Immediate assurance review of the 9 August 2021 demand management event

Review of the system operator's tools, processes and communications around the event

10 September 2021

Executive summary

1.1 The Electricity Authority (Authority) has used its statutory powers under section 16(1)(g) of the Electricity Industry Act 2010 (Act) to undertake an urgent review of the event on 9 August 2021.

1.2 The Authority's review has two phases. The first phase of the review sought to assure New Zealand consumers immediately that any systemic and process issues that led to the electricity cuts on 9 August are urgently corrected. In particular, the review was around:

(a) Transpower[1] 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.

1.3 This report provides the Authority's findings from phase one of its review.

What the Authority has found

1.4 On 9 August the country faced the largest New Zealand demand peak on record in response to one of the coldest nights this year. Transpower, as the system operator, was managing a situation in real time where dispatch and forecast schedules indicated all available generation had been dispatched, there was insufficient reserve available to protect the power system from a significant loss of supply and it was unable to manage grid frequency. The Authority acknowledges that the system operator's operations staff took immediate action under difficult circumstances to avert a potentially more widespread and longer duration event. This represented the first use of widespread, island-wide or national, demand management since the rolling blackouts of 1992.

1.5 The Authority has found shortcomings in the system operator's tools and processes. The key areas of concern were ambiguous and at times unsatisfactory communication processes and a miscalculation of demand allocation using the LSR decision support tool.

1.6 The review identified communication and operational issues including:

(a) confusion among distributors as to whether some communications issued by the system operator about the 9 August event were instructions to act immediately or notices that action would be required later. This resulted in some distributors being unsure about the action required.

(b) limited stakeholder and customer communications as the communications from the system operator were, by necessity, operationally focussed and did not provide the context needed for distributors and retailers to share with their customers and communities.

[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 system operator role and accordingly where the term "Transpower" is used in this report it refers to Transpower in its system operator role.

(c) functional issues with the system operator's LSR decision support tool and the use of the tool during the event, including significant discrepancies between the allocated demand limits and the demand individual distributors and direct connect consumers were consuming at the time or were physically capable of consuming.

Communications

1.7 Clear communication is critical in an emergency. The Authority recommends an annual pan-industry contingency exercise to test processes, actions and communications and clarify responsibilities ahead of responding to a real emergency. To ensure effective communication during an emergency, the exercise should include testing of:

(a) operational communications between the system operator and distributors and direct connect consumers

(b) wider communications from the system operator to the electricity industry and key stakeholders including the Authority, officials and Ministers on the response and actions underway

(c) communication channels to support the cascade of information from distributors to customers and from retailers to customers.

1.8 The Authority has included other specific recommendations to support an effective communications protocol in the event of an emergency, such as an automated emergency notification system that does not rely on email communication.

Load shed and restore decision support tool (LSR)

1.9 The LSR decision support tool is used to calculate and equitably allocate how much load distribution companies and direct connect consumers need to shed and then restore if and when required to support a secure electricity system.

1.10 This tool is a decision support tool used by the system operator operations staff when managing a grid emergency requiring load disconnection in real time. The tool is not fully automated and requires manual setup to define the scale of the load management required. This is both in terms of the amount of load required to be disconnected and the geographical regions affected, and those distributors and direct connect consumers that will be required to manage their load. The output of the LSR decision support tool is a demand allocation notice, this contains a megawatt (MW) load setpoint that each selected distributor and direct connect consumer must limit their load to until further notice. This allows the system operator to stabilise the power system and determine any further action they need to take to return the grid to a secure operating state.

1.11 On 9 August, issues with the LSR decision support tool resulted in some distributors being instructed to disconnect significant numbers of consumers. At the same time, other distributors were issued MW load setpoints above their original load levels.

1.12 Following enquiries from some distributors regarding their demand allocation, the system operator suspended the use of the tool. Under the grid emergency management process, the LSR decision support tool would have been used to calculate an equitable distribution of load restoration for distributors and direct connect consumers. This would have resulted in a further demand allocation notice being sent that would have included the same calculation errors as the original allocation notice.

1.13 The 9 August event was the first time the 14-year-old tool had been used in a national event outside of annual system operator staff training. When it has been used previously, it has been for localised events involving a limited number of parties in the same geographical region.

1.14 The Authority recommends the system operator complete a review of the tool, and the information it relies on, to ensure it meets the needs of the current power system before a decision is made to reinstate it.

Key recommendations

1.15 The following table summarises the key findings and recommendations of this immediate assurance review. A full table of issues, actions and recommendations is in Appendix A. Transpower has two weeks to provide the Authority with a detailed plan in response to these recommendations (note Next Steps).

Table 1: Summary of issues and recommendations relating to the *Immediate Assurance review of the 9 August Demand management event*

Issue	Recommendation
Significant communication volumes and call durations to National Coordination Centre (NCC) staff added to the operational overhead in the control room	The system operator will 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). The first exercise will place emphasis on resolving the objectives of communications between the system operator and distributors and direct connect consumers.
Industry stakeholder and customer communications by distributors and retailers were limited by a lack of information regarding the event from the system operator	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.

The system operator had little visibility of actions taken, or planned to be taken, by distributors and direct connect consumers	The system operator will establish baseline information on the general demand management resources available within the system, and update this on a regular basis. 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.
There were significant discrepancies between the 19.09 allocated demand limits and the demand individual participants were consuming at the time, or indeed were physically capable of consuming	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. Specific to the LSR decision support tool, the system operator must determine if the LSR decision support tool continues to be fit for purpose.
The receipt of email notifications was not always noticed by the recipient operations staff	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). 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. 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.

Confusion as to whether notices were calls to immediate action or forewarning of possible future 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.

Steps taken by Transpower since 9 August

1.16 The system operator has made improvements to its communication processes and associated protocols since 9 August. This was demonstrated on 17 August 2021 when Transpower, as the system operator, initiated proactive industry communications, a media statement and teleconference when a grid emergency occurred. This better reflects the Authority's expectations of effective communications and information exchange in the event of a grid emergency.

1.17 The system operator has also suspended use of the LSR decision support tool for island and nation-wide demand management events.

1.18 The system operator is rarely faced with the situation that requires consumer disconnection. The actions taken by the system operator on 17 August 2021 provides assurance to the Authority that the system operator has learned from the process and tool shortcomings exposed during the 9 August event.

