TRANSPOWER

Winter 2026



Industry coordination in low residual situations

10 November 2026

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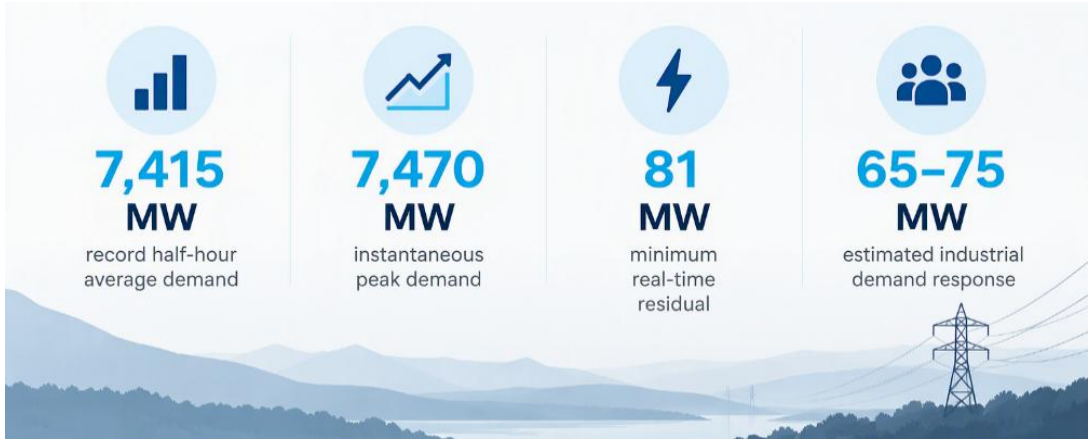
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1 Executive summary



Winter 2026 largely progressed with limited issues on the power system. An abundant hydro situation, supported by the arrival of battery storage and significant thermal back-up, meant that despite cold weather bringing eight of the ten highest demand peaks on record, the power system delivered reliably. This is a good outcome for New Zealand and highlights a range of improvements and changes that have occurred to ensure that winter risks are managed.

This success does not however mean that there are not important lessons to be drawn from this winter. Freezing temperatures brought calm conditions and low wind generation, while high hydrology contributed to a starting position of low thermal commitment.

Managing these situations with no impact on consumers required industry to respond effectively to the changing demand and supply balance. This proactive, cross-industry co-ordination was most important on the morning of 6 August 2026 when very cold and still conditions contributed to our highest ever electricity demand peak of 7,415 MW averaged across the 07:30 trading period. The industry managed through the record peak without the need for Warning or Grid Emergency notices and without needing to use controllable load.

The successful navigation of this and other events over winter reflected a strong, constructive and coordinated response across the electricity sector. Forecasts and forward schedules identified the emerging risk. Customer Advice Notices, an industry briefing and direct engagement gave participants early visibility and a shared view of the expected conditions. Generators, distributors, industrial consumers, the Grid Owner and the System Operator then took actions that increased available capacity, prepared demand response and reduced risk. This paper provides a summary of the 6 August low residual event, our key learnings, and some areas for improvement we will prioritise ahead of Winter 2027.

Key observations

1. Security of supply is a collective outcome

No single intervention resolved the situation. Generation, BESS, transmission, demand response, distribution, forecast providers, communication and operational judgement all contributed. Individual actions varied in scale, with significant planning in advance for things like fuel, but collectively they improved system conditions and reduced risk.

2. Firm and flexible resources provide options when conditions tighten

Hydro, thermal generation, batteries, industrial co-generation and demand response contributed during the peak. The event showed the importance of these firm and flexible resources that can respond on the required timescale. While our annual Security of Supply Assessments highlight the importance of additional investment in firm and flexible resources, the forward generation investment pipeline for the next few years is dominated by intermittent generation, and BESS.

3. Timely and accurate price signals in the week-ahead schedules (WDS) give time for participants to respond

The WDS provides valuable visibility of the risk several days ahead. But its usefulness depends on the quality of bids, offers and transmission information provided to it by participants. More accurate and timely bids and offers within the WDS timeframe would result in more reliable price schedules and sensitivity schedules, which would help participants including purchasers to make hedging and unit commitment decisions earlier. It would also provide better information to inform our System Operator risk assessments, potentially helping to reduce the frequency of low residual situations.

4. The low residual threshold is sized relative to forecast schedule uncertainties

Forecasts performed well, but there was still significant uncertainty around demand, intermittent generation, plant availability and participant behaviour. The Low Residual threshold (200MW) is set at a level consistent with observed within-trading period variability (relative to half-hourly bids and offers) including due to uncertainties in the forecasts for demand, wind and solar. The threshold should not be interpreted as also providing headroom for other factors such as unplanned asset outages.

5. Communication is part of operating the power system

Customer Advice Notices, the industry briefing and direct engagement were part of the operational response, helping participants understand the risk and the actions available to them. We found that the difference between a *Potential Low Residual or Shortfall* CAN and a *Low Residual Situation* CAN was not sufficiently clear to some participants.

