Emergency reserve scheme – Code amendment proposal

Consultation paper

17 October 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is considering establishing an emergency reserve scheme (ERS) to enhance the reliability of New Zealand's electricity system and support security of supply.

Following consultation on a high-level design for the ERS, the Authority has decided, in-principle, to proceed with implementation. This decision will enable the Authority to do more detailed implementation work with the System Operator (Transpower) in parallel with consultation on the proposed Code amendment. While we have made an in-principle decision to implement the ERS, we will only make a final decision once we have considered your feedback on the proposed Code amendment.

This paper therefore seeks your feedback on the Authority's proposed amendment to the Electricity Industry Participation Code 2010 (Code) to establish an ERS, including our consideration of the costs and benefits of the scheme.

An emergency reserve scheme can support electricity system reliability and security of supply

All consumers should have electricity when they want it. The Authority has a broad programme of work to support security of supply, including managing peak demand periods.

The increasing proportion of intermittent generation in New Zealand's electricity generation mix, along with growth in electricity demand and the declining availability of thermal fuel for generation (especially gas), are contributing to peak capacity risks. The System Operator's 2025 Security of Supply Annual Assessment suggests peak capacity risks will continue until there is sufficient investment in flexible resources, such as batteries and demand flexibility.

While noting the declining availability of thermal fuel for flexible electricity generation, the existing market mechanisms generally provide sufficient price signals for investment in, and operation of, the electricity system to manage peak capacity risk and balance the system under normal conditions. However, in limited circumstances – such as a combination of high demand and a high level of unplanned outages – there is a risk that the market will not balance supply and demand. There are a range of tools available to the System Operator in these situations, with the aim of avoiding the last resort of involuntary disconnection of consumers.

The Authority considers that an ERS would provide an additional tool for the System Operator to use in periods of acute system stress; it would promote power system reliability and security (by helping to manage critical supply shortfalls over short periods of time) and could avoid consumers' power being disconnected during emergency events. It is not intended to be a solution to address long-duration events causing system stress, such as dry years.

We propose to amend the Code to establish an emergency reserve ancillary service

Our proposed Code amendment would establish an ERS as a new emergency reserve ancillary service for the System Operator to activate as a 'penultimate resort' (ie, prior to involuntary disconnection) using pre-contracted demand flexibility and off-market generation. We intend other forms of generation and demand flexibility to be used ahead of an ERS (including controllable load).

Our proposed ERS design aims to deliver benefits to consumers by enhancing security of supply and efficiency, while minimising the risks of market distortion.

The Authority commissioned Concept Consulting to undertake a cost benefit analysis (CBA) on the proposed emergency reserve scheme, comparing it against two other scenarios:

- A scenario where **involuntary load shedding** continues to be the primary means to deal with peak capacity risks (after controllable load is used).
- A scenario where **the Government invests in reserve generation capacity** in place of the ERS. This would include build CAPEX as well as ongoing CAPEX and OPEX to keep the new plant(s) running.

Concept's CBA concluded that establishing the emergency reserve as proposed would deliver an estimated $21 million net benefit when compared to the status quo. The CBA also estimates that the net costs of emergency reserve would be significantly lower than the cost of investment in additional generation capacity to be used in grid emergencies (which occur infrequently). The CBA identifies material, non-quantifiable benefits, which Concept estimates could be as high as, or exceed, the quantifiable benefits of the scheme. The CBA is attached in full at Appendix B.

Next steps

The Authority welcomes your feedback on this consultation paper by 14 November 2025. We will make our final decision on the Code amendment proposal after considering all submissions received.

Should we decide to amend the Code to establish an ERS, we plan to finalise the Code amendments in late 2025. This is to enable the System Operator to undertake consultation on the detailed requirements of the scheme ahead of its targeted commencement in time for winter 2026.

We envisage that staged implementation may be required, moving to full implementation of the design features proposed in this paper as participants gain experience with the scheme.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The Electricity Authority Te Mana Hiko (Authority) is seeking your feedback on proposed amendments to the Electricity Industry Participation Code 2010 (the Code) to establish an emergency reserve scheme (ERS) as a new ancillary service in the New Zealand electricity market. The Authority has made an in-principle decision to implement the scheme, to enable further implementation activities by the System Operator to proceed in parallel to the Authority's Code amendment process.

1.2. The primary objective of the ERS is to help maintain security of supply by avoiding or minimising involuntary load shedding in the event of a grid emergency where there is insufficient supply to meet demand over a short period of time. A secondary objective is to help activate greater use of demand flexibility. As an ancillary service, the ERS would be procured and operated by Transpower as the System Operator. Many of the details of the scheme would be set out in the Ancillary Services Procurement Plan.

1.3. Section 6 of this paper outlines details of the proposed Code amendment, while section 7 presents a regulatory statement for the proposal. The regulatory statement assesses the proposal against the requirements of section 32(1) of the Electricity Industry Act 2010 (Act). The regulatory statement identifies the proposed amendment's objectives, an evaluation of the anticipated costs and benefits, and an evaluation of alternative means of achieving the objectives.

1.4. We have assessed the proposal against the Authority's main objective under section 15(1) of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. We have also assessed the proposal against the Authority's additional objective in section 15(2) of the Act, which is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.

How to make a submission

1.5. We prefer to receive feedback in electronic format (Microsoft Word) in the format shown in Appendix C. Please email your feedback to OperationsConsult@ea.govt.nz with 'Emergency reserve scheme – Code amendment proposal' in the subject line.

1.6. If you cannot send your submission electronically, please contact the Authority on OperationsConsult@ea.govt.nz or 04 460 8860 to discuss alternative arrangements.

1.7. Please note that the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published and explain why we should not publish that part

(b) provide a version of your submission the Authority can publish (if we agree not to publish your full submission).

1.8. If you request part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.9. However, all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority could be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you requested should not be published.

When to make a submission

1.10. Please deliver your submission by 5pm, 14 November 2025. Authority staff will acknowledge receipt of all submissions electronically.

1.11. Please contact the Authority at OperationsConsult@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

Next steps following our consultation

1.12. The Authority is aiming to make a final decision on the proposed Code amendment by the end of the year, once feedback from submitters has been considered. If the decision is made to proceed, our intention is for the scheme to be in place to support the power system over winter 2026.

2. Introduction

2.1. New Zealand's power system is transitioning from being dominated by large synchronous power stations, to including a greater mix of supply technologies of various sizes. At the same time, consumers are engaging with their electricity supply in new and innovative ways, including by installing consumer energy resources (CER) such as on-site solar generation and batteries. Demand for electricity is also growing, including as consumers electrify more of their home and business appliances and transport.

2.2. Operating a power system is complex and dynamic. The System Operator must consistently balance supply and demand for electricity and must also procure ancillary services (such as balancing voltage and frequency, and maintaining sufficient reserves) to handle unexpected events and keep the system within its operational limits. This is to ensure a secure and reliable power system that continuously meets consumers' demand for electricity.

2.3. Most of the time, the wholesale electricity market, which includes both the real-time spot market and ancillary services, provides effective price signals for market participants to invest in and operate electricity supply options in order to meet customer demand and to manage risks such as planned and unplanned outages.

2.4. However, it is difficult for the market to justify investing in system reliability to the point where the electricity system can ensure that generation will always meet demand. This is because events where supply is inadequate to meet demand are rare, and it is very difficult to predict both the scale and frequency of such events. This is particularly the case in situations where high demand coincides with limitations on supply due to unexpected plant outages and low wind generation. In these rare events, load shedding currently operates as the last-resort mechanism to maintain the supply-demand balance and the security of the power system.

2.5. One example of this type of event was the low residual event on 9 August 2021, when unexpectedly low wind output coincided with an all-time high demand period because of a significant weather event, along with the unexpected loss of generation from a hydro plant. The System Operator directed electricity distribution businesses (EDBs) to reduce load on their networks by around 1% to maintain the security of the power system. Actual load curtailment exceeded this level, although the Ministerial review of the event found that this load shedding did not need to happen.[1]

2.6. The increasing proportion of intermittent supply sources (such as wind and solar) in New Zealand's electricity generation mix is creating challenges for security of supply – especially on cold, still mornings and evenings. Growth in electricity demand and the declining availability of thermal fuel for generation (especially gas) are exacerbating this risk. Transpower's 2025 Security of Supply Assessment (SOSA) suggest that peak capacity risks will continue until there is sufficient investment in flexible resources, such as batteries and demand flexibility.[2]

2.7. The system faces an ongoing challenge to coordinate a wide range of available resources as efficiently as possible for security of supply, to maximise benefits for consumers.

Both the Authority and System Operator expect peak demand management to remain an issue over the coming years

2.8. To date, there have been few instances of grid emergency events that have resulted in involuntary load shedding.[3]

2.9. As the share of intermittent generation increases, so does the potential for an unforeseen mismatch in supply and demand, including due to inherent uncertainty in wind forecasts. The SOSA identifies that winter capacity margins are sensitive to the availability of thermal generation units, including the timing of retirements. It highlights the increasing need for investment in peaking capacity, such as peaking generation, batteries, and demand response to maintain the capacity margins above the standards.

2.10. Transpower's long-term forecasts consider when new supply projects are expected to be in operation. Continued investment in new supply sources will be required to maintain security of supply into the future; project delays pose a further risk to the supply-demand balance.

2.11. Moreover, the SOSA does not consider the incidence of 'perfect storm' conditions where high demand coincides with unexpected supply limitations. This means that even if adequate supply reflecting longer-term forecasts is in place, operational

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1 Electricity Authority, 9 August 2021 demand management event review final report. We note that, in practice, load reduction attributed to this action was estimated to be ~3%. The Ministerial review found that load shedding need not have occurred. Both The Authority's review and the Ministerial review identified improvements to be made to the System Operator's communications.

2 See for example, the System Operator's 2025 Security of Supply Assessment.

3 We discussed the most recent examples in section 4.8 of the Establishing an Emergency Reserve Scheme consultation paper.

conditions and supply availability at a point in time may still require further measures, including load curtailment.

2.12. Transpower includes a ‘constrained operational capacity’ sensitivity in the SOSA, to consider the impacts of low thermal generation availability coinciding with low output from intermittent generation. Under these conditions, the North Island – Winter Capacity Margin would be breached from 2026.

We identified the potential to introduce an emergency reserve scheme as part of our industrial flexibility roadmap and undertook further consultation

2.13. On 28 May 2025, as part of our Energy Competition Task Force, we released the *Rewarding industrial demand flexibility – issues and options paper* (Issues and options paper). We identified an ERS as an action that could be relatively low cost and quick to implement as part of a proposed roadmap of actions to enable more efficient use of industrial demand flexibility.

2.14. We also identified that, while existing demand flexibility capability of industrial consumers may be modest, this capability could make a meaningful contribution to improving the cost and reliability of supply during tight supply-demand conditions. These resources may also be lower cost, when compared to investment in additional sources of supply to be used infrequently during emergency events.

2.15. Following submissions on the Issues and options paper,[4] on 31 July 2025 we released the *Establishing an Emergency Reserve Scheme consultation paper* (ERS consultation paper), which outlined:

(a) what an ERS is;

(b) our rationale for considering establishing an ERS; and

(c) a proposed high-level design for an ERS for New Zealand’s electricity market.

