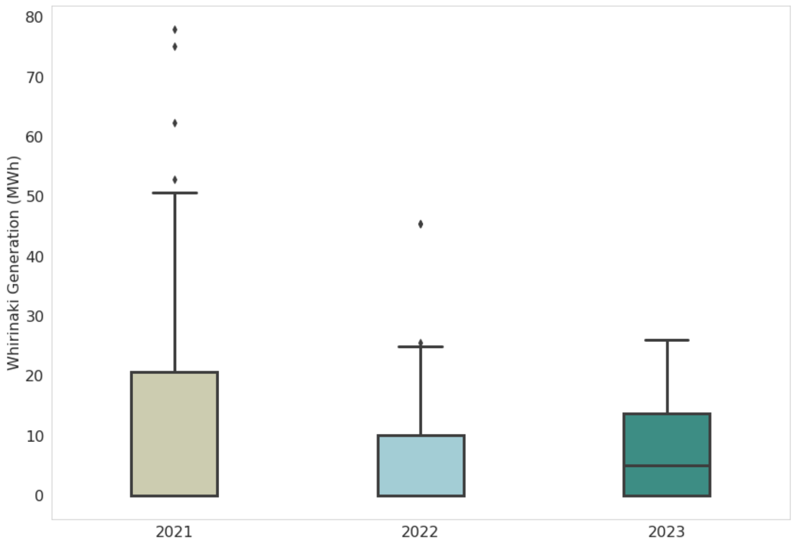
Usually some generation was not running at maximum

6.41 Average idle thermal capacity, that is, available capacity that was not being used for generation (although not accounting for capacity needed for reserves)[36], was higher in 2022 and 2023 than in 2021 (around 365MW on average in 2022 and 2023 compared to 300MW in 2021).

6.42 The idle capacity available from Whirinaki (for the events it ran for) was higher in the 2022 and 2023 events (around 109MW compared to 82MW for 2021). Whirinaki ran for six events in 2021 and seven events in both 2022 and 2023.[37]

6.43 While less capacity from Whirinaki was used (see Figure 10), more was used from other thermal peakers during the events in 2022 and 2023. Idle capacity from other thermal peakers during the events was 72MW on average in 2021 compared to around 55MW on average in 2022 and 2023.

Figure 10 - Whirinaki generation during the events



6.44 Figure 11 shows that usually during most of the events, one or two Rankine units were running. On only one event in each year were all three Rankine units running.[38] There

---

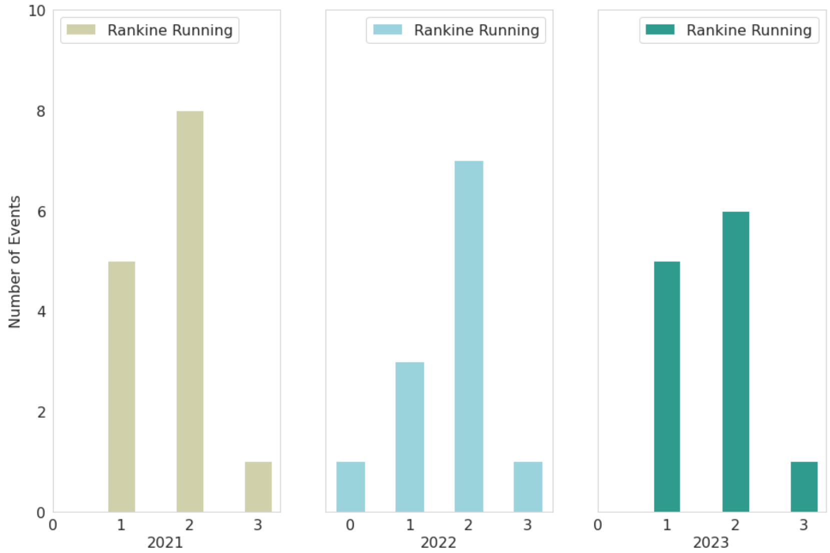
36 Idle available capacity accounts for generation that was on outage. It treats Rankine and e3p available capacity as the capacity of the running units that are not being used for generation. Idle peaker capacity (including Whirinaki) is all available capacity regardless of whether the unit is already running or not. Calculations do not include TCC.