2 Increasing peaks in a weather dependent system

New Zealand's power system is winter peaking with the highest demand for electricity occurring over winter, as shown by Figure 1 below. The very highest peak demands occur across morning and evening during very cold, and often still, weather nationwide. Supply available to meet winter demands is affected by hydro inflows and storage, thermal fuels availability, planned and unplanned generator and transmission outages, and the output of weather-dependent wind and solar generation. Risks of energy shortage, known as *dry year* risks, increase during extended periods of low inflows into hydro storage catchments when less fuel, or stored energy, is available across the power system over time. Capacity risks arise when insufficient generation or demand flexibility is available to meet consumer demands for energy at a particular time.

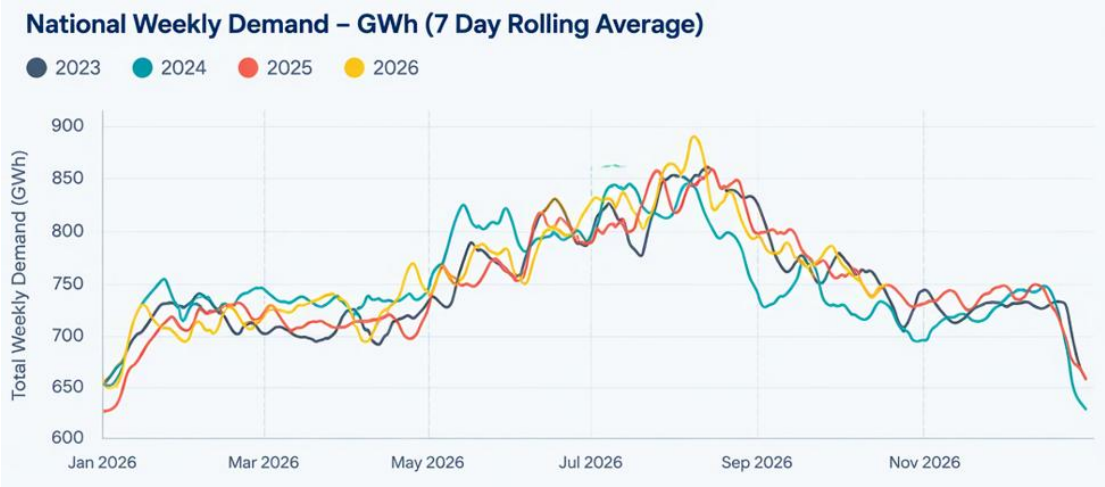


Figure 1: Weekly national demand 2023-2026 (GWh)

Winter 2026 was characterised by high national hydro storage. That reduced dry year energy risks and lowered real-time spot prices for energy. But prevailing lower energy prices also meant higher-cost generation (typically slower start thermal generation) was less likely to be running and able to quickly ramp up at peak. This exacerbated the risk of insufficient generation capacity being available during periods

of very high demand. Within the industry, such capacity risk events are known as *low residual situations*. They occur when the remaining offered generation capacity (residual) for a given trading period drops to a level that increases the risk of a grid emergency and potential demand management.

During late July and early August, sustained periods of very cold weather nationally resulted in a series of extremely high morning and evening peak demands. Historical records were broken with 8 of the 10 highest peak demand days ever being recorded through Winter 2026 (see Figure 2). Most notable was morning of 6 August, which is now the highest peak demand New Zealand has experienced.

Peak electricity demand reached a new record-high of 7,415 MW (half-hour average) at 7:30-8:00 AM on Thursday, 6 August 2026, with instantaneous demand peaking at 7,470 MW at 7:50 AM. This was an increase of almost 300 MW from the previous historical demand peaks that occurred in 2021 and 2023.



Figure 2: Top 10 demand peaks in New Zealand (trading period average)

The underlying cause of the record peak was very cold weather nationally including unusually cold weather in the Auckland and Northland regions. In addition, we are seeing a developing trend of peak demand being more sensitive to colder weather. Government policies such as the Healthy Homes Standards[1] and Warmer Kiwi Homes programme[2] contribute to this transition.

1 Healthy homes standards - Ministry for Cities, Environment, Regions and Transport (Formerly Te Tūāpapa Kura Kāinga – Ministry of Housing and Urban Development)

2 Warmer Kiwi Homes — Insulation and heater grants | EECA

The power system is increasingly weather-dependent

As the electricity system transition progresses, power system behaviour is increasingly influenced by the weather. Our experience coordinating the industry to navigate very high demand peaks like the morning of 6 August highlights the importance of our ability to forecast demand, and wind and solar generation. Changes in consumer energy choices such as the adoption of heat pumps are impacting the shape of demand and its responsiveness to different weather conditions. At the same time the portion of the generation fleet that depends on the wind to be blowing, or the sun to be shining, is growing. Utility scale batteries are now a feature of the power system, and the role of thermal generators is changing.

Consequently, we are increasingly focussed on the potential for actual demand, wind and solar generation to vary away from the forecast anticipated ahead of real-time. When low residual situations are forecast, particularly in cold snaps, we monitor weather, wind and solar risk percentiles to assess how much actuals may differ from forecast on the day. Demand and wind can be difficult to forecast. Unusually warm or cold weather can quickly increase (or decrease) demand relative to the forecast, particularly in the major residential load centres where households use more (or less) electricity for heating. Very cold weather nationwide is often associated with clear, still atmospheric conditions. If the weather is colder than forecast, demand is higher, and often wind generation is also lower. Because most low residual situations occur on winter mornings and evenings when the sun is not shining, the risk of solar generation varying from the forecast is low. Planned asset outages affect capacity available to meet demand, and the risk of unplanned asset outages is ever-present. Our job as System Operator is to be mindful of all these constantly shifting elements and ensure participants have timely, accurate information to respond so that consumers receive the reliable electricity supply they expect the industry to provide.