We have considered submissions on the proposed emergency reserve scheme

2.16. We received 17 submissions in response to our ERS consultation paper. Most submissions indicated support for the proposal to establish an ERS, and for the proposed high-level design. Submissions also made suggestions and raised questions relating to various elements of the detailed design of the potential ERS. Our consideration of submissions is discussed in section 5.

2.17. Noting the broad level of support for the ERS and the high-level design,[5] the Authority has made an in-principle decision to proceed with the implementation of an ERS. This has enabled the Authority and the System Operator to consider the practical elements of implementing an ERS in parallel with the Authority’s Code change process. This supports our aim to have an ERS in place by winter 2026, if a decision is made to proceed.

4 Our ERS consultation paper included the Authority’s consideration of submissions to the Issues and options paper that provided comment on the proposed ERS.

5 We note that two submitters, Unison and Centralines and Simply Energy considered that the Authority should instead focus on enabling more use of industrial flexibility on a day-to-day basis.

The Authority commissioned a cost benefit analysis

2.18. The Authority commissioned Concept Consulting (Concept) to undertake a cost benefit analysis (CBA) for the proposed ERS. The CBA considers three options:

(a) the status quo;

(b) introducing the ERS as outlined in this Code consultation; and

(c) investing in additional generation to enhance reliability and reduce the risk of involuntary load shedding in a grid emergency.

2.19. The findings of the CBA are discussed in section 7 of this paper and a copy of the Concept CBA report is attached as Appendix B.

The Authority engaged with the System Operator

2.20. Based on the positive feedback we received through the Issues and options paper and the ERS consultation paper, we have started engagement with the System Operator to consider the practical elements in implementing an ERS. This includes consideration of a 'minimum viable product' that could be established ahead of winter 2026, with full implementation to follow.

2.21. While the ERS would be established in the Code, the detailed requirements of the ERS would be set out in documents maintained by the System Operator, in particular the Ancillary Services Procurement Plan. Subject to the Authority's final decision to implement an ERS, following consideration of submissions on this ERS Code consultation paper, the System Operator will undertake further consultation on amendments to the relevant technical documents including the procurement plan.[6]

2.22. Throughout this engagement, the Authority has worked to refine elements of the ERS design and the information-sharing and coordination framework. This is to ensure that:

(a) an ERS is practical;

(b) its costs of implementation and administration are minimised; and

(c) it provides overall benefit to New Zealand electricity consumers.

3. Existing arrangements

3.1. Generally, the operation of the wholesale market[7] ensures that adequate supply is provided to meet demand and to maintain the necessary reserves to ensure the

[6] Clauses 7.13 to 7.22 of the Code set out the process for amending system operation documents, including the procurement plan. This process requires the System Operator to seek the Authority's approval to commence consultation on proposed amendments (clause 7.16), to undertake consultation (clause 7.20) and to seek the Authority's approval of the proposed amendments following consultation (clause 7.21).

[7] The wholesale market includes: the spot market, in which generators and battery energy storage systems bid their available energy to be dispatched in real-time to meet demand; dispatchable demand and dispatch notification mechanisms for price-responsive demand to adjust in response to spot market prices; and ancillary services, which are reserves to maintain the power system within its operational limits including managing the risk of a contingency event such as the trip of a generation unit.

security and reliability of the power system. The levels of supply required to meet demand in the wholesale market are also influenced by:

(a) bilateral agreements with industry participants (ie, retailers and EDBs), which may provide for consumers to vary their consumption in response to wholesale prices or network constraints; and

(b) controllable loads (eg, controllable hot water) by EDBs, which may provide for load management to minimise periods of peak demand on a local network, instead of upgrading the capacity of the network.

3.2. In rare events, these 'business-as-usual' mechanisms are insufficient to ensure adequate supply to meet demand and to maintain minimum levels of reserves, giving rise to an emergency. These emergencies can occur due to a range of circumstances, such as insufficient generation to meet demand, or insufficient network capacity to deliver supply from generation sources to consumers.

Emergencies of different durations are managed differently by the System Operator

3.3. Emergencies can occur due to a range of circumstances, and emergencies of different durations require different approaches for management. Accordingly, the Code sets out a range of responsibilities of the System Operator and industry participants.

3.4. Emergencies can be relatively brief, such as a period of high demand and low supply over a period of hours or days. Such a situation may arise when demand is unusually high because of a combination of a cold snap and unplanned outages of generation units and/or low wind availability. Such an event will resolve when supply and demand return to more 'normal' levels. An ERS is designed to apply in an event of this nature, which is referred to as a 'grid emergency' and managed in accordance with Part 8 of the Code.[8]

3.5. Emergencies may also occur over extended periods of weeks or months, often referred to as 'seasonal' supply shortfalls. These longer-duration emergencies generally occur during the winter months when demand tends to be higher, and in circumstances where there are lower levels of fuel available for power stations – typically lower levels of water in storage for hydroelectric generation.

3.6. Because such events require management over longer periods of time, with more significant disruptions to consumers and risks of prolonged high prices for wholesale market purchasers (and hence consumers), they:

(a) require longer-term planning and preparations;

(b) can require more bespoke arrangements for additional supply or demand response, which tend to be managed via bilateral arrangements for demand response or via contingent storage on the supply side; and

(c) may trigger provisions of the Code which require the payment of compensation to consumers, if significant power conservation is required to manage the situation.[9]

8 As set out in Schedule 8.3 – Technical Code B – Emergencies.

9 Refer to Part 9 of the Code (Security of supply).

3.7. The proposed ERS is intended to be a tool to help manage grid emergencies, and is not proposed as a tool to help manage a seasonal supply shortfall.[10]

Current approach to managing grid emergencies

3.8. Schedule 8.3 Technical Code B – Emergencies (Technical Code B) – sets out:

‘*the basis on which the system operator and participants must plan for, anticipate and respond to emergency events on the grid that affect the system operator’s ability to plan to comply, and to comply with its principal performance obligations*.’[11]

3.9. Clause 6(1) of Technical Code B provides for the actions that the System Operator can take to manage scenarios in which an actual or potential unsupplied demand situation, or insufficient generation and frequency keeping give rise to a grid emergency, which are to (in order):

(a) request that a generator varies its offer and dispatch the generator in accordance with that offer, to ensure there is sufficient generation and frequency keeping;

(b) request that a purchaser or a connected asset owner reduce demand;

(c) require a grid owner to reconfigure the grid;

(d) require electrical disconnection of demand in accordance with clause 7(20) (ie, involuntary load shedding); and

(e) take any other reasonable action to alleviate the grid emergency.

3.10. Clause 6(2) of Technical Code B makes similar provision for the actions the System Operator can take when insufficient transmission capacity gives rise to a grid emergency, which also includes ‘*(b) request that an asset owner restores its assets that are not in service.’*

3.11. These provisions, however, do not provide a mechanism for the System Operator to use resources that may be available and willing to help manage a supply-demand imbalance in return for payment. This is even though these payments may be lower than the ‘cost’ to consumers of involuntary load shedding.

4. The issue the Authority would like to address

The problem: minimising uneconomic curtailment of electricity consumption

What is uneconomic load shedding?

4.1. ‘Uneconomic’ load shedding refers to a situation where consumers whose supply has been interrupted would have been willing to pay a price higher than the prevailing spot market price to avoid an outage.

4.2. By contrast, load shedding would be ‘economic’ if a consumer is unwilling to pay more than the cost of the additional action (ie, more supply, or reduced demand

[10] While the ERS is not proposed to be established to help manage a seasonal supply shortfall, it is possible that there will be some overlap between a short-term grid emergency and a longer-term event in certain circumstances, in which an ERS may have a role to play.

[11] Technical Code B, clause 1. The principal performance obligations are set out in sections 7.2A to 7.2D of the Code, and relate to maintaining the security and reliability of the power system.

from other consumers) required to balance demand and supply and avoid an outage. The upper limit on the price consumers are notionally willing to pay to avoid an outage is known as the value of lost load (VoLL).

What can an emergency reserve scheme offer the electricity system?

4.3. An ERS has the potential to support a reliable and efficient electricity system by helping balance supply and demand to prevent, or reduce the extent of, uneconomic load shedding.

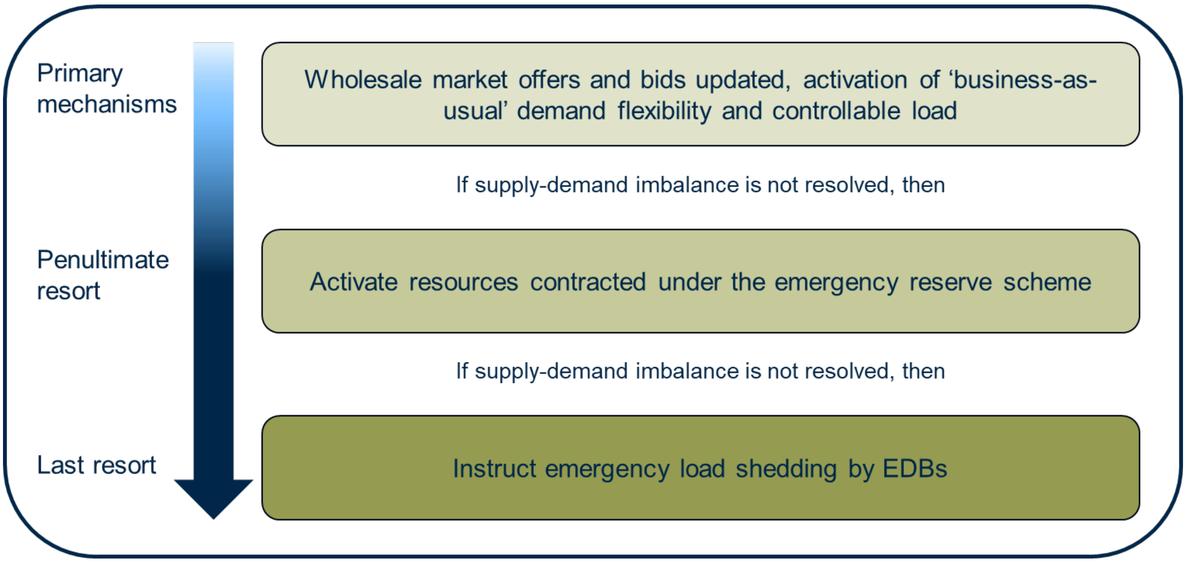
4.4. An ERS would provide a means for purchasers to pay for additional reliability on behalf of consumers when these infrequent events occur. Where that payment is less than the 'cost' of the alternative – an involuntary power cut – the ERS would contribute to an efficient electricity supply (ie, where it limits or prevents uneconomic load shedding).

An emergency reserve scheme could support security of supply during emergency events

4.5. While grid emergencies have been rare (as noted in section 2.8) the System Operator and the Authority consider that there is an elevated risk of such events due to changes to the supply and demand of electricity in New Zealand.

4.6. The Authority wants to ensure that load shedding only occurs when absolutely necessary, given the impact that disconnection can have on consumers. The ERS, as proposed, would provide a 'penultimate resort' mechanism to be used ahead of involuntary load shedding to support security of supply, as shown in Figure 1.

Figure 1: Role of an ERS in the hierarchy of response to a potential supply-demand imbalance



Note: the use of any individual mechanism will be subject to the specific timing and nature of the emergency event.

