9 August 2021 demand management event

Review under the Electricity Industry Act 2010

Phase 2

FINAL REPORT

27 April 2022

Executive summary

Context

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, with the biggest impact in the Waikato region where over 17,000 customers were disconnected.

The Authority is exercising its function under section 16(1)(g) of the Electricity Industry Act 2010 to undertake industry and market monitoring, and carry out and make publicly available reviews, studies and inquiries into any matter relating to the electricity industry. The Authority undertook a two phase review into the 9 August peak demand event:

- Phase 1 of the review, which was published in September 2021, focused on assuring New Zealand consumers immediately that any systemic and process issues that led to the electricity cuts on 9 August were urgently corrected. It related specifically to the tools and processes used by Transpower, as the system operator.[1]
- The focus of this report, the Authority's Phase 2 review is broader than the system operator's response to the event.

There have been a number of other reviews and investigations into the 9 August peak demand event, including an investigation commissioned by the Minister of Energy and Resources (the Ministerial Investigation), and reviews commissioned by Transpower. The Authority is also investigating a claimed undesirable trading situation (UTS) and has investigated several allegations of breaches of the Electricity Industry Participation Code 2010 (the Code).

In the Phase 1 report the Authority acknowledged that the system operator's operational staff took immediate action under difficult circumstances to avert a potentially more widespread and longer duration event. Phase 1 targeted the issues identified by the Authority specific to Transpower's communications with industry around the event, and failings of its demand allocation tools, protocols and supporting processes. The Phase 1 report served to assure industrial, commercial, and household consumers that any systemic and process issues that led to the electricity cuts on 9 August were urgently corrected.

Over the next 10 years, the New Zealand power system is expected to undergo a significant transformation. The Authority instigated the Future Security and Resilience programme of work and has engaged the system operator to advise on the implications of key trends for electricity systems including decarbonisation and a more distributed

1 Transpower has two parts to its business. As the grid owner, Transpower owns and operates the National Grid. As the system operator, Transpower is responsible for managing the real-time power system and operating the wholesale electricity market. This report focuses on Transpower's role and accordingly where the term "Transpower" is used in this report it refers to Transpower in its system operator role.

electricity system, with increasing digitalisation with increased use of data-driven decision-making. This aligns with the need for the Authority and the system operator to focus on ongoing improvement, and readiness to deal with digitalisation and automation.

The Phase 2 review has not found any new information to counter the Ministerial Investigation position that the 'forced disconnection of household electricity [by Transpower] was entirely avoidable'. As emphasised by the Ministerial Investigation, 'demand side had enough discretionary load to maintain the system.'[2] Transpower's coordination and communication failures meant consumers were disconnected unnecessarily on 9 August.

As part of this Phase 2 review, the Electricity Authority has collected additional information to increase the awareness and understanding of maintenance and commercial imperatives considered by generators when committing thermal generation into the market for dispatch.

With respect to comments in various reviews as to whether Genesis' HLY4 or Contact's Taranaki Combined Cycle plant should have run, the review maintains that there was not an issue of a shortage of generation to supply the evening peak demand.

Separate to this review, the Authority's compliance enquiries into Genesis' and Contact's decisions not to offer specific thermal generation to support the evening peak found those decisions did not breach the trading conduct rules and were decisions reasonably open to these companies.

Thermal unit commitment and slow start times are issues that most international systems are grappling with. Thermal unit commitment issues occur because the dispatch engine solves for one trading period at a time with no ability to dispatch conditional on other trading periods without manual intervention (constrained-on generation). This is exacerbated by the increasing need to run plant designed for baseload as peaking plant. This problem is likely to become more acute as more renewables enter the market. From overseas there are a number of approaches to the problem, none of which are perfect. The PBA report commissioned by Transpower[3], makes a number of recommendations specific to unit commitment, which are predicated on unit commitment being a systemic problem with market design. We question if this conclusion can be drawn from the events of one day and note the PBA report does recognise the complexity of these proposals.

We agree that this needs to be addressed over time and have policy processes in place that we expect will offer a New Zealand-specific response to the challenge.

In October, the Authority briefed the Security Reliability Council (SRC) on the terms of reference for Phase 2 and provided a further update in March 2022. Subsequent to this, the SRC has provided advice to the Authority in which it notes SRC members "were

[2] MBIE, Investigation into electricity supply interruptions of 9 August 2021. Page 4. The report can be found here: https://www.mbie.govt.nz/dmsdocument/17988-investigation-into-electricity-supply-interruptions-of-9-august-2021.

[3] The PBA Consulting Independent Investigation of the 9 August 2021 Grid Emergency for Transpower can be found here: https://www.transpower.co.nz/sites/default/files/news-articles/attachments/PBA%20Consulting_9%20Aug%2021%20Grid%20Emergency%20Investigation_Final%20Report.pdf.

concerned that comments made by the system operator at the meeting indicates the system operator may view the events of 9 August 2021 as being solely or principally caused by a lack of generation. Members consider such sentiment is not supported by the review findings and downplays the impact communications and information from the system operator had in consumers being disconnected on 9 August."[4].

Scope of the Authority's Phase 2 review under the Electricity Industry Act 2010

The Terms of Reference for the Authority's Phase 2 review includes lessons for the Authority, lines companies, the system operator, generators, retailers (with a focus on medically dependent consumers), and direct connect consumers. The Terms of Reference also includes the use and performance of communication mechanisms with consumers.

This report thematically summarises observations and recommendations from other reports into the 9 August peak demand event. This ensures the Phase 2 report provides an extensive overview of the different factors at play on 9 August but without duplicating the work of other reports.

The Authority has also made additional observations and recommendations that have not been identified in the other reports into the 9 August event, in line with the Phase 2 Terms of Reference. The Authority has made new observations based on:

- the Authority's analysis of the observations and recommendations contained in existing reports released into the 9 August event since the Authority's Phase 1 report was released in September 2021;
- lessons learnt from the 2019 undesirable trading situation (UTS);[5]
- information contained in reviews into previous events – the South Island Automatic Under Frequency Load Shedding (AUFLS) event in 2017[6] and high-voltage direct current (HVDC) limit setting error event in 2018;[7] and
- information provided by electricity distribution businesses (EDBs) in response to an information request about the type of load control available on their networks, the policies and procedures around using these load control methods, their responses to the grid emergency event, and their communications with Transpower during the event.

[4] Letter from SRC Chair to Authority Chair, 25 March 2022

[5] Further information on the 2019 UTS can be found on the Authority's website at: https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/.

[6] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event https://www.transpower.co.nz/sites/default/files/publications/resources/Report%2520on%25202%2520March%25202017%2520South%2520Island%2520AUFLS%2520Event.pdf.

[7] Advisian, 2019. Independent report into HVDC current limit setting error.

Thematic summary of observations and recommendations from other reports into the 9 August event

The Authority has identified four key themes that sit across all reports into the 9 August event – communications, contract management, wholesale market settings, and tools and processes.

At a high-level, the existing reports into the 9 August event observed:

- **Communications –** Communication with industry, governance and consumers during the 9 August event was inconsistent and, in some cases, inadequate;
- **Wholesale market settings** – Reports into 9 August made recommendations on possible changes to wholesale market settings (both supply and demand side) to address the risk of future events;
- **Tools and processes** – The tools and processes used in the leadup to and during the 9 August event did not operate as intended or were used incorrectly, contributing to the disconnection of consumers; and
- **Contract management –** That the Authority scrutinise its relationship with Transpower with a view to holding Transpower more firmly to the rules and contracts that bind it, and to move away from any reliance on Transpower's self-assessment and self-monitoring given that Transpower has not always responded to the findings of reviews in relation to previous events.

The Authority's Phase 2 review report is framed around these four key themes to ensure all existing observations and recommendations are reflected in the report.

The Authority considers there has been good progress on all recommendations from the existing reviews and investigations into the 9 August event. The Authority has focused on progressing immediately actionable recommendations so that the system operator and wider industry are much better placed to manage future demand management events and minimise the impact on consumers ahead of winter 2022, when we expect there to be increased demand in the system, particularly given the risk of a dry year.

Further information on progress made to date can be found on the Authority's website at: Electricity Authority Review of 9 August 2021 event under the Electricity Industry Act 2010 — Electricity Authority (ea.govt.nz)

The Authority has made new observations and recommendations as part of the Phase 2 Review

In addition to the observations made in other reports into the 9 August event, the Authority has made the following new observations and recommendations as part of its Phase 2 Review. Consistent with the Authority's view that Transpower's coordination and communication failures meant consumers were disconnected unnecessarily on 9 August., these recommendations are all aimed at improved system coordination.

1. The issues identified with the system operator's performance on 9 August are similar to previously identified issues regarding its performance, which were

identified in reviews of previous events – the South Island AUFLS event in 2017 and HVDC limit setting error event in 2018. The relevance of these to 9 August is:

a. the system operator's communications were inadequate because internal communications were unclear and informal in responding to the event at hand, which exacerbated each event;

b. the system operator incorrectly or inappropriately used tools in past emergency situations, which exacerbated each event. In the 2017 AUFLS event, the system operator did not follow procedures and operation of tools was not well understood[8]. In the 2018 HVDC event, Transpower's ICAM report provided as part of Advisian's review found operators made errors when setting current limits for the HVDC[9]. Advisian found that there were improvements that could be made to the change control processes around new tools[10]; and

c. the system operator did not provide sufficient or regular training, especially for event management, to its control room staff, which exacerbated each event.

In response to this observation, the Authority recommends:

- The system operator should develop and publish a plan for how issues raised by reports into the events listed above are being addressed. This plan should be agreed with the Authority and published no later than 30 June 2022.
- The system operator should develop ongoing assurance reporting that these issues continue to be actively managed. This reporting should be quarterly, starting 30 September 2022, and set out how each quarter's actions in response to this review were addressed and maintained.
- The Authority in turn needs to become a more informed and methodical monitor of the system operator and agreeing this plan and scrutinising this regular assurance reporting will be part of what enables the Authority to do so.

2. Maintenance and commercial considerations influenced the owners of thermal generation units on 9 August:

a. owners of thermal generation units noted that price and demand forecasts are key factors when considering whether to offer their plant. These companies offer generation when it is profitable to do so, based on price and demand forecasts. Owners indicated that if forecasts were more accurate, they would have been more confident to commit generation to the market; and

b. most companies have maintenance contracts that scale with the number of starts and stops, which incentivises companies to bid the generation in so it runs for multiple trading periods. Frequently starting and stopping thermal units increases wear and tear, which increases the frequency and

[8] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event. Page 25

[9] Advisian, 2019. Independent report into HVDC current limit setting error. Section 4.6.

[10] Advisian, 2019. Independent report into HVDC current limit setting error. Section 2.3 of the attached ICAM report

cost of maintenance. Therefore, this creates additional costs on these parties because maintenance takes units out of action for multiple days.

In response to these observations:

- The Authority is assessing the accuracy of forecasting data that contributes to the pre-dispatch schedules. These are the wind forecasts from generators, the system operator's demand forecast, and the bids from large industrial consumers at non-conforming nodes.
- The Authority also recommends further investigation into the accuracy of forecasts used to develop the pricing schedules that generators rely on to decide whether to offer generation into the market. This work will be undertaken by the Authority and will be published by October 31 2022.

3. Scarcity pricing – There may be an opportunity to improve how scarcity pricing processes work under real time pricing because the discretion the system operator currently exercises under scarcity pricing rules will not be available under real time pricing (RTP). Therefore, there will be no confusion between reducing demand and electrical disconnection.

The Authority notes this observation will be addressed through the following:

- The system operator will agree with distributors how, under RTP:

  a. price signals and demand reduction requirements during scarcity events will be communicated to distributors; and

  b. controllable load will be used prior to any demand reductions being sent to distributors.

- The Authority expects the system operator to publish details of this agreement with distributors under RTP by 30 September 2022.

4. Equity rule –

   a. When the system operator requires electrical disconnection, the Code requires the system operator, to the extent practicable, to use reasonable endeavours to ensure equity between connected asset owners. There is no equity requirement in relation to requests by the system operator to reduce demand. The system operator did not instruct electrical disconnection on 9 August, rather it issued notices to reduce demand, accordingly the equity rule does not apply.

   b. The Ministerial investigation found that the equity provisions in the Code contributed to the forced disconnection of load on the evening of 9 August. The Ministerial Investigation considered the Demand Allocation Notice following the notice to reduce demand by 1% was faulty and that both notices had been issued to address the equity requirement. The Ministerial investigation recommended that the rule be changed to address this. At the time of the Ministerial Investigation however, the system operator and the Authority's view that the system operator had

issued notices to reduce demand (and therefore the equity rule did not apply) had not been publicised.

c. The Authority disagrees with the Ministerial Investigation's finding of "[the equity] rule to be ill conceived and in need of prompt revision". The equity rule did not apply to the events of 9 August. However, the Authority considers the rule, when applied correctly, provides sufficient guidance and flexibility for events such as 9 August (had the system operator issued instructions to electrically disconnect) and other security events.

Based on this interpretation:

- the Authority outlined to MBIE that it does not consider a Code change to be necessary to implement this recommendation.
- The Authority is considering further, formal, guidance.

5. Instantaneous reserves – Instantaneous reserve offers fell throughout the day on 9 August. Generally, reductions in offers in the of reserve interruptible load market indicate reductions in load as providers start using their controllable load to manage demand. The net effect of this tends to be neutral as the reduced load helps the grid emergency, but substituting spinning reserves for interruptible load has the opposite effect.

   The Authority does not consider any further action is required based on this observation.

6. Direct connect consumers – North Island direct connected consumers reduced demand materially during the grid emergency.

   The Authority does not consider any further action is required based on this observation.

7. Communications – It is important to note that industry stakeholder and customer communications by distributors and retailers were limited by a lack of information regarding the event from the system operator. However, there were gaps in some EDB policies and procedures to respond to the system operator's notices. Several EDBs noted that they did not receive the system operator's Grid Emergency Notices (GEN) notices because their network control rooms are only staffed, and emails are only checked, during business hours. Some EDBs' response procedures are designed to follow the system operator's directions, whereas other EDBs' have more flexible response procedures.

The Authority does not consider any further action is required based on this observation because these matters are expected to be addressed in the pan-industry exercise, which was recommended by the Authority in its Phase 1 review[11] and is scheduled for May. As noted in other reviews, generally EDBs responded promptly and sought to assist in managing the situation as it developed. The key findings are around ensuring consistent protocols and procedures are in place and a general understanding of what is required under these.

[11] Authority Phase 1 Report. Page 11.

The Authority included other new observations to ensure that all aspects of the event were examined. These are set out in the paper but do not require a response.

The Authority wishes to note that it is easy in hindsight to see how the event could have been managed better. However, the Transpower operators do not have the advantage of hindsight. While the Authority has said elsewhere that the system operator's actions were reasonable and justified given the real time information it was observing, looking back at this event in detail suggests that there is also room for improvement in coordinating these events.

Next steps

The Authority will monitor the progress of the Phase 2 recommendations as part of the existing systems and processes that have been put in place to respond to recommendations from reports into the 9 August event. As such, the Authority expects quarterly reporting against these recommendations, which is consistent with the approach for reporting progress against the Ministerial Investigation recommendations. This information will be made publicly available on the Authority's website as part of the broader suite of reporting progress against the recommendations. This reporting will form part of the Authority's monitoring of the system operator's performance.

1 Purpose

1.1 This report provides the Authority's findings from Phase 2 of its review under section 16(1)(g) of the Electricity Industry Act 2010 (the Act). The report thematically summarises the observations and recommendations from other reports into the 9 August peak demand event. The report also contains further observations and recommendations, in line with the Phase 2 Terms of Reference, that have not been identified in other reports.