37 Whirinaki has a capacity of 150MW.

38 Note that it can be quite rare for all 3 Rankine units to run together. This is because they are quite expensive to run, and more expensive to run if they will only be used infrequently for short periods (due to start-up costs, wear and tear from turning on and off, and extra staffing costs). In recent years, the Rankine Units have been used as hydro-firming energy. That is, increasing generation to offset periods of sustained low hydro generation. When hydro storage is high however, this hydro-firming role is not needed, and prices may be lower most of the time than the cost to turn the Rankines on. In 2022, the three Rankine units only ran together on one day (the day of the event discussed here), as hydro storage was healthy over winter and

was one event in 2022 where no Rankine units were running (4 October, discussed below).

Figure 11 - Rankine units running during the events



6.45 For the events where one Rankine was running, the average idle capacity of this already-running Rankine was higher in 2021 and 2023 compared to 2022 (around 80MW in 2021 and 2023, 26MW in 2022). However, for the events where two Rankines were running, the average idle capacity of the two Rankines was higher in 2022 and 2023 than in 2021 (about 140MW in 2022 and 2023, 39MW in 2021).

6.46 There was one event in each year where three Rankine units were running, but the reasons differ. On 18 August 2021, a HVDC fault on the day before prompted the addition of an extra Rankine unit, and whilst all three units were running, they were only generating a combined total of 286MW, on average (so the idle capacity of these three Rankines was 434MW). The idle peaker capacity during this event was 233MW. Mild temperatures might have contributed to demand remaining relatively low nationwide. On 12 August 2022, on the other hand, near-record levels of demand, due to cold morning temperatures across the country contributed to more than 440MW (on average) of generation from the Rankine units. The idle peaker capacity on 12 August was only around 25MW. In 2023, partially due to an extended E3P outage and partially due to expected high peak demand (which turned out to be not as high), all three Rankine units were running on 11 August 2023, generating 540MW on average during the event. The idle peaker capacity was 117MW on that day.

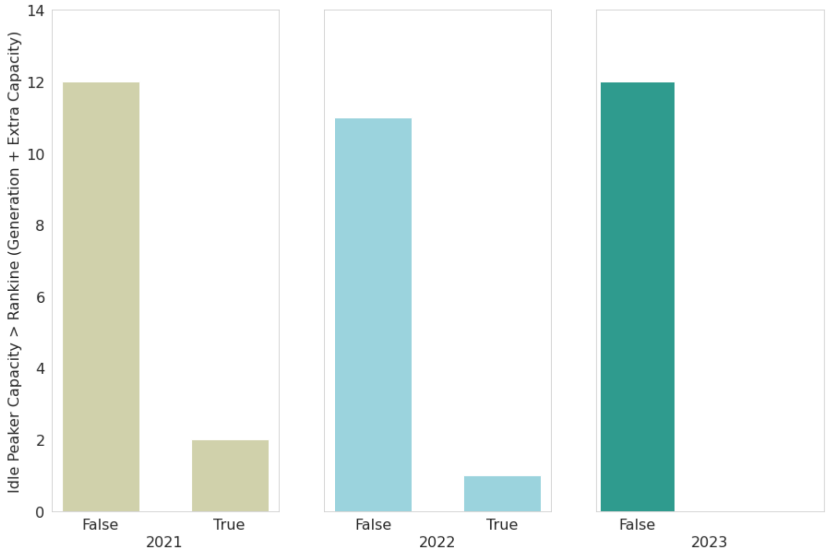
6.47 Finally, for the single event when no Rankine units were running, on 4 October 2022, demand was below 6000MW nationwide, despite a colder morning in the lower North Island and the South Island. Peaker plants (excluding Whirinaki) were only generating around 168MW on average that day, with idle peaker capacity (plus Whirinaki) of around 150MW. Additionally, the CAN was released only 4.5hrs before the event, which likely

spring in this year. In 2021, hydro storage was lower over summer and autumn so all three Rankine units ran more frequently together during this time – on 106 days in total. By August however – when most of the events occurred in 2021 – storage was higher than average and increasing. In 2023, hydro storage was again high leading into winter. However, when Huntly Unit 5 went on long-term outage unexpectedly in July, all three Rankine units began running together reasonably often to make up for this outage.

prevented the addition of slow-starting Rankine units, and one Rankine unit was on outage.