An emergency reserve scheme could also help unlock efficient demand flexibility

4.7. In addition to promoting a more secure and reliable supply, an ERS could also help unlock efficient demand flexibility. As discussed in the Issues and options paper and noted in section 2.14, industrial demand flexibility can be a lower cost alternative to additional supply when it is expected to be used infrequently.

4.8. An ERS would provide an opportunity to reward demand response for its highest value use – to avoid involuntary uneconomic load shedding. This value provides the greatest opportunity to offer incentives for demand flexibility, noting that insufficient incentives are one of the main barriers the Authority has identified to greater use of demand flexibility in the electricity market.

Managing the risks of an emergency reserve scheme in its design

4.9. In the ERS consultation paper, we outlined several risks associated with an ERS, which have been identified by the Authority and others.[12] These include that an ERS could:

(a) not guarantee that it would only reward resources that were additional to the counterfactual scenario (referred to as a lack of additionality);

(b) be unlikely to be effective at providing additional resilience in the short term to manage peak capacity issues;

(c) be a significant departure from the current market design;

(d) carry several market risks – including potentially chilling investment signals and undermining confidence in the market;

(e) have the potential to be high cost; and

(f) give rise to a moral hazard, leading to sub-optimal investment or operational decisions because market participants are 'insured' against the risk of a supply shortfall and no longer consider this a risk they need to manage.

4.10. We also outlined how the Authority proposed to mitigate or manage these risks through designing the ERS to:

(a) **Require 'additionality'**, by excluding participation by those for which other mechanisms are more appropriate (eg, excluding generation, dispatchable demand and dispatch notification participants), or price-sensitive load that would otherwise be used in the absence of an ERS.

(b) Not affect the operation of existing market, contractual and other mechanisms, or long-term investment signals to maintain supply-demand balance by:

(i) **operating as late as possible**, after all other market and demand flexibility mechanisms, as a penultimate action ahead of involuntary load shedding;

(ii) **being used infrequently**, only in situations that are very difficult to forecast;

(iii) **ensuring scarcity price signals** still take effect when the scheme is activated, to maintain short-term operational and long-term investment signals;

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12 Refer to pages 20-23 of the ERS consultation paper for further discussion of previous consideration of an ERS by the Authority and others, and the identified risks.

(iv) **using existing operational processes for planning for, and managing, grid emergencies,** which will ensure the scheme complements existing wholesale market and grid emergency mechanisms and should also minimise implementation and administration costs.

(c) **Facilitate risk management,** allocating costs in a manner which ensures the participants best placed to manage risks of ERS use are incentivised to do so.

(d) **Be relatively low cost to implement and operate**, whilst ensuring ERS providers have the necessary capability to deliver the service, including by:

(i) **capping ERS costs at VoLL** to ensure ERS is only used where it is lower cost than the maximum consumers are willing to pay to avoid an outage;

(ii) **avoiding unnecessary technical requirements**, which could deter participation and increase costs; and

(iii) **leveraging existing market processes** with minimal change where practical, such as for settling ancillary services costs, to minimise the need for changes to complex existing market scheduling and dispatch processes.

5. The Authority consulted on the establishment of an emergency reserve scheme and its high-level design

5.1. As noted in section 2.15, on 31 July 2025 the Authority released the ERS consultation paper, which outlined:

(a) what an ERS is;

(b) our rationale for establishing an ERS; and

(c) a proposed high-level design for an ERS for New Zealand's electricity market.

5.2. In this section, we:

(a) provide an overview of our proposed ERS design;

(b) discuss the feedback received in submissions; and

(c) outline our updated design proposal, which is summarised in a box at the end of each relevant section.

General feedback in submissions

5.3. We received 17 submissions in response to the ERS consultation paper, with most submitters supporting the establishment of an ERS. Two submissions – from Unison and Centralines, and Contact and Simply Energy – did not support the establishment of an ERS, encouraging prioritisation of mechanisms to enable demand flexibility more broadly.

5.4. Table 1 provides a list of submissions received; the submissions are available on the Authority's website.

Table 1: Parties who provided submissions

Category	Submitters
Industrial consumers and associations	NZ Steel, Business NZ Energy Council (BNZEC) Major Electricity Users' Group (MEUG)
Gentailers and associations	Mercury, Meridian Energy, Electricity Retailers' and Generators' Association of New Zealand (ERGANZ)
Electricity distribution businesses and associations	Counties Energy, Orion, Powerco, Unison and Centralines, WEL Networks
Retailers and flexibility providers	Enel X, Contact and Simply Energy (Simply Energy), Nova Energy, Supa Energy
Others	Sustainable Energy Association of New Zealand (SEANZ), Transpower (as System Operator)

Encouraging the development of flexible demand more broadly

5.5. Almost half of the submissions received encouraged the Authority to focus on enabling demand flexibility more broadly, not just in emergencies. NZ Steel and MEUG both suggested that an ERS would have limited attractiveness to potential providers due to the fact that – by design – it would only be used infrequently.

5.6. Submissions from ERGANZ, Mercury, Meridian and Orion encouraged the Authority to consider establishing an ERS on a temporary basis, while broader demand flexibility mechanisms are developed or investment occurs in flexible supply sources.

5.7. The Authority notes that the ERS is just one initiative underway that could enable greater use of demand flexibility. Our broader work programme is continuing to focus on enabling more demand-side flexibility. We recently:

(a) introduced new rules to make time-of-use pricing plans compulsory for large electricity retailers, to help shift demand from higher-priced to lower-priced periods and give consumers more options to manage their electricity bills;

(b) published a consultation paper that put forward three alternative models for distribution system operators, which are needed to coordinate the operation of CER such as rooftop solar, household batteries, electric vehicles, and hot water cylinders; and

(c) consulted on ways to enable more industrial demand flexibility, with development of an ERS being one of the early initiatives. Submissions have been published on the Authority's website. The Authority is considering the next steps for the broader roadmap; particularly how actions to enable more industrial demand flexibility are best integrated with a wider flexibility work programme to ensure we can efficiently leverage all forms of flexibility.

5.8. The Authority proposes to establish the ERS as an ancillary service that the System Operator may procure as required. This means that if the System Operator does not identify a need for the service (for example due to increases in generation or demand flexibility), it does not need to procure it. Voltage support is an example of an existing ancillary service which the System Operator is empowered to procure, but, to date, has not.

Proposed objectives for the emergency reserve scheme

5.9. In accordance with our main objective, any ERS put in place needs to promote reliability and efficiency, without impeding competition in the wider market, or distorting investment incentives.[13]

5.10. The Authority outlined two objectives for the proposed ERS:

(a) **primary objective: promote system security and reliability** and minimise the likelihood and extent of uneconomic load shedding during infrequent periods when demand is high and inadequate supply is available from other sources; and

(b) **secondary objective: build consumer capability to provide demand flexibility** more generally, through organisational capability building and investments in equipment.

5.11. Most submissions indicated broad support for the rationale for establishing an ERS, although few commented specifically on the proposed objectives of the scheme. Of those that did comment, Counties Energy submitted that the scheme should only pursue the primary objective of limiting uneconomic load shedding, while others (Business NZ Energy Council, Mercury, MEUG) supported the secondary objective.

5.12. The Authority proposes to retain both the primary and secondary objectives for an ERS. Most importantly, the primary objective of an ERS is to support a reliable electricity system by providing an additional source of capacity to minimise the risk of uneconomic load shedding during grid emergencies.

5.13. The Authority also considers, however, that an ERS would have the potential to provide a first step for some consumers to offer their demand flexibility more broadly. This is, however, a secondary driver when compared to the primary objective.

5.14. An ERS is designed to enable providers to recover their costs of providing the service, which could facilitate the necessary investments in systems and processes to enable demand flexibility. Some consumers, having gained this experience, could transition to providing their flexibility outside of emergency situations where there is greater potential to maximise their revenue and offset their energy costs. Experience in other jurisdictions indicates that some customers do transition over time from emergency response schemes to more business-as-usual demand flexibility opportunities. The Authority welcomes such a transition over time, which could reduce the need to procure emergency reserves and contribute to a more reliable and efficient electricity system outside of emergency events.

Assessment of the emergency reserve scheme against the guiding principles

5.15. The ERS consultation paper included at Appendix B the Authority's assessment of the proposed ERS against a set of guiding principles, which sought to ensure an

[13] The Authority's main objective is set out in section 15 of the Act.

ERS would satisfy the Authority's main objective, as well as effectively manage the potential risks of such a scheme. The guiding principles were to:

(a) enable diversity of parties competing to bring solutions;

(b) ensure the secure and reliable supply of electricity;

(c) enable efficient operation and minimise costs for consumers in the long run;

(d) minimise cost, complexity and effort of participation; and

(e) maximise strategic alignment with Task Force and Authority work programme.

5.16. Submissions from Counties Energy, ERGANZ, Mercury, SEANZ and Transpower supported the Authority's assessment against the guiding principles.

5.17. Orion's submission disagreed with elements of the assessment, including:

(a) that exclusion of generation and batteries did not fully enable diversity of parties to bring competing solutions;

(b) that the Authority had not adequately explored the need for the scheme, meaning it was not clear the scheme would enable efficient operation of the electricity industry and minimise costs in the long run; and

(c) that the ERS could distort market signals and increase cost, which would not minimise cost, complexity and effort of participation.

5.18. NZ Steel's submission agreed that the proposed ERS design promotes efficient incentives but did not consider they would be effective enough to encourage participation.

5.19. The Authority notes that there would inevitably be some trade-offs between different elements of the guiding principles, in the same way there can be between the different elements of the Authority's main objective. The Authority considers the proposed ERS promotes both the main objective and the guiding principles as a whole. We also note that we:

(a) propose to expand eligibility to participate to off-market generation (see section 5.40 below);

(b) have designed the scheme to minimise the risks identified by Orion, as discussed in the ERS consultation paper and section 4.9 above; and

(c) acknowledge that the intended limited use of the scheme may mean some potential providers are not sufficiently incentivised. However, there is a need to ensure the scheme does not over-incentivise participation at the expense of participating in more business-as-usual flexibility mechanisms or distort the operation of the wholesale market, which are concerns raised by several stakeholders in the consideration of the ERS and similar schemes.

5.20. The regulatory statement in section 7 of this Code consultation paper also addresses these issues.

Commencing with implementation of a minimum viable product

5.21. In the ERS consultation paper, the Authority indicated it was considering a staged implementation of the ERS. We proposed that initial introduction of the scheme could be limited to a ‘minimum viable product’, to enable the System Operator to implement it for winter 2026, with full implementation to follow.

5.22. Several submissions supported this approach, including ERGANZ, Meridian, Mercury and Transpower. Not only would such an approach enable the timely implementation of the ERS for winter 2026, it would also provide an opportunity for learning-by-doing. Transpower also indicated that full implementation could take two years or more.

5.23. Mercury’s submission suggested commencing the ERS in 2026 with high-confidence capacity, and ERGANZ suggested commencing with large, single-site industrials. Enel X’s submission suggested that aggregations could participate in 2026, while ERGANZ suggested that aggregations could be phased in at a later date. Meridian’s submission suggested that the Authority should identify a trigger for full implementation of the ERS.