This less predictable context has implications for generators too. When situations are very tight as was the case on 6 August, it can be difficult to know ahead of time whether or not the last available capacity in the generation offer stack will be needed to run at short notice in real-time. The market design and dispatch tools do not anticipate generation start-up times beyond their offered ramp rate, relying on market participants offering their generation so that it can respond to dispatch instructions in real-time within the physical capability of the asset. When a generator's offers are insufficient to achieve this outcome it can put real-time system security at risk. The System Operator therefore applies discretion to balance the efficient dispatch of the system while maintaining security on the real-time power system, constraining on that generation in time for it to be started and able to ramp up very quickly when needed. Our purpose in doing so is so that, as an industry, we keep homes and businesses across the country warm and minimise the potential for impacts on consumers. This is described in the Policy Statement and our operational procedures published on our website.

As more uncertain intermittent generation and charge-limited BESS come on-line we anticipate the need for more frequent manual intervention to ensure risks to real-time security are appropriately mitigated. This need for active inter-temporal coordination into the

future has been raised through earlier System Operator future-focussed work and submissions.[3] Changes to System Operator scheduling and dispatch tools, and potentially rule changes by the Authority, may be needed to reduce the incidence of manual intervention by our control rooms and provide transparency and certainty for participants.

Mitigating demand variability and weather-dependent generation relies on firm, flexible capacity

In real-time the System Operator needs controllable, firm and flexible generation to be able to respond rapidly as demand and intermittent generation vary. By *firm* we mean generation that has control over its ability to generate at a point in time, including a reliable supply of its fuel. Firm generation is also *flexible* if it can rapidly modulate its output in real-time in a controlled way.

Generally, geothermal is firm but with limited flexibility to modulate or turn off and on in real-time. Hydro is firm, but dependent on inflows or controlled storage and constrained by other factors such as resource consent conditions. A portion of hydro capacity nationally is flexible and able to rapidly ramp up or down in real-time. Thermal generation is firm (as long as its fuel is available), and typically flexible in real-time once it is running. However, warm-up or start-up times vary across the fleet. Typically, unit commitment decisions for thermal generation plant need to be made hours to days ahead of real-time. Battery Energy Storage Systems (BESS) can be firm and flexible when they are charged. Similarly, some consumer demands are flexible and – with enough notice - able to respond by reducing demand in response to market conditions including low residual situations and forecast high spot prices.

Winter 2024 featured low hydro generation, low wind generation, and high thermal generation despite the limited availability of gas. This was reflected in very high spot prices and meant that there was dry year risk but typically little capacity risk. By contrast in Winter 2026 hydro generation was high, and generation from solar, wind and BESS displaced thermal generation. Due to recent investments, geothermal generation was also higher than it had been in prior years. Further, the Taranaki Combined Cycle (TCC) generator had been retired in early 2026, and Huntly Unit 5 was taken offline in June. Both these generators had typically run as baseload across winter.

The different generation mixes that contributed to meeting peak demand across Winters 2024 and 2026 are shown in Figure 3 below. The y-axes in Figure 3 have been truncated such that baseload technologies (geothermal and cogeneration) that run smoothly across time are not visible, which helps to more clearly see the changing contributions from other generation types. What is clear is that thermal generation made an important contribution to meeting peak demands in both years. Even with an influx of new non-thermal generation including BESS, thermal generation is still needed to meet the peaks, especially on cold days, but also at other times throughout the winter period.

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3 See our consultation on Evolving market resource coordination in Aotearoa New Zealand (July 2024)