6.48 Figure 12 shows the number of events per year when idle peaker capacity was above the running Rankine capacity. Idle peaker capacity being greater than combined Rankine generation plus extra capacity means that the Rankine units could be successfully replaced by the peaker plants if needed. In more than 90%of the events, at least one Rankine unit was needed. The idle peaker capacity was greater than the running Rankine capacity in only two events in 2021 and one event in 2022 (none in 2023). The idle peaker capacity includes the Whirinaki plant. This analysis does not account for reserves.

Figure 12 – Idle peaker capacity greater than Rankine generation (plus available capacity)



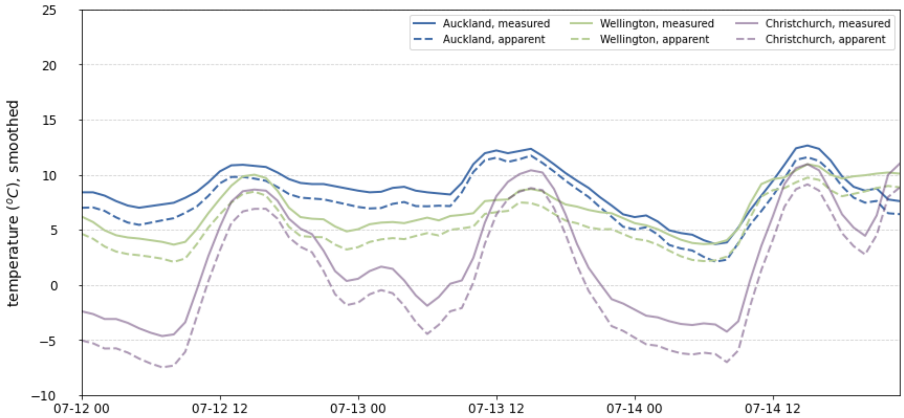
7 WRNs with no prior CANs were issued in 2021

7.1 On three occasions in 2021 the system operator released WRN notices without the use of previous CANs. On the first of these occasions, 14 July, the WRN notice was caused by low temperatures across the country, as shown in Figure 13. During the first and second weeks of July 2021, cold fronts reached the country and temperatures dropped. Electricity demand increased due to the cold weather and the system operator released two CANs for 12 and 13 July, informing the possibility of residuals being lower than 200MW between 5:30pm and 7pm on both days[39]. However, we estimate that the residuals four hours prior to the event on 14 July were above 200MW (hence no low residual CAN was issued)[40], dropping below that threshold around two hours before the event. We also noticed that a change in Huntly unit 5 offers at 5:47am (24 minutes before the WRN notice was published at 6:11am) on 14 July from around 410MW to 0MW might have contributed to the release of the notice. The offers went back to the 410MW level at 6:07am, only four minutes before the notice was published. During this event one Rankine unit was on outage (until 19 July), as well as 482MW of hydro generation.

39 See: Cold spell, generation woes increase system stress | Energy News

40 In this section we assumed that the system operator was following its previous timeline for issuing the CANs, ranging from one week to four hours before real-time.

Figure 13 - Measured and apparent temperatures for Auckland, Wellington, and Christchurch - 12 to 14 July 2021



7.2 A combination of relatively low temperatures, lower than forecast wind generation and above average amounts of hydro on outage may have triggered the WRN notice sent by the system operator on 3 August 2021. Temperatures in Wellington and Christchurch were below 10ºC on that day. There was a decrease in the residual levels around 3.5 hours before the event to below 200MW (ie, after the cut-off time specified by the system operator for sending out low residual CANs at that time (see paragraph 2.3)). The WRN notice was sent out about 2.5 hours before the start of the event indicating the situation had deteriorated to forecast insufficient generation. There was a 38MW decrease in reserve offers (excluding Rankine units) from 3:10pm to 3:14pm, which may have contributed to this deterioration. Wind offers were above 400MW from one day before the event until the release of the notice.