5.24. The Authority is engaging with the System Operator on development of a minimum viable product version of the ERS to be implemented for winter 2026. If we make a final decision to proceed with the ERS, we will communicate with stakeholders about the proposed approach for winter 2026 implementation.

Feedback on specific elements of the proposed emergency reserve scheme

5.25. In the remainder of this section, we outline the feedback from submissions on elements of the design of an ERS, along with our updated proposal having considered this feedback.

5.26. We have followed the same structure as the ERS consultation paper, which sets out the ERS design across six elements: eligibility to participate; procurement; activation; pricing and settlement; performance management; and information provision and publication.

Eligibility to participate

The Authority proposed that demand flexibility should be eligible to provide emergency reserves

5.27. Additionality is a key consideration in the design of an ERS, to ensure that it does not result in consumers paying for services that would already be provided, or for capacity that should be supplied in the competitive market.

5.28. The Authority proposed that specified forms of demand flexibility would be eligible to provide ERS. This includes both large commercial and industrial consumers, as well as aggregations of smaller business and household consumers. Participants would need to:

(a) meet the relevant service requirements determined by the System Operator;[14] and

(b) not already have been contracted or otherwise used before an ERS is activated (ie, the response is ‘additional’ to what would have occurred in the absence of the ERS).

[14] To be specified in the Ancillary Services Procurement Plan.

5.29. The Authority considered that generation already offered in the market and battery energy storage systems (BESS) should be excluded from participating in the scheme. This is because these resources should already be participating in the wholesale electricity market at an earlier stage of a potential supply-demand imbalance, with strong market signals to make capacity available when shortfall conditions may give rise to a grid emergency. Interruptible load capacity used to provide instantaneous reserves was also excluded from participation as these resources should also be responding to signals in the wholesale market.

5.30. The Authority also considered that off-market generation should be excluded from providing emergency reserves as, like market generation, these resources could already be operating in response to market price signals. However, the Authority specifically sought feedback on this, to better understand whether off-market generation would already be operating in an emergency, or whether an ERS could unlock this capacity for use.

5.31. The Authority further proposed that, where a consumer is required to make a portion of their load available for automatic underfrequency load shedding (AUFLS), that portion of the consumers' load could not participate in the ERS.

5.32. The Authority also sought feedback on whether submitters were likely to seek to provide ERS, if the scheme was established.

What submitters said

5.33. Submitters generally supported the principle of additionality to determine eligibility to participate in an ERS. Many submitters sought further details on how additionality would be determined by the System Operator. They noted that not all demand flexibility is delivered pursuant to contracts,[15] and that the System Operator may not have visibility of metered consumption for all sites or sources of demand flexibility. To address this issue, Meridian suggested establishing a register of demand flexibility contracts, and requiring potential ERS providers to sign a declaration regarding pre-existing demand-response commitments.

5.34. Some submissions raised a concern that the ERS may not attract sufficient volumes. However, Enel X and Meridian's submissions indicated they may be interested in participating in the ERS, and SEANZ's submission indicated potential interest from its members.

5.35. Submitters had mixed views on whether off-market generation should be included. Counties Energy, Enel X, Meridian, Orion, Transpower and WEL Networks encouraged their inclusion. In contrast, BNZEC considered they should be excluded if there are other mechanisms for them to provide services. ERGANZ and Mercury indicated that it may be practical to exclude them as part of initial implementation from winter 2026. Simply Energy considered that network-controlled assets should not be permitted to participate at all, as doing so would be inconsistent with the role of a regulated network service provider.

5.36. Submissions from Enel X and NZ Steel suggested that interruptible loads and loads reserved for AUFLS should be eligible to participate in the ERS on the basis that

15 For example, Orion's demand-response mechanisms do not require a contract for a customer to provide the service and be rewarded.

reducing load ahead of the use of emergency and contingency measures would be desirable.

5.37. Orion’s submission also noted the potential for EDB controllable load resources to be deployed ahead of scarcity pricing.

The Authority’s response and updated design

5.38. The information contained in submissions, and additional engagement with the System Operator, indicates that off-market generation may not be operating in the circumstances giving rise to use of the ERS. That is, these resources are likely to satisfy the requirement for additionality.

5.39. The Authority also considered the net benefit of including off-market generation in the ERS as part of the CBA undertaken by Concept. Concept’s view is that the average cost of off-market generation to provide ERS is likely to be lower than some sources of demand-response. The Authority also supports this view.

5.40. The Authority considers, therefore, that the inclusion of off-market generation in the ERS would reduce the cost and improve the net benefits of the scheme. Inclusion of off-market generation would also increase the potential pool of ERS providers, which could enable a higher volume of the service to be contracted if required.

5.41. The Authority therefore proposes to update the eligibility for the ERS to include off-market generation, provided that it can demonstrate that any response would meet the additionality requirement and otherwise satisfy the System Operator’s service requirements.

We maintain that market generation, interruptible load and AUFLS load should remain ineligible to participate

5.42. The Authority maintains that market generation, interruptible load and load reserved for AUFLS should be ineligible to participate. Interruptible load and AUFLS are mechanisms to prevent system failure. It might be desirable to activate as much demand response as possible ahead of involuntary load shedding. However, the Authority does not consider it appropriate to do so at the expense of these important system security mechanisms.

5.43. We have decided to take a different approach in respect of BESS based on where it is located. We propose to:

(a) Exclude BESS connected to either the grid or a distribution network. Few BESS are currently connected ‘in front’ of the meter on the grid or distribution networks, and the Authority has work underway to effectively integrate this new technology into the Code and existing market arrangements. We will consider the services BESS can provide, and the associated technical requirements, as part of this work.

(b) Include BESS connected ‘behind’ the meter at consumers’ premises, to enable the consumer to operate with a reduced supply from the grid. This is because we consider these BESS to be part of demand response, along with on-site generators. As stated in the ERS consultation paper, the Authority considers these resources as demand flexibility that can be used to enable their participation in the ERS.[16]

5.44. The Authority also maintains, as shown in the hierarchy of response illustrated in Figure 1, that EDB controllable load resources should be activated ahead of emergency reserves and are not eligible to participate in the ERS. Controllable load is a low marginal cost form of demand response, with minimal impact on consumers, and should therefore be activated ahead of the more costly ERS. The Authority welcomes moves by retailers and EDBs to enter bilateral agreements relating to the use of controllable load resources. We consider this to be the most appropriate way to realise greater benefit from this capability, rather than have controllable load participate in the spot market or ancillary services directly. The activation hierarchy is discussed further in section 5.77 below.

5.45. The System Operator would be required to assess additionality as part of the procurement of ERS. The Authority acknowledges there may be some complexity in determining this. If the Authority decides to establish the ERS, further details are likely to be set out in the Ancillary Services Procurement Plan, which would be developed by the System Operator in consultation with stakeholders. Initiatives such as a register of demand flexibility contracts are being considered as part of the broader roadmap for demand flexibility.[17]

5.46. The Authority proposes to include high-level guidance in the Code for the System Operator to assess additionality. This includes a 12-month 'look back' to preclude participation by resources that have provided a demand response in tight supply-demand conditions in the previous 12 months, to minimise the risk of capacity withdrawing from other mechanisms to participate in ERS. The proposed Code amendments in section 6 and attached at Appendix A set out further details.

Updated design element 1: Eligibility for emergency reserves

Demand flexibility, including aggregations, and off-market generation are eligible to provide emergency reserves, provided they can meet the additionality and service requirements set out in the Ancillary Services Procurement Plan and contracts determined by the System Operator.

Procurement

The Authority proposed the System Operator should procure the service via a competitive tender process within one month of an identified need

5.47. The Authority proposed that the System Operator should procure emergency reserves via a competitive procurement process. We proposed it would procure a firm (fixed) quantity, similar to other ancillary services (eg, black start).

5.48. We proposed that procurement should take place up to one month before emergency reserves may be needed, with the System Operator to determine this based on the New Zealand Generation Balance (NZGB) forecast. This timing was

16 Submissions indicated there could be as much as 50MW of on-site generation and BESS at consumers' premises, which may be able to support demand flexibility for the ERS.

17 More information on the proposed industrial flexibility roadmap can be found on our website.

designed to balance the need to attract a sufficient pool of providers with use of the most accurate forecast possible. We also suggested the System Operator could establish a pre-qualified panel to increase the potential pool of providers, and to streamline procurement closer to real time.

5.49. The Authority also considered whether the System Operator should update its forecasts (for procurement and activation). This was to take account of forecast uncertainty, which is increasingly important as intermittent renewable generation sources and CER play a growing role in our electricity supplies. The Authority did not propose to require this adjustment. Rather we considered this to be a matter for the System Operator and acknowledged its continuous efforts to enhance its planning mechanisms in response to changing power system conditions.

What submitters said

5.50. Submitters generally supported the proposed procurement approach, including the use of a competitive tender process.

5.51. NZ Steel's submission raised concerns with the proposed procurement process, considering it may reduce participation by not catering for the unique characteristics of different consumers, including those without dedicated energy management resources.

5.52. Submissions from Transpower and Meridian both raised concerns with the suitability of the NZGB as a trigger for procurement. This forecast currently does not include all of the details that would be required to determine the quantity and locations where shortfalls may arise.

5.53. Transpower's submission also highlighted the importance of balancing efficiency with operability and suggested an annual tender process. Transpower noted that further design work would be needed before it could reach any conclusions about the work needed to procure ERS providers, including potential procurement timelines.

5.54. Several submissions suggested that the System Operator should be required to update its forecasts to take account of forecast uncertainty (Counties Energy, ERGANZ, Mercury, Meridian).

5.55. Transpower considered the approach proposed by Robinson Bowmaker Paul (RBP)[18] to updating its forecasts would require significant enhancement and would not be possible ahead of winter 2026. Transpower's submission acknowledged that many elements of system operation are becoming more complex, and that it is continually improving its forecasts to incorporate probabilistic analysis. It stated:

'Consistent with our other processes, we would seek to incorporate forecast uncertainty into ERS procurement and scheduling (pre-activation and activation) to the extent practicable, and to review over time the effectiveness of those processes.' (page 6)

18 RBP provided advice to the Authority in the design of the ERS. RBP's report was provided at Appendix A to the ERS consultation paper.

The Authority's response and updated proposal

5.56. The Authority confirms that it intends to proceed with the proposal for:

(a) creating a competitive tender to procure emergency reserves;

(b) starting procurement up to four weeks before an identified shortfall; and

(c) using a pre-qualified panel of providers established in advance.

5.57. We acknowledge that the standardised service requirements and tender approach may not suit all consumers. However, we consider that a competitive mechanism is required to minimise the overall cost of the service. Outside of the procurement mechanism itself, our proposed design seeks to provide flexibility for the System Operator and potential ERS providers to negotiate elements of the service, subject to meeting minimum requirements. Consumers that require a more bespoke arrangement than can be accommodated within the ERS may find a bilateral agreement with a retailer to be more appropriate. The specifications for the ERS could provide guidance in developing such an agreement.

5.58. The methodology for triggering procurement of emergency reserves would be set out in the Ancillary Services Procurement Plan. The Authority does not intend to prescribe the approach or inputs to be used, but would continue to engage with the System Operator on the most appropriate approach. This is consistent with the procurement plan for other ancillary services.