2 Background

Background to the 9 August peak demand event

2.1 On the evening of Monday 9 August 2021, a significant weather event caused national demand to reach a record high. On 9 August at 6.40am, Transpower as the system operator notified market participants that the forecast market schedules were signalling the possibility of a shortage of supply that evening, if the conditions were to worsen.

2.2 By 1pm, the conditions had worsened, and the system operator notified market participants that further generation offers were required to avert the risk of demand management. By 5pm, conditions had deteriorated even further, and a Grid Emergency Notice (GEN) was sent. This notified market participants that there were insufficient offers to cover both energy and reserve requirements, and that reserve dispatch would be reduced to provide energy supply.

2.3 At 6.48pm[12], all distributors were requested to reduce demand by 1% and were notified that a Demand Allocation Notice (DAN) would follow. The DAN was issued at 7.09pm but contained a number of errors regarding the maximum demand limits requested of distributors.

2.4 The errors in the DAN resulted in a number of distributors, who had already disconnected load in response to the 6.48pm request, further managing their load. Whereas the initial response would have had little impact on consumers (ripple control hot water and street lighting disconnection being common mechanisms), the subsequent response was enacted through disconnecting consumers completely.

2.5 As a result, five distribution companies disconnected approximately 34,000 consumers for up to two hours on the coldest night of the year across the country. With demand management being greater than required, generation was no longer dispatched as it was not required to meet the demand. This led to the situation where consumers were without power whilst generation capacity was available.

2.6 At 8.20pm the original GEN was revised to allow distributors to return up to 5% of their current load levels.

2.7 At 9.01pm the system operator revised the GEN, stating all participants can restore all load, ending the grid emergency.

[12] The notice was issued at 6.47pm, but the email was received by distributors at 6.48pm. This paper therefore refers to the "6.47pm Notice".

2.8 At 9.15pm, EDBs had reconnected all customers and restored all load.

2.9 The Authority published a detailed chronology of events on 10 September 2021 as part of its Phase 1 review.[13]

2.10 In addition, the Authority has developed Figure 1, (see next page) which shows the timeline of the 9 August 2021 event. The bottom panel shows the number and location of disconnected consumers. The middle panel shows generation from Whirinaki station which is usually the last station to be dispatched due to its high cost of operation. The top panel shows demand. The different notices issued by the system operator are shown as vertical lines on the chart.

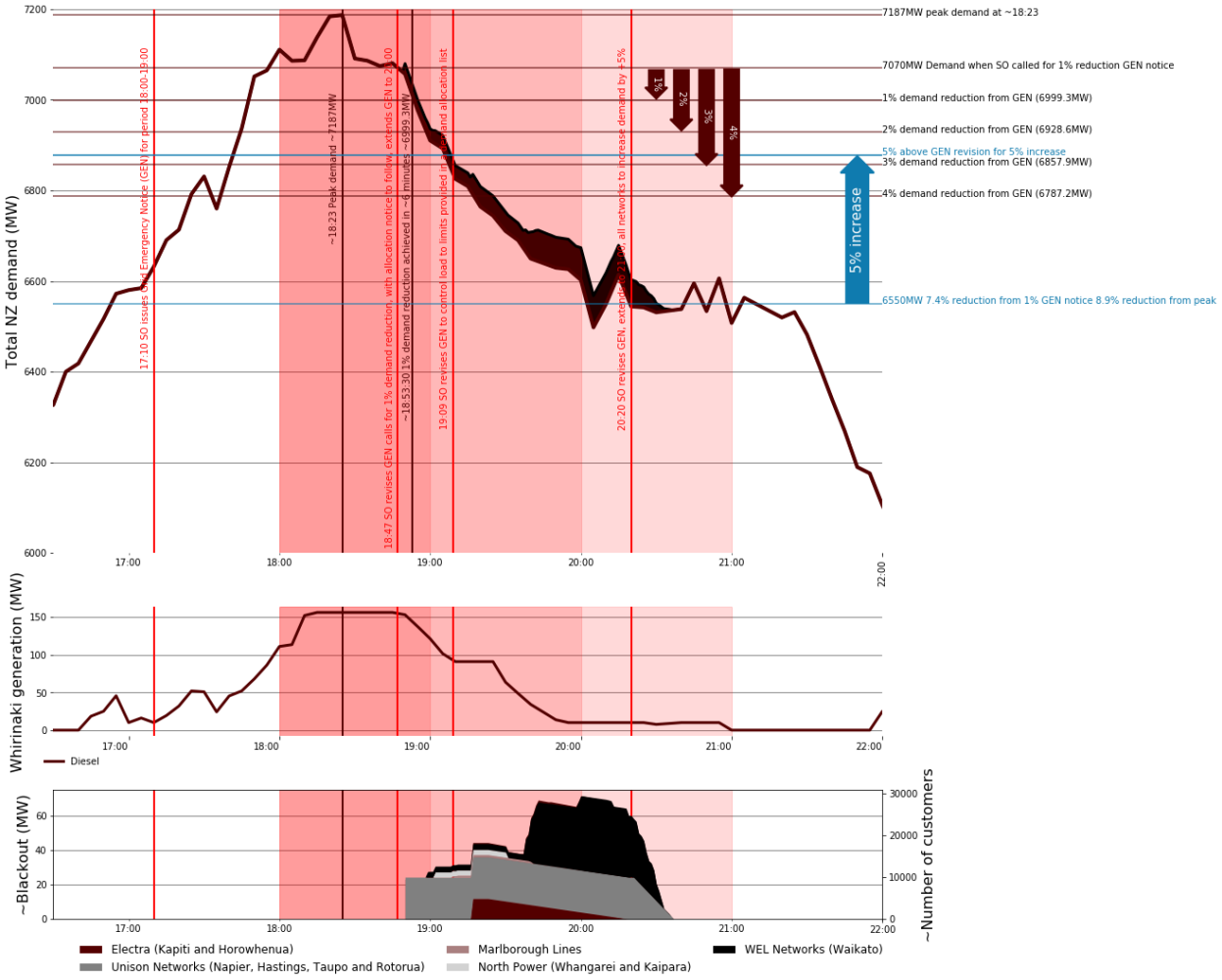
2.11 The chart shows that demand reached its peak at 6:23pm, after which it fell away. Demand fell away sharply in response to the 6:47pm notice to reduce demand by one percent. This coincided with Whirinaki generation being dispatched down, and customers beginning to be disconnected. The one percent demand reduction needed for system security was reached at 6:53pm—demand reduction past this point did not contribute to system security. Demand continued downwards on the same trajectory as more customers were disconnected.

2.12 This suggests strongly that the cause of the events of 9 August was a lack of coordination between various parts of the system. This is supported by the conclusion from the Ministerial Investigation that there was also sufficient controllable load available to avoid disconnecting consumers which is symptomatic of a lack of coordination.

2.13 With this in mind, the recommendations in this paper are primarily aimed at improved system coordination and build on the findings and recommendations of the Authority's Phase 1 review.

[13] Published on the Authority's website: https://www.ea.govt.nz/assets/dms-assets/28/Immediate-assurance-review-ofthe-9-August-2021-demand-management-event.pdf.

Figure 1: a timeline of events on 9 August



Reviews and investigations into the 9 August peak demand event

2.14 There have been a number of reviews and investigations into the 9 August peak demand event, including the Ministerial Investigation, and reviews by the Authority and Transpower.

2.15 Figure 2 below contains an overview of the various reports into the 9 August peak demand event in addition to this report, which is Phase 2 of the Authority's review under section 16(1)(g) of the Act.

Figure 2: Overview of reports into the 9 August peak demand event

Report	Legal Status	Purpose	Published
The Authority Phase 1 Report	Section 16(1)(g) of the Act	Immediate assurance	10 September 2021
Ministerial Investigation (sponsored by MBIE, led by Hon Pete Hodgson and Erik Westergaard)	Ministerial request	Understand root cause and identify improvements	25 November 2021
Transpower commissioned PBA Consulting report	Report to be provided to the Authority under contractual arrangements	Causes of event and industry response	12 October 2021
Transpower commissioned Thompson Lewis report	N/A	Communications with governance and internal stakeholders	12 October 2021
Additional reviews and investigations by the Authority			
Alleged Undesirable Trading Situation	Claim made under the Electricity Industry Participation Code (the Code)	Consider whether an 'undesirable trading situation' as defined in the Code has occurred.	Ongoing. Preliminary decision published 16 December 2021
Alleged breach by Contact of the trading conduct rules	Compliance breach allegation process under the Electricity Industry (Enforcement) Regulations	Consider whether a breach of the Code occurred.	Conclusion published 14 December 2021- no breach found.
Alleged breach by Genesis of the trading conduct rules	Compliance breach allegation process under the Electricity Industry (Enforcement) Regulations	Consider whether a breach of the Code occurred.	Investigation closed 28 February 2022 – no breach found.
Alleged breach by Transpower as the system operator of various Code provisions	Compliance breach allegation process under the Electricity Industry (Enforcement) Regulations	Consider whether a breach of the Code occurred.	Formal complaint laid with the Rulings Panel.
Claim of a Pricing Error	Process under the Code.	Address any pricing errors.	Claim not upheld – 1 September 2021. Subsequent request to reconsider was not upheld 26 January 2022

The Authority's reviews and investigations

2.16 The Authority has carried out several reviews and investigations into different aspects of the 9 August peak demand event.

2.17 The Authority carried out a two-phase review under section 16(1)(g) of the Act. This is the second phase of this review. The first part of the review (Phase 1) of the review focused on assuring New Zealand consumers immediately that any systemic and process issues that led to the electricity cuts on 9 August were urgently corrected. The Phase 1 Report, published on 10 September[14] focused on:

(a) Transpower as the system operator's communications with industry around the event of 9 August 2021.

(b) The system operator's load shed and restore (LSR) decision support tool used to generate the demand allocation and the processes and protocols associated with its use and maintenance.

2.18 The Authority also separately considered several allegations of breaches of the Electricity Industry Participation Code. These allegations relate to the system operator and generators' actions in relation to the 9 August peak demand event:

(a) Compliance enquiries into each of Contact Energy and Genesis Energy have been closed with no further action being taken (in the case of Contact Energy this was closed at the preliminary stage, in the case of Genesis this was a formal investigation) . The Authority considered these generators had not breached the trading conduct provisions of the Code.

(b) The investigation into the system operator has been concluded and the Authority has laid a complaint with the Rulings Panel.

2.19 The Authority is also carrying out an investigation into a claimed undesirable trading situation (UTS). The claim alleged that Contact Energy Limited (Contact Energy) and Genesis Energy Limited (Genesis Energy) individually and jointly caused the peak demand event. Although not part of the claim, the Authority decided, following an initial review of the data, to also consider whether Transpower as the system operator contributed to the alleged UTS.

2.20 The Authority released its preliminary decision on 16 December, which found that there was no UTS because there was no situation that threatened or may have threatened confidence in, or the integrity of, the wholesale market.[15] Consultation on this decision closed on 3 February 2022 and subsequently the Authority has released a short consultation on a discrete issue (related to the application of scarcity pricing) as a result of new information raised during the compliance process.

2.21 Finally, on 11 August 2021 a pricing error claim was made by Haast Energy Trading Limited (Haast) and Electric Kiwi Limited who alleged that the grid emergency on 9 August 2021 led to a pricing error (the original pricing error claim). The original pricing error claim was not upheld.

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[14] The Authority's Phase 1 report can be found here: https://www.ea.govt.nz/assets/dms-assets/28/Immediate-assurance-review-of-the-9-August-2021-demand-management-event.pdf.

[15] The Authority's preliminary decision on whether an undesirable trading situation occurred on 9 August 2021 can be found here: https://www.ea.govt.nz/assets/dms-assets/29/9-August-2021-UTS-Preliminary-decision-paper.pdf.

2.22 On 20 December 2021 Haast asked the Authority to reconsider its decision not to uphold the original pricing error claim. That request was declined because the Authority was unable in the circumstances to re-exercise that power, and even if it were able to do so, there had been no pricing error[16].

Ministerial Investigation

2.23 The Minister for Energy and Resources commissioned an investigation into the electricity supply interruptions of 9 August 2021 on 10 August. MBIE is the project sponsor of the Ministerial Investigation. The Ministerial Investigation was headed by Hon Pete Hodgson, assisted by specialist technical advisor Erik Westergaard and MBIE. The purpose of the Ministerial Investigation was to:

(a) "understand the causes of power supply interruptions on the evening of 9 August 2021, when more than 34,000 consumers lost power in the evening following a direction from the system operator to curtail national demand, and

(b) learn lessons from the event to identify and recommend improvements to ensure similar circumstances are better managed in future."[17]

2.24 MBIE published the Ministerial Investigation on 25 November 2021. The Investigation focused on the system operator, generators, and electricity distribution business (EDB) actions, along with the Authority's role in regulating the market and overseeing the system operator. The Ministerial Investigation made recommendations relating to performance of the system and system operator, wholesale market and supply side, demand response and demand side participation, information and communications, and looking ahead.

Transpower reviews

2.25 Transpower carried out two self-reviews of its own performance as the system operator on 9 August. Transpower commissioned PBA Consulting to investigate the event and industry's response on 9 August, and to identify where the system operator needed to make changes. Transpower commissioned Thompson Lewis to review Transpower's communications with stakeholders on 9 August.[18] Transpower published both of these reports on 12 October 2021.

2.26 The Authority was not directly involved with these reviews, but these reports were provided under the contractual framework between the system operator and the Authority.[19]

3 Phase 2: Review approach

3.1 The Authority is exercising its function under section 16(1)(g) of the Electricity Industry Act 2010 to undertake industry and market monitoring, and carry out and

[16] The Authority's decision can be found here: Market Brief - 1 February 2022 (ea.govt.nz)

[17] The full terms of reference for the Ministerial Investigation into electricity supply interruptions of 9 August 2021 can be found here: https://www.mbie.govt.nz/dmsdocument/16637-terms-of-reference-investigation-into-electricity-supply-interruptions-of-9-august-2021.

[18] The Thompson Lewis into Transpower Communications 9 August 2021 Grid Emergency Report can be found here: https://www.transpower.co.nz/sites/default/files/news-articles/attachments/Thompson%20Lewis_9%20Aug%2021%20Grid%20Emergency%20Investigation_Final%20Report.pdf.

[19] Further details in relation to the SOSPA including the Authority's powers to request reviews can be found at - https://www.ea.govt.nz/operations/market-operation-service-providers/system-operator/what-the-system-operator-does/

make publicly available reviews, studies and inquiries into any matter relating to the electricity industry.

3.2 The Authority has undertaken its Phase 2 review under those statutory powers. As outlined above, the Authority has conducted this review into the events of 9 August 2021 in two phases.

3.3 The Authority's Terms of Reference for Phase 2 of the review was published on 19 October 2021 and includes:

(a) What lessons can the Authority learn from the event? This will involve considering the Authority's management and monitoring of the system operator service contract.

(b) What lessons can be learnt from the experience of the lines companies during the event? This will include an assessment of the capability of controllable load at different points during the event.

(c) What lessons are there for the system operator that extend beyond those revealed in phase one or the UTS investigation? This may include reviewing relevant systems and processes, including training of control room staff and forecasting capability and tools that are not covered in phase one or the UTS investigation.

(d) What lessons are there from the event for generators? This will include understanding unit commitment and generation investment incentives.

(e) What lessons are there from the event for retailers, with a particular focus on whether retailers were adequately prepared and responded appropriately to support the wellbeing of their customers especially medically dependent consumers?

(f) What lessons are there from the event for direct connect consumers?

(g) What mechanisms were used to communicate with consumers and how did these perform?

3.4 Alongside the Phase 2 review Terms of Reference, the Authority has undertaken a stocktake of the evidence, observations and recommendations across all reports into the 9 August event. As part of this, the Authority identified four key themes that sit across all reports into the 9 August event.