Next steps

1.19 The Authority expects Transpower, as the system operator, to respond to the recommendations in this report to improve communications and processes for demand management events within two weeks of publication of this report. Transpower's response must include a plan of action to implement the recommendations of this report.

1.20 While the system operator cannot guarantee supply under all circumstances, the Authority is confident that adoption of the recommendations outlined in this report will ensure the system operator's decision support tools and communications processes are better placed to manage future demand management events to minimise impact on consumers.

1.21 The Authority also notes there may be further recommendations in the Authority's phase two report that will contribute to improving any future demand management event.

Phase two review

1.22 The Authority also has the following activities under way in relation to the 9 August 2021 event:

(a) phase two of its section 16 review – scope and timing to be confirmed, but will be informed by this phase one review

(b) investigation into an alleged undesirable trading situation

(c) allegations of breaches of the Electricity Industry Participation Code 2010.

1.23 The Authority's phase two review will be broader than the system operator's response to the event. In particular, the first phase of the review did not consider any potential issues in market rules, settings or incentives related to the 9 August demand management event, nor did it consider the basis for unit commitment decisions of generators in the hours or days prior to 9 August.

1.24 The Authority has started gathering information for the phase two review and will be seeking industry input throughout the process.

1.25 The Authority expects to confirm the scope of its phase two review during September.

1.26 The Authority notes the Ministry of Business, Innovation and Employment (MBIE) has also commenced an investigation and the system operator is conducting its own review.

Acknowledgement

1.27 In preparing this report, the Authority worked closely with the system operator and interviewed a range of industry participants, including direct connect consumers, distributors, retailers and generators, to establish the facts and understand the response. The Authority thanks all of the organisations who took part in this review and notes the way all parties were quick to provide information and engaged openly and constructively.

Contents

Tables

Glossary of abbreviations and terms

CAN	Customer Advice Notice – advises participants of upcoming changes to market conditions, does not require immediate action on the part of the recipient.
WRN	Warning Notice – notice of a potential grid emergency starting one or more hours in the future. Participants should take action relevant to the trading periods of the potential grid emergency eg, update market offers for the emergency periods, prepare for possible demand management.
GEN	Grid Emergency Notice – notice of a grid emergency requiring participant action starting within the next hour. Participants should take action relevant to the trading periods of the grid emergency.
ISSN	Island Shortage Situation Notice – provides notice that an island-wide notice to disconnect demand has been issued, amended or revoked.

NCC	National Coordination Centre – the system operator's two national dispatch and market scheduling control centres.
NGOC	National Grid Operations Centre – the grid owner's three national grid switching control centres.
NRSS/L schedule	Non-Response Schedule Short/Long – market forecast schedules for the next eight (short) or 72 (long) trading periods that do not use the pricing information in direct connect consumer demand bids to reduce their total cleared demand in response to forecast price.
RCPD	Regional Coincident Peak Demand – a methodology used to allocate transmission charges to grid connected parties based on the proportion of their top 100 demand peaks within their region.
MDC	Medically Dependant Consumer – means a consumer, whether a customer of a retailer or a consumer permanently or temporarily resident at a customer's premises, who depends on mains electricity for critical medical support, such that loss of electricity may result in loss of life or serious harm. For the avoidance of doubt, medical dependence on electricity could be for use of medical or other electrical equipment needed to support the treatment regime (eg, a microwave to heat fluids for renal dialysis).
IERP	Individual Emergency Response Plan – means a plan an MDC has in place to respond to any electricity outage. Such a plan will be particular to the MDC, and may range from ensuring that a stand-by battery is always fully charged to relocating to a friend's or family member's premises which has electricity at that point in time or even calling an ambulance to be taken to hospital. Any support person(s) included in the MDC's IERP should be aware of this and have their contact details included in the IERP. An IERP template is available on the Authority's website. The Ministry of Health has also provided the IERP template to DHBs so that medical staff can advise MDCs on completing the IERP at the time when the MDC is given the medical or other electrical equipment needed for critical medical support.
FK	Frequency Keeping – a service provided by one or more generators to balance any generation and demand inequalities in the time between the system operator's issuing of generation dispatch instructions.
LSR	Load Shed and Restore – the tool used by the system operator to equitably share demand reduction and restoration instructions between affected distributors and direct connect consumers. The output of the LSR tool is a demand allocation that provides MW based demand setpoints to parties to control their demand to.
GXP	Grid Exit Point – any point of connection to the grid at which electricity predominantly flows out of the grid.

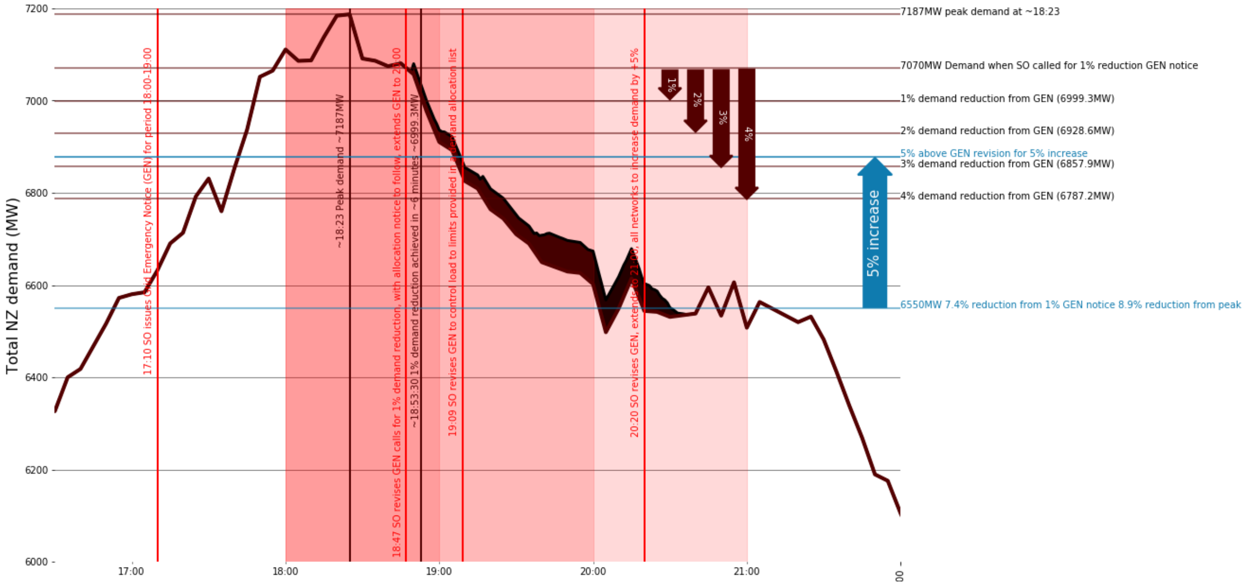
2 Background

2.1 On 9 August the country faced the largest New Zealand demand peak on record in response to one of the coldest nights this year. The Authority acknowledges that the system operator's operations staff took immediate action under difficult circumstances to avert a potentially more widespread and longer duration event.