5.59. The Authority suggests the System Operator should consider how to enhance its forecasts to take account of forecast uncertainty. Doing so would have benefits beyond the ERS. However, the Authority does not consider it necessary to require this for the ERS as the System Operator is continually reviewing its forecasts and seeking opportunities for improvement.

Updated design element 2: Procurement of emergency reserves

The System Operator should procure emergency reserves up to four weeks ahead of an identified shortfall via a competitive tender process. The trigger methodology and service requirements will be set out in the Ancillary Services Procurement Plan and determined by the System Operator.

Activation

The Authority proposed a two-stage activation process

5.60. The Authority proposed a two-step activation approach for emergency reserves. This approach was designed to be integrated into existing grid emergency processes but could be managed outside of central dispatch systems.

(a) **Pre-activation** would occur up to 36 hours ahead of a forecast shortfall in the Week-ahead Dispatch Schedule (WDS) or Non-Response Schedule Long (NRSL). Pre-activation refers to preparatory activities (including communications) that occur in the lead up to an activation event to ensure providers can deliver the service as intended.

(b) **Activation** would occur after gate closure, with up to an hour's notice, if the Short Non-Response Schedule (NRSS) indicate the shortfall has not been resolved. Activation refers to the actual use of the service, which is triggered by a notification from the System Operator to the provider.

5.61. As with the trigger for procurement of ERS, the Authority considered that it may be appropriate to update the short-term forecasts used for pre-activation and activation to take account of forecast uncertainty. However, we refrained from proposing that the System Operator be required to do this for the implementation of the ERS. This was to take into account both time concerns and the System Operator's ongoing efforts to update its tools.

5.62. Activation of ERS was proposed to occur as a penultimate measure. We proposed that ERS would be used after all market, contractual and other business-as-usual mechanisms, including EDB controllable load resources, and ahead of involuntary load shedding.

5.63. The Authority also proposed a mechanism designed to prevent any demand reduction as a result of ERS activation from distorting market prices. This would be achieved by adding the ERS demand reduction 'back' into the nodal load schedule to ensure prices were maintained at the level they would have been (ie, scarcity levels) in the absence of the ERS.[19]

What submitters said

5.64. Most submissions broadly supported the proposed approach to pre-activation and activation.

5.65. Most submissions specifically endorsed the approach to 'add back' any ERS demand reduction to ensure that final prices accurately reflect the imbalance between generation and demand. Submitters noted this would ensure the ERS does not distort the signals for the operation of or investment in wholesale market resources.

5.66. The submission from ERGANZ (supported by Mercury), acknowledged that the design of the ERS should mitigate the risk of it creating a moral hazard, which was a risk discussed by the Authority in the ERS consultation paper. ERGANZs' submission noted that the late-stage activation, add back of ERS load and anticipated infrequent use of the ERS would help mitigate this risk.

5.67. Submissions from EDBs and ERGANZ also noted the importance of coordination between the System Operator, ERS providers and EDBs in the activation and restoration of ERS resources, to ensure the security of local networks along with the broader power system. Meridian and Powerco's submission encouraged the Authority to consider how information sharing can be improved to support operational decision-making in emergencies.

5.68. As discussed above, several submissions supported the System Operator updating its forecast processes to take account of forecast uncertainty, for both procurement and activation decisions.

5.69. Simply Energy's submissions also noted the challenge for the System Operator in deciding to activate ERS, as activation decisions need to be made based on

19 This is akin to the approach currently taken when EDBs are instructed to curtail load in their local network, where the Real-Time Dispatch Pricing Schedule is adjusted to add back the instructed load shedding at the relevant nodes, restoring prices to the higher levels.

forecasts which will inevitably deviate from the actual conditions that emerge, which may in turn result in greater activation of the ERS than required. Feedback from Unison and Centralines also sought to limit the use of the ERS, by ensuring ERS resources are genuinely additional and through implementing robust forecasting and monitoring to reduce unnecessary activation processes.

5.70. Several submissions sought further information on the hierarchy of activation of various resources in an emergency.

5.71. Meridian's submission sought clarification of the use of an ERS for a nation-wide peak capacity event, rather than regional peak capacity events driven by network constraints.

The Authority's response and updated proposal

5.72. The Authority confirms that it intends to proceed with the proposed approach to activation of ERS. This includes adding back any ERS load reduction to ensure wholesale market price signals are maintained.

5.73. The Authority agrees with submitters that coordination with EDBs will be necessary and important. We propose to require ERS providers that are not connected to the grid to advise their EDB when they enter into an ERS contract. A similar obligation currently exists for providers of interruptible load.

5.74. The Code does not prescribe coordination mechanisms between the System Operator and EDBs. However, the Authority expects that the System Operator and EDBs would make any necessary modifications to existing processes to support the implementation of the ERS. We consider that coordination is likely to be required:

(a) as part of due diligence by the System Operator before entering a contract with a potential ERS provider, to ensure the service is capable of being provided having regard to the security and reliability of the local network; and

(b) as part of activation and restoration to ensure these real-time actions are undertaken in a secure and reliable manner for the grid and the local network.

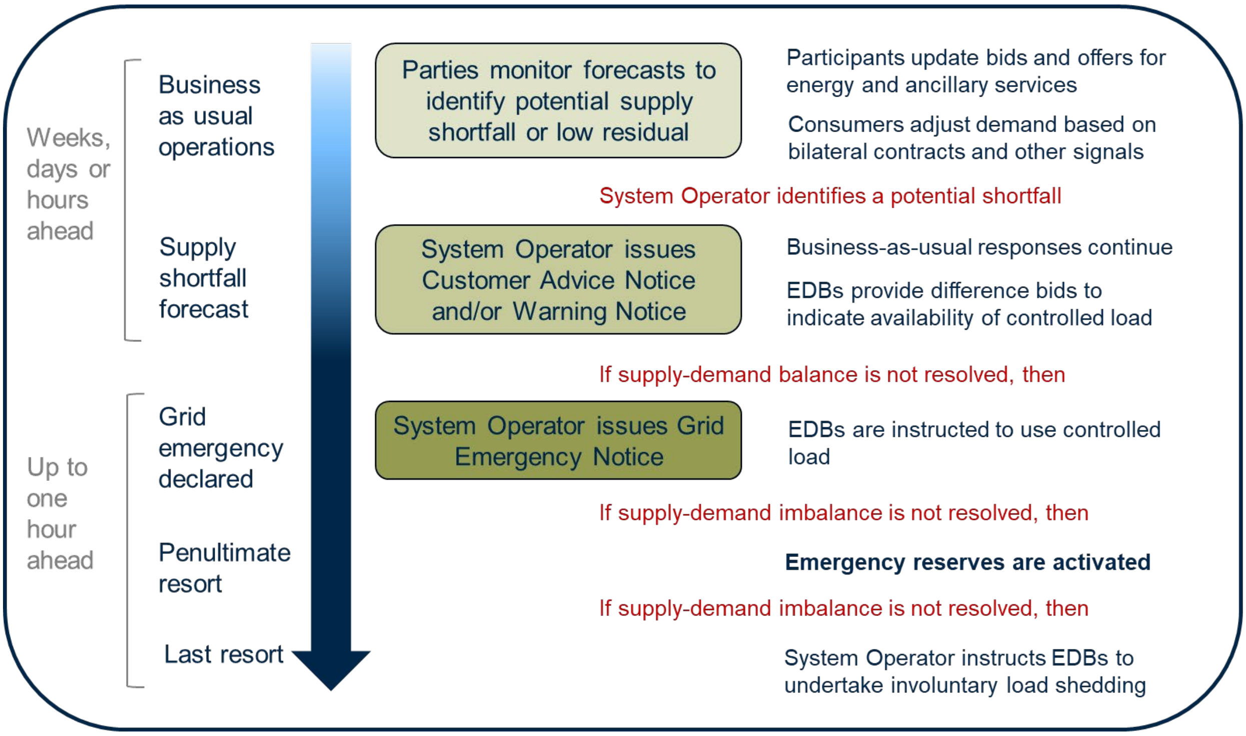
5.75. The Authority considers that the System Operator, in consultation with relevant parties, is best placed to ensure that information is available and communicated to all relevant parties involved in the management of a grid emergency.

5.76. The Authority is also monitoring the development of the proposed common load management protocol being developed as part of the Electricity Networks Aotearoa (ENA) Future Networks Forum. This protocol may provide for more effective coordination of flexible demand resources connected to distribution networks.[20]

5.77. As noted previously, we intend for the activation of emergency reserves to be a penultimate resort, after all business-as-usual mechanisms are deployed. These include EDB controllable load resources. Figure 2 provides a summary of the intended hierarchy, which would be given effect via Schedule 8.3 – Technical Code B in the Code.

[20] Information on the ENA's forums is available on the ENA website.

Figure 2: Proposed emergency reserve activation as part of a hierarchy of response to manage a grid emergency



5.78. The Authority acknowledges concerns that an ERS may be activated more than is strictly necessary, which could increase costs for consumers. However, we note that a similar risk also arises with any decision to reduce load in a grid emergency. In these cases the System Operator acts on the best information available and is guided by the reasonable and prudent system operator standard[21] to meet its principal performance obligations.

5.79. The Authority also notes, that while we proposed the use of the WDS/NRSL and NRSS to inform pre-activation and activation decisions, the trigger methodology would be set out in the Ancillary Services Procurement Plan and determined by the System Operator.

5.80. With regard to the scope of the ERS (nation-wide vs regional), the Authority notes that the purpose of an ERS is to minimise the risk of uneconomic load shedding during capacity shortfalls. Such a shortfall could be national, or confined to one island or a region. In all cases, if emergency reserves are available in the relevant locations and in the time available, the System Operator should have the option of procuring and activating the ERS.

Updated design element 3: Activation of emergency reserves

The System Operator can activate emergency reserves in a grid emergency after the operation of all market and business-as-usual mechanisms, including the use of EDB controllable load, and ahead of involuntary load curtailment.

The System Operator should pre-activate emergency reserves up to 36 hours ahead of real-time and activate emergency reserves up to one hour ahead, after

21 See clause 7.1A of the Code.

all business-as-usual mechanisms have operated including the use of EDB controllable load resources.

Demand reduction as a result of the activation of ERS should be added back into the nodal load schedule to restore prices to the level they would have been without ERS.

The trigger methodology and service requirements will be set out in the Ancillary Services Procurement Plan and determined by the System Operator.

Pricing and settlement

The Authority proposed a flexible pricing structure, capped at the value of lost load, with cost recovery from purchasers

5.81. The Authority proposed that each provider would determine the price at which they were willing to offer emergency reserve as part of their contract with the System Operator. Providers could structure their pricing to best meet their own cost structures. Pricing structures could include both pre-event costs (including preparation and activation costs) and event costs (including pre-activation and activation costs).

5.82. The competitive tender process is intended to encourage efficient pricing by providers. Additionally, the Authority also proposed that the System Operator should make reasonable endeavours to ensure that, at the time of procurement, the forecast cost per unit of ERS provision is not greater than VoLL.

5.83. The Authority also considered whether, at the time of activation, the System Operator should be required to ensure that total market costs are less than VoLL. We understood market costs to include total spot market costs, which are likely to be at scarcity pricing levels, plus ERS activation costs. However, we did not propose to introduce this requirement. This is because the assessment could be complex and would need to be undertaken in in a compressed and high-pressure time (as the System Operator would be managing a potential supply shortfall).