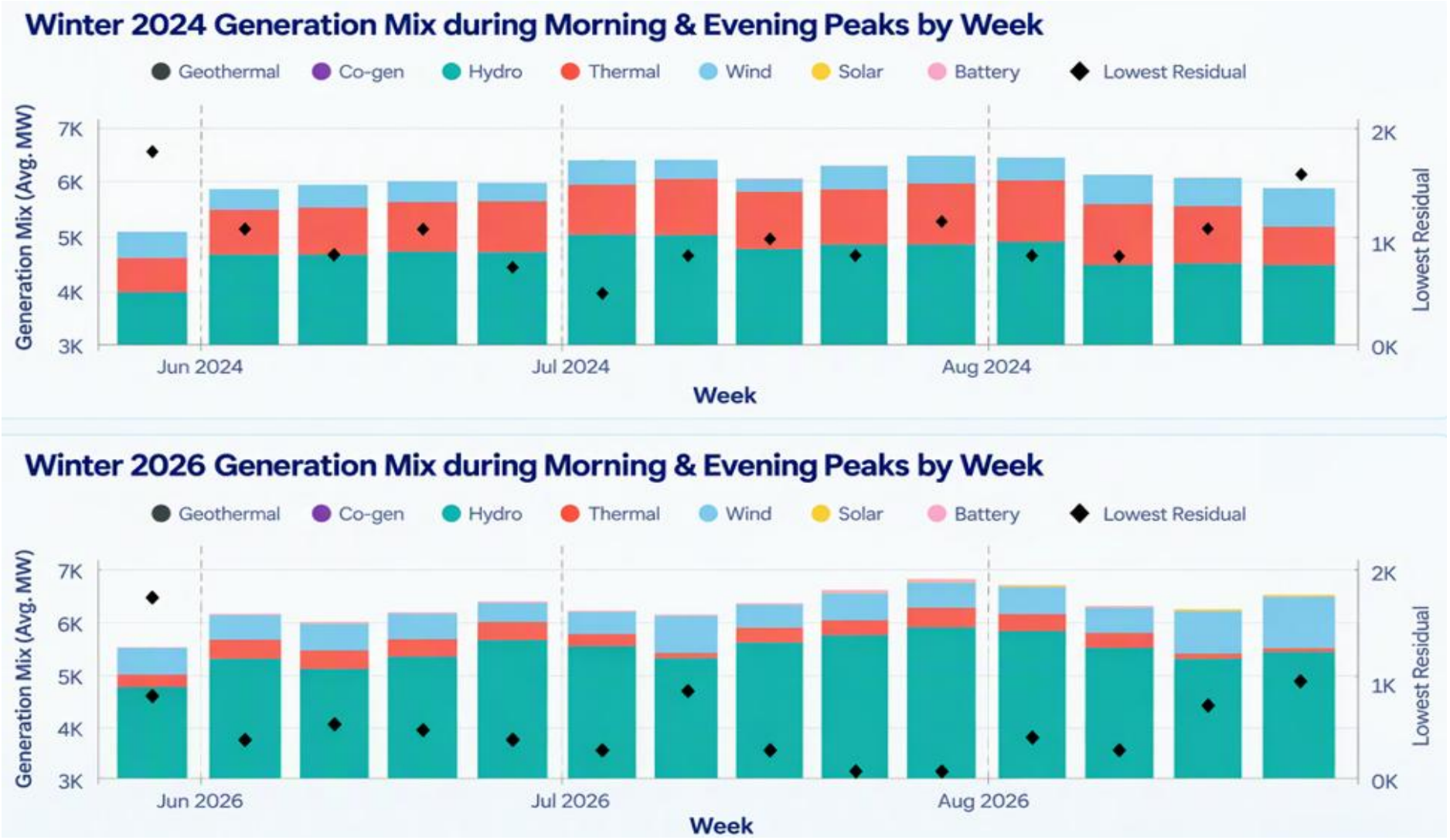


Figure 3 Generation mix during peaks 2024 vs 2026



Our latest annual Security of Supply Assessment (SOSA 2026) highlighted that industry committing to additional investment in firm fuel supplies and/or real-time flexibility capability will better mitigate risks to thermal generator availability. This would also reduce exposure to downside risks such as lower gas supply and higher-demand growth associated with step changes in demand due to electrification and/or data centre connections. It also highlights the importance of sufficient unit commitment to winter peak demand periods by slower-start thermal generators. The supply pipeline information collected for SOSA 2026, and the pipeline that is being commissioned and onboarded into markets for energy and ancillary services nearer-term, are both dominated by investments in intermittent generation and BESS.

The System Operator provides information for participants to understand risks

Transpower, in its role as System Operator, monitors the security of New Zealand's power system from longer-term outlooks through to real-time operation. As conditions move closer to real time, forecasts, market schedules and operational information provide an increasingly detailed view of expected demand, available generation, reserves and transmission capability.

When those sources indicate that the margin between available supply and demand may become tight, the System Operator assesses the risk and communicates relevant information to industry participants. The tools include forward schedules, Customer Advice Notices, industry briefings and direct engagement, followed by real-time coordination and dispatch if the risk persists. The forward schedules include sensitivity schedules which show how forecast wholesale electricity prices could change if electricity demand is higher or lower than forecast. By proxy this also provides an indication of the sensitivity of prices to an unplanned reduction in supply capacity, whether due to plant failure or lower than forecast intermittent generation. Anecdotally, we understand traders value this information to support their operational decisions during tighter market conditions.

Residual is the offered capacity remaining after scheduled demand and reserve requirements have been met. A low residual indicates that the system has less capacity available to absorb forecast error, a generation outage or another adverse change. It is an indicator of increased risk, not a prediction that electricity supply will be interrupted. Importantly, some residual is needed to meet instantaneous demand and intermittent generation variability within a half-hour trading period (relative to the forward schedules).

The trigger for a Low Residual Situation is a residual at or below 200 MW (the Low Residual threshold) in the forward schedules, including the WDS.[4] This threshold reflects the uncertainties in the inputs of the schedules and provides for real-time variability relative to half-hour average bids and offers ahead of time. It does not provide headroom for other factors such as unplanned asset outages.[5] Identifying and communicating forecast Low Residual Situations early preserves options. Participants may be able to change plant availability, bids and offers, planned generation and transmission outages, battery charging, on-site generation, controllable load and other forms of demand flexibility. The schedules will then reflect the changes and enable participants to prepare for real-time operational decisions such as hedging and unit commitment.

If risks of an energy or reserve shortfall still exist in real-time dispatch schedules, or the near future, then the System Operator control room is expected to manually intervene to dispatch any remaining generation that can reduce that risk. This can include dispatching slow-start thermal to minimum levels ahead of need so it is started and ready to deliver generation promptly as needed. This can impact spot pricing when the supply and demand balance is tight.