7.3 On 8 August 2021, low temperatures may again have contributed to the WRN notice released on this day. Wellington and Christchurch had apparent temperatures below 5ºC. Around 2 hours before the event, residual values began to degrade, (reaching levels below 200MW), again after the cut-off time specified by the system operator for sending out low residual CANs (see paragraph 2.3). The WRN of forecast insufficient generation was sent out 1.5 hours before the event. We notice a 131MW decrease in reserve offers from around four hours before the event to 2.5 hours before the event.[41] The decrease in reserve offers and the fact that demand and wind generation forecasts were well off the actual values, as shown in Figure 14 and Figure 15, might have contributed to the release of the WRN notice. The 1-hour ahead wind generation forecast was 100MW below actual values on average, whilst the 12-hour ahead wind forecast was 154MW above the actual generation. For the demand side, the inverse behaviour happened: the 1-hour ahead forecast demand was more than 100MW above actual values, and the 12-hour ahead forecast was more than 100MW below actual values - although, in this case demand was requested to be cut, thus contributing to differences between actual and forecast values. There was 537MW of hydro outage during 8 August, along with 22MW of wind and 3MW of cogeneration, which might also have contributed to the release of the WRN notice.

41 The majority of the low residual was due to decreases in reserve offers at Mercury's Waikato plants and Genesis's Waikaremoana plants, due to an increase in expected energy dispatch and therefore less capacity available to offer as reserves.

Figure 14 - Forecast and actual demand - 08 August 2021

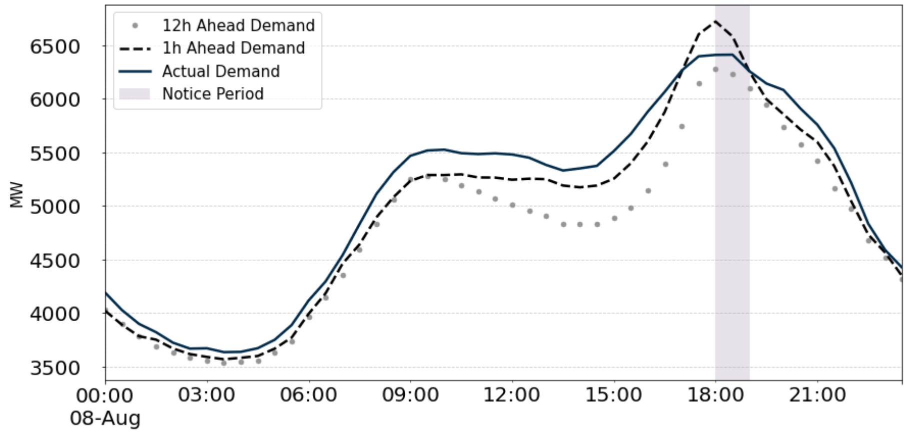
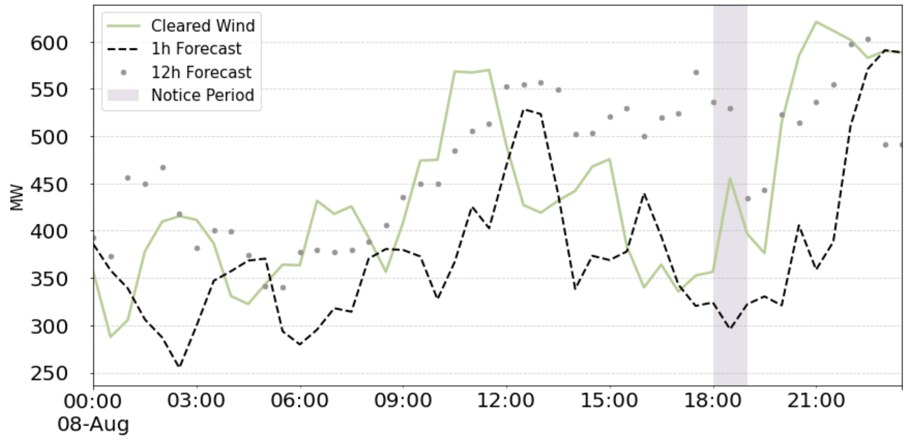


Figure 15 - Forecast and generated wind energy - 08 August 2021



7.4 In summary, a combination of low temperatures, inaccurate wind and demand forecasts, and relatively high amounts of hydro on outage contributed to the three events that started with WRN notices in 2021.