5.84. The Authority proposed the use of an interim VoLL value of $35,305 per MWh for the commencement of the ERS, which would apply until the Authority completes a planned review of VoLL and security standards in the Code. The level of VoLL set by the Code ($20,000 per MWh) has not been changed since 2004.

5.85. The Authority proposed that the costs of the ERS be allocated on a national basis to 'loads', including retailers and consumers who participate directly in the spot market – referred to in the Code as 'purchasers'. Pre-event and event costs should be allocated separately:

(a) **Pre-event costs** should be allocated to loads based on their share of monthly metered consumption in relevant months when emergency reserves have been procured.

(b) **Event costs** should be allocated to loads based on their metered consumption during activation events.

5.86. The Authority also identified alternative cost allocation approaches and sought stakeholder feedback on the options.

5.87. The Authority anticipated that existing settlement processes for ancillary services could be leveraged to accommodate this approach for emergency reserves.

What submitters said

5.88. Submissions broadly supported the Authority's proposed payment and settlement approach. Meridian indicated a preference for the use of activation (event) fees rather than availability (pre-event) fees, to reduce the risk of gaming and to potentially lower overall costs.

5.89. Submissions broadly supported efforts to ensure that the expected costs of the ERS are less than VoLL. Submissions from ERGANZ, Mercury, Meridian and Orion indicated support for the System Operator to assess total cost at the point of activation, but only if practicable. A similar number of submissions commented that a 'reasonable endeavours' requirement, along with performance monitoring, would be sufficient.

5.90. All of the submissions that commented on the proposed interim VoLL indicated support for this. Submissions also generally supported the planned review of the VoLL and security standards in the Code.

5.91. No submissions supported either of the alternative cost allocation approaches identified in the ERS consultation paper.

The Authority's response and updated proposal

5.92. The Authority confirms that it intends to proceed with the proposed approach to pricing and settlement.

5.93. We consider that the use of pre-event and event fees is important to ensure that ERS providers have confidence that their costs can be recovered, and to attract a wider pool of potential providers. We anticipate that the assessment of costs at the time of procurement (as well as performance management, which we discuss in the following section), will act to ensure that an ERS delivers benefits for consumers.

Updated design element: Pricing and settlement

ERS providers can recover both pre-event and event fees, which can be determined on an individual basis and set out in the providers' contract with the System Operator. The System Operator must make reasonable endeavours to ensure the anticipated costs of ERS are less than VoLL (on a per-unit basis).

ERS costs are to be recovered from purchasers on a national basis, with pre-event costs allocated to loads based on their share of monthly metered consumption in relevant months and event costs allocated to loads based on their metered consumption during activation events.

Performance management

The Authority proposed up-front measures to enhance performance, and loss of payments for non-performance

5.94. The Authority proposed the following measures to ensure performance:

(a) due diligence by the System Operator as part of procurement (or establishment of the pre-qualified panel);

(b) testing;

(c) consideration by the System Operator of the risk of 'resource fatigue', which might result in diminished performance over time, as part of procurement;

(d) a pre-activation step to enable providers to prepare to provide the service close to real-time; and

(e) forfeiture of activation and availability payments for the relevant period, if an ERS provider fails to satisfy its performance requirements in an activation event without bone fide reasons.

5.95. The Authority did not propose to introduce additional penalties for non-performance. These could be a significant disincentive to entry and risk reducing participation and competition within an ERS.

What submitters said

5.96. Submissions generally supported the Authority's proposed approach to performance management.

5.97. Submissions from BNZEC, Meridian, NZ Steel and Nova Energy believed it would be appropriate to charge penalties for non-performance. Enel X's submission suggested a scaled approach to reducing payments for non-performance.

5.98. Several submissions sought to understand how performance would be measured, including the establishment of baselines and verification of performance. Counties Energy, Enel X and ERGANZ indicated that portfolio level measurement should be enabled for aggregations. ERGANZ, Mercury and Orion all raised the potential for baselines to be gamed, highlighting the importance of a robust approach.

5.99. MEUG and NZ Steel also sought more information on the penalty regime and service standards.

Authority's response and updated proposal

5.100. The Authority confirms that it intends to proceed with its proposed approach to performance management.

5.101. At this stage, the Authority considers that non-payment is the only mechanism that is necessary to deal with underperformance. The upfront measures taken by the System Operator to ensure performance should reduce the likelihood of a provider being contracted for ERS without being able to perform the service. Additionally, providers would be expected to take their obligations very seriously to support reliability during an emergency. These incentives mirror those of other ancillary services.

5.102. This position could be revisited if there was evidence that providers were not making sufficient effort to meet their obligations.

5.103. The details of performance management elements would be specified by the System Operator in the Ancillary Services Procurement Plan and contracts with ERS providers, as appropriate. This includes the approach to determining baselines and requirements for measurement and verification. The Authority anticipates that the System Operator will be guided by how this has been determined for other initiatives (eg, existing wholesale market demand response mechanisms in New Zealand and other jurisdictions, and Transpower's FlexPoint system[22]).

5.104. The Authority agrees that for aggregations, portfolio-level baselines and measurement would be appropriate.

Updated design element 5: Performance management

> The System Operator should include performance management measures in the process of procurement and pre-activation (due diligence, consideration of resource fatigue and effective communication), along with the performance requirements of the service, in the Ancillary Services Procurement Plan and ERS contracts.
>
> ERS contracts should provide for testing, along with forfeiture of payments proportionate to any non-performance.

Information provision and publication

The Authority proposed that the System Operator publish, or provide to the Authority, information on the need for and use of emergency reserves

5.105. The Authority proposed that the System Operator publish the following information:

(a) forecasts, including the annual expected unserved energy assessment setting out the quantum, location and duration of any potential shortfalls and the NZGB including the N-1 balance;

(b) standardised ERS contracts, the service specification and technical requirements, and other information to support procurement and the establishment of a panel of providers; and

(c) quarterly updates of ERS procurement and activation.

5.106. We also proposed that the System Operator provides the Authority with the following information, which we would then aggregate before publishing it:

(a) the number of providers and their offer details;

(b) the providers selected and the rationale for their selection; and

(c) forecast ERS costs based on selection.

What submitters said

5.107. Submissions generally supported the Authority's proposed information requirements.

5.108. Meridian suggested that post-event reporting should identify any non-performance by ERS providers, to strengthen the incentives for performance.

5.109. Submissions from Enel X, ERGANZ and Mercury sought the timely publication of post-event reports. Enel X noted the importance of providing purchasers with an

22 Information about FlexPoint is available on Transpower's website.

early indication of the likely costs of the ERS. ERGANZ and Mercury noted that ex-post reviews provide transparency about the performance of ERS providers.

5.110. Some submissions also indicated interest in understanding when the Authority would review the operation of the ERS. Meridian suggested a review of the costs and benefits of each event. Mercury and Meridian suggested the ERS should be reviewed after winter 2026 or winter 2027 respectively, with MEUG also expressing interest in a review in 2027.

The Authority's response and updated proposal

5.111. The Authority confirms that it largely intends to proceed with its proposed approach to information provision and publication. We note the following:

(a) We should always seek to achieve an appropriate level of information transparency, taking into account the fact that there may be good reasons to treat some information confidentially. The System Operator and Authority can be expected to have regard to this general approach in determining what information to publish.

(b) Given the discussion in section 5.58 on the appropriate forecasts to trigger procurement of the ERS, the System Operator will be best placed to ensure that it publishes the relevant forecast, once identified.

5.112. Under clause 13.101 of the Code, the System Operator is required to publish a report on the basis on which it decided to declare a grid emergency within 12 hours of the conclusion of a grid emergency. In addition, following recent power system events, the System Operator has produced an initial event report within two-three weeks following the event.[23]

5.113. We consider there to be benefit in specifying the requirement for post-event reporting on the use and estimated costs of the ERS and have proposed an amendment to Part 8 of the Code (see section 6.18). This information will assist purchasers to understand their likely ERS costs.

5.114. If the decision is made to proceed, the Authority intends to review the ERS once it has been in operation. We understand that there will be considerable interest in the scheme following any use (and the corresponding grid emergency event). Reviewing the event could provide an opportunity to learn about the use of ERS and identify potential improvements. The post-event reporting by the System Operator is an important element to address this.

5.115. The timing and scope of any scheme review would be determined by the Authority.

Updated design element 6: Information provision and publication

The System Operator should publish the forecasts on which it bases its decision to procure and activate emergency reserves.

The System Operator should be required to publish information to support the procurement of emergency reserves as part of the Ancillary Services Procurement Plan and associated contract.

[23] The System Operator publishes reports about system events and reports on its website.

The System Operator would be required to publish details of the use and expected cost of emergency reserve within 20 business days following any use of the service.

The System Operator’s periodic reporting should include information about the procurement and use of emergency reserves, to be specified in the procurement plan.

The System Operator should also provide the Authority with further details of the procurement and cost of emergency reserves, to be specified in the procurement plan.

6. Code amendment proposal

6.1. The Authority proposes to amend Parts 1, 8 and 13 of the Code to establish the ERS as a new ancillary service known as ‘emergency reserve’. Code changes are required to enable the System Operator to procure and use emergency reserve, provide for the recovery of emergency reserve costs and manage interactions with other mechanisms used to maintain the security and reliability of the power system in emergency situations.

6.2. The proposed Code amendments to establish emergency reserve seek to:

(a) establish the new emergency reserve ancillary service and enable the recovery of emergency reserve costs;

(b) integrate emergency reserve into grid emergency processes; and

(c) address other interactions between emergency reserve and existing Code provisions, including requirements that should not apply to emergency reserve providers.

6.3. The following sections outline the proposed Code changes. **Appendix A** contains a draft of the proposed amendments.

Code changes to establish emergency reserve

6.4. The Code amendment proposal would establish a new ancillary service known as emergency reserve, which is a service that provides access to generation capacity that can be used, or load that can be interrupted, to minimise the electrical disconnection of demand in a grid emergency, as specified in the Ancillary Services Procurement Plan.

6.5. Clauses 8.43 and 8.45 of the Code (which, respectively, specify what the System Operator must include in its procurement plan for each ancillary service, and make provisions regarding contracts with ancillary service agents), would apply to the new emergency reserve ancillary service. These are outlined in section 6.22.

6.6. The definition of ‘emergency reserve’ in Part 1 would identify those services which are not eligible to provide emergency reserve. This is to ensure the service is additional to other mechanisms which are intended to be deployed prior to – and with the intention of avoiding – emergency reserve being required. We propose to exclude from eligibility any generation or load capacity that:

(a) is otherwise used to provide generation or demand response in the wholesale market, other than black start ancillary service, including where it has been used to provide this within the 12 months prior to being offered for use as emergency reserve;

(b) provides generation or demand response under a contract or other arrangement, such as with a retailer or EDB, including where it has been used under such a contract or arrangement in the 12 months prior to the need for emergency reserve; or

(c) is provided from a BESS, other than a BESS connected at a consumer's premises.