2.2 In this section we outline what occurred on the night of 9 August. It is important to note in this phase of the review, the Authority has focussed on the events that occurred on 9 August and has not, for example, considered the basis for unit commitment decisions of generators in the hours or days prior to 9 August. Those events will be considered as part of the Authority's phase two review.

2.3 The following load plot overlays the market notices issued by the system operator with the national demand over the course of the grid emergency.

Figure 1: National demand profile and key market notices 9 August 2021



Source: Electricity Authority

2.4 The vertical red lines indicate the timing of when each GEN notice was sent, while the shaded pink regions indicate the evolving grid emergency period. At 5.10pm, the system operator issued the first GEN for the peak period between 6pm and 7pm (darker shaded pink region), calling for increased generation offers and decreased demand.

2.5 Distributors responded by reducing controllable demand such as hot water heating and other industrial demand. By 6pm the grid emergency had started. Total generation reached a peak by about this time. Between 6.05pm and 6.10pm around 124 MW of generation was lost on contingency from the Tokaanu hydro station. This loss was partially replaced by additional generation dispatch.

2.6 By around 6.20pm peak demand was reached, remaining essentially constant for around 25 minutes until 6.45pm. At 6.47pm the system operator issued a revision to the GEN notice. This was in response to their dispatch and forecast schedules indicating that:

(a) all available generation being dispatched and

(b) the power system being dispatched with insufficient reserves to cover for the loss of the single largest generator and

(c) the generator dispatched as frequency keeper running at maximum output and unable to manage grid frequency.[1]

2.7 This notice required all distributors to reduce demand by 1%. It also extended the grid emergency end time from 7pm to 8pm and stated that a demand allocation notice would follow. Immediately following this notice demand promptly fell.

2.8 Distributors (especially those who had used all controllable demand) started disconnecting customers in their attempts to comply with the 1% reduction notice – these power cuts are illustrated by the darker brown area in the chart. By around 6.53pm, six minutes after the 1% GEN revision, total demand had decreased by the 1% targeted reduction set by the system operator. However, with distributors responding at different times and with natural demand reduction occurring after the peak period, demand continued to drop as illustrated in the chart.

2.9 By 7.09pm the system operator revised the GEN notice, issuing individual demand allocations for various participants. As illustrated in the chart, by this time total demand had decreased by over 3% since the 1% call and many generators were dispatched back from their maximum generation to balance this reduction in demand.

2.10 At 8.20pm the system operator issued a further GEN revision, extending the grid emergency end time from 8pm to 9pm – illustrated by the lighter shaded pink area. This GEN revision stated that all distributors can increase demand by 5%. As illustrated in the chart, by this time total demand was around 6550 MW, or 7.4% lower than when the 1% GEN notice was sent. As illustrated by the blue arrow, a 5% increase in demand from this point indicates a total demand higher than the demand at the time of the 7.09pm demand allocation notice.

2.11 At 9.01pm the system operator revised the GEN, ending the grid emergency.

2.12 The following table describes the events and operational communications in the lead up to and during the 9 August 2021 demand management event. The event timeline is based on information from the system operator call logs and market notices. Further information and clarification has been provided by the system operator and from distributor call log transcripts.

Table 2: 9 August event timeline

Time	Event
Day of the event up to the issuing of the GEN at 17:10	
9 August 2021 6:30am	Overnight, the load forecast increased to 7170MW and the residual dropped to 142MW.
06:42	CAN issued for forecast low residual generation during the 17:30 – 20:00 trading periods. This notice advised the market:

[1] One or more generators are dispatched each trading period to provide the frequency keeping ancillary service. The frequency keeper is responsible for ensuring that grid frequency is maintained at, or about, 50Hz. If grid frequency is allowed to deviate too far from 50Hz generators can automatically disconnect from the power system to prevent damage to themselves.

Time	Event
	Transpower as system operator advises that North Island residual generation is less than 200MW, including spare HVDC capacity, for trading periods TP 36 - 41 (17:30 -20:00) on 9 August 2021. If system conditions worsen, it could result in a WRN or GEN being issued due to insufficient offers being available to cover for the largest contingency or meet demand and maintain frequency keeping reserve. Participants should ensure energy and reserve offers and load bids are accurate for the times noted, and if not, please update accordingly. If you are aware of information that could impact system security, please advise the System Operator duty operations manager on XX XXX XXXX. This notice will not be updated unless conditions worsen and a WRN or GEN notice is required.
09:19 – 10:03	Tokaanu claimed a bona fide situation to reduce their market offers in stages to 0MW. High winds had blown weed into the station intake screens blocking them.
10:30	10:00 NRSL schedule published at 10:30 forecasts a reserve deficit of up to 149.6MW for 18:00 – 20:00.
12:30	12:00 NRSL schedule published at 12:30 forecasts a reserve deficit of up to 208MW for 18:00 – 20:00
13:02	WRN notice issued forecasting insufficient generation offers on a national basis during the 17:30 – 20:30 trading periods. This notice advised the market: Transpower as system operator advises there is a risk of insufficient generation and reserve offers to meet demand and provide for N-1 security for a contingent event. It then requested that participants increase generation and reserve offers and decrease demand. It then notified that if there was insufficient response by participants, the system operator will manage demand to restore power system security.
14:30 to 16:30	Tokaanu gradually reoffered its full 240MW capacity for the evening peak. This returned residual to positive in the 14:00 NRSL and 16:00 NRSS schedules. The residual hovers around the 100MW to 200MW range.
17:00	The 17:00 NRSS schedule forecasts a reserve deficit of up to 31MW for the 18:00 – 19:00 trading periods. This is largely driven by a 125MW drop in wind offers for the evening peak and a 21MW increase in forecast load.
GEN declared at 17:10 and GEN notice issued	
17:10	GEN notice issued forecasting insufficient generation offers on a national basis during the 18:00 – 19:00 trading periods. This notice advised the market:

Time	Event
	This is a New Zealand wide emergency. There is Insufficient Generation offers to meet demand and provide for N-1 security for a contingent event. The level of instantaneous reserves being scheduled may or will need to be reduced. It then requested that participants increase generation and reserve offers and decrease demand. It then notified that if there was insufficient response by participants, the system operator will manage demand to alleviate the grid emergency.
17:30	Visible drop in demand (74MW).
	Several calls from distributors via NGOC, eg, Mainpower noting that controllable demand had been in use most of the day. Two further distributors contacted NCC querying whether immediate demand management was required.
17:50	Unison manage controllable hot water load, confirmed by Unison was in response to 17:10 GEN. Approx. 17MW.
18:06	Tokaanu bona fide their generation offers down from 218MW to 94MW – weed blocking intake screens.
18:25	Mercury call offering extra 12MW of generation for half an hour. This offer was inside the trading period and so was not able to be accepted[2].
18:30 to 18:45	Waipipi generation reduces between 15MW to 20MW over 15 minutes due to falling wind speeds.
1% Load reduction notice issued via GEN notice	
18:40 to 18:47 1% reduce load notice sent	Frequency keeping (FK) band had been eroded, running deficit reserves, needed demand management to restore FK. 1% (~70MW) requested). NGOCs phoned connected parties to confirm instruction to reduce demand by 1%. Vector raised that it already had controllable load off – relayed to NCC via NGOC. At 18:47, GEN revision notice sent – period extended 18:00 – 20:00 all network companies to reduce load by 1% until further notice. Demand allocation notice to follow.
18:52	Tokaanu bona fide their generation offers down from 94MW to 47MW – weed blocking intake screens.

[2] The market system is configured to only dispatch generation up to their maximum offered capacity, this prevents the market from scheduling generation above their maximum capacity. Current market system limitations prevent bids and offers from being updated in the current trading period.

Time	Event
18:53	1% load reduction achieved on a national basis, 71MW reduction in load measured by system operator indications.
19:08	3% of load reduction has been observed, or 228MW. Many distributors appear to have dropped 1% then declined further.
19:09 to 20:20 Response to the DAN 19:26 to 19:59 19:31	19:09 Demand allocation notice sent. 7 out of 33 recipients are asked to reduce load further. The total reduction requested was 236MW. These recipients are Unison, Electra, TOP, Orion, Delta, Wellington Electricity, Vector, and WEL. 3 recipients [Orion, WEL, and Electra] appear to have acted on the DAN. Based on 1-minute Scada data there does not appear to be other controlled changes. Voice recordings from the control room identify several participants that phoned and were provided clarity. Orion reduced its demand by 17MW at 19:15. Orion managed demand with controllable load. NGOC contacted NCC to pass on demand allocation queries from Wellington Electricity (reduce from 551MW to 430MW) and Unison (reduce from 298MW to 192MW). Both parties were querying the scale of their allocated reduction. Both were told to hold off managing demand. Electra reduced its demand by 4MW at 20:17 until 20:32, then lift its load (after the 20:20 notice – see below).
19:09 to 20:20 Total load reduction	The remaining load reduction across this time for many distributors is consistent with normal post peak demand decline. When a demand curve is superimposed using the demand shape from 29 June 2021 (previous record demand), many of the distributors appear to have acted on the 1% GEN notice at 18:48 and held this reduction and then allowed demand to decline naturally. Across this time, some units, notably, Huntly and Whirinaki were dispatched back to provide reserves (reserves were previously in deficit) and maintain system stability. From approximately 19:50 generation begins to be dispatched down due to dropping demand.
Log of key calls and conversations with distributors, NGOC, and NCC	
19:22	NGOC to NCC: Northpower queried demand allocation. Allocate 207.7MW vs 165MW actual, able to increase to 190MW.
19:26 19:59	NGOC Instruction to WEL Networks to stay below total load of 224MW. WEL contacted NGOC to confirm start time of demand management requirement, confirmed as an immediate requirement. Subsequent calls

Time	Event
	highlighted a discrepancy between the NGOC load indications for WEL Networks compared to the WEL Networks operational indications. NGOC advised WEL could come up by 24MW from its current load.
19:31	NGOC contacted NCC to discuss demand allocation for Wellington Electricity and Unison. Advised distributors to stay at current demand with no action required from demand allocation notice, load is falling naturally.
19:34	Orion question demand allocation via NGOC, currently below DAN target. Advised can increase to 675MW.
19:38	NCC to operations management: issues recognised with demand allocation. Current load indications well below allocation total. Agree to plan load restoration allowing to run reserve deficit.
19:54	NCC to operations management: Discussed LSR tool and increasing load by 5%. System operator attempted to solve with LSR but still encountered issues with the tool.
20:03	NCC to operations management: Confirm use of “restore 5% of current load” instruction. Confirmed that 5% does not constitute all load shed.
20:05 - 20:07	NCC to all NGOC: contact distributors to restore 5% of current load, GEN extended to 21:00
20:20	GEN revision notice issued – period extended 18:00 – 21:00 all network companies can increase load by 5% based on current load.
20:25	Residual generation now at 390MW, NCC to instruct full load restoration.
20:28 – 20:33	NCC to NGOC: instruct all distributors to restore all load excluding hot water heating. Vector instructed to restore 50MW every 5 minutes until restored. WEL restore 20MW every 5 minutes until restored.
20:39	NCC to NGOC: instruct all distributors to restore all load including hot water heating.
21:01	GEN revision notice issued – grid emergency ended; all participants can restore all load.