3.5 Through this report, the Authority has provided thematic observations (using these four themes) about the event by summarising the observations and recommendations from the other reports. This ensures the Phase 2 report provides an extensive overview of the different factors at play on 9 August without duplicating the work of other reports.

3.6 The Authority has also made additional observations and recommendations that have not been identified in the other reports into the 9 August event, which are also detailed through the report. These observations and recommendations build on and are an extension of the findings in the other reports.

3.7 Appendix 1 contains a list of recommendations made in other reports into the 9 August event.

4 Overview of key themes

4.1 Figure 1 indicates that this event is characterised by a lack of coordination between different parts of the system. But beneath this overall characteristic, four key themes sit across all reports into the 9 August event. These are:

(a) **Communications**, which details how industry, consumers and governance stakeholders were engaged and informed on 9 August;

(b) **Wholesale market settings**, which details how the supply and demand side rules influenced market participants on 9 August;

(c) **Tools and processes**, which details the tools and processes used in making key decisions, in particular the tools and processes of how the system operator made decisions; and

(d) **Contract management**, which details how the Authority is managing its relationship with the system operator.

4.2 Each of the themes is discussed separately in the following sections.

5 Communications

5.1 Clear communications build trust and confidence that the system is operating effectively and producing the optimal outcomes for New Zealand. It ensures market participants and other stakeholders are aware of potential situations occurring within the electricity market and are able to respond to these in an effective and coordinated way.

5.2 Communications relates to all aspects of the Phase 2 Terms of Reference, with a particular focus on the use and performance of communications with consumers.

5.3 Communications with consumers is an area where there is significant scope for improvement in the industry. Parties tend to only communicate with their own customers, despite having information relevant to other parts of the sector. In events such as 9 August, lines companies experienced communications with the system operator that were inconsistent. As a consequence, lines companies had patchy knowledge of the overall event. This both inhibited responses to the event in terms of demand response, but also made it very unlikely any consumer would be able to get information about what was occurring.

5.4 The specific issues raised by 9 August were the subject of recommendations in the Authority's Phase 1 review and further recommendations from the Ministerial Investigation. The Authority will review the outcomes of the pan industry exercise which will occur in May to determine whether further or more general action is required to improve communications with consumers.

5.5 This section summarises observations from other reports related to how industry, consumers and governance stakeholders were engaged and informed on 9 August.

5.6 This section also details new observations related to the system operator's communications in previous reviews, and EDB communication on 9 August.

Communications observations and recommendations made through other reports into the 9 August event

Communication with industry

5.7 The Authority's Phase 1 report and the Ministerial Investigation made observations and recommendations relating to communication with industry.

Incorrect and inconsistent communication with industry

5.8 The Ministerial Investigation and the Authority's Phase 1 report observed the system operator provided industry participants with incorrect and late information, and in some cases no information over the course of 9 August.[20]

5.9 The Authority's Phase 1 report also observed the system operator inconsistently handled queries from industry.[21] For instance, queries relating to DAN from industry participants were inconsistently handled because some parties' concerns were passed to the National Coordination Centre (NCC), while others were not. Those that were passed on highlighted a possible issue with the notice and were told to hold action.

5.10 The Ministerial Investigation[22] and the Authority's Phase 1 report observed that the system operator predominately delivered information by email, even on the evening of 9 August, and did not follow up with phone calls communicating the importance of the system operator's notices.[23] The reports stated that e-mails are not a reliable form of communication for receiving notifications in these types of events because industry participants did not always see email notifications.

5.11 In response to these observations around the system operator's inconsistent communication approach, the Authority recommended that the system operator improve the electricity sector's readiness to respond to a critical demand management incident.[24] This included recommendations that the system operator:

(a) provide clear and consistent communications with industry;[25]

(b) direct queries relating to island-wide or national demand management to NCC;[26]

(c) keep up to date information of participants who may need to respond to emergency notices;

(d) provide participants with updates using standardised forms and notices that contain clear actions and timeframes; and

(e) follow email and notices with phone calls.

[20] Ministerial Investigation. Page 35.

[21] Ministerial Investigation. Page 56.

[22] Ministerial Investigation. Page 35.

[23] Ministerial Investigation. Page 56.

[24] Phase 1 Report. Page 11.

[25] Authority Phase 1 Report. Page 19.

[26] Authority Phase 1 Report. Page 18.

5.12 The Ministerial Investigation recommended the system operator ensures it has adequate communications staff available at all times who can reliably and promptly communicate and respond to emergencies.[27]

Lack of familiarity with communications protocols

5.13 The Ministerial Investigation[28] and the Authority's Phase 1[29] report observed that the system operator's lack of communication with industry participants created confusion about the actions the system operator required of industry participants.

5.14 The Authority's Phase 1 report also observed that industry participants were unfamiliar with protocols and requirements during a shortage situation.[30] Industry participants relied on processes designed for short-term outages. This led to an inconsistent response to the system operator's notices.

5.15 The Authority recommended that the system operator run an annual pan-industry contingency exercise to test processes and communications.[31] The Ministerial Investigation endorsed that recommendation.[32]

5.16 The Authority's Phase 1 recommendations outlined in the subsection above seek to improve clarity for industry participants in responding to the system operator's notices.

Information asymmetries

5.17 The Ministerial Investigation and the Authority's Phase 1 Report found there were information asymmetries between the system operator, EDBs, retailers and consumers. The system operator had information about the outage, EDBs had information relevant to their area, and retailers have information about which of their customers are medically dependent consumers.

5.18 It is important to note that industry stakeholder and customer communications by distributors and retailers were limited by a lack of information regarding the event from the system operator. The lack of earlier direct communication from the system operator regarding actions planned to be, or already, taken by distributors meant opportunities to use remaining discretionary load in some distribution networks ahead of customer disconnection in other distribution networks may have been missed.[33]

5.19 The Authority's consumer care guidelines place an expectation that retailers work proactively with their customers to minimise harm caused by difficulty accessing electricity (including by disconnection). The guidelines expect retailers to ensure that their medically dependent consumers have an individual emergency response plan to mitigate loss of supply in an emergency. During the August 9 event, several retailers took this a step further and proactively contacted their medically dependant consumers to confirm their supply status and that their emergency plans were in effect if needed.

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[27] Ministerial Investigation, Page 37.

[28] Ministerial Investigation. Page 56.

[29] Authority Phase 1 Report. Page 8.

[30] Authority Phase 1 Report. Page 11.

[31] Authority Phase 1 Report. Page 11.

[32] Ministerial Investigation. Page 37.

[33] Authority Phase 1 Report, Page 8-9.

5.20 The consumer care guidelines are recognised in the Ministerial Investigation's recommendations regarding medically dependent consumers. Each party had information that would have been useful for others to be aware of. The Authority's Phase 1 report observed that a lack of communication from the system operator meant that some retailers were unaware their customers had been disconnected until after the event.[34]

5.21 The Ministerial Investigation recommended that both the system operator and EDBs should be proactively in touch with retailers, and should have established and agreed systems to achieve this.[35]

Communications with governance

5.22 Thompson Lewis made observations relating to the system operator's communication with Ministers, government agencies, and Transpower Chief Executive and Chair.

5.23 Thompson Lewis concluded that the system operator's lack of process and communications to notify the Transpower Chief Executive and Board, and key government stakeholders (Ministers, officials and the Authority) "led to unsatisfactory outcomes".[36]

Communications with system operator executive leadership and Board

5.24 Thompson Lewis made a range of recommendations to improve the system operator's internal processes, so leadership and the Board are notified immediately.[37] As these are internal matters for Transpower the Authority offers no particular comment.

Communications with key government stakeholders

5.25 Thompson Lewis observed that the Authority was informed by the GM Operations via email at 7:40pm and a follow up text from the Chief Executive of Transpower to the Authority's Chief Executive at 7:50pm.[38]

5.26 The Minister of Energy and Resources was notified too late of the situation. The Minister's office was notified via an email to her Private Secretary at 7:51pm, which was not picked up that evening. The Minister was not informed until a journalist contacted the Press Secretary at 8.30pm.

5.27 The system operator did not notify Shareholding Ministers, officials from MBIE and the Treasury at all on the evening of 9 August.

5.28 Thompson Lewis recommended that Transpower establish communications protocol with key government stakeholders, and build ongoing relationships with key officials in government agencies and in Ministers' offices.[39]

5.29 In the event of a grid emergency, Thompson Lewis recommended the Chief Executive or Chair should notify these key stakeholders, including the Minister, via phone, and that the Transpower leadership team should jointly focus on

[34] Authority Phase 1 Report. Page 10.

[35] Ministerial Investigation. Page 38.

[36] Thompson Lewis. Page 6.

[37] Thompson Lewis. Pages 13-14

[38] Thompson Lewis. Page 3.

[39] Thompson Lewis. Page 13.

meeting the Board and key external stakeholders' information needs.[40] Thompson Lewis recommended that Transpower develop an annual scenario practice session to ensure it is ready for future events.[41]

Communications with consumers

5.30 The Ministerial Investigation, the Authority's Phase 1 report and PBA Consulting made observations and recommendations relating to the system operator's communications with consumers.

Consumer access to accurate and timely information

5.31 The Ministerial Investigation observed that consumers had a lack of accurate and timely information about the grid emergency on 9 August and likely reconnection.[42]

5.32 This observation was shared by the report for Transpower from PBA Consulting, which stated that the system operator has a better overview of system-wide incidents, such as the 9 August grid emergency, than other market participants.[43] However, disconnected consumers directed their first queries to distributors and retailers who may not have the necessary information.

5.33 The Ministerial Investigation and PBA Consulting recommended that the system operator improve its processes for providing the public with information, particularly when consumers have been disconnected.[44]

5.34 The Authority observed that some retailers did not know that their customers had been disconnected, because of the information asymmetries between industry outlined in the section above.[45] Those that did know of the disconnection did not know which of their consumers had been affected,

5.35 The Authority recommended that the system operator work with stakeholders to develop an agreed communications approach to ensure prompt and consistent information. Where customers have been disconnected, the Authority recommended communication between distributors and retailers should be active (e.g., automated message extension on webpages and/or phone apps) rather than passive forms of communication.[46]

Medically dependent consumers

5.36 The Ministerial Investigation and the Authority's Phase 1 Report indicated that communication with medically dependent consumers can improve. Medically dependent consumers had a lack of accurate and timely information about the grid emergency on 9 August and when they would likely be reconnected.

5.37 As noted above, the Authority's consumer care guidelines place an expectation that retailers work proactively with their customers to minimise harm caused by difficulty accessing electricity (including by disconnection). Consumers (including

[40] Thompson Lewis. Page 13.

[41] Thompson Lewis. Page 14.

[42] Ministerial Investigation. Page 37.

[43] PBA Report. Page 10.

[44] Ministerial Investigation. Page 38 and PBA Report. Page 10.

[45] Authority Phase 1 Report. Page 10

[46] Authority Phase 1 Report. Page 12.

medically dependent consumers), had a lack of accurate and timely information about the grid emergency on 9 August and likely reconnection.[47]

5.38 The Ministerial Investigation recommended that the Authority work with industry to establish best practice communication arrangements, for consumers including medically dependent consumers, in a grid emergency.[48]

5.39 The Ministerial Investigation recommended that the Authority and industry launch an education campaign to ensure medically dependent consumers are aware of the importance of having a personalised emergency response plan.[49]

The Authority has made new observations relating communications as part of its Phase 2 review

The system operator's communications were unclear or inappropriate in previous events

5.40 The Authority has made new observations that the issues identified with the system operator's communications was a theme that contributed to two previous events – the South Island AUFLS event in 2017[50] and HVDC limit setting error event in 2018.[51] In these cases the system operator's communications were unclear and did not follow the correct protocols. This observation relates to the Phase 2 Terms of Reference through the performance of the system operator.

5.41 The 2017 South Island AUFLS event was caused by the disconnection of two 220kV circuits at the Clyde substation during scheduled equipment testing. Technicians did not recognise or properly isolate intertripping equipment during testing. This created two unbalanced electrical islands where the Lower South Island had excess generation and the Upper South Island had a deficit of generation. As a result, the Lower South Island was disconnected from the rest of the grid, and AUFLS shed 120MW (16%) of load in the Upper South Island for up to 90 minutes. Transpower carried out a self-review of this event.

5.42 Transpower's review of the 2017 South Island AUFLS event found that its "operational communications were poor, insufficiently clear, formal or effective."[52]

5.43 Transpower also found its communications lacked context. For example, Transpower observed that the system operator's technicians "the quality and clarity of the operational communications during this high-pressure, complex event did not meet the standards expected of operational communications and

[47] The current health practitioner notice of Potential Medically Dependent Consumer (MDC) Status, referred to in the Consumer Care Guidelines requires the health practitioner to certify that the patient "*has been provided knowledge, training and support, in accordance with appropriate clinical practice*" for "*what to do in an emergency, including when the supply of electricity may be interrupted for any reason*."

[48] Ministerial Investigation. Pages 38-39.

[49] Ministerial Investigation. Page 39.

[50] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event https://www.transpower.co.nz/sites/default/files/publications/resources/Report%2520on%25202%2520March%25202017%2520South%2520Island%2520AUFLS%2520Event.pdf.

[51] Advisian, 2019. Independent report into HVDC current limit setting error.

[52] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Key Finding 4. Page 4.

this impacted on the parties' situational awareness and their ability to effectively manage the event."[53]

5.44 To address these findings, Transpower committed to work with industry and real-time teams within Transpower to address issues with operational communications[54].

5.45 The 2018 HVDC limit setting error occurred when the system operator entered incorrect values into the HVDC SCADA (Supervisory control and data acquisition tool) currently limit field on three different occasions between August 2017 and April 2018. These incorrectly entered values did not cause a major event but could have limited the HVDC's ability to help maintain security of supply for New Zealand. Transpower reviewed the incident and commissioned a review by Advisian.

5.46 Advisian's review of the 2018 HVDC limit setting error found that "the style of communication between the grid owner and system operator is at times unduly informal given the nature of information being conveyed. It is critical that the communication style and format is fit for purpose". [55]

5.47 To address these issues, Transpower "embedded the process of regular voice communication monitoring in [its] control rooms. Operators are taking personal accountability for improvement with the support of coaching and feedback from peers and Operations Managers". [56]

5.48 The Authority notes that existing reports into 9 August observed that the system operator's communications failed to follow protocol, were inconsistent and at times used ineffective channels. It is of concern that the system operator has not effectively addressed recommendations made in relation to previous events. The Authority's recommendation to address this observation is contained in paragraph 7 of the contract management section on this report because it relates to the Authority's management of its contract with the system operator.

EDB communications on 9 August

5.49 The Authority has observed that there were gaps in some EDBs' policies and procedures to respond to the system operator's notices. Several EDBs noted that they did not receive the system operator's GEN notices because their network control rooms are only staffed, and emails are only checked, during business hours.

5.50 Most EDBs' response procedures assume the system operator will follow emails with phone calls if the system operator required urgent action. This meant that these EDBs did not have procedures in place to respond to the system operator's emails.

5.51 There are also inconsistencies between EDBs' response procedures. Some EDBs' response procedures are designed to follow the system operator's directions, whereas other EDBs' have more flexible response procedures.

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[53] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, . Page 16.

[54] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Action 9. Page 5.

[55] Advisian, 2019. Independent report into HVDC current limit setting error. Pages 3.

[56] Correspondence with Transpower on HVDC Cable Setting Error - Advisian Management Actions Closeout.

5.52 The Authority also observed a mixed approach to communications by the five EDBs (Northpower, Electra, WEL Networks, Unison and Marlborough Lines) who disconnected consumers on 9 August. Further detail is included in Appendix 2.