3 The 6 August peak demand event

On the morning of 6 August 2026 very cold temperatures across the country drove a record half-hour average demand of 7,415 MW during the 07:30 trading period. Instantaneous demand reached 7,470 MW at 07:50. At the same time, calm weather meant wind generation was low, while unplanned outages reduced available generation in the lead-up to the peak. Against that background, the 6 August event provides a useful case study of how early information, clear communication and coordinated participant action can help manage uncertainty and maintain secure supply. The timeline is detailed in Table 1.

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4 Depending on our risk assessment of the situation we may decide to trigger our Low Residual Situation processes above the Low Residual threshold. Our processes for coordinating Low Residual Situations, including the current Low Residual threshold are set out on our webpage: Process for notifying and managing energy or reserve shortfalls | Transpower

5 The variability of the residual in real time is monitored and reported monthly in the System Operator monthly reports to inform the appropriate size of the threshold. System Operator | Electricity Authority.

Table 1 Timeline of the 6 August peak demand event

Time	Overview of event
2 August	The load forecast showed the potential for very large loads on 5 and 6 August because of forecast cold weather. We began engaging with our load forecast provider and MetService to verify this forecast.
3 August	The Week-ahead Dispatch Schedule (WDS)[6] showed a 290 MW residual for the 6 August morning peak. The System Operator identified downside risks from potentially higher demand, lower wind and transmission constraints. Our risk assessment indicated that lower than forecast intermittent generation, combined with colder than forecast weather leading to higher demand, was a plausible outcome. Consequently, at 8:29AM we issued a *Potential Low Residual or Shortfall* customer advice notice (CAN) to raise awareness across the industry.[7] The CAN requested that participants ensure energy, wind generation, reserve offers, and load bids are accurate, increase energy and reserve offers, and that the Grid Owner increase transmission offers where generation may be constrained. We verified the load forecast, which confirmed a high degree of confidence in record high conforming load on the morning of 6 August.[8] Our daily MetService briefing indicated very cold temperatures over Auckland and much of the country for 4 - 6 August, with the possibility temperature records in the upper North Island would be broken. This supported our assessment that demand could be higher and wind generation lower than shown in the forward schedules. The System Operator engaged directly with key thermal and BESS generation participants to ensure awareness of the situation. Generators revised offers and the Grid Owner recalled any transmission outages that could have impacted generation and/or improved system security. Some distributors submitted difference bids for controllable load, indicating a potential lack of clarity that this action was not required by the *Potential* Low Residual or Shortfall CAN.
4 August	The WDS showed potential shortfall for the morning of 6 August: -82 MW for the 07:30 trading period and -31 MW for the 08:00 trading period. At this stage one Rankine unit at Huntly (HLY4) was offered through 5 and 6 August. We

6 Schedules are described in the glossary in Appendix A.

7 CAN Potential Shortfall or Low Residual Situation 800000274.pdf

8 Conforming load is load that follows a predictable pattern such as suburban or commercial areas. This type of load tends to be driven by heating or lighting.

Time	Overview of event
	continued to see downside risks from potentially higher demand and lower wind generation. The situation for 5 August had improved but remained tight. At 09:24 we invited participants to attend a short-notice industry briefing, to raise awareness across the industry including the need to ensure bids and offers were accurate. During the morning the situation improved with a second Rankine unit (HLY1) offered from the morning of 5 August. In early afternoon the remaining, third Rankine (HLY2) was offered from midday on 5 August. The MetService daily briefing continued to indicate that the coldest temperatures of the year were expected with little to no wind generation, and temperatures and wind generation improving on Friday 7 August. The industry briefing was convened at 15:30 with good attendance from across the industry. At 19:46 Huntly Unit 4 (HLY4) tripped, which did not affect consumers at the time but was later confirmed as an Under-Frequency Event. At around 21:30 Genesis offers were updated with HLY4 not offered across 5 and 6 August. The 22:00 NRSL indicated low residual (but not shortfall) for the 6 August 07:30 (32 MW residual) and 08:00 (125 MW residual) trading periods. A *Low Residual Situation CAN* was issued because we were inside the 36 hours-ahead NRS/PRS timeframe, and the risk assessment still indicated that a combination of lower intermittent generation and colder weather was a plausible outcome. The CAN was issued at 23:08, requesting that participants ensure energy, wind generation, reserve offers, and load bids are accurate, increase energy and reserve offers, submit difference bids for controllable load (for the identified time plus 1 hour either side), and increase transmission offers where generation may be constrained.[9]
5 August	In response to the CAN, distribution businesses submitted difference bids for controllable load. A total of 134 MW was bid for the key 07:30 and 08:00 trading periods (of which 7 MW was bid by phone). A few distributors required follow up phone calls from our System Operator control rooms, but all distributors submitted bids either by WITS or phone. Forward schedules remained tight. Direct engagement with industrial participants confirmed where there was potential for demand response and/or additional generation. By 22:00, the scheduled residual had improved to above 200 MW