Source: the system operator NCC call logs, supplementary notes, market notices and distributor call transcripts

3 Review approach

3.1 The Authority ordered a review of the 9 August 2021 electricity cuts using its statutory powers under section 16(1)(g) of the Act. The review is being conducted in two phases:

(a) Phase one of the review sought immediate assurance that any systemic and process issues that led to the 9 August power cuts are urgently corrected. In particular, the review is around the system operator’s demand allocation tool (called the load shed and restore tool) and communications, as outlined in this report.

(b) Phase two of the review will be wider than the system operator’s role. The scope will be informed by the findings in this report.

3.2 The Minister of Energy and Resources has also directed MBIE to investigate and report on the causes and factors contributing to the power supply interruptions of 9 August. More information about the scope of this review and process is on MBIE's website. The Authority will coordinate with MBIE to contribute to the investigation. The investigation is intended to take between 6 and 10 weeks.

Communications in the lead up to and during the event

3.3 The Authority took the following approach to establish an end-to-end understanding of the operational communication undertaken by the system operator on 9 August 2021:

(a) interviewed 13 industry participants and system operations staff (a list of interviewed parties is included in Appendix B)

(b) reviewed system operator process and policy documentation

(c) reviewed recordings of the system operator control room phone calls.

3.4 The Authority compiled this information to assess the system operator's intent when issuing communications and the recipients' understanding of any action required of them.

Load shed and restore tool

3.5 The Authority reviewed the system operator documentation relating to the design, operation and maintenance of the LSR decision support tool.

3.6 The LSR decision support tool is used to allocate demand management targets equitably between affected participants and provide a MW based demand target to control to. This demand target is intended to prevent participant demand from increasing naturally following a management instruction and allow the system operator to stabilise the power system.

3.7 The system operator also shared its preliminary report into the issues encountered in the use of the tool on 9 August 2021.

4 Communications

4.1 The system operator has the most complete picture of the circumstances of a grid emergency event, whether the event is forecast for a future time period or happening in real time. Their operations staff in the National Coordination Centres (NCC) are responsible for analysing the event, determining the appropriate operational actions needing to be taken to restore grid security and communicating those actions to the parties it needs to take them.

4.2 It is essential the operational communications issued by the system operator clearly communicate the nature of the emergency, the actions required and the timeframes for action to all affected parties.

4.3 Once distributors have determined the action they will take in response to a system operator communication, it is the responsibility of the distributor to communicate any consumer impacts to affected retailers. If the distributor is disconnecting supply to retail customers, this communication must be via a preestablished, active communication channel. There must be sufficient information to allow the retailer to identify which of their customers are impacted and proactively communicate with them.

4.4 In addition to this operational communication, the system operator is responsible for event information that needs to be communicated to other electricity industry stakeholders. This includes Transpower management and governance stakeholders, the Electricity Authority, the Minister of Energy and Resources and the general public via media statements. While the NCC staff are responsible for operational communications, system operator management must ensure that suitable information and notices are escalated to the appropriate stakeholders in a timely fashion using established mechanisms appropriate to the urgency of the situation.

Operational communications

Direct connect consumers

4.5 Direct connect consumers were generally watching the market indicators as signals to respond – scheduled and real time prices. Peak demand management was also a factor in load control decision making.

4.6 The focus of the direct connect consumer operational staff was not on email communication during the event so some GEN notices were missed – if they were received at all.

4.7 Verbal communication from the system operator was minimal and little information as to the nature of the shortage was available. One interviewee commented that more detailed information would have helped in managing load versus interruptible load requirements commitments. This could have been in the form of verbal communication or more detailed and specific written communication. This could include guidance on the prioritisation of demand management that does not impact interruptible load reserve offers and the size of the energy or reserve deficit being managed.

4.8 The timing and magnitude of the response needed to manage the shortage situation was not clear in the earlier communications.

4.9 There was consensus that email is not a good medium for communicating operational information that requires urgent action. A communication that grabs attention and requires acknowledgment would help. One suggestion was accompanying e-text alerts for appropriate GENs and developing a method of acknowledgment of receipt and action. The recent dispatch service enhancements project introduced the ability to transmit formal notices using the same platform used for energy and reserve dispatch. Enabling this functionality would allow for the more robust communication of critical notices with the ability to acknowledge receipt.

4.10 The system operator maintains two email lists for notifications on their website: one for CANs and the other for “formal notices” (WRNs and GENs). One participant had registered for CANs but was unaware that a second registration was required for the WRNs and GENs so did not receive any demand management instructions or enquiries until a phone call was received from the system operator at 7.09pm.

Distributors

4.11 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.

4.12 Some distributors noted that the system operator did contact them to manage discretionary load during the 17 August 2021 grid emergency.

4.13 A review of the phone calls between NGOC and one distributor highlighted possible discrepancies between the load that Transpower believed the network was consuming and what the distributors tools were telling them. This led to some confusion between the distributor and NGOC as to how much load needed to be disconnected.

4.14 When queries were raised regarding the results of the 7.09pm demand allocation notice, some were passed on to the system operator by NGOC and others were not. Those that were passed on highlighted a possible issue with the notice and were told to hold action. This decision was not widely communicated and resulted in some distributors continuing to manage demand to the levels calculated by the LSR decision support tool. This resulted in some distributors disconnecting further customers at the same time as others restoring some previously disconnected discretionary load such as hot water load.

Generators

4.15 The 6.48am CAN was treated with a high level of scepticism regarding the forecast potential shortfall. CANs are quite common in winter and regularly resolve themselves as the system operator demand forecast improves (reduces) over the course of the day. There had been three low residual situation CANs issued in the preceding four weeks that had not resulted in either warning or grid emergency notices being issued.

4.16 Some generators procure a third-party load forecast to provide a check point against the system operator load forecast. Whilst their procured load forecast suggested that the evening peak would be high, it was forecasting a lower demand peak than the system operator at this point.

4.17 Despite this, generators did act to recall outages that were in progress where possible and postpone any outages due to start over the evening peak[3].

4.18 The 8.00am market schedule, published around 8.30am, forecasting the evening peak reinforced this view with a ~100 MW drop in forecast demand.

4.19 The 10.00am market schedule, published around 10.30am, was the first to show infeasible prices over the evening peak. These infeasible prices indicated there would be insufficient reserves available over the peak.

4.20 By the time the 5.10pm GEN was declared the generators had taken all market action that they could with the resources available to them at that time.