6 Wholesale market settings

6.1 In a competitive market, the wholesale electricity price largely reflects underlying supply and demand conditions. Therefore, wholesale market settings are important to incentivise market participant behaviour, signal opportunities for investment and support efficient, consumer focussed outcomes. Effective wholesale market settings improve trust and confidence that the market will continue to produce effective long term consumer focussed outcomes, even when the system is experiencing high demand or stress.

6.2 Wholesale market settings relate to the Phase 2 Terms of Reference through the lessons learnt for the Authority, system operator, EDBs, generators and direct connect consumers.

6.3 This section summarises observations about how wholesale market rules influenced the behaviour of key stakeholders on 9 August, and existing recommendations to improve wholesale market settings.

6.4 This section also details new observations relating to thermal generation unit commitment, scarcity pricing review and direct connected major electricity users.

Wholesale market setting observations and recommendations made through other reports into 9 August

6.5 The Ministerial Investigation and PBA Consulting made observations and recommendations relating to how wholesale market settings influenced market participants' behaviour on 9 August.

Supply side

Wind generation

6.6 The Ministerial Investigation and PBA Consulting both observed there was less supply than expected through wind generation on 9 August.[57] The reports outlined that the system operator received offers of just under 500MW from the wind generators by mid-afternoon on 9 August. Over the evening peak, only 300MW of wind generation was being produced.

6.7 To improve forecasting related to wind generation, both reports recommended that the Authority amend the Code to disallow persistence forecasting and require wind generations make more accurate offers to the system operator about supply.[58]

6.8 The Authority is assessing the accuracy of forecasting data that contribute to the pre-dispatch schedules. These are the wind forecasts from generators, the system operator's demand forecast, and the bids from large industrial consumers at non-conforming nodes. The Authority is progressing this work and intends to consult on changes to improve the accuracy of forecasting in the second half of 2022.

[57] Ministerial Investigation. Page 25, PBA Consulting Page 9.

[58] Ministerial Investigation. Page 25 and PBA Report. Pages 9-10.

Large generation plants

6.9 Immediately after the event it was noted that some generation was not available on the evening of 9 August. Genesis Energy did not offer Huntly Rankine Unit 4 (HLY4) to the market and Contact Energy did not run Taranaki Combined Cycle station (TCC). Allegations were made that Genesis Energy and Contact Energy breached the trading conduct provisions of the Code and in addition there was a UTS claim made.

6.10 In a decision on 6 December 2021, the Authority found that there was inadequate time for Contact Energy to make TCC available in response to any forecast price before the system operator's first GEN notice at 5.10pm. As a result, Contact Energy was not considered to have breached the Code and the matter was closed.

6.11 An investigation into Genesis Energy's decision not to run HLY4 found that there was no breach of the trading conduct provisions and the investigation was closed in a decision made on 28 February 2022. The investigation concluded that "Genesis' behaviour to not offer HLY4 for the evening of 9 August was within the realm of behaviours consistent with that of a rational generator which does not hold significant market power"[59].

Pricing signals

6.12 PBA Consulting observed that market pricing signals did not provide sufficient commercial incentive to start-up inflexible generators (e.g., Contact Energy's Taranaki Combined Cycle unit or Genesis Energy's HLY4 unit) in time to meet peak demand in the evening of 9 August.[60]

6.13 The Authority does not agree with this conclusion. Genesis has stated that it lost significant amounts of money on 9 August[61], so the commercial incentives are clearly sending the right signals. The PBA consulting recommendations are predicated on unit commitment being a systemic problem with market design. We question if this conclusion can be drawn from the events of one day and note the PBA report does recognise the complexity of these proposals.[62]

6.14 PBA Consulting recommended no changes to existing market rules if these conditions are expected to occur infrequently.[63] However, PBA also made four recommendations[64] to improve commercial incentives for slow start-up generators through altering wholesale market design, if these conditions are expected to occur more frequently in the future, including:

(a) encouraging more elastic demand response to high prices;

(b) adapting the existing scarcity pricing mechanism to cover scarcity of standby reserves;

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[59] Investigations closed - no settlement reached — Electricity Authority

[60] PBA Report. Page 6.

[61] Marc England interview Radio NZ 10 August 2021; https://www.rnz.co.nz/news/national/448874/power-cuts-due-to-commercial-decisions-minister-megan-woods

[62] PBA Report. Page 8.

[63] PBA Report. Page 7-8

[64] PBA Report. Page 7-8

(c) adding unit commitment to existing energy and reserve markets to give inflexible generators revenue certainty to start up; and

(d) creating a market pricing signal for standby residual generation in addition to existing pricing signals for energy and reserves.

6.15 The Authority's investigation into the alleged Code breach found Genesis Energy did not breach the Code because it is plausible a rational generator may have acted in the same way, and Genesis did not have significant market power through HLY4.

6.16 The Authority considered that a rational generator may have behaved in the same way because:

(a) The investigator modelled HLY4 turning on at different times on the morning of 9 August, allowing for scenarios where it was operating at its full capacity by 6:00 pm, and where it had only partially ramped up by this time. In this case, the timing of available information during the morning was a key factor.

(b) The modelling found, for HLY4 to be at full capacity by 6:00 pm, price signals did not merit offering HLY4 generation.

(c) There was a small window from approximately 10:45 am to 11:15am when Genesis could have made a decision to offer generation from HLY4 and been profitable. HLY4 is not a peaking unit and was cold on the morning of 9 August, meaning it would need around 9 hours to ramp up to generate at full capacity. Making a decision at this time would have enabled HLY4 to reach its minimum load by 6:51 pm, after the peak demand had passed.

(d) This would have involved various risks, such as forecast prices changing, the start- up taking longer than expected, and running the unit in a way that creates extra physical risks to the unit. The investigator considered a rational generator may have weighed up the potential expected profit against the risks of running, and come to the same decision as Genesis not to run the unit.

6.17 The Authority also found that the possible market power Genesis may have expected to have through HLY4 for the evening of 9 August was not assessed to be significant.

6.18 In making its decision the Authority noted the investigator had assessed Genesis' actions using the information that was available to Genesis during the timing window when it would have been able to start HLY4 in time to generate at full or partial capacity for the evening peak. Later actions by other parties may have exacerbated the evening situation, but that was not relevant to Genesis' decision making earlier in the day.

6.19 MBIE interviewed some participants as part of the Ministerial Investigation, particularly independent retailers and major consumers. Participants told MBIE they have little ability to insure themselves against high spot prices that can occur unpredictably, such as on 9 August 2021. The Ministerial Investigation observed that New Zealand lacks a deep and liquid market for products to help wholesale

buyers efficiently manage their exposure to high spot prices at times of low residual generation.[65]

6.20 To respond to this gap in the market, the Ministerial Investigation recommended that the Authority explore a market for cap products.[66]

6.21 Cap products were previously identified as a potential new product by the Authority in approximately 2016 and work was undertaken with Australian Stock Exchange (ASX) to have these products listed. However, there were initially regulatory issues in Australia and once those were resolved there was insufficient interest from the market. ASX has recently discussed the introduction of a monthly option product. This product is likely to be seen as a close substitute for a cap-type contract. The Authority encouraged ASX to develop new products and does not see any barriers to this (or other products) being introduced by ASX if there is a market for them.

6.22 The role of cap products is not being looked at in isolation. The Authority's Market Design Advisory Group (MDAG) is exploring cap and cap-like products as part of its workstream on price discovery under 100% renewables, which are likely to be needed to a much greater extent under 100% renewables to support investment in supply and manage risks of more volatile prices.

Demand side

Reducing load

6.23 On the demand side, the Ministerial Investigation observed that the 9 August event occurred because the system failed to reduce or shift enough load from the peak to later in the evening, even though only a small amount of load needed to be shifted. [67]

6.24 To address this, the Ministerial Investigation recommended that the Authority and system operator develop an ancillary service product to manage multi-hour shortfalls and shift load away from peaks.[68] The Ministerial Investigation also recommended the Authority should harness emerging demand side opportunities that are in the public interest as they emerge.[69]

6.25 The Authority is progressing this recommendation as part of MDAG's 100% renewable energy policy work. Specifically, the MDAG is considering what additional changes could be made to promote greater demand-side participation in the wholesale market, taking the existing interruptible load arrangements and the soon-to-be-introduced dispatch notification product as a baseline. The Authority has concerns that developing a new ancillary service in isolation of wide policy work risks undermining market signals. The Authority considers it would be preferable to use market price signals to provide the right incentives.

6.26 Recent changes to allow grid scale batteries to participate in the reserves market will support improved management of shortfalls in the future. Additionally, there is work underway relating to Future Security and Reliability, and the impending

[65] Ministerial Investigation. Page 28.

[66] Ministerial Investigation. Page 28.

[67] Ministerial Investigation. Page 31.

[68] Ministerial Investigation. Page 32.

[69] Ministerial Investigation. Page 32.

introduction of the dispatch notification product. These should be implemented before considering if additional ancillary services are required. The dispatch notification product will incorporate demand response and distributed energy resources into the spot market, providing a co-optimised, whole of market approach to the dispatch of flexibility services. Introducing a paid ancillary service that is not integrated to the market could lead to inefficient outcomes that lock in resources that would be better employed directly competing with generation offers in the spot market.

Direct connect consumers

6.27 The Ministerial Investigation observed that there was significant variation in direct connect consumers' contribution to reducing load – direct connect consumers who were exposed to high spot prices responded by reducing their load or increasing their back up generation.[70] However, other direct connect consumers who were fully hedged, such as the New Zealand Aluminium Smelter (NZAS) did not reduce their consumption. The system operator requested NZAS increase its demand to a level that was higher than it was using on 9 August.

6.28 To address this, the Ministerial Investigation recommended that the Authority include clauses in commercial arrangements (and if this is not possible, regulate) so that major users are able to offer an acceptable demand side response when there is short term generation shortages.[71]

6.29 There is an opportunity for a demand response under Real Time Pricing (RTP), which remains on track to go live on 1 November 2022 and for a market solution for bidding demand response to be available from February 2023. The Authority has previously briefed MBIE on the scope and benefits of RTP, and MBIE supported the RTP business case. This recommendation for major users to offer an acceptable demand side response is also being considered as part of MDAG's 100% renewables policy work.

Equity rule in the Code

6.30 The Ministerial Investigation considered the equity rule in the Code to be flawed and contributed to household disconnections.[72] The Ministerial Investigation observed the system operator was guided by this rule when it issued the 6.47pm Notice for each EDB to reduce its load by one per cent.[73] However, some EDBs were able to deploy their ripple control systems to offer more than the one per cent requested and other EDBs had little or no remaining ripple control available by this time, and therefore had to disconnect householders.

6.31 The Ministerial Investigation observed the system operator was also guided by the equity rule in the Code when it issued a DAN at 7.09pm which gave each EDB its permitted maximum load, where eight EDBs were asked to reduce their load further, resulting in two EDBs disconnecting additional customers.[74]

6.32 To address this, the Ministerial Investigation recommended the Authority amend the Code so that the equity rule is only applied once discretionary load has been

[70] Ministerial Investigation. Page 30.

[71] Ministerial Investigation. Page 30.

[72] Ministerial Investigation. Page 15.

[73] Ministerial Investigation. Page 15.

[74] Ministerial Investigation. Page 16.

exhausted.[75]When the system operator requires electrical disconnection, the Code requires the system operator to the extent practicable to use reasonable endeavours to ensure equity between connected asset owners. The system operator did not instruct electrical disconnection on 9 August, so the equity rule did not apply. However, the Ministerial Investigation considered that the system operator issued notices that resulted in consumers being cut off because of the equity rule. The Ministerial Investigation recommended that the rule be changed to address this. At the time of the Ministerial Investigation, the system operator and the Authority's view that the system operator had issued notices to reduce demand (rather than instructions to electrically disconnect) had not been publicised.

6.33 The Authority notes that the equity rule has been in existence since before the Authority was established in 2010. There have been no compliance cases regarding its interpretation. Notwithstanding the Authority's view that the equity rule did not apply on 9 August, the Authority has considered the comments from the Ministerial Investigation and is of the view is that the rule itself is not flawed. Rather, its interpretation needs to be addressed.

6.34 The equity rule is not an absolute obligation to treat all demand equally when disconnecting. It specifically requires only "reasonable endeavours" – a lower standard than best endeavours and it talks about equity, not equality. Because it is not an absolute obligation, the rule affords the system operator flexibility to do what is needed in an emergency. It guides the system operator, while preserving it freedom to do what is best for system stability.

6.35 The Authority does not consider that "[the equity rule] means that the SO ought not ask a particular EDB to do more than its fair share."[76] Nor does the Authority consider that getting the system operator to use the available controllable load would have required the system operator to breach the equity rule.[77]

6.36 The Authority view is that the equity provision is exactly what was needed on 9 August because of the flexibility it affords the system operator should electrical disconnection as defined in the Code be required. This is supported by the fact that without any Code change the system operator has already changed its processes to ensure that all controllable load is shed prior to disconnecting consumers.

6.37 The Authority discussed its position with MBIE on 15 February and outlined that it considers equity means the absence of avoidable or remediable differences among groups of people. In the context of the NZ power system this means that consumers should continue to have the same level of access to supply regardless of their differences. Based on this interpretation, the Authority outlined to MBIE that it does not consider a Code change to be necessary to implement this recommendation.

6.38 On 18 March the system operator submitted a Code change proposal to the Authority regarding the equity rule intended to clarify that the system operator may not achieve equity during a grid emergency. Notwithstanding the above, the

[75] Ministerial Investigation. Page 17.

[76] Ministerial Investigation. Page 15

[77] Ministerial Investigation. Page 16.

Authority will consider the request as required through the normal Code Amendment Request process.

The Authority has made new observations areas related to the wholesale market settings as part of Phase 2

6.39 The Authority has also made new observations, which have not been covered in previous reports, related to:

(a) Thermal generation decision making;

(b) Scarcity pricing; and

(c) Direct connected major electricity users.

6.40 In response to the thermal generation decision making observations, the Authority recommends action to address this.

Thermal generation decision making

6.41 The Authority has made new observations about thermal generators' decision making. These build on those made in the Authority's UTS investigations.

6.42 These observations are based on information provided by Genesis Energy and Contact Energy after 9 August, and Nova Energy via a submission to options to correct the 2019 UTS[78]. Interviews conducted were with Genesis Energy, Contact Energy and Nova Energy staff.

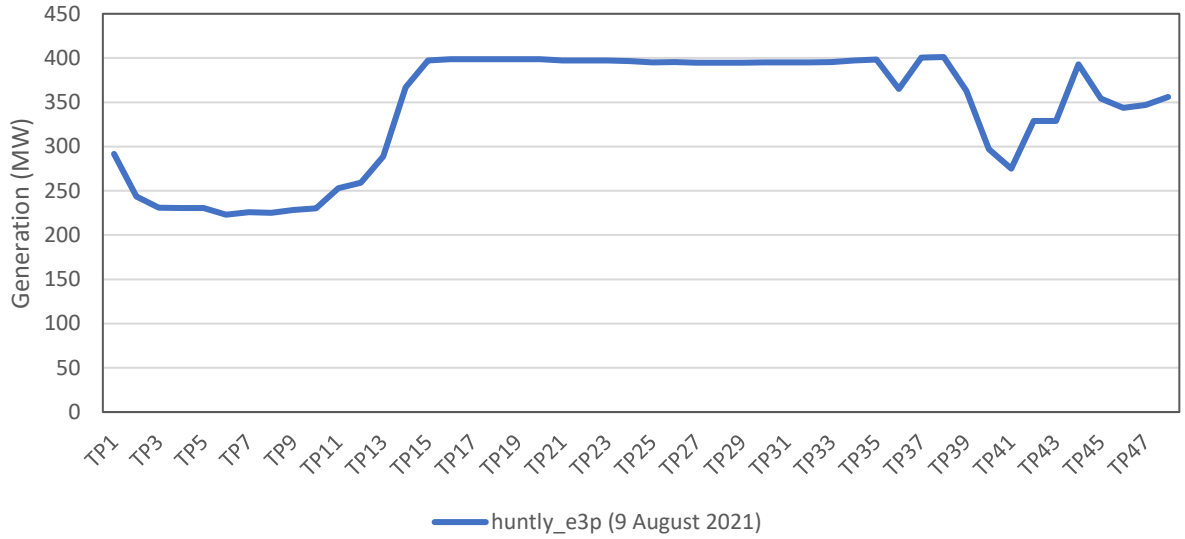
Considerations around baseload generation

6.43 Genesis Energy owns the E3P unit at Huntly, which is a combined cycle gas turbine. E3P was generating at its 400MW capacity for most of 9 August 2021, but delivered between 275 MW and 400 MW during the grid emergency (trading periods 35-43, 5-9pm).