9 CAN Low Residual Situation 800000279.pdf

Time	Overview of event
	for the key periods. All BESS traders had ensured offers and bids were scheduled so that BESS were injecting at maximum offered capacity through the tightest period. Industrial participants had also updated load bids to reflected planned response to the forecast tight market conditions. The MetService briefing provided good confidence of very low temperatures with low wind generation across the country for morning of 6th August. There was a low probability of colder temperatures than forecast. Media requests were received following the release of the Low Residual CAN. The Executive General Manager Operations undertook several media interviews across television and radio confirming that we were working with industry to ensure that enough generation was offered to meet record demand and that we did not anticipate any impact on consumers. Manapouri offers were updated to reflect an early return of unit G1 from outage. The 22:00 forward schedules showed improved residual of 204 MW at 07:30 and 237 MW at 08:00.
6 August	Ahead of peak, at 06:43 Manapouri unit G7 tripped removing 50 MW of supply. The 07:00 schedules showed residuals at 07:30 and 08:00 above 200 MW with some industrial demand response indicated in bids. The System Operator needed to discretion on the last remaining generation in the stack to ensure it was started in time to meet real-time dispatch when needed. Whirinaki was discretioned on to 20 MW (minimum generation for two units) with residual still dropping and given its 10-minute start-up time. This ensured Whirinaki was able to respond given uncertainty in the level of real-time demand increase as well as potential intermittent generation output reductions (e.g. wind drop or solar ramp delays). In real-time, residual reduced to a minimum of 81 MW with wind generation dropping to 152 MW, solar increasing to 21 MW, around 65-75 MW of industrial demand response, all BESS injecting at maximum offered output, and Whirinaki dispatched to 42 MW. At 07:50:08 demand peaked at 7470 MW (instantaneously). The prepared GEN was not issued and controllable load did not need to be instructed off. Some 114 MW of uncleared energy offers remained warm and available for dispatch at Whirinaki.

4 How well was real-time forecast?

As expected, the accuracy of forecast demand, wind and solar generation improved closer to real-time. Figure 4 below forecast residual shifts from the WDS on 3 August, through to the 04:00 forward schedule some 3.5h ahead of real-time. It also shows the key shifts between that 04:00 forward schedule and real-time.

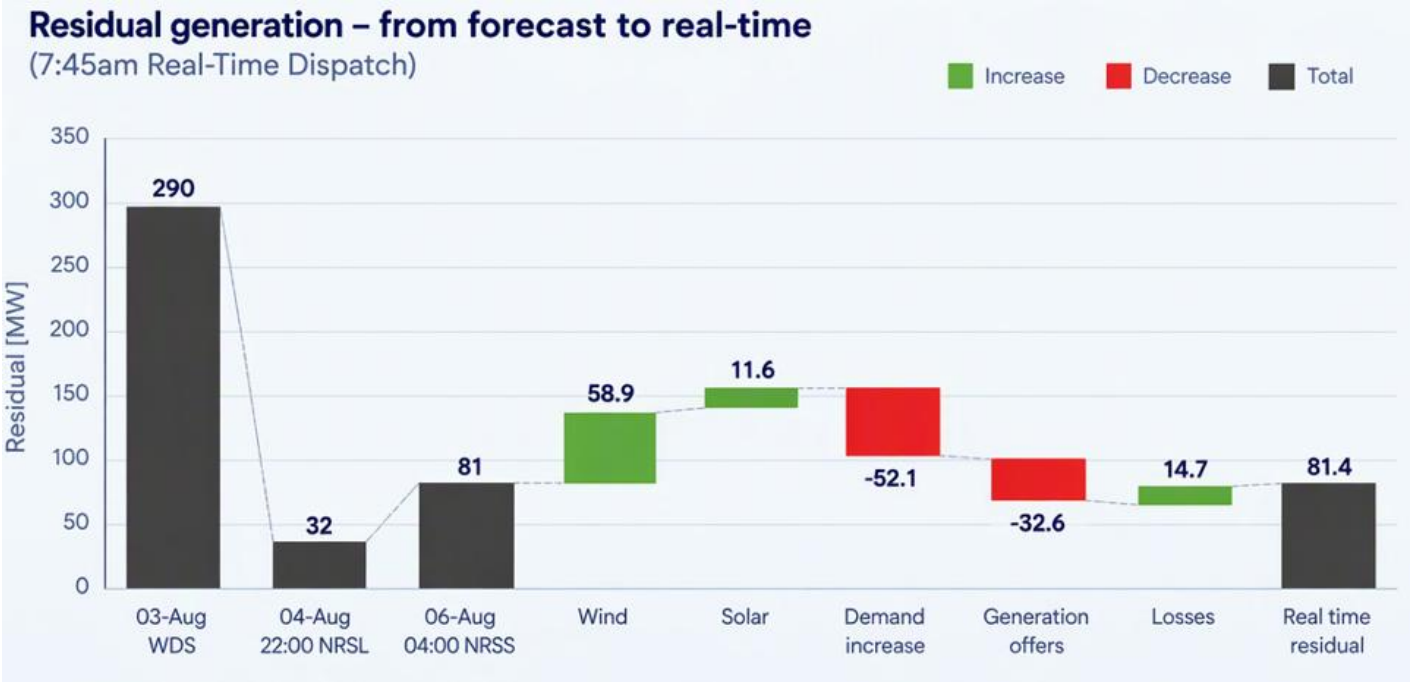


Figure 4 Residual movement between the forward schedules (forecast), and real-time

The forecast residual of 290 MW from the WDS on 3 August decreased to 32 MW in the Non-Response Schedule Long (NRSL), and to 81 MW in the Non-Response Schedule Short (NRSS). The real time residual ended up being a minimum 81.4 MW, closely matching the NRSS schedule. However, we can see from the green and red blocks that it did not play out exactly as predicted. Green shows where the residual was increased, in this case from more wind and solar generation and less losses than forecast in the schedules. Red indicates a decrease to

residual from demand being higher than expected[10], and generation offers lower than expected (primarily due to the Manapouri unit trip at 06:43).