Stakeholder and customer communication

4.21 All organisations spoken to have both internal and external communication and escalation processes. Most did not progress beyond operational escalation until the 6.48pm GEN to instruct a national 1% demand reduction.

4.22 For some organisations, multiple email addresses are registered to receive the formal notices to ensure that critical events are communicated through the organisation in a timely manner.

[3] A full outage of Westwind windfarm was due to start at 19:00 but was delayed to 21:00

Distributors

4.23 Some distributors noted that the wider context of the grid emergency was missing in the notices they received. This made it difficult to answer queries from connected parties (both residential and industrial consumers)[4] and produce any proactive communications.

4.24 Most distributors interviewed used their own website, outage apps and social media channels to inform connected parties in their networks. This same communication channel was used to inform connected parties and retailers. As noted earlier though, they could only say it was a national event and no end time was able to be given.

Retailers

4.25 Some retailers interviewed were unaware that their customers had been disconnected until after the event. Those that did know some customers had been disconnected did not know which of their customers had been affected. This led to retailers calling all distributors to find out who had been disconnected to check up on medically dependant consumers.

4.26 One retailer described sending text messages to all their medically dependant consumers to find out if they had been disconnected. Consumers that did not reply to the text were followed up with a phone call.

4.27 Medically dependent consumers (MDCs) should each have an individualised emergency response plan (IERP) for situations in which their power supply is interrupted – including weather-related and car versus pole outages. The current health practitioner (HP) certification notice template requests the MDC's HP to certify that the MDC "*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.*"

4.28 Part 1 of the consumer care guidelines[5] contains the purpose, principles and intended outcomes for the guidelines. Under the principle that "*Electricity is important to the health, wellbeing and social participation of people and whānau in communities*", one of the intended outcomes is that "*Retailers work proactively to minimise harm caused by difficulty accessing electricity (including by disconnection).*" While not an explicit recommendation, alignment with this outcome would naturally lead retailers to reach out to their MDCs after a major unplanned outage.

4.29 All the retailers interviewed (which is a subset of all retailers) followed up with their medically dependant consumers starting on 10 August 2021 as information regarding the affected distributors became known.

Actions taken to date

4.30 The system operator has provided information supporting actions it has already taken to address the communication issues with the 9 August demand management event.

4.31 The system operator has issued a temporary instruction to NCC staff to prioritise the disconnection of discretionary load ahead of actual load.

[4] A residential consumer is a customer of a retailer and a connected party in the distribution network. The billing relationship with the distributor is through the retailer. An industrial consumer is a large consumer connected to the distribution network.

[5] https://www.ea.govt.nz/assets/dms-assets/28/Consumer-Care-Guidelines.pdf

4.32 Transpower, as the system operator, initiated proactive industry communications and teleconference in the lead up to the 17 August 2021 evening peak. The industry teleconference was initiated before a grid emergency was declared and explained the upcoming emergency situation, including what actions were likely to be required by distributors.

4.33 Communication during the 17 August event included a specific request for distributors to manage discretionary load.

4.34 This communication was well received and considered a step in the right direction.

Recommendations

The system operator to further electricity sector readiness to respond to critical demand management incidents, including an annual pan-industry exercise

4.35 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. A pan-industry 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.

The system operator to work with stakeholders to develop an agreed and comprehensive communication approach to ensure prompt and consistent information

4.36 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.

4.37 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.

4.38 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.

4.39 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.

The system operator must improve their access to information on general demand management resource availability

4.40 The system operator will establish baseline information on the general demand management resources available within the system, and update this on a regular basis.

4.41 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.

Review the contents of the formal notices

4.42 Where practicable, the system operator should ensure earlier formal notices include specific actions to take, the timeframes when these actions must be taken and confirmation of when the action taken is required, for example:

(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) Direct connect consumers and distributors must prepare for demand management call for 18.00 onwards

(d) System operator requires all controlled and discretionary load to be managed on a national basis and confirmation when the action is taken

(e) Current forecast energy/reserve shortfall is XXXMW

Evaluate alternative communications systems

4.43 The system operator must 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).

4.44 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 from NCC (via NGOC where appropriate) explaining the issue and the actions required. This communication would confirm the recipient's understanding of the issue being addressed and the actions required of them. The earlier this is done the more likely participants can plan and execute the required actions to minimise consumer impact.

4.45 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.

Update participants on any worsening of the situation

4.46 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.

Communicate any changes to actions required to all participants

4.47 Where practicable updates to, or errors identified in, actions required by a formal notice should be communicated to all parties immediately. This is critical in events where consumer disconnection, beyond discretionary load management, has been instructed.

Review operational tools for accuracy

4.48 For clear communication to take place, all parties must be working from a common view of the situation. Discrepancies between the information seen by different parties can lead to confusion and distract from the issue at hand. The allocation of grid exit point (GXP) demand indications to distributors in the system operator tools must be reviewed to ensure it is current.

5 Load shed and restore tool

5.1 The LSR decision support tool has been used by the system operator for more than 14 years. Whilst the software platform was updated in 2009, the functional specification was not reviewed at that time and has remained unchanged from at least 2006, if not earlier.

5.2 The system operator indicated that the tool has been employed approximately a dozen times in the past 12 months for localised demand management events involving a limited number of parties in the same geographical region. The 9 August demand management event was the first time the tool had been used in a wider event outside of annual system operator staff simulator training.

5.3 The use of the LSR decision support tool is intended to meet two aims:

(a) ensure that demand management is allocated equitably across all parties and,

(b) provide specific demand targets to manage to. This is intended to ensure that the power system is stabilised during the event.

5.4 When used in an island-wide or national event, the tool is designed to use the annual energy consumption of the affected parties to proportion demand management targets equitably between them.

5.5 Localised increases in summertime demand for irrigation purposes will distort this relationship between regions with and without heavy irrigation load. The inclusion of industrial load in the LSR decision support tool would further distort any load allocation based on annual energy consumption.

5.6 Functional testing of the LSR decision support tool has been conducted following any market system software release that has impacted the tool. This testing has focussed on whether the tool is still producing results, not whether those results are correct.