6.44 Genesis Energy advised the Authority that E3P typically operates all day or between the morning and evening peaks, but can scale generation up and down during the day. Genesis Energy advised that its maintenance costs for this unit scale with the number of starts and stops. Figure 3 details generation from E3P on 9 August.

[78] Information regarding the 2019 UTS can be found on the Authority's website: 10 November 2019 — Electricity Authority (ea.govt.nz)

Figure 3: Generation from E3P (Huntly 5) on 9 August 2021[79]



Considerations around open cycle gas turbine (OCGT) plant

6.45 There are four large scale open cycle gas turbine (OCGT) plants in New Zealand. All OCGTs were generating on 9 August 2021. This includes generation from:

(a) a 40–50 MW gas-fired OCGT at the Huntly Power Station (Huntly p40 or Huntly unit 6);

(b) a 200 MW (two 100 MW units) gas fired OCGT at Stratford;

(c) two 50 MW gas fired OCGTs at McKee; and

(d) a 155 MW diesel fired OCGT at Whirinaki.

6.46 OCGT plants started in the morning, generated strongly through the day, and during the grid emergency (trading periods 35-43, 5-9pm). Figure 4 shows the generation from these plants on 9 August. The Authority's key observations for each plant are that:

(a) the McKee plant generated a profile aligned to the morning and evening peaks;

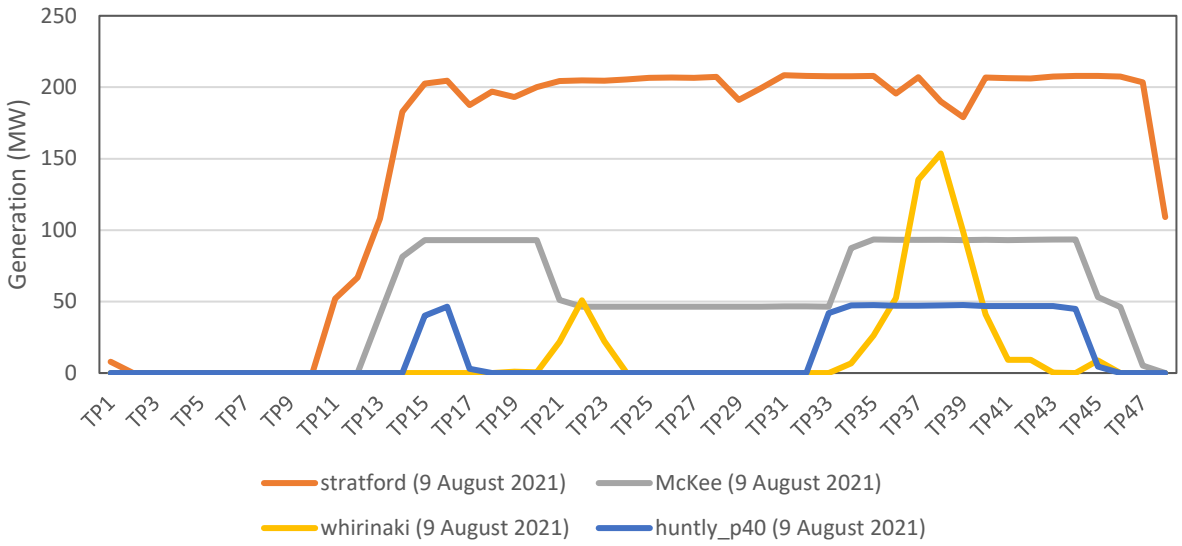
(b) Huntly P40 generated a profile aligned to the evening peak;

(c) the Stratford plant reached full capacity by TP15 (7 am) and ran at this level until TP 47 (11 pm); and

(d) Whirinaki's generation peaked at TP38 (6.30 pm) during the height of the grid emergency.

[79] Electricity Authority, 2021. EMI website, monthly generation data by plant, August 2021. https://emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD/202108_Generation_MD.csv

Figure 4: Generation from OCGTs on 9 August 2021



Considerations around committing OCGTs for dispatch

6.47 The Authority has made some observations about the factors OCGT operators consider when committing them for dispatch. These observations are consistent with the Authority's investigation into an alleged Code breach that found Genesis Energy did not breach the Code because it is plausible a rational generator may have acted in the same way, and Genesis did not have significant market power through HLY4. These observations are based on information provided by Genesis Energy and Contact Energy following the 9 August event and Nova's submission on the 2019 UTS. These considerations are:

(a) engineering and maintenance costs; and

(b) commercial imperatives.

6.48 Generators noted that maintenance costs are a key consideration in whether to commit OCGTs for dispatch. OCGTs take around 7 minutes to start and 10 minutes to be at full capacity. Generators noted that they do not start and stop their OCGTs quickly because the units have poor efficiency under 80% load.

6.49 Most companies have maintenance contracts that scale with the number of starts and stops, which incentivise companies to run their OCGTs for multiple trading periods. Further, frequently starting and stopping OCGTs increases wear and tear, which increases the frequency and cost of maintenance. Therefore, this creates additional costs on these parties because maintenance takes units out of action for multiple days.

6.50 Generators noted that price and demand forecasts are key factors when considering whether to dispatch their OCGTs. These companies offer their OCGTs when it is profitable to do so, i.e. expected revenue meets or exceeds operating costs.

6.51 Contact Energy indicated that it may offer the OCGTs at a lower price to avoid stops and starts or excessive ramping on the unit. Generators also consider that if forecasts were more accurate, they would have more confidence to commit generation to the market.

6.52 Nova stated that it aims to run the OCGTs when spot prices are expected to exceed the short run marginal cost (SMRC) of these units. Nova usually offered the units in at or near $0.01 per MWh for multiple trading periods when committing the units to run. Outside these times, Nova bids in at a price high enough to cover its costs if it were dispatched to run for only one trading period, which reflects the higher maintenance costs associated with frequent start-ups and shut-downs.

Is there a systemic problem?

6.53 The solutions that were proposed in both the Ministerial Investigation and the PBA report are predicated on the problem being a systemic problem. The Authority questions if such a conclusion can be drawn from a single event. In addition, Genesis has stated publicly that it lost money on 9 August[80] indicating that incentives are operating correctly and Genesis made a choice when faced with uncertainty that in retrospect would ideally have been different.

Decisions by generators will never be perfect but it is important that these are made with the best information available

6.54 Unit commitment decisions by generators are an example of decision making under uncertainty. These decisions are made within the context of different commercial incentives and engineering issues as outlined above. In these circumstances, there will be times when errors are made.

6.55 What is important is that generators are able to access the best possible information on which to base their decisions – information such as forecasts of load and price.

6.56 The Authority also expects upcoming improvements to the wholesale market to contribute to a more flexible system. These include mechanisms for new and emerging aggregated demand response and distributed energy resources to be offered into the wholesale market in early 2023 and recent changes to allow batteries to participate in the reserves market.

Recommendation

6.57 The Authority recommends further investigation into the accuracy of forecasts used to develop the pricing schedules generators rely on when deciding if to offer into the market[81]. This will identify what inputs into the pricing schedules can improve, and support informed generator decision making.

6.58 This will be important for the transition to 100% renewable energy as legacy slow start thermal plant will be used to firm an increasingly intermittent generation fleet, and then eventually retired or converted to sustainable fuel.

6.59 This work will be undertaken by the Authority and will be published by October 31 2022.

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80 Marc England interview Radio NZ 10 August 2021; https://www.rnz.co.nz/news/national/448874/power-cuts-due-to-commercial-decisions-minister-megan-woods

81 This includes but is not limited to intermittent generation offers system operator's load forecast at conforming GXPs, difference bids at conforming GXPs, demand bids at non-conforming GXPs.

9 August revealed some problems with scarcity pricing that real time pricing will address, but there are some other opportunities for improvement

6.60 In November 2022, scarcity pricing is being updated due to the introduction of real time pricing, From 1 November 2022 scarcity pricing will:

(a) be nodal rather than island wide;

(b) happen in real time rather than through an ex-post process;

(c) include forward looking information to signal possible scarcity; and

(d) have increasing scarcity prices for increased quantities of energy deficit.

6.61 The discretion that the system operator exercises under current scarcity pricing rules is not available under real time pricing, so there will be no confusion between reducing demand and electrical disconnection.

6.62 The plans that distributors maintain to support electrical disconnection are ideal for energy shortages that happen over weeks. The likely event that would cause this is very low hydro inflows. The plans support rolling outages over weeks rather than a one-off reduction in demand as required on 9 August.

6.63 As recommended in the Authority's Phase 1 report, more agile, short term demand reduction plans may be required to respond to system operator instructions to reduce demand during a short-term energy shortage.[82]

6.64 As the dispatch engine will signal scarcity under real time pricing, these signals will go to generators as part of the forward price schedules. In addition, the dispatch engine will determine the quantity of demand that needs to be reduced. In both cases it would be useful to find a mechanism to get this information to distributors in real time, as it is created. This would help signal the potential need to demand reduction and allow time for distributors to prepare for any subsequent load reduction.

6.65 Given the variation in the communications to distributors on 9 August, it is important that whatever solution is decided on works for all distributors.

6.66 It is not clear under RTP how the system operator will ask for controllable load to be shed prior to any forced demand reduction. This needs to be clarified by the system operator. In addition, the real time price signals and demand reduction signals leading up to a similar event will be useful information for distributors to have to prepare to respond, and to prepare any communications with their customers. Under real time pricing, this data may change every five minutes. Emails and phone calls will be inadequate to communicate this sort of information to distributors in a timely way.

Recommendations

6.67 The system operator will agree with distributors how, under RTP:

(a) price signals and demand reduction requirements will be communicated to distributors in a way that distributors can easily access real time data and receive notifications of changes to different data; and

(b) instructions to use controllable load will be sent.

[82] Authority Phase 1 Report. Page 18.

6.68 The Authority expects the system operator to publish details of this agreement by 30 September 2022.

Direct connected major electricity users

6.69 The Authority has observed that New Zealand Steel, Central North Island Forestry and Hawkes Bay forestry, who are North Island direct connect users, significantly reduced their demand on 9 August following the system operator's GEN notices.

6.70 However, NZAS located at Tiwai Point did not reduce its demand during the grid emergency on 9 August. This is unsurprising given an existing observation made by PBA Consulting that the system operator requested NZAS increase its demand on 9 August to unachievable levels.

6.71 Further detail is attached in Appendix 2.

7 Tools and processes

7.1 Tools and processes are essential to support robust operational decisions and give effect to policy outcomes. Poorly designed or implemented tools and processes can lead to poor decisions and adverse market outcomes.

7.2 This theme primarily relates to the Phase 2 Terms of Reference through the lessons learnt for the system operator.

7.3 This section summarises observations about how the tools and processes were used, particularly by the system operator, in making key decisions on 9 August.

7.4 This section also details new observations related to the system operator's use of tools and processes in previous reviews, and interruptible load in instantaneous reserve market.

Tools and processes observations and recommendations made through other reports into 9 August

7.5 The Ministerial Investigation, the Authority's Phase 1 review, and PBA Consulting have made observations and recommendations relating to the tools and processes used on 9 August.

Visibility of demand side participation and controllable load

7.6 Existing reports observed the system operator had inadequate real time visibility of demand side participation – the resources expected to be available. Further, the system operator had inadequate awareness of the actions taken or planned to be taken by EDBs and direct connect consumers, and the discretionary load available through the ripple control of each EDB. The Ministerial Investigation and PBA Consulting both made observations that it was desirable to shed controllable load (e.g., ripple controlled load) before disconnecting consumers.[83] Shedding load, such as ripple controlled load, would have avoided consumers being disconnected on 9 August.

7.7 The Authority's Phase 1 report recommended the system operator improve access to information on demand management resource available[84] and

[83] Ministerial Investigation. Page 58, PBA Report. Page 9.

[84] Authority Phase 1 Report. Page 12.

establish processes to verify the actual demand management resource available to market participants and stakeholders.[85]

7.8 PBA Consulting and the Ministerial Investigation both recommended improvements relating to controllable load. PBA Consulting recommended[86] operational improvements to increase the system operator's visibility of controllable load, ensure controllable load is shed before disconnecting households, and establishing processes to manage this. The Ministerial Investigation recommended that the Code be amended to require distributors to provide real time, acceptably accurate awareness of discretionary load to the system operator.[87]

Load shed and restore (LSR) decision support tool

7.9 The Authority's Phase 1 report provided specific observations in relation to issues with the load shed and restore (LSR) decision support tool on 9 August. The Authority observed there were significant discrepancies between the 7.09pm allocated demand limits and the demand individual participants were consuming at the time. This resulted in some distributors being instructed to disconnect a significant number of consumers, while other distributors were issued load setpoints above their original load levels. The Ministerial Investigation also observed that the system operator attempted to use the LSR tool but encountered issues with using it.[88]

7.10 To address these observations, the Authority's Phase 1 report recommended the system operator establish assurance systems for decision making tools.[89] The Authority's Phase 1 report also recommended the system operator investigate, develop and implement any fixes, or wholesale redesign, of the LSR decision support tool.[90] The Authority recommended it monitor the system operator's progress in actioning the LSR recommendations under its contractual arrangements.[91] The Ministerial Investigation also recommended reviewing operational tools for accuracy.[92]

7.11 In response to the Authority's Phase 1 report, the system operator removed the LSR tool from service for island wide and national demand management events.

7.12 The system operator's process is now to request the disconnection of all discretionary load ahead of any call for actual demand management that would require the disconnection of consumers. This will be called for as a percentage of actual demand at the time the call is made. The system operator has engaged with distributors and direct connect consumers to verify that communication of these requests are clear and will elicit the required response.

7.13 These changes, alongside the improvements in system operator visibility of discretionary load, are considered adequate to manage potential events in the

[85] Authority Phase 1 Report. Page 12.

[86] PBA Report. Page 9.

[87] Ministerial Investigation. Page 30.

[88] Ministerial Investigation. Page 56

[89] Authority Phase 1 Report. Page 15

[90] Authority Phase 1 Report. Page 13.

[91] Authority Phase 1 Report. Page 16.

[92] Ministerial Investigation. Page 34.

near term. Development of a new LSR tool has been deferred until after winter 2022.

7.14 Importantly, these changes to processes are also consistent with the equity rule in the Code, further supporting the Authority's view that no change is required.

Demand allocation process

7.15 The Authority's Phase 1 Review and PBA Consulting observed that 9 August was the first time the demand allocation processes had been used for a nation-wide demand reduction.[93] The demand allocation calculation to be used in a demand management event is described in the system operator's policy statement (which sets out how the system operator carries out its functions). In the case of an Island wide or national event, the allocation of demand management targets is based on the historical total annual demand for the regions affected. Both the PBA Consulting report and the Authority's Phase 1 review observed that it does not appear to be appropriate for reallocating demand shed on a real time percentage basis, as occurred on 9 August.[94]

7.16 To address these observations, the Authority's Phase 1 review and PBA Consulting[95] recommended improvements to the demand allocation process, including reviewing whether the calculation used is fit-for-purpose, improving how DANs are checked before being issued, and improving training for staff involved in the DAN process.