An adverse movement equivalent to approximately 100 MW, such as higher demand, lower intermittent generation, an unplanned generator outage, or less demand response, could have resulted in a shortfall of approximately 35 MW in the tightest five-minute interval on the day. In that situation, the System Operator may have needed to issue a Grid Emergency Notice and work with distributors to manage controllable load. This reflects the range of plausible outcomes that industry must be prepared for when planning for and coordinating its response to low residual situations in real time operations.

The residual would have been much tighter without around 65-75 MW of industrial demand response, which made a significant difference in real time. Industrial customers had updated bids ahead of time, which meant we knew what to expect in real-time. The need for the demand-side, as well as the supply side to act in response to power system and market needs is becoming more important with the increasingly variable supply mix and peakier load profile. On the morning of August 6 industrial consumers who were able to either idle or draw down their load did so. Some of this was a response to forecast prices, where consumers could benefit from the avoided energy cost. There were also other responses where industrial customers recognised the broader system need and took proactive action to help ensure the lights stayed on. We are aware that many industrial customers see this demand responsiveness as an integral part of their operations, but it can come at a cost that may not be sufficiently compensated by avoided energy costs alone.

As more large, electrified loads connect to the power system we will need to consider their attributes and load profiles, and ensure that project designs contemplate the broader needs of the power system. The System Operator has recently released Guidelines to support large loads to understand design requirements for their projects as they seek connection to the grid.[11] We are also working to provision Emergency Reserve as a new ancillary service for Winter 2027.[12] Emergency Reserve providers will be paid to provide demand-response during acute system stress events, acting as a penultimate step before instructed involuntary demand management. Facilitating a sustainable response from large loads including through design requirements, and paid demand response products that can be available to the system in a visible and consistent way, is a valuable opportunity to support electricity affordability into the future.

[10] This compares half-hour forecast load to five-minute real-time dispatch load so some difference is expected.

[11] Technical Guideline for Commissioning Large Loads

[12] Emergency Reserve scheme | Transpower

5 Early visibility and information enabled a whole-of-industry response

In the days and hours ahead of real-time, we issued notices that requested participants review their bids and offers, an industry briefing created a shared understanding of the physical risk, and direct engagement helped translate that understanding into participant action. This early visibility and communication created a common picture and gave industry to respond, and flexible resources gave participants practical options. The response to information we provided to industry, and the information we received from participants as we engaged ahead of and through the event, was strong. The System Operator is grateful for the industry's proactive response to ensuring as an industry we effectively mitigated the risk of real-time impacts for consumers. The key notices and communication methods we used, and the outcome they supported, are summarised in Table 2 below.

Table 2 Public and industry communication channels

Channel	Role in the event	Communication outcome
Forward schedules	Showed emerging changes in forecast residuals and prices.	Created early visibility of the risk.
Customer Advice Notices	Notified industry of potential and then forecast low residual conditions.	Signalled that participants should review readiness and required responses.
Industry briefing	Explained the physical system conditions and uncertainty around the forecasts.	Created a shared picture and an opportunity for clarification.
Direct engagement	Checked that relevant parties were aware and available flexibility was reflected in market information.	Helped turn general awareness into participant-specific action.
Public and media communication	Confirmed that industry was responding and there was no need for the public to reduce consumption.	Accurate and calm reporting alongside proactive social media messaging supported clear public understanding.

6 Key take-outs from Winter 2026

The event highlights five connected lessons. One is central: security of supply during tight conditions is a collective outcome. The remaining lessons explain what makes that coordinated response possible and where there are opportunities for improvement in future.

1. Security of supply is a collective outcome

No single intervention resolved the situation. Generation, BESS, transmission, demand response, distribution, forecast providers, communication and operational judgement all contributed. Individual actions varied in scale, with significant planning in advance for things like fuel, but collectively they improved system conditions and reduced risk.

2. Firm and flexible resources provide options when conditions tighten

Hydro, thermal generation, batteries, industrial co-generation and demand response contributed during the peak. The event showed the importance of these firm and flexible resources that can respond on the required timescale. While our annual Security of Supply Assessments highlight the importance of additional investment in firm and flexible resources, the forward generation investment pipeline for the next few years is dominated by intermittent generation, and BESS. .

3. Timely and accurate price signals in the week-ahead schedules (WDS) give time for participants to respond

The WDS provides valuable visibility of the risk several days ahead. But its usefulness depends on the quality of bids, offers and transmission information provided to it by participants. More accurate and timely bids and offers within the WDS timeframe would result in more reliable price schedules and sensitivity schedules, which would help participants including purchasers to make hedging and unit commitment decisions earlier. It would also provide better information to inform our System Operator risk assessments, potentially helping to reduce the frequency of low residual situations.