5.7 Following an initial run of the LSR decision support tool on the 9 August, system operator staff did realise that the inclusion of the industrial loads in the LSR tool were causing discrepancies in the demand allocation. Staff endeavoured to correct the issue but, due to unfamiliarity with the tool, their load contribution was not completely removed from the allocation calculation.

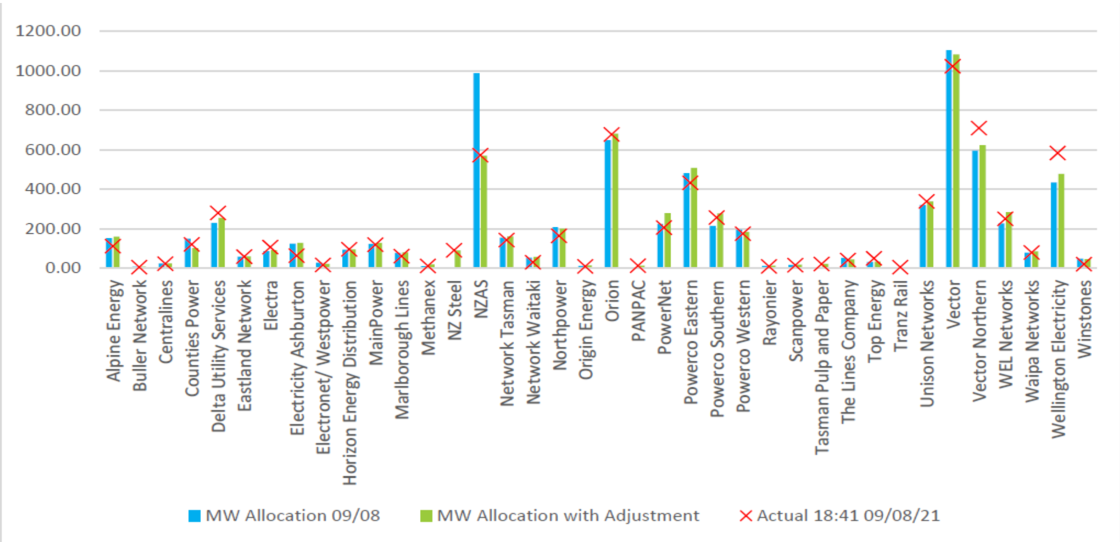
5.8 Some industrial consumers were removed from the list of parties to be allocated a demand management limit but their expected demand was not removed from the control total. This resulted in their share of the demand reduction being distributed among the remaining participants on the demand allocation notice. This error, and its impact on the demand allocation, would not be apparent to the system coordinator.

5.9 Operational processes and training of system operator staff has focussed on identifying the need for the use of the tool, producing a demand management result with the tool and issuing the demand allocation notice. The associated operation process documentation includes a single “sanity check results” step but includes no guidance as to what to look for in the results.

5.10 A preliminary report provided by the system operator highlighted that the process to load historical data into the tool was a manually triggered script with responsibility residing in the Transpower IT support teams. It was discovered earlier in 2021 that this process had not been run since 2017. An update script was developed and run. Unidentified errors in the update script meant that the data load was not successful. This went unnoticed as no checks were performed to confirm the data update was successful.

5.11 As part of its post event review of the LSR decision support tool, the system operator corrected the errors highlighted above and re-ran the allocation process. When compared to distributor load at 6.41pm, in most cases the revised allocation notice was closer to the distributors actual load though in a limited number of cases the demand allocation did change the response requested in the original notice from reduce to increase demand or vice versa. Notably, the revised demand allocation for WEL Networks would have been above their total demand at 6.41pm and no further customer disconnection would have been required. The demand allocation for some others that did respond to the 7.09pm demand allocation notice appears to have not changed by an appreciable amount.

Figure 2: Adjusted demand allocation (system operator analysis)



Source: Transpower

5.12 Distributors stated they had little understanding of the aims of the demand allocation notice. This made it impossible for them to identify and query potential errors even though some of the numbers in the notice did not seem to make sense based on actions already taken. This notice was essentially treated as a command instruction from the system operator.

5.13 Following the events of 9 August, the system operator reviewed the use of the LSR decision support tool in the operations control room. On 16 August, the system operator issued a CAN informing industry participants that the LSR decision support tool will not be used in the control room until a full review of the tool has been completed.

Actions taken to date

5.14 On 13 August 2021 the system operator issued a new temporary instruction to the NCC operations staff. This instruction confirmed that the operational use of the LSR decision support tool for island-wide or national shortage events was suspended pending a full review of the tool. Use of the tool for localised demand management events was subject to careful review of the outputs before any notification was sent.

5.15 The system operator will instead rely on requiring percentage-based load reductions of the affected parties. The calculation of the percentage load management requirement will be based on the system operator's assessment of the security needs of the affected region at the time of issuing the instruction.

5.16 An initial review of the LSR decision support tool by the system operator has identified both functional and process issues with use of the tool for an island-wide or national event. The system operator is conducting a full review of the LSR decision support tool with a view to fixing the issues identified.

Recommendations

Assurance system for decision support tools relied upon in medium and large-scale events

5.17 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.

5.18 Specific to the LSR decision support tool, the system operator must determine if the LSR decision support tool continues to be fit for purpose.

Review the technical and functional debt associated with other legacy tools and processes

5.19 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.

Redesign the LSR interface to simplify its operation

5.20 The outputs of the LSR decision support tool are critical in securely managing a serious shortage of supply. By their nature these events are rare, and the tool is not likely to be used in this form often by individual operations staff members. The situation in which it is likely to be most needed will invariably be a high stress event for operations staff with many demands on their attention. As such, 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.

Enhance training on the revised LSR decision support tool

5.21 Training on any reinstated LSR decision support tool must include validating tool outputs and corrective actions that can be made.

Enhance post market system update testing to validate LSR decision support tool inputs and outputs

5.22 A process needs to be put in place to ensure that any data upload is carried out at the required frequency and is tested and signed off as complete, correct and functional after each upload.

5.23 Testing processes and tools must not only confirm that the LSR decision support tool still functions following a related software update, but that the tool is producing the correct results based on its data inputs.

The Authority will monitor the system operator's review of the LSR decision support tool

5.24 The Authority will closely monitor the investigation, development and implementation of any fixes, or wholesale redesign, of the LSR decision support tool.