Staff training for demand allocation processes

7.17 The Authority's Phase 1 report and PBA Consulting observed limitations with the system's operators training for rare events, such as those that occurred on 9 August.[96] The reports observed the system operator's staff were unfamiliar with the LSR tool, which contributed to the issues observed above. The Authority's report also observed gaps in the system operators operational processes and training.[97] Both reports outlined that 9 August was the first time the LSR tool had been used in a national event outside of annual system operator training.

7.18 The Authority's Phase 1 and PBA Consulting's investigation both recommended improving training for demand allocation process and LSR.[98] PBA Consulting also recommended the system operator review the adequacy of the training simulator used to train staff, and identify other rarely used process and the adequacy of their training requirements.[99]

[93] Ministerial Investigation. Page 57. PBA Report. Page 8.

[94] Ministerial Investigation. Page 57. PBA Report. Page 8.

[95] PBA Report. Pages 8-9.

[96] Ministerial Investigation. Page 58. PBA Report. Page 11.

[97] Authority Phase 1 Investigation. Page 13.

[98] Authority Phase 1 Report. Page 16 and PBA Report. Page 10.

[99] PBA Report. Page 10.

The Authority has made new observations related to tools and processes

7.19 The Authority has observed that reports into 9 August made similar observations to previous reviews of the system events – the South Island AUFLS event in 2017 and HVDC limit setting error event in 2018.

7.20 These previous reviews observed that the system operator incorrectly or inappropriately used software tools in emergency situations, and there was insufficient training of control room staff.

System operator incorrectly or inappropriately used tools in emergency situations in past events

7.21 Transpower's review of the 2017 South Island AUFLS event found that its control room staff incorrectly used the Autosync tool in an attempt to reconnect the electrical islands that had been created in the South Island. Transpower's review also outlined that the Autosync tool was rarely used, and was not well understood or user friendly[100].

7.22 To address these findings, Transpower committed to review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems can be effectively operationalised[101].

7.23 In the 2018 HVDC event, Transpower's ICAM report provided as part of Advisian's review observed that the system operator used inconsistent language when referring to limit settings for the HVDC in the SCADA controls[102]. This confused the system operator's control room staff who were entering data, which along with inadequate procedures resulted in incorrect values being entered into the tool.

7.24 Advisian found that most of the system operator's tools were generally fit for purpose there were areas where improvements could be made both in terms of the existing tools and the process for procurement of tools in the future[103].

7.25 These findings are comparable with the Authority's Phase 1 observations that the system operator incorrectly used the LSR tool on 9 August 2022.

7.26 The reviews and investigations into 9 August observed that the LSR tool, and the process set out for emergencies did not operate as intended or were used incorrectly, contributing to the disconnection of consumers. The system operator had access to the necessary tools central to event management, but in the three cases, it failed to use them correctly. It is of concern that the system operator has not effectively addressed recommendations made in relation to previous events. The Authority's recommendation to address this observation is contained in paragraph 8.27 in the contract management section on this report because it relates to the Authority's management of its contract with the system operator.

[100] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event. Page 25.

[101] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event. Action 7, Page 5.

[102] Advisian, 2019. Independent report into HVDC current limit setting error. Section 2.3 of the attached ICAM report.

[103] Advisian, 2019. Independent report into HVDC current limit setting error, Section 4.6.

The system operator's insufficient training to control room staff was a feature past events

7.27 Transpower's review of the 2017 South Island AUFLS event found that the system operator's staff did not receive sufficient training to understand or correctly use the Autosync tool.[104]

7.28 Further, in the same review, Transpower found that there was a lack of effective event management between the National Coordination Centre (NCC) and National Grid Operations Centres (NGOC), which impacted the system operator's situational awareness and ability to resolve the event.[105]

7.29 To address these findings, Transpower committed to "re-emphasise and embed through regular training of NGOC and NCC staff the importance of compliance with policies and use of procedures during restoration after rare events."[106]

7.30 In the 2018 HVDC event, Advisian observed that there were systemic issues with training for control room operators, and issues related to the use and updating of the HVDC training simulator. To address these findings, since January 2019 the system operator's training simulation exercises have "included significant, unexpected situations to gauge both technical and behavioural responses". [107]

7.31 These findings are comparable with PBA Consulting and the Authority's Phase 1 Report's observations that the system operator's staff received inadequate training.[108]

7.32 The PBA Consulting and the Authority's Phase 1 report noted the lack of adequate training for rare events. It is of concern that the system operator has not effectively addressed recommendations made in relation to previous events. The Authority's recommendation to address this observation is contained in paragraph 7 in the contract management section on this report because it relates to the Authority's management of its contract with the system operator.

Lower instantaneous reserves available on 9 August

7.33 The Authority has made new observations that offers of instantaneous reserve reduced during the day on 9 August. Generally, reductions in offers of interruptible load indicate reductions in load as providers start using their controllable load to manage demand. The net effect of this tends to be neutral as the reduced load helps the grid emergency, but substituting spinning reserves for interruptible load has the opposite effect. . Further detail is attached in Appendix 2.

8 Contract management

8.1 The performance and accountability framework applicable to the system operator is found in a mix of legal instruments – the Act (which creates a statutory monopoly), the Code, and the system operator service provider agreement (SOSPA). The Authority acknowledges that it must be a more proactive and

[104] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Key Finding 7. Page 4.

[105] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Key Finding 5. Page 4.

[106] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Action 6. Page 5.

[107] Correspondence with Transpower on HVDC Cable Setting Error - Advisian Management Actions Closeout.

[108] Ministerial Investigation. Page 58. PBA Report. Page 11.

informed monitor of the system operator's legal obligations, including by more firmly holding the system operator to its contractual obligations. The system operator's self-assessment of its performance is a necessary input, but not a sufficient measure.

8.2 Contract management is therefore important because, alongside the Authority's monitoring of obligations in the Act and the Code, it is one of the key ways in which the Authority oversees, manages and monitors the performance of the system operator who is responsible for the day-to-date operation of the electricity system.

8.3 Recognising this, in November 2021 the Authority separated the contract management function into a team with the objective of giving contract management a commercial focus.

8.4 This section summarises observations from other reports related to (a) how the Authority is managing its relationship with Transpower as system operator and (b) recommendations to improve contract management.

8.5 The Authority has made new observations that issues that arose on 9 August have also been consistent features of previous events, and recommends action to address this.

Contract management observations and recommendations made through other reports into 9 August

8.6 The Ministerial Investigation made observations and recommendations relating to contract management.

8.7 The Ministerial Investigation observed that "it is a difficult relationship for the regulator, the EA, which cannot by law look elsewhere for services, and which suffers from a significant information imbalance. That is perhaps why the system relies on Transpower's self-assessment and self-monitoring to the extent that it does."[109] The Ministerial Investigation also observed that it "suspect[s] the current arrangements are inadequate" and that "Transpower has not always responded to the findings of reviews of earlier events" and that the Authority must lift its performance in terms of its monitoring role.[110]

8.8 To address the Authority's contractual relationship with the system operator, the Ministerial Investigation recommended that the Authority should hold Transpower more firmly to the rules and contracts in its performance as the system operators.[111] The Authority acknowledges that it needs to become a more informed and methodical monitor of the system operator.

8.9 In response to the Ministerial Investigation recommendation, the Authority:

(a) has undertaken an internal management review to inform its approach.

(b) has commissioned and has received a draft report on international best practice in this area. The report was finalised in early April.

(c) is organising a workshop, which we expect to occur in April or May 2022, with the Ministry for Primary Industries (MPI) to understand how it

[109] Ministerial Investigation. Page 58. PBA Report. Page 18.

[110] MBIE, Investigation into electricity supply interruptions of 9 August 2021, pp18-19.

[111] Ministerial Investigation. Page 19.

regulates and supports sectors within the primary industries. The Authority considers that standing of MPI's regulatory stewardship model, and performance in developing and regulating primary industries, is well recognised in the Public Sector and should provide insights to how we evolve our own regulatory model.

8.10 Once the findings of the report have been considered and workshop with MPI is concluded, the Authority will develop a work programme of key activities by building on the findings of the report and seeking to implement transferable aspects of MPI's regulatory practice. The Authority therefore does not have further observations and recommendations in terms of contract management at this time however notes it is a key area of focus for the Authority.

The Authority has made new observations that issues that arose on 9 August have also been consistent features of previous events

8.11 As set out in the sections above, the Authority has observed that reports into 9 August made similar observations to previous reviews of the system events – the South Island AUFLS event in 2017[112] and HVDC limit setting error event in 2018.[113]

8.12 The 9 August event showed serious issues in coordination. The system operator is the centre of coordination in grid emergencies, and the issues identified in this, and other event reviews are all central to system coordination in an emergency. The Authority's recommendation is aimed at improving accountability and transparency for actions addressing these persistent issues.

8.13 The Authority has recognised that its management of different service providers, including the system operator, needs to be more closely aligned with commercial disciplines. To this end the Authority has reorganised this function in part to improve accountability for actions that flow from these sorts of events. This will better enable the Authority to hold service providers, such as the system operator, accountable for learning lessons from events in the future.

Communications

8.14 System operator communications were inadequate in all three cases.

8.15 In response to the 2017 South Island AUFLS event, the system operator found communications were "poor, insufficiently clear, formal or effective".[114]

8.16 In response to the 2018 HVDC limit setting error event, Advisian found that communications were "unduly informal given the nature of information being conveyed".[115]

8.17 Reports into 9 August observed that the system operator's communications failed to follow protocol, were inconsistent and at times used ineffective channels.

[112] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event

[113] Advisian, 2019. Independent report into HVDC current limit setting error. Pages 2-5 refer.

[114] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Key Finding 4. Page 4.

[115] Advisian, 2019. Independent report into HVDC current limit setting error. Pages 3.

Staff training

8.18 System operator staff were insufficiently trained for all three cases.

8.19 In response to the 2017 South Island AUFLS event, the system operator found that "the procedure to operate Autosync was not accessed (or followed) during this period", [116] and ineffective event management needed to be addressed by regular training.

8.20 In response to the 2018 HVDC limit setting error event, Transpower found that "the root cause was the lack of formal processes, training and assessment when changes occur to DC SCADA controls combined with a lack of operational rigour around language and tasks" [117].

8.21 In 2021, PBA Consulting and the Authority's Phase 1 report noted the lack of adequate training for rare events.

Tools and processes

8.22 The system operator had tools central to event management, but in the three cases, either failed to use them correctly, or in the case of 9 August, the LSR tool was not fit for purpose.

8.23 In the 2017 South Island AUFLS event "the procedures for using the Autosync tool, returning assets to service and voice communications were not followed. Operation of the Autosync tool was not well understood by either NCC or NGOC personnel."[118]

8.24 In the 2018 HVDC limit setting error event, Transpower found that "the root cause was the lack of formal processes, training and assessment when changes occur to DC SCADA controls combined with a lack of operational rigour around language and tasks".[119]

8.25 The reviews and investigations into 9 August observed that the LSR tool, and the process set out for emergencies did not operate as intended or were used incorrectly, contributing to the disconnection of consumers.

The need for an approach that makes accountability for change more transparent

8.26 As noted above, the Authority needs to become a more informed and methodical monitor of the system operator, and, to a greater extent than in the past, hold the system operator to its obligations.

8.27 The Authority would like the system operator to produce and publish a plan for how it is going to address the issues identified by the reports into the three events and report against the plan to the industry. In addition the system operator should develop ongoing reporting to reassure the industry that these issues continue to be actively managed. This reporting should then be expanded to include any lessons learnt from subsequent events.

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[116] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event. Page 24.

[117] Advisian, 2019. Independent report into HVDC current limit setting error. Section 4.4 Page 30-32.

[118] Transpower, 2018. Report on 2 March 2017 South Island AUFLS Event, Key Finding 7. Page 4.

[119] Advisian, 2019. Independent report into HVDC current limit setting error. Page 67. Appendix B: Transpower's ICAM report.

Recommendation

8.28 The system operator should:

(a) develop and publish a plan for how issues raised by reports into the events listed above are being addressed. This plan should be agreed with the Authority and published no later than 30 June 2022; and

(b) develop ongoing assurance reporting that these issues continue to be actively managed. This reporting should be quarterly and set out how each quarter's actions in response to this review were addressed and/or maintained, and include any responses to subsequent event reviews. This reporting will be published by the Authority and form part of how the Authority manages the system operator's performance, which will be part of what enables the Authority to more proactively hold the system operator to account.

9 Progressing recommendations made into the 9 August event

9.1 The Ministerial Investigation recommended that the Authority and system operator address the findings and recommendations of the Authority's Phase 1 Report, the PBA Consulting and Thompson Lewis as a matter of priority.[120] The Ministerial Investigation also recommended that the Authority and system operator should provide quarterly progress updates to the Minister.[121]

9.2 Good progress has been made on all recommendations from existing reviews and investigations into the 9 August event. The Authority has focused on progressing immediately actionable recommendations so that the system operator and wider industry are much better placed to manage future demand management events and minimise the impact on consumers ahead of winter 2022, when we expect there to be increased demand in the system, particularly given the risk of a dry year.

9.3 The Authority has undertaken rigorous assurance of the system operator's actions to address the recommendations through regular project meetings and assessing information provided by the system operator. The Authority is comfortable that these actions are being progressed and will continue to monitor the system operator's progress.

9.4 Further information on progress made to date can be found on the Authority's website at: Electricity Authority Review of 9 August 2021 event under the Electricity Industry Act 2010 — Electricity Authority (ea.govt.nz)

10 Appendices

Appendix 1: Long list of recommendations made in existing reports into the 9 August grid emergency

Appendix 2: Further background information

[120] Ministerial Investigation. Page 36.

[121] Ministerial Investigation. Page 39

Appendix 1: Long list of recommendations made in existing reports into the 9 August grid emergency

Ministerial Investigation recommendations

Number and theme	Recommendation for action
MBIE1 Performance of the system and system operator (section 3)	We recommend that the EA amend the Code to ensure the equity rule is deployed only when ripple control and any other type of discretionary load available has been exhausted.
MBIE2 **Performance of the system and system operator (section 3)**	We recommend that the EA scrutinise its relationship with Transpower, perhaps with international input, with a view to holding Transpower more firmly to the rules and contracts that bind it. We believe the EA should report its progress on this recommendation to the Minister of Energy and Resources after six months. We invite the EA to engage with other regulators in New Zealand which successfully both support and regulate their industries.
MBIE3 **Wholesale market and supply side (section 4)**	We recommend that the EA seek to disallow persistence forecasting and require all wind generators to use acceptably accurate ways to make their offers to the SO
MBIE4 **Wholesale market and supply side (section 4)**	We recommend that the EA explore afresh the market for cap products.
MBIE5 **Demand response and demand side participation (section 5)**	We recommend that the EA demand major users are able to offer an acceptable demand side response in the event of a short-term generation shortage and regulate if commercial arrangements are not reached in a short period.
MBIE6 **Demand response and demand side participation (section 5)**	We recommend that the Code must be amended so that the SO has real time, and acceptably accurate, awareness of discretionary load available from each EDB by winter 2022. We commend the Upper South Island load management programme as a starting point.
MBIE7 **Demand response and demand side participation (section 5)**	We recommend that the EA and the SO design and implement a new product to manage multi-hour shortfalls.
MBIE8 **Demand response and demand side participation (section 5)**	We recommend that a new ancillary service be given serious consideration as the first step in the life cycle of this new product.
MBIE9 **Information and communications (section 6)**	We recommend that the EA and Transpower address the findings and recommendations in the EA's Immediate Assurance Review report, and reports by PBA and Thomson Lewis (both commissioned by Transpower) as a matter of priority, with each immediately initiating a programme of work, co-ordinating where appropriate.