6.7. The definition of 'controllable load' in Part 1 would also be amended to exclude any contracted emergency reserve.

6.8. The Code amendment proposal would amend Part 8, subpart 4 to require ancillary service agents to provide information to their EDB to advise the EDB that they have entered into a contract to provide emergency reserve. This would only apply if their resources were connected to the network. This obligation already exists for providers of interruptible load, under clause 8.54B of the Code, so we propose to make similar provision in respect of emergency reserve in a new clause 8.54BA.

6.9. We are proposing to introduce a new clause (8.58A) to enable the recovery of emergency reserve costs from purchasers. Costs to be recovered include:

(a) **'pre-event costs',** to be recovered from purchasers in proportion to their share of total metered consumption during the emergency reserve availability trading intervals identified by the System Operator (ie, the periods when ERS providers are required to be available)

(b) **'event costs',** to be recovered from purchasers in proportion to their share of total metered consumption during the emergency reserve pre-activation and activation trading periods identified by the System Operator.

6.10. The Clearing Manager would determine each purchaser's share of the allocable costs for emergency reserve using information provided by the System Operator (costs and trading periods) and the Reconciliation Manager (metered quantities), in accordance with existing processes.

6.11. We propose to include other new definitions and amended existing ones in Part 1 to support the establishment of the new emergency reserve ancillary service, including:

(a) **new definitions** of 'activate', 'emergency reserve event', 'emergency reserve event costs', 'emergency reserve event trading period', 'emergency reserve pre-event costs', 'emergency reserve pre-event trading period', and 'pre-activate'; and

(b) **consequential amendments** to the definitions of 'allocable cost' and 'ancillary service' to include emergency reserves.

Registration and other implications

6.12. Providers of emergency reserve, which may include individual providers or aggregators, would be required to register with the Authority in accordance with section 9 of the Act on the basis that they are ‘industry participants’ for the purposes of section 7 of the Act. Providers will also be ancillary service agents under section 7(2) of the Act and for the purposes of the Code.

Code changes to integrate emergency reserves into grid emergency processes

6.13. We propose to include the activation of emergency reserve in the list of actions to be taken by the System Operator in subclauses 6(1) and 6(2) of Schedule 8.3 – Technical Code B. This would allow us to establish emergency reserves as a penultimate action the System Operator may take in case of a grid emergency.

6.14. We also propose to introduce a new clause (5B) in Technical Code B to require emergency reserve providers to provide information to the System Operator about their availability to provide emergency reserve when the System Operator is preparing for and managing a grid emergency.

6.15. The Code amendment proposal would also amend clause 3 of Schedule 13.3AA to adjust the demand profile for demand that was unable to be supplied to include any load reduction as a result of emergency reserve activation. This would have the effect of ensuring wholesale market prices are set at the level they would have been in the absence of emergency reserve activation.

Other code changes to implement emergency reserves

6.16. The Code amendment proposal also makes related and consequential amendments to establish emergency reserves in accordance with the proposed design outlined in section 5.

6.17. We propose to amend the definition of ‘bona fide physical reason’ in Part 1 to also cover the non-provision of emergency reserve by a contracted emergency reserve provider.

6.18. We propose to introduce a new clause (8.54BA) for the System Operator to publish a post-event report on the use and anticipated costs of emergency reserves within 20 business days of an emergency reserve event.

6.19. We also propose to amend Schedule 8.3 – Technical Code B to clarify the interactions between emergency reserves, AUFLS, and other elements of emergency management, including:

(a) that the demand calculated to comprise AUFLS blocks must be net of any emergency reserve procured by the System Operator (subclause 7(7)), and ensure coordination by relevant parties in relation to emergency reserves and AUFLS (subclause 7(17))

(b) excluding emergency reserve providers from the requirement to be able to automatically respond to extreme variations in frequency and voltage (new subclause 9(2)).

System Operator documents would also require amendment

6.20. As noted above, most elements of the detailed design of the ERS would be set out in the Ancillary Services Procurement Plan as required by clause 8.43 of the Code, along with the terms and conditions of contracts with emergency reserve providers established under clause 8.45 of the Code.

6.21. The System Operator would undertake consultation on proposed amendments to the procurement plan following a decision by the Authority to proceed with the implementation of an ERS.

6.22. Clause 8.43 specifies what the System Operator must include in its procurement plan for each ancillary service. Applying those requirements to emergency reserve, we anticipate that this would include the following:

(a) how the System Operator will make a net purchase quantity assessment and achieve the dispatch objective (ie, the trigger and quantum of emergency reserve to be procured);

(b) the process for procuring the emergency reserve service;

(c) the System Operator's administrative costs for the emergency reserve service, which form part of the allocable costs for the service;

(d) the permitted costs/payments for providers (ie, pre-event and event fees);

(e) the System Operator's technical requirements and key contract terms for the service, including:

i. how it will assess eligibility to provide emergency reserves to ensure additionality;

ii. any minimum service requirements, such as quantity and duration;

iii. the activation process, including measurement and communication requirements;

iv. testing, monitoring and performance requirements;

v. unavailability requirements; and

vi. other technical requirements.

(f) the rights and obligations of the System Operator in relation to procurement of emergency reserves in circumstances not anticipated by the procurement plan; and

(g) how the System Operator will report on progress in implementing the procurement plan.

Questions

Q1. Do you support the Authority's proposal to amend the Code to establish an emergency reserve scheme?

Q2. Do you have any comments on the drafting of the proposed amendments?

Q3. Do you consider any further Code amendments are required to establish the emergency reserve scheme as outlined in section 5?

Q4. Do you see any unintended consequences in making the proposed amendments?

Please explain your answers.

7. Regulatory Statement

Objectives of the proposed amendment

7.1. The primary objective of the proposed amendment is to provide the System Operator with access to load and off-market generation capacity, to be used to minimise the likelihood and extent of uneconomic load shedding during infrequent periods when demand is high and inadequate supply is available from other sources.

7.2. The secondary objective of the proposed amendments is to help build consumer capability to provide demand flexibility, which could be used in future to support the efficient and reliable supply of electricity and minimise electricity costs outside of emergency situations.

Evaluation of the costs and benefits of the proposed amendments

7.3. The proposed amendment is intended to deliver a net benefit to electricity consumers by improving the reliability of New Zealand's electricity supply and reducing the likelihood and quantity of involuntary uneconomic load shedding.

7.4. The theoretical cost of involuntary load shedding is known as VoLL. This is the amount that a consumer would have been willing to pay to avoid a MWh of load curtailment. If emergency reserve can be delivered at a lower cost than VoLL, the difference between the cost and VoLL represents a net benefit to consumers.

7.5. The costs associated with the establishment and operation of the ERS are anticipated to include:

(a) establishment costs, such as the costs of updating the System Operator and Clearing Manager's processes and systems to enable the procurement and activation of, and payments for, emergency reserve;

(b) the operational costs of procuring and activating emergency reserve, including:

(i) the costs incurred by the System Operator; and

(ii) the costs of preparing for and providing the service by emergency reserve providers.

7.6. In addition, there are many non-quantifiable costs associated with involuntary load shedding, including the inconvenience to individual consumers and society as a whole, possible adverse impacts on individuals' health and wellbeing from interrupted access to services that require electricity, and reduced confidence in New Zealand's electricity system.

7.7. The Authority engaged Concept to undertake a CBA for the proposed ERS. The full CBA report is attached as Appendix B to this consultation paper. The Authority has considered Concept's CBA and is satisfied that it provides a reasonable basis on which to estimate the costs and benefits of the Authority's proposals.

7.8. Concept's CBA concluded that establishing emergency reserve as proposed would deliver an estimated $21 million net benefit when compared to the status quo, and estimates that the net costs of emergency reserve would be significantly lower than the cost of investment in additional generation capacity to be used in grid emergencies (which occur infrequently). The CBA also identifies material, non-quantifiable benefits, which Concept estimates could be as high as, or exceed, the quantifiable benefits of the scheme.

7.9. Table 2 provides a summary of the estimated costs and benefits of the proposed amendment.

Table 2: Summary of the costs and benefits of the proposed Code amendment from Concept's CBA

Benefit/cost	Magnitude
The quantifiable benefit of avoiding involuntary load shedding, represented by VoLL.	Significant
The unquantifiable benefit of avoided impacts (costs) on consumers from the unavailability of their electricity supply during an emergency event (eg, inconvenience, triggering the purchase of back-up generation and possible risks to health and safety).	Significant
The unquantifiable benefit (avoided costs) to the System Operator, EDBs and others of managing involuntary load shedding, including communications with consumers.	Minor
The unquantifiable benefit (avoided costs) to the System Operator, regulatory authorities and government of post-event reviews and other actions triggered as a result of involuntary load shedding.	Moderate
The unquantifiable benefit (avoided costs) of any impact on consumers' confidence in the electricity system and reputational damage to 'NZ inc.'	Potentially significant
Quantifiable implementation costs for the System Operator and Clearing Manager.	Minor
Quantifiable ongoing costs for the System Operator to procure and activate emergency reserves, and for emergency reserve providers to be available and provide the service (including direct costs and opportunity costs).	Moderate
The unquantifiable costs of any moral hazard created by the ERS, including the potential to influence, at the margin, decisions to invest in additional supply capacity.	Minor
Expected net benefit	**Significant**

7.10. Concept's analysis indicates that the potential benefits of the Authority's proposals are relatively sensitive to the frequency and size of events. However, Concept considers that neither of these factors alone is likely to neutralise the net benefits of the ERS and, if one or both increase, the overall net benefits could also significantly increase.

Including off-grid generation increases the expected net benefit

7.11. Concept's sensitivity analysis also considered the impact of including or excluding off-market generation from the ERS. Concept's analysis indicates that off-market generation is likely to be able to provide emergency reserve at a lower cost, on average, than demand flexibility. Inclusion of off-market generation therefore has the potential to reduce the costs of emergency reserve provided.

Evaluation of alternative means of achieving the objectives of the proposed amendment

7.12. Concept considered two alternative options to the proposed amendment – the status quo, and investment in additional flexible supply to avoid the level of involuntary load shedding expected to be met using the proposed ERS.

7.13. Concept considers that an ERS is expected to deliver a higher net benefit when compared to both the status quo and investment in additional supply. Table 3 summarises Concept's evaluation of the alternative options.

Table 3: Evaluation of alternative options from Concept's cost benefit assessment

Alternative option	Reasons not favoured
Status quo	Results in an overall net cost to consumers and regulatory bodies, along with broader negative impacts on the community and broader economy.
Additional supply	Results in an overall net cost for consumers, as the cost of investing in and operating additional generation to avoid involuntary load shedding in infrequent emergency events exceeds the quantifiable benefits.

The proposed amendment complies with section 32(1) of the Act

7.14. The Authority considers that the proposed Code amendment complies with section 32(1) of the Act and is consistent with the Authority's main objective, because it promotes the reliable supply of electricity to consumers and the efficient operation of the electricity industry, while minimising the risks of market distortion.

7.15. The Authority considers that the proposed amendment would achieve these goals by providing the System Operator with additional capacity to meet demand during a grid emergency, which would improve the System Operator's ability to plan to comply, and to comply with the principal performance obligations and achieve the dispatch objective in clause 13.57 of the Code.