8 Escalation of system operator notices in 2021 and 2022

8.1 This section provides a summary of the events that led to the escalation of the notices released by the system operator in 2021 and 2022, aiming to understand what caused the escalation of the events.

9 & 10 August 2021

8.2 *"On the evening of Monday 9 August 2021, New Zealand faced the largest electricity demand peak on record because of one of the coldest nights of the year. The 9 August event led to approximately 34,000 customers experiencing an electricity cut without warning"*[42]. The sentence, extracted from the 9 August 2021 demand management event - Review under the Electricity Industry Act 2010 (final report), summarises the causes and effects of system operator notices released during the days of 9 and 10 August 2021.

8.3 Figure 16 shows the temperature and apparent temperature for three major urban areas: Auckland, Wellington, and Christchurch. On 9 August 2021, Auckland showed apparent

42 See: 9-August-2021-demand-management-event-Phase-2-Report.pdf (ea.govt.nz)

temperatures below 10ºC during the afternoon and night, whilst apparent temperatures in Wellington were around or below 5ºC on the same day. On the morning of 10 August, all locations showed apparent temperatures around or below 5 ºC. To put in perspective, NIWA reports that the 1981-2010 average temperatures for August in Auckland, Christchurch, and Wellington were 11.3ºC, 7.9ºC, and 9.4ºC respectively[43], above the temperatures observed for 9 August 2021 at those locations.

8.4 The low temperatures caused an increase in demand above expected values, as shown in Figure 17. During the event, demand was 181MW above the 1-hour forecasts, reaching more than 7000MW (closer to the levels indicated by the 12-hour ahead forecast). Wind generation also ended up being below forecast levels for most of the time during the events (although the forecast levels were already low).

8.5 More than 500MW of hydro was on outage during the event, as well as around 50MW of co-generation and wind (combined).

Figure 16 - Measured and apparent temperatures for Auckland, Wellington, and Christchurch - 9 and 10 August 2021

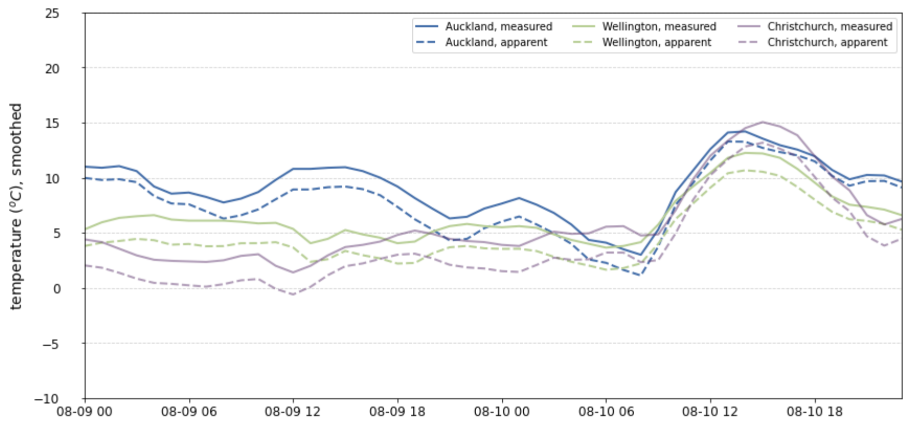
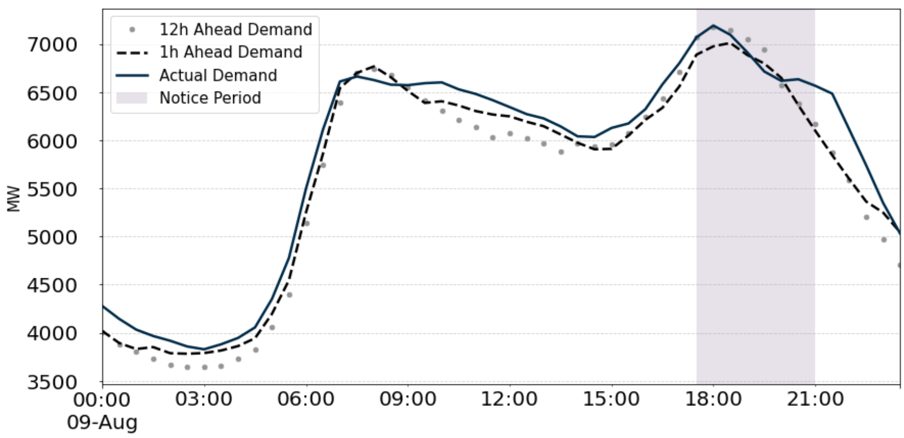