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Forecasts performed well, but there was still significant uncertainty around demand, intermittent generation, plant availability and participant behaviour. The Low Residual threshold (200 MW) is set at a level consistent with observed within-trading period variability (relative to half-hourly bids and offers) including due to uncertainties in the forecasts for demand, wind and solar. The threshold should not be interpreted as also providing headroom for other factors such as unplanned asset outages.

5. Communication is part of operating the power system

Customer Advice Notices, the industry briefing and direct engagement were part of the operational response, helping participants understand the risk and the actions available to them. We found that the difference between a *Potential Low Residual or Shortfall* CAN and a *Low Residual Situation* CAN was not sufficiently clear to some participants.

7 Looking ahead to Winter 2027

The events of 6 August highlighted opportunities for us to further strengthen how low residual risk is identified, communicated and managed. Table 3 below sets out the priorities we will focus on ahead of Winter 2027.

Description	Planned delivery
Improve the clarity of low residual communications, including clearer distinctions between Potential Low Residual notices and forecast Low Residual Situation notices, and improving the supporting information provided to participants.	Before Winter 2027
Continue to enhance residual-sensitivity analysis and underlying information, to improve understanding of how different demand, generation and network conditions may affect residual levels.	Ongoing
Maintain strong industry engagement and communication pathways, ensuring relevant participants can respond quickly and effectively during emerging low residual situations.	Ongoing
Work with industry and the Electricity Authority to improve week-ahead information quality, including the importance of accurate and up-to-date bids, offers and transmission information in the week-ahead forecast.	Ongoing
Build awareness of Emergency Reserve arrangements planned for 2027 and implications for the operational management of forecast shortfalls or low residual situations.	Expected late 2026–2027
Clarify the operational processes for risks not fully represented in scheduling and dispatch tools, ensuring operators can continue to manage emerging system risks using a combination of market information, operational judgement and industry engagement.	Completed (September 2026) Review of PR-DP-257 Manage Demand and Insufficient Generation Offers

Appendix A: Glossary

Term	Description
BESS	**Battery Energy Storage System:** A system that takes electricity from the power system and stores the energy for later use, then releases it back as electricity when needed. A BESS acts as electricity demand when charging and as generation when discharging
CAN	**Customer Advice Notice:** A notice issued by the System Operator to provide market participants with important information about events or expected conditions on the power system.
Conforming load	**Conforming load** is load that follows a predictable pattern such as suburban or commercial areas. This type of load tends to be driven by heating or lighting.
Difference bids	**Difference bids** allow consumers or aggregators to signal their price sensitivity in the forecast schedules and assess the impact of their resources by comparing the non-responsive and price responsive schedule results. The difference bids are not binding and are not included in the dispatch schedules. Participants can signal both a reduction in load at higher prices and an increase in load at lower prices. When requested by the System Operator, as part of the response to a potential low residual situation, Distributors may use negative difference bids (reduction in demand) to signal the quantity of controllable load they have available. Any difference bids submitted in this way must be priced at $20,000/MWh to preserve market signals. Distributors can also signal their controllable load availability directly to the System Operator.
ER	**Emergency Reserve:** An ancillary service that strengthens power system reliability by enabling paid demand-response during acute system stress events, acting as a penultimate step before instructed involuntary demand management.
GEN	**Grid Emergency Notice:** A formal notice issued by the System Operator when a grid emergency has been declared. For an energy or reserve shortfall, a GEN is issued when the shortfall is within one hour of real time (inside gate closure) and may require participants to take action. During a grid emergency the System Operator has access to additional actions to assist with the management of the situation. For example, the System

Term	Description
	Operator may request that generators vary their offers, request purchasers and connected parties reduce demand, require the grid owner reconfigure the grid, or instruct load shedding.
Non-conforming load	**Non-conforming load** is electricity demand that does not follow a predictable daily pattern. Purchasers with non-conforming load provide bids of how much electricity they expect to use.
NRS, NRSS, NRSL	**Non-Response Schedules:** The schedules that forecast expected market and system conditions without incorporating the effect of price-responsive demand, except for dispatchable demand. The NRS therefore shows expected outcomes before allowing for demand that may change in response to forecast prices. Comes in both "short" (NRSS – current trading period plus the next 7 trading periods) or "long" (NRSL - current trading period plus the next 71 trading periods.)
PRS, PRSS, PRSL	**Price-Responsive Schedules:** The schedules that forecast expected market and system conditions while considering the effect of signalled demand response through bids. Comes in both "short" (PRSS - current trading period plus the next 7 trading periods) or "long" (PRSL - current trading period plus the next 71 trading periods.)
RTD	**Real Time Dispatch:** Forms basis of dispatch instructions for generation, ancillary services, and demand in real time as well as generating dispatch prices that will form the settlement price.
Sensitivity schedules	**Sensitivity schedules** show how forecast wholesale electricity prices could change if forecast electricity demand is higher or lower. They help market participants understand how sensitive forecast prices are to changing system conditions, particularly when the supply-demand balance is tight.
WDS	**Week-ahead Dispatch Schedule:** The schedule that forecasts expected generation, demand, constraints and prices over the coming week, based on information available at the time the schedule is produced. The WDS runs around 2 am each day and looks forward six days.
Residual	**Residual generation:** The amount of calculated generation that is left in the offer stack after considering the calculated demand and generation for the period it is solving for. Residual generation is calculated every time a case is solved and dispatched – this includes the RTD, NRS, PRS and WDS forward schedules.

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