Ensure distributors and direct connect consumers are familiar with the aims and outputs of the new LSR decision support tool

5.25 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.

6 Assurance statement

6.1 The Authority acknowledges that the system operator has already taken a number of proactive steps in response to the 9 August demand management event, which are outlined in this report.

6.2 The Authority expects Transpower, as the system operator, to respond to the recommendations in this report to improve communications and processes for demand management events.

6.3 While the system operator cannot guarantee supply under all circumstances, the Authority is confident that adoption of the recommendations outlined in this report will ensure the system operator's decision support tools and communications processes are better placed to manage future demand management events to minimise impact on consumers.

6.4 The Authority also notes there may be further recommendations in the Authority's phase two report that will contribute to improving any future demand management event.

Acknowledgement

6.1 In preparing this report, the Authority worked closely with the system operator and interviewed a range of industry participants, including direct connect consumers, distributors, retailers and generators, to establish the facts and understand the response.

The Authority thanks all of the organisations who took part in this review and notes the way all parties were quick to provide information and engaged openly and constructively.

Appendix A Table of recommendations and actions

Communications		
Issue	**Action taken to date**	**Recommendations for further action**
Inconsistent handling of recipient queries to demand allocation notice: some parties concerns were passed to NCC others were not. Those passed to NCC were told to hold action. Significant communication volumes and call durations to NCC staff added to the operational overhead in the control room. Participants relied upon processes designed for rolling outage plans to manage a short-term outage event. One call to NGOC highlighted potential differences between NGOC actual load indications and distributor load indications. In interview, another distributor queried why their load allocation was split between 2 NGOC areas.	No action taken to date.	**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. For island-wide and national demand management, queries regarding notices must be directed to NCC via NGOC.

		Clear and consistent lines of communication must be made known to recipients and where those communication lines differ – ie, NCC vs NGOC the messaging between them needs to remain consistent. **Communicate any changes to actions required to all participants.** Any update information regarding the demand management notices, ie, 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. **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.
Industry stakeholder and customer communications by distributors and retailers were limited by a lack of information regarding the event from the system operator. Outage communications from distributors to retailers tended to be passive eg, via a website update.	Transpower, as the system operator, release of media statements for 17 August grid emergency allowed proactive communications from participants to manage customer and stakeholder perception of the event. Internal escalation processes are being reviewed by both the system operator and some participants.	**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.

Comments were made by retailers that this works well for planned outages but not for unplanned outages.		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. 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. 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.

The system operator had little visibility of the actions taken, or planned to be taken, by demand side participants in the lead up to the event and what resources were expected to still be available to them over the period the system operator expected to need to call for demand management. Some interviewees understood that the formal notices issued prior to 6.48pm GEN (1% demand reduction) did not have a specific call to action nor indicate scale of the problem being forecast be the system operator. This led to an uneven response to notifications in the time before the 6.48pm GEN. Lack of communication between when the 13.02 WRN and 17.10 GEN were issued led some recipients to view the 17.10 GEN as an instruction to act immediately whilst others viewed it as a notice that action was required from the 18.00 trading period. The actual response by distributors to the 1% demand reduction GEN was closer to 3% on a national average but	On 13 August the system operator released a new temporary instruction to the control centres (TI-DP-962 Managing low residual or grid emergencies with deficit generation or reserve). This process instructs: • The LSR decision support tool is not to be used to create demand allocation notices for island-wide or national energy shortfall events. • If circumstances allow, be specific and targeted with the instructions, eg, "participants are requested to reduce controllable load not currently offered as instantaneous reserve" • If national load reduction is instructed, the required percentage and the total amount required should be communicated.	**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. 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. **Review the contents of the formal notices.** 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. 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, eg, (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

significantly higher in some distribution businesses. Confusion as to whether notices were calls to immediate action or forewarning of possible future action.		(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. The language used in the notices must be consistent and clear on the consequences to affected participants of an insufficient response. **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.

Earlier formal notices were not consistently reinforced with phone calls to communicate urgency and discuss mitigation options. Some participant operations centres do not have access to email for IT security purposes, so notices were missed. The receipt of email notifications was not always noticed by the recipient operations staff. Not all participants received all notifications from the system operator.	Transpower, as the system operator, initiated proactive industry communications and teleconference in the lead up to 17 August evening peak. This was well received and considered a step in the right direction.	**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). 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. 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.
Load shed and restore decision support tool (LSR)		
Issue	**Action taken to date**	**Recommendations for further action**
There were significant discrepancies between the 19.09 allocated demand limits and the demand individual participants were consuming at the	The system operator has suspended the use of the LSR decision support tool in the control centres. A review of the tool will be conducted, the tool will not be reintroduced to real time operations until all issues have	**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

time, or indeed were physically capable of consuming.	been addressed. In the interim, all calls for demand management will be for percentage reductions based on the participant's actual demand at the time. As noted in the system operator's temporary instruction TI-DP-962: "The historical data that LSR uses can result in LSR producing a load allocation considerably different to the current demand. These differences are mainly due to non-conforming flat load like NZAS or summer peaking loads like ASB and other SI GXP with large irrigation loads that are out of sync with the normal conforming load patterns." The system operator has conducted a preliminary review of the LSR decision support tool. A number of issues with both the tool and the use of the tool during the event have been identified: • The base consumption data used in the tool had not been updated since 2017. • Tiwai's annual energy consumption, as a proportion of national energy consumption, is significantly higher than its instantaneous demand proportion to national demand. The demand allocation calculation was not corrected for this.	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. Specific to the ***LSR decision support tool***, the system operator must determine if the LSR decision support tool continues to be fit for purpose. **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. **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

	• Three other direct connect consumers were removed from the allocation calculation but their load was not removed from the island total demand.	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. **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. **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. 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 – ie, historic data is appropriate and the output it generates is correct. **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.

		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.

Appendix B Operational communications interview list

Distributors:

Electra Limited
Marlborough Lines Limited
Orion New Zealand Limited
WEL Networks Limited
Vector Limited
Unison Networks Limited

Generator/retailers:

Meridian Energy Limited
Contact Energy Limited
Genesis Energy Limited
Mercury NZ Limited
Trustpower Limited

Direct Connect Consumers:

Winstone Pulp International Limited
New Zealand Steel Limited