Figure 17 - Actual and forecast demand - 9 August 2021



Unplanned HVDC outage on 7 October 2022

8.6 The system operator released a low residual CAN at 2:59pm on 6 October for the morning of 7 October (7:30am to 9:00am). At 5:37am on the 7 October, a fault in filter 4B

43 See: https://niwa.co.nz/education-and-training/schools/resources/climate/meanairtemp

at the Haywards substation caused a reduction in HVDC capacity (Figure 18). This led to the system operator issuing a WRN and later a GEN for insufficient generation in the North Island (as less generation was available to be transported from the South Island).

8.7 The WRN and GEN notices requested participants to decrease demand using controllable load (not offered as instantaneous reserves) and increase energy and instantaneous reserve offers. We observed a difference of more than 300MW between the North Island demand forecast around the release time of the WRN notice (07 October 2022 at 05:37am) and the actual demand during the event, likely contributing to the escalation of the WRN notice into a GEN.

8.8 Figure 19 shows that the participants increased their energy offers before the event and sustained the increased amount of offers during and for some hours after the event, reacting in accordance with the notice requests. A Rankine unit was added to the offers after the release of the first CAN notice on 6 October (from one to two units being offered). There was also a 121MW increase in reserve offers after the release of the CAN. On the other hand, there was a 41MW decrease in thermal offers (other than Rankines), due to a planned McKee outage (4MW withdrawn). Demand was being managed by the beginning of the event, resuming normal operations at around 8:00am, when the issue with the Haywards filter 4B was resolved.

Figure 18 - HVDC max capacity and interchange during unplanned HVDC outage

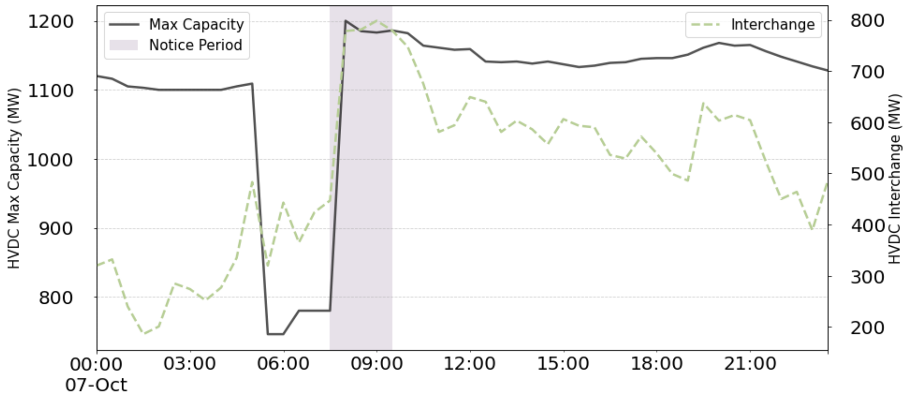
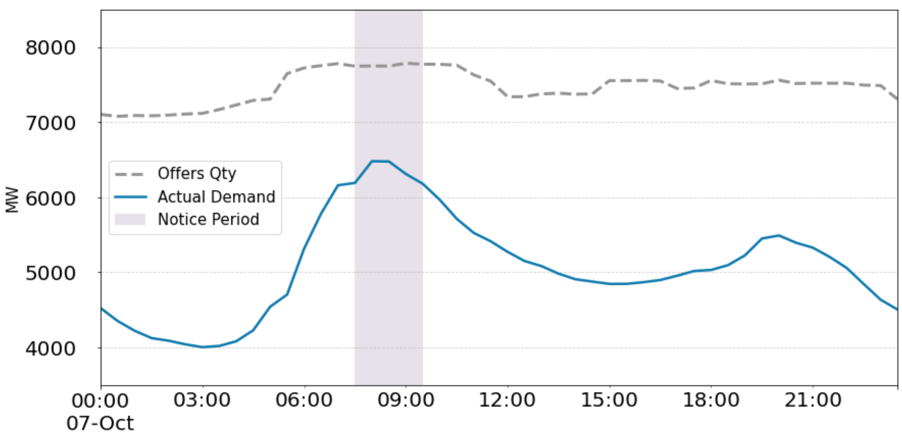