Number and theme	Recommendation for action
MBIE10 **Information and communications (section 6)**	We recommend that the EA and Transpower should each be asked to provide quarterly updates to the Minister setting out progress until the systems are in place. The EA should undertake subsequent compliance monitoring.
MBIE11 **Information and communications (section 6)**	Transpower should ensure that it henceforth reliably and promptly provide the 24/7 communications needs of the SO in generation emergencies.
MBIE12 **Information and communications (section 6)**	Transpower should design and undertake pan-industry contingency exercises, monitored by the EA, sufficient to test processes actions and communications, and to clarify responsibilities in a generation emergency. Transpower should consider engaging the National Emergency Management Agency in designing communications policies for use in an emergency
MBIE13 **Information and communications (section 6)**	We endorse the recommendation of PBA Consulting that the SO should improve its process for providing the public with timely and simple explanations for system-wide incidents, particularly where consumers have been disconnected.
MBIE14 **Information and communications (section 6)**	However, we add that EDBs will usually hold relevant information that the SO does not, and are therefore also obliged to establish communication protocols, by multiple means. Both the SO and EDBs should be proactively in touch with all retailers and should have established and agreed systems to achieve that.
MBIE15 **Information and communications (section 6)**	We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication in a grid emergency and encode such arrangements where appropriate.
MBIE16 **Information and communications (section 6)**	We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication with medically dependent consumers in a grid emergency and encode such arrangements where appropriate.
MBIE17 **Information and communications (section 6)**	Noting that these arrangements may not be materially different from those applying in the above recommendation, we suggest the EA and industry also consider an education campaign to ensure medically dependent consumers are aware of the importance of having a personalised emergency response plan.
MBIE18 **Looking ahead (section 7)**	MBIE and the EA should demonstrate leadership in their respective roles in standard setting where it is in the public interest to harness emerging demand side opportunities.

The Authority's Phase 1 recommendations

Source	Recommendation for action
EA Phase 1	1A The system operator to further electricity sector readiness to respond to critical demand management incidents. This will include (but not be limited to) an annual pan-industry exercise - (similar to critical gas contingency incident management exercises). No Business Continuity Plan style exercises with the system operator have ever been held for a supply shortage situation, this left participants unfamiliar with protocols and requirements. Protocols developed for a rolling outage situation lasting many hours do not appear to have the flexibility to manage a short term, short notice event The development of an annual exercise, involving the system operator, distributors, generators and retailers would allow operational and communication processes to be refined and responsibilities better defined. The first exercise will place emphasis on resolving the objectives of communications between the system operator and distributors and direct connect consumers.
EA Phase 1	1B For island-wide and national demand management, queries regarding notices must be directed to NCC via NGOC.
EA Phase 1	1C Clear and consistent lines of communication must be made known to recipients and where those communication lines differ – i.e., NCC vs NGOC the messaging between them needs to remain consistent.
EA Phase 1	1E Review operational tools for accuracy. The system operator must review grid exit point to distributor modelling in their operational tools to ensure it is current.
EA Phase 1	1D Communicate any changes to actions required to all participants. Any update information regarding the demand management notices, i.e., instruction to some participants to hold action, must be immediately communicated to NGOC and all participants. This is critical in events where customer demand has been, or is intended to be, disconnected beyond discretionary load management.
EA Phase 1	2A The system operator to work with stakeholders to develop an agreed and comprehensive communication approach to ensure prompt and consistent information. The system operator will work with distributors and retailers to resolve and formalise how priority information is to be promptly and consistently cascaded, and how affected customers and stakeholders will be notified for critical grid emergencies, unplanned outages, and material deterioration in network security. The system operator will put in place an agreed communication approach that will enable distributors and direct connect consumers to support a response to critical grid emergencies, in parallel to managing localised network support pressures.
EA Phase 1	2B Communication between distributors and retailers during an emergency situation, where customers are being disconnected, should be active rather than the passive forms used for planned outage communication. This must be balanced against the operational needs and workload of the distributors during the event. Distributors and retailers must work together to formalise contact points and communication methods. The agreed communication methods must: (a) be between identified roles within each organisation with responsibility for ensuring the communication is sent, received and escalated appropriately, and (b) not rely on individual communication, alternate contacts should have access to the notification process to mitigate the risk of staff absence impacting the communication process, and (c) use standard language to provide formal notice of outages identifying the customers being disconnected.
EA Phase 1	2C Given most distributors use webpages and/or phone apps to communicate local outages, an automated messaging extension to this system may be a suitable long-term solution.
EA Phase 1	3A The system operator must improve their access to information on general demand management resource availability. The system operator will establish baseline information on the general demand management resources available within the system, and update this on a regular basis.
EA Phase 1	3B In support of potential grid emergency responses, the system operator will establish processes capable of timely verification of the actual demand management resources available to the system operator, to the distributors, and to direct connect consumers.
EA Phase 1	3C Review the contents of the formal notices.

Source	Recommendation for action
	Where practicable, the system operator must ensure formal notices include specific actions to take, the reason, the timeframes when these actions must be taken and confirmation of when the action taken is required – supported by timely feedback from the system operator on the effectiveness of those actions.
EA Phase 1	3D Where practicable, ensure earlier formal notices include specific actions to take, the timeframes when these actions must be taken and if there is a requirement to acknowledge the action has been taken, e.g., a) Immediately update demand bids for 18.00-20.00 to reflect expected offtake and confirm when the action is taken (b) Reserve dispatch will be reduced to release generation volume from 18.00 (c) System operator requires all controlled and discretionary load to be managed on a national basis and confirm when the action is taken (d) Direct connect consumers and distributors must prepare for demand management call from 18.00 onwards (e) Current forecast energy/reserve shortfall is XXXMW.
EA Phase 1	3E The language used in the notices must be consistent and clear on the consequences to affected participants of an insufficient response.
EA Phase 1	3F Update participants on any worsening of the situation. Ensure relevant market indicators of the event are clearly communicated to all affected parties. The language used in any notification should use a standardised form that has been developed in conjunction with the expected recipients. This will ensure a common understanding of the meaning of the notification and any actions required of the recipients. Changes in the shortfall or residual level published through the market schedules would not necessarily be seen or understood by distributor operations staff even though they are most likely to be impacted by a worsening situation.
EA Phase 1	4A Evaluate alternatives to email distribution for critical notices. The system operator will evaluate alternative communications systems that would better support notification to the operations focussed staff that are the target recipients (separate to the current email-based notification approach).
EA Phase 1	4B In the interim, where practicable, formal notices published using the existing email delivery approach which require timely recipient action should be followed up with phone calls. This communication would confirm the recipient's understanding of the issue being addressed and the actions required of them.
EA Phase 1	4C To support the current email-based notification, the system operator will put in place an assurance system to maintain up to date contact lists for key operational staff (and back up contacts) across distributors, direct connect consumers, generators and any other parties that could be required to respond to an emergency notice from the system operator.
EA Phase 1	5A Assurance system for decision support tools relied upon in medium and large-scale events. The system operator will put in place an assurance system that identifies the current state of the suite of decision support tools that are relied upon to respond to medium and large-scale events. The purpose is to ensure that the stock of tools is regularly maintained and adjusted to reflect material changes in networks.
EA Phase 1	5B Specific to the LSR decision support tool, the system operator must determine if the LSR decision support tool continues to be fit for purpose.
EA Phase 1	5C Review the technical and functional debt associated with other legacy tools and processes. The issues with the manual data updates for the LSR decision support tool and questions regarding the fitness of the LSR functional specification raise concerns of further technical and functional debt in the system operator tool suite. While the ongoing Market System Simplification project run by Transpower, is addressing technical debt in the core market systems, the system operator should also review: (a) any further manual data update processes for market system tools and their fitness for purpose, and (b) the fitness of the functional specification of any other legacy tools and processes, particularly those that are used infrequently or in a manner that does not use their full functionality.

Source	Recommendation for action
EA Phase 1	5D Redesign the LSR interface to simplify its operation. The user interface must be simple, clear and allow for intuitive assessment of the tool outputs to ensure they meet the needs of the power system. Process documentation should be clear and explicit about the expected operation of the tool and the checks necessary to validate the outputs of the tool.
EA Phase 1	5E Enhance training on the revised LSR decision support tool. Training on any reinstated LSR decision support tool must include validating tool outputs and corrective actions that can be taken.
EA Phase 1	5F Enhance post market system update testing to validate LSR decision support tool inputs and outputs. A process needs to be put in place to ensure that the data load is carried out at the required frequency and is tested and signed off as complete, correct and functional after each upload.
EA Phase 1	5G Testing scripts in the test automation suite need to be updated to not only check that the tool remains usable after any changes but also that the inputs it requires – i.e., historic data is appropriate and the output it generates is correct.
EA Phase 1	5H Ensure distributors and direct connect consumers are familiar with the aims and outputs of the new LSR tool. The system operator must ensure that distributors are made familiar with the function, and expected outputs, of any future LSR decision support tool and the actions expected of them in response to related notices.
EA Phase 1	5I The Authority will monitor the system operator's review of the LSR decision support tool. The Authority must closely monitor the investigation, development and implementation of any fixes, or wholesale redesign, of the LSR decision support tool.

PBA Consulting recommendations

Source	Recommendation for action
PBA	i. Slow Start-up Generators

Source	Recommendation for action
	Market pricing signals did not provide sufficient commercial incentive to start-up inflexible generators in time to meet the evening peak demand. The Investigator recommends that the Electricity Authority consider the relative benefits of the following suggestions: 1) If these conditions are expected to occur very infrequently, then make no changes to the existing market rules, and accept that demand management may be infrequently required when inflexible generators cannot start in time to make up for unexpected generation shortages. 2) Encourage a more elastic demand response to high prices. There may be a future opportunity here for aggregators to offer control of household batteries and EV charging. 3) Adapt the existing scarcity pricing mechanism to also cover scarcity of standby reserves. The scarcity pricing price floor and cap might improve revenue certainty for slow start expensive generators. This might be a relatively small change to the present market design. 4) Add unit commitment to the existing energy and reserve markets to give slow start generators the revenue certainty needed to start and run when there is uncertainty in the ability of generation to meet peak demands. This would be a significant change to the market design. 5) Create a market pricing signal for standby residual generation, additional to the existing pricing signals for energy and reserves (some might call this a short-term capacity market). This would be a significant change to the market design.
PBA	ii. Demand Allocation Process This Grid Emergency was the first time the demand allocation process has been used after a nation-wide demand reduction. The demand allocation calculation in the Policy Statement is based on historical demands and does not appear to be appropriate for reallocating demand shed on a real time percentage basis, as occurred for this event. The Investigator recommends that: 1) The Electricity Authority and System Operator review whether the demand allocation calculation defined in the Policy Statement, and implemented in the LSR tool, is fit for purpose for reallocating demand shed on a real time percentage basis.
PBA	iii. Controllable Load In principle, it is preferable to shed controllable load before disconnecting consumers. At present, the SO has very limited visibility of controllable load in the distribution networks. Better visibility will be needed to determine how much controllable load is available for shedding at any point in time. The Investigator recommends that the Electricity Authority, System Operator, and distributors work together to improve the utilization of controllable load by: 1) Improving the System Operator's visibility of controllable load. 2) Formally agreeing that all relevant controllable load should be shed before disconnecting consumers. This includes shedding the controllable load of one distributor to avoid disconnecting consumers of another distributor. 3) Establishing processes for how the System Operator requests distributors to manage shedding and restoration of controllable load. 4) Considering the Upper South Island Load Manager (operated by Orion and visible to the System Operator) as a possible model for better utilization of controllable load.
PBA	iv. Wind Generation Forecasts Offers of wind generation significantly over-estimated the amount of wind generation that could supply the evening peak demand. This was partly due to the use of a persistence model for forecasting wind offers 2 hours ahead. The Investigator recommends that the Electricity Authority reviews the way persistence is currently used for offering or forecasting intermittent generation and considers improving forecasting requirements for intermittent generation.
PBA	v. Public Communications During Incidents The System Operator has a much better overview of system-wide incidents, such as this Grid Emergency, than other market participants. However, disconnected consumers direct their first queries at distributors and retailers who may not have ready answers to the situation and likely reconnection times. The Investigator recommends that the System Operator improves the process for providing the public with timely and simple explanations for system-wide incidents, particularly where consumers have been disconnected.
PBA	vi. NCC Staffing and Training The continuous improvement of NCC coordinators is challenging because in addition to their primary roles of managing system energy and security there are additional demands from projects for subject matter experts, change implementation, and COVID requirements. Aside from challenges with finding time for continuous improvement, it is increasingly difficult to access the training simulator environment for internal training as well as real time exercises including industry partners. The Investigator recommends that the System Operator: 1) Reviews the staffing of NCC coordinator roles with a view to facilitating continuous improvement. 2) Reviews the adequacy of the training simulator environment for meeting the overall needs of training coordinators, real time exercises with industry partners, and projects.
PBA	vii. Industry Training for Rare Events Training for rare events is a common problem for many industries. In this case, the NCC coordinators lack of familiarity with the LSR tool for nation-wide generation capacity shortages contributed to the incorrect DAN.

Source	Recommendation for action
	The Investigator recommends that the System Operator identify rarely used procedures, review the associated training requirements, and take leadership in maintaining industry competence in handling rare events.

Thompson Lewis recommendations

Source	Recommendation for action
TL	1. GM External Affairs and Corporate Communications Manager to continue work to agree a communications protocol with key government stakeholders to ensure clarity of events to be escalated and the information requirements when escalation occurs.
TL	2. Transpower policy GL-DP-008 Guidelines for Internal Communication During an Event or Incident be amended to specify in a GEN being issued due to anticipated insufficient generation, the GM Operations and CEO are to be immediately notified by phone.
TL	3. That a System Operator policy focused on communications with external stakeholders be developed - could be based on the grid owner's Event Response – Major System Event Policy.
TL	4. Event Response – Major System Event policy be amended to make clear reference to both the Minister of Energy and Resources and shareholding Ministers being advised in a timely manner should a significant event occur to meet Transpower's "no surprises" obligation
TL	5. Amend the Process for Unplanned Outage Communications to specify in the case of significant events the CEO's approval for key messages is to be sought and obtained and advice provided to Chair and Board in appropriate cases.
TL	6. That in future security of supply situations, escalation both to the CEO/Chair and to key government stakeholders be undertaken via phone rather than text/email.
TL	7. In the event that significant security of supply issues occur or can be reasonably foreseen to occur in the coming hours, the GM Operations and/or Duty GM should in a timely fashion pull together key management in an Incident Management Team (IMT).
TL	8. External Affairs and Corporate Communications management continue to build ongoing relationships with key officials and the relevant Private Secretaries in Ministers offices to understand their information needs and make it easier to make direct calls in times of need.
TL	9. System Operator and Corporate Communications develop an annual scenario practice session to help ensure readiness for future events.

Appendix 2: Further background information

EDB communications on 9 August

The Authority has observed that there were gaps in some EDB's policies and procedures to respond to the system operator's notices

10.1 Several EDBs noted that they did not receive the system operator's GEN notices because their network control rooms are only staffed, and emails are only checked, during business hours. In response to these observations, EDBs that do not operate 24/7 control rooms have updated their policies and procedures to ensure network controllers receive WRN and GEN notices when they are released by the system operator.

10.2 Most EDBs' response procedures assume the system operator to follow emails with phone calls if the system operator required urgent action. This meant that these EDBs did not have procedures in place to respond to the system operator's emails.

10.3 There are also inconsistencies between EDBs' response procedures. Some EDBs' response procedures are designed to follow the system operator's directions, whereas other EDBs' have more flexible response procedures.

The Authority has observed a mix of approaches to communications from EDB to customers

10.4 Five EDBs (Northpower, Electra, WEL Networks, Unison and Marlborough Lines) disconnected consumers on 9 August. This section outlines how and when these EDBs communicated with their customers on 9 August.

10.5 Northpower, who cut two rural feeders on their network for approximately 30 minutes in response to the system operator's 6.47pm GEN notice, did not proactively inform consumers that power would be disconnected or seek that large industrial consumers reduce their load. Northpower noted that "this [situation] may have been mitigated had energy conservation messages been sent to all mass-market consumers earlier in the day." Northpower also noted that they could not use the system operator's notices to inform their customers of the grid emergency and the need to save energy because the notices were "non-specific in nature and generic in their form."

10.6 Electra, who opened circuit breakers for nine feeders in response to the system operator's 6.47pm GEN notice, did not proactively inform consumers that power would be disconnected. Electra notified its customers at 7.42pm of the disconnections through a message on its website and Facebook page. Electra also made updates to its website at 9.05pm, following the system operator's GEN notice stating the grid emergency has ended, and at 9.33pm.

10.7 WEL Networks, who opened circuit breakers following both the system operator's 6.47pm GEN notice and 7.09 pm notice, did not proactively inform consumers that power would be disconnected. WEL Network notified its customers at 7.48 through a post on its Facebook page. WEL Networks did not make further posts.

10.8 Unison activated their communications team, and began monitoring and responding to medium inquiries and social media in parallel to opening circuit breakers following the system operator's 6.47pm GEN notice. Unison also

indicated that it asked the system operator to release social media or communications messages at 7.32pm (the system operator released a Facebook post at 8.56pm). Unison also notified customers of disconnections at 7.48pm via a Facebook post. Union notified customers at 9pm that power had been restored.

10.9 Marlborough Lines, who opened circuit breakers following the system operator's GEN notice and subsequent phone call at 6.56pm requesting they reduce load by 1 percent, informed their call centre and retailers affected by the outage. Marlborough Lines does not appear to have an active presence on Facebook.

Lower instantaneous reserves available on 9 August

Overview of instantaneous reserves market

10.10 Instantaneous reserves are spare capacity in the electricity system that can be quickly called upon to ensure that generation and load in the electricity system remains balanced. Instantaneous reserves can be increases to generation (from partially loaded generators that can increase generation quickly) or reductions in load (from users).

10.11 Generally, reductions in offers in the reserve market indicate reductions in load – if load is off, it is not available to the reserves market. The amount of reserve required is designed to be at least as large as the single biggest element in the system, the 'risk setter' – this is either the largest generator in each island, or the HVDC, whichever is larger. This is so that if the risk setter (HVDC or largest generator) suddenly drops out, the power system remains balanced.

10.12 There are two types of instantaneous reserve:[122]

(a) fast instantaneous reserve (FIR) – must respond within 6 seconds and stay on for 60 seconds

(b) sustained instantaneous reserve (SIR) – must respond within 60 seconds and stay on for 15 minutes.

Observations relating to instantaneous reserves market from 9 August

10.13 Instantaneous reserve offers through the National Market for Instantaneous Reserves (NMIR) reduced throughout the day on 9 August, particularly between 5-9pm, as available controllable load was deployed. The available amount of interruptible load (e.g., ripple controlled hot water load) reduced as it was controlled off during the day of 9 August, particularly during the middle of the day.

10.14 During the early trading periods on 9 August, there were instantaneous reserve offers totalling 425 MW. This included offers of FIR of around 175 MW and offers of SIR of around 250 MW.

10.15 As the morning peak approached (between 6 and 9 am), FIR and SIR offers reduced as load control was deployed by EDBs and other participants. At about 7 am, offers reduced to 380 MW (FIR offers were around 155 MW and SIR offers were 225 MW). This mostly occurred due to WEL Networks removing its offers of ripple control from the market.

[122] Electricity Authority, 2019. Post implementation review of national market for instantaneous reserves: Market performance review. https://www.ea.govt.nz/assets/dms-assets/26/26043NMIR-review.pdf.

10.16 Further reductions in FIR and SIR occurred between around 8 am and noon, as Vector removed its controlled load from the market.

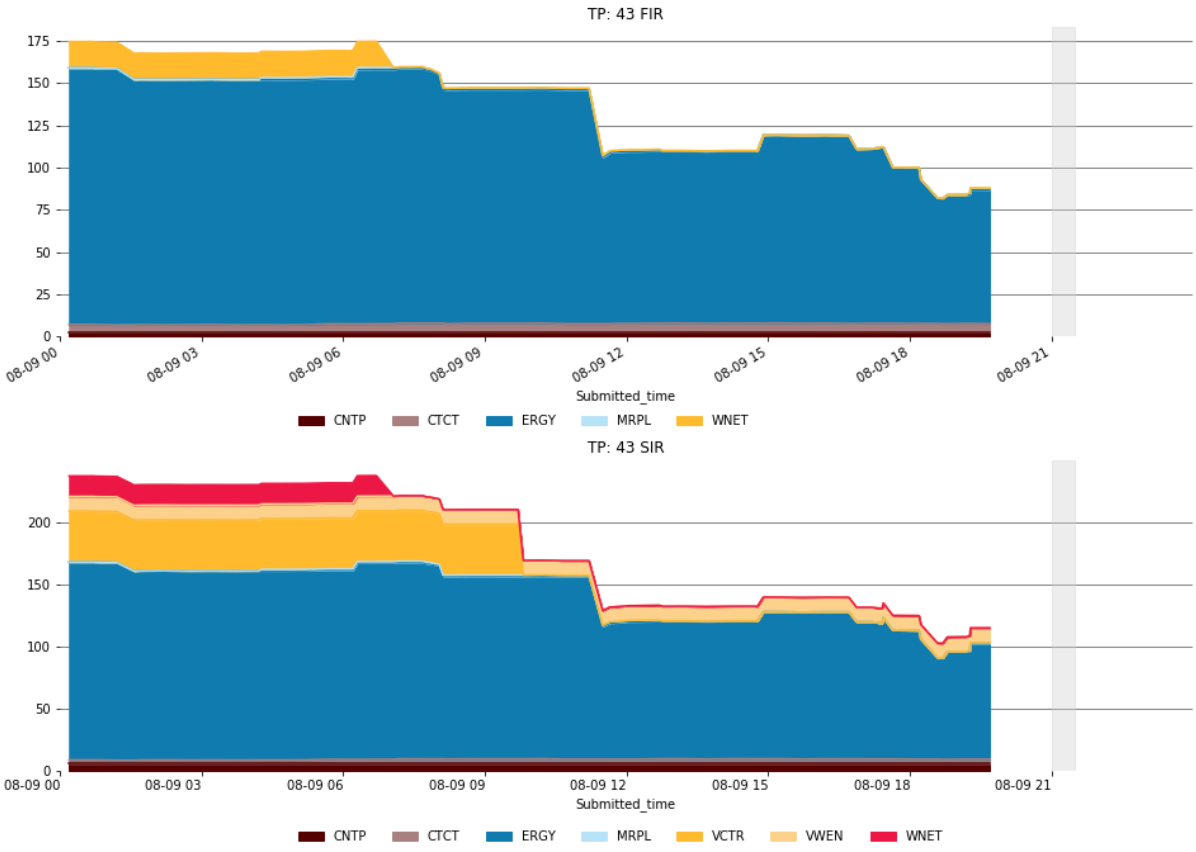
10.17 From about noon, offers were around 230 MW (FIR offers were about 110 MW and SIR offers were about 130 MW). Offers of FIR and SIR stayed reasonably stable between noon and around 4 pm.

10.18 Around 4 pm, offers of interruptible load in the market reduced further as more load control was deployed as the evening peak approached. Offers were around 180 MW at about 7.30 pm (FIR offers were around 80MW and SIR offers were around 100 MW). Enernoc, which is a demand response aggregator and the largest provider of FIR and SIR, contributed almost all the reduction.

10.19 Figure 4 outlines the FIR and SIR offers on the National market for Instantaneous Reserves on 9 August 2021.

Figure 4: FIR and SIR offers on the National Market for Instantaneous Reserves on 9 August 2021

10.20



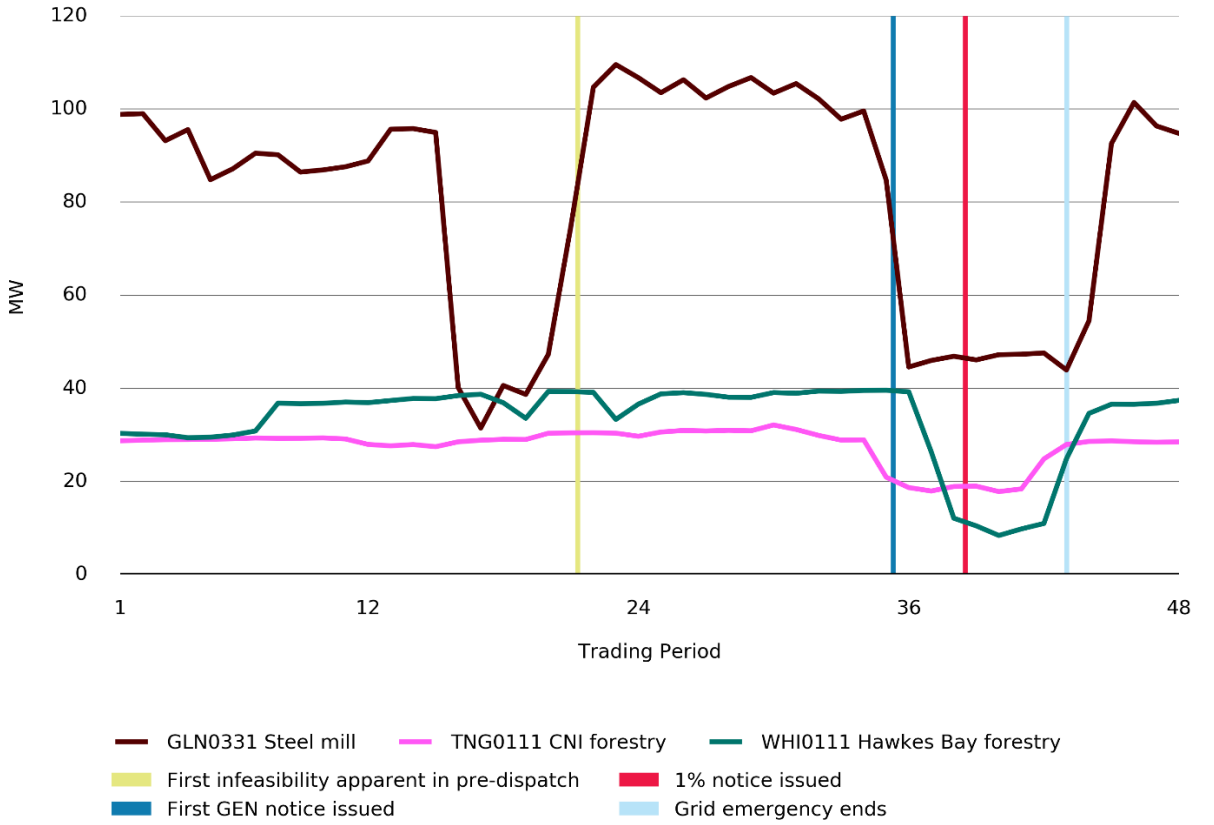
Direct connected major electricity users

10.21 Existing reports into 9 August made observations around direct connect consumers reducing their demand on 9 August. This section presents data on the demand reductions from direct connected major electricity users on 9 August, which demonstrates that major North Island direct connected electricity users reduced demand following the system operator's notices, but that NZAS did not.

10.22 New Zealand Steel, Central North Island Forestry and Hawkes Bay forestry, who are North Island direct connect users, significantly reduced their demand on 9

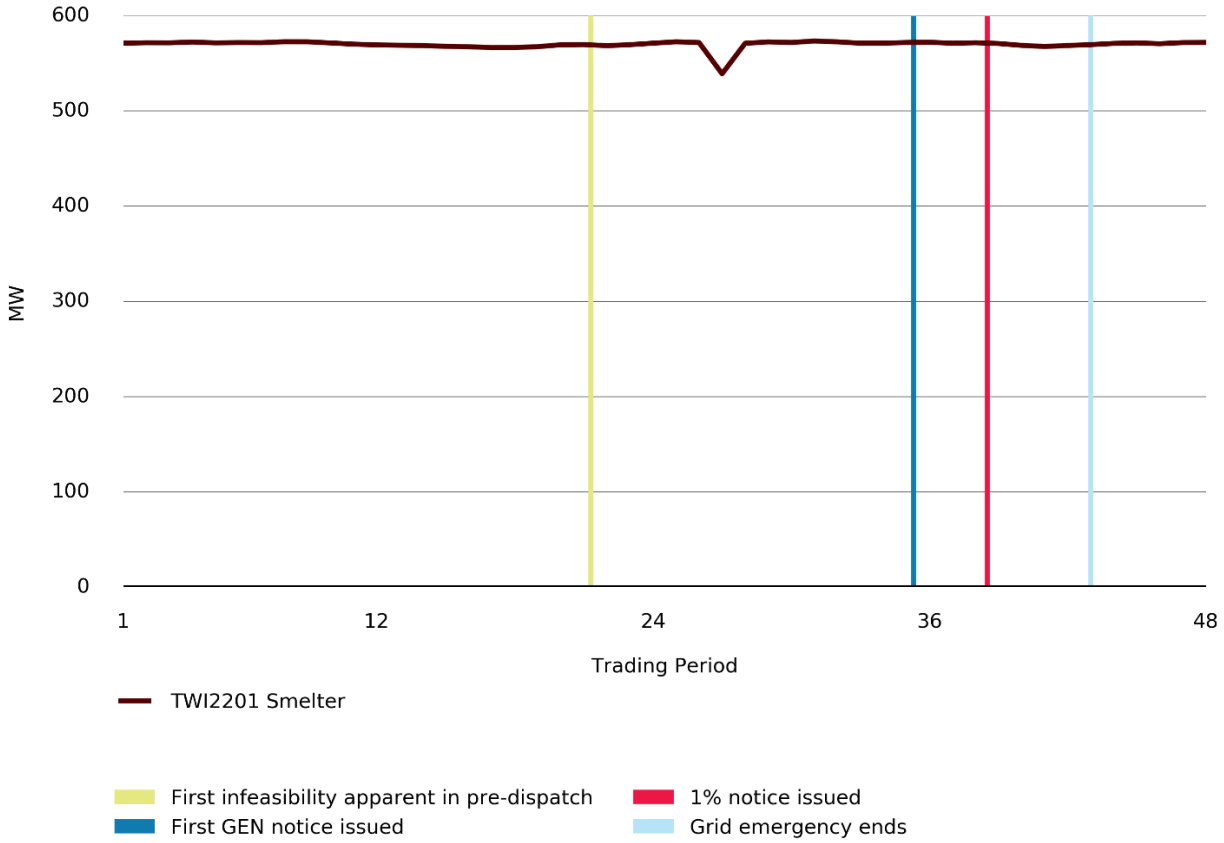
August following the system operator's GEN notices. Figure 5 below outlines these three North Island direct connect users electricity demand on 9 August.

Figure 5: Demand from North Island direct connect electricity users on 9 August



10.23 NZAS located at Tiwai Point did not reduce its demand during the grid emergency on 9 August. NZAS's demand profile on 9 August was flat across the day at around 572 MW, with a small dip around 1:00 pm (Trading Period 27). Figure 6 below outlines NZAS' demand on 9 August.

Figure 6: Demand from NZAS direct connect electricity users on 9 August



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