Figure 19 - Total energy offers during 7 October 2022



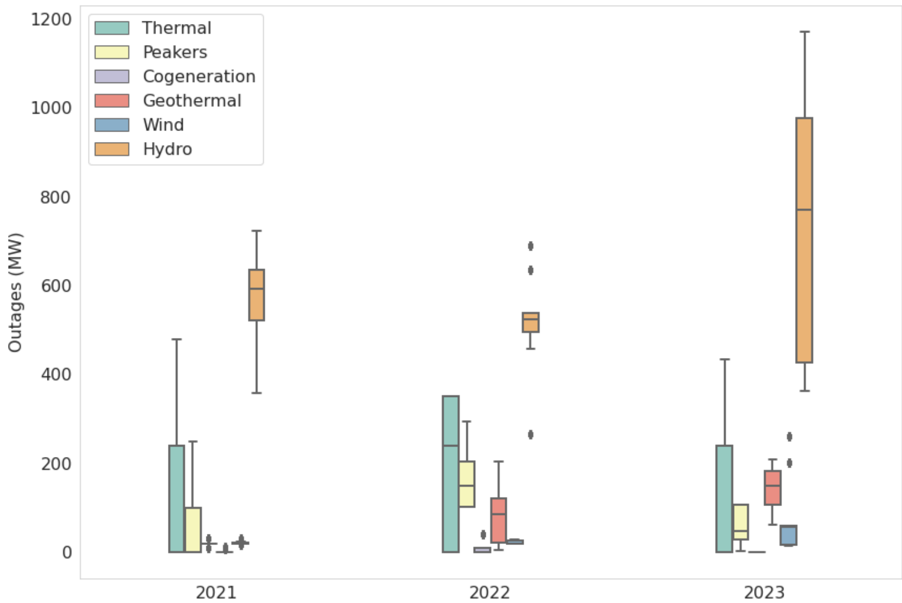
9 More generation was on outage during the 2022 events

9.1 Average hydro outage values for the events were relatively high compared to average winter outages[44], above 500MW for all three years (as shown in Figure 20 and Table 8).[45] Thermal and peaker outages were higher than average for the 2022 events, but were lower than average for the 2023 events. Geothermal and wind outages were higher than average for the 2023 events, the latter tied to the West Wind station outage (44MW from 30 May to 24 November).

9.2 It is worth noting that the Taranaki Combined Cycle (TCC) plant was on outage for almost half of the time in 2021 due to gas supply issues (on outage after July) and was either on outage or had limited running capacity in 2022 and 2023. One Stratford peaker was on outage for most of 2022.

9.3 Generation and transmission outages are disclosed through Transpower's POCP website. There were only two events where outages were added or modified after the release of the notice. On 6 October 2022 Mercury entered outages for two units (Maraetai 35MW and Waipapa 18MW), decreasing offers accordingly before the 7 October 2022 event. On 29 March 2023 Mercury extended the end time of an outage at its Whakamaru station (30MW) to after the end of the event. All other outages were already entered on POCP prior to the release of the notices.

Figure 20 - Outages distributions per fuel type per year



44 We considered winter as the period between 01 June to 30 September.

45 The 2023 March events occurred while there was an HVDC outage. South Island hydro generators often schedule outages to coincide with HVDC outages. This increased the average hydro outages over all events in 2023. However, excluding these March events, the average hydro generation on outage was still similar to the 2021 and 2022 event averages at 541MW.

Table 8 - Outages during the events compared to 2019-2023 winter outages

	Average Outages for Winter 2019 – 2023 (MW)	Average Outages: 2021 Events (MW)	Average Outages: 2022 Events (MW)	Average Outages: 2023 Events (MW)
Thermal	216	120	205	185
Peakers	71	32	167	53
Cogeneration	8	20	8	0
Geothermal	35	1	72	145
Wind	34	22	24	69
Hydro	408	554	529	712