7.16. The Authority's additional objective, to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers, applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers. This proposal applies primarily in relation to dealings between participants rather than those between participants and small consumers. Nevertheless, the Authority also considers that the proposed Code amendment is consistent with the Authority's additional objective because it protects the interests of consumers by minimising the likelihood and extent of involuntary load shedding.

7.17. The Authority considers that it would also achieve both the main and additional objectives by reducing the anticipated costs of involuntary load shedding when compared to the alternative options.

7.18. As discussed in section 5.15 above, the Authority also evaluated the establishment of an ERS against a set of guiding principles designed to ensure that the design of the scheme was consistent with the Authority's main objective.

The Authority has complied with section 17(1) of the Act

7.19. Under section 17(1) of the Act, the Authority, in performing its functions, must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister for Energy. Table 4 sets out our consideration of how the proposed amendment meets the expectations of the Government Policy Statement on Electricity.[24]

Table 4: Consideration of the proposed amendment against the Government Policy Statement

Clause	Consideration
2. The Government therefore expects the electricity system to deliver reliable electricity at the lowest possible cost to consumers, including through the provision of sufficient electricity infrastructure to ensure security of supply and avoid excessive prices.	The proposal would strengthen the reliability of the electricity system by providing the System Operator with additional capacity to avoid having insufficient supply to meet demand. It would do this at the lowest possible cost by providing access to emergency reserves that could be dispatched to deliver an overall net benefit that is higher than the alternative options, avoiding the cost of investing in more expensive supply infrastructure. It would also do this by ensuring the price signals for operation and investment in the wholesale market were maintained.
21. Neither the Government nor the Electricity Authority nor the System Operator will step in to insulate wholesale market participants from risk or to protect them from their failure to manage their own energy supply risks.	The proposal aligns with the Government Policy Statement as it would only be triggered in circumstances which are were unlikely to be reasonably foreseeable by market participants and, through the allocation of costs, would encourage participants to take steps to minimise the need for emergency reserves when emergency situations arise.
23. In accordance with market rules and arrangements, the System Operator is responsible for efficiently co-ordinating the utilisation of electricity generation and demand-side offers that have been made available in the wholesale market by market participants in response to price signals.	The proposal aligns with the Government Policy Statement as it would maintain the primacy of the wholesale electricity market to co-ordinate electricity generation and demand-side offers, with emergency reserves only accessed if the wholesale market is unable to balance demand and supply. It would also do this by ensuring the price signals for operation and investment in the wholesale market are maintained.

24 New Zealand Government, Government Policy Statement on Electricity, October 2024.

30. As part of its obligation to promote competition, the Electricity Authority should ensure that market arrangements facilitate this competition, including in relation to flexible supply.	The proposal aligns with the Government Policy Statement as it would provide for competition in the procurement of emergency reserves in a manner consistent with existing ancillary services.
31. The Electricity Authority should be aware that it is not the Electricity Authority's role to prefer one form of supply over any other.	The proposal aligns with the Government Policy Statement as it provides for both generation and demand-response to provide emergency reserves, where the provider is able to meet the technical specifications of the service and is able to provide a service that is additional to that provided through other mechanisms.

The Authority has had regard to the Code amendment principles

7.20. When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to the Code amendment principles, to the extent that the Authority considers they are applicable. Table 5 describes the Authority's regard to the Code amendment principles in the preparation of the Code amendment proposal.

Table 5: Regard to the Code amendment principles

Principle	Consideration
Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	The Authority and the System Operator consider that the risk of a short-term occurrence of inadequate supply to meet demand is increasing, as the power system transitions to more intermittent generation and CER, along with the risk of unavailability of thermal generation and growing demand. The wholesale market generally provides effective signals for participants to invest in and operate adequate supply to meet demand. However, it is neither: • possible for participants to effectively predict (and hence manage) the risk of a grid emergency due to an unusual coincidence of high demand and low supply; nor • cost-effective to invest in additional sources of supply for these infrequent events.
Costs and benefits are summarised	The costs and benefits of the Code amendment proposal are set out in the evaluation of costs and benefits in section 7.3. The Authority considers that the key benefits of this Code amendment proposal include: • a more secure and reliable power system; • reduced costs to consumers from involuntary load curtailment; and • greater confidence in New Zealand's electricity supply.

	The Authority considers that the key costs of this Code amendment proposal include: • implementation and operation costs for the System Operator and Clearing Manager; and • the costs to providers of emergency reserves, including preparation, availability and activation costs, which can be recovered as pre-event and event fees.

Questions

Q5. Do you agree with the objective of the proposed amendment? If not, why not?

Q6. Do you agree the benefits of the proposed amendment outweigh its costs? Please provide evidence to support your view.

Q7. Do you agree the amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's objectives in section 15 of the Act.

Q8. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act? If not, why not?

8. Next steps

8.1. If we decide to proceed with the implementation of an ERS in time for winter 2026, we propose the following next steps:

(a) finalisation of Code changes, targeted for December 2025;

(b) System Operator to consult on amendments to the Ancillary Services Procurement Plan and key contract terms for emergency reserve, targeted for early 2026; and

(c) commencement of the ERS in Q1 or early Q2 2026, to enable use in winter 2026.

9. List of Appendices

Appendix A: Proposed Code Amendment

Appendix B: Concept Consulting Cost Benefit Analysis

Appendix C: Format for submissions

Appendix A Proposed Code Amendment

Appendix A Proposed Code amendment

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

activate, for the purpose of **emergency reserve**, means the process of issuing instructions and notifications to providers of **emergency reserve** for the use of **emergency reserve** in real-time, as specified in the **procurement plan**

allocable cost has the meaning set out in clauses 8.55 to 8.58A

ancillary service means **black start**, **emergency reserve**, **over frequency reserve**, **frequency keeping**, **instantaneous reserve** or **voltage support**

bona fide physical reason includes,—

[…]

(bb) in relation to an **ancillary service agent** providing **emergency reserve**,—

(i) a reasonably unforeseeable full or partial loss of demand or reserve capability (as the case may be) that is the subject of an **ancillary service arrangement** to provide **emergency reserve**; or

(ii) a reasonably unforeseeable full or partial loss of generating capability from an item of **generating plant** that is the subject of an **ancillary service arrangement** to provide **emergency reserve**; or

(iii) a reasonably unforeseeable change in circumstances such that the **ancillary service agent** will breach any consent held by it under the Resource Management Act 1991; and

[…]

controllable load, for the purposes of Part 8, means the quantity of resources (in MW) that a **connected asset owner** estimates will be available for use by the **system operator** under a **grid emergency**. The available **controllable load** must exclude—

(a) resources a **connected asset owner** intends to use for its own network demand management purposes; and

(b) any resources offered into the **instantaneous reserves** market; and

(c) any resources bid or offered on behalf of a **dispatch-capable load station** or **dispatch notification purchaser** or **dispatch notification generator**; and

(d) any contracted **emergency reserve**

emergency reserve means—

(a) an **ancillary service** that provides access to generation capacity or load that can be used to minimise the **electrical disconnection** of **demand** in a **grid emergency**, as specified in the **procurement plan**; but

(b) excludes any generating capacity or load that—

(i) otherwise provides services, or has been used to provide such services within the 12 months prior to being offered for use as **emergency reserve**—

(A) in the **wholesale market** other than **black start**; or

(B) in response to a contract or other arrangement with a **purchaser** or **asset owner** in circumstances that may correspond with a **grid emergency**; or

(ii) is provided by an **energy storage system**, other than an **energy storage system** that is located on a **consumer's** premises for the purpose of reducing demand from the **grid**

emergency reserve event is an event involving the **pre-activation** or **activation** of **emergency reserve** in a **grid emergency,** or when a **grid emergency** is reasonably foreseeable by the **system operator**, in accordance with an **emergency reserve** contract and as specified in the **procurement plan**

emergency reserve event cost means the total costs payable under **emergency reserve** contracts relating to an **emergency reserve event** within a **billing period**

emergency reserve pre-event cost means the total amount of pre-event costs payable under **emergency reserve** contracts within a **billing period**

emergency reserve pre-event trading period means the relevant **trading period** or periods in which the **system operator** determines that **emergency reserve** must be available, as specified in the **procurement plan** or **emergency reserve** contract

emergency reserve event trading period means the relevant **trading period** or periods in which an **emergency reserve event** occurs

pre-activate, for the purposes of **emergency reserve**, means the process of issuing instructions and notifications to providers of **emergency reserve** to prepare for the use of **emergency reserve**, as specified in the **procurement plan**

Subpart 4—Interruptible load and emergency reserve

8.54A Contents of this subpart

This subpart provides for the provision of information relating to **interruptible load** and **emergency reserve**.

8.54B Ancillary service agents to provide information about interruptible load and emergency reserve

(1) Each **ancillary service agent** that contracts for **interruptible load** or **emergency reserve** in a **network** must, within 10 **business days** of entering

into the contract, give the following **participants** the information in subclause (2):

(a) if the **interruptible load** or **emergency reserve** is contracted on a **local network**, the **connected asset owner** that operates the **local network**:

(b if the **interruptible load** or **emergency reserve** is contracted on an **embedded network**, the **connected asset owner** that operates the **local network** to which the **embedded network** is connected:

(c) if the **interruptible load** or **emergency reserve** is contracted on the **grid**, the **grid owner** that owns or operates the part of the **grid** on which the **interruptible load** or **emergency reserve** is contracted.

(2) The information required is—

(a) a list of the **ICPs** to which the contract relates; and

(b) the maximum **MW** that can be **activated** or interrupted under the contract; and

(c) the commencement and expiry dates of the contract.

(3) If an **ancillary service agent** has given a **connected asset owner** or **grid owner** information under subclause (1), the **connected asset owner** or **grid owner** may require the **ancillary service agent** to provide further information about the **interruptible load** or **emergency reserve** to which the contract relates.

(4) An **ancillary service agent** must comply with a requirement under subclause (3).

8.54BA Provision of information about the use of emergency reserve

The **system operator** must, within 20 **business days** of the conclusion of a **grid emergency** for which the **system operator** has procured or **activated emergency reserves**, **publish** a report containing:

(a) the total amount of **emergency reserve** procured in anticipation of the **grid emergency**;

(b) the total amounts of **emergency reserve pre-activated** or **activated** during the **grid emergency**;

(c) the estimated **emergency reserve pre-event cost** related to the **grid emergency** and the corresponding **emergency reserve pre-event trading periods**; and

(d) the estimated **emergency reserve event cost** related to the **grid emergency** and the corresponding **emergency reserve event trading periods**.

8.58A Emergency reserve costs are allocated to purchasers

The **allocable cost** of **emergency reserve** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula:

$$Share_{PURx} = \left|\frac{ERP_{ct} \times max(0, \Sigma_t ERPOfftake_{PURxt})}{\Sigma_x max(0, \Sigma_t\ ERPOfftake_{PURxt}}\right| + \left[\frac{ERE_{ct} \times max(0, \Sigma_t EREOfftake_{PURxt})}{\Sigma_x\ max(0, \Sigma_t EREOfftake_{PURxt})}\right]$$

where

$Share_{PURx}$	is **purchaser** x's share of **emergency reserve allocable costs.**
ERP_{ct}	is the **emergency reserve pre-event cost** in the billing period
$ERPOfftake_{PURx}$	is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **emergency reserve pre-event trading periods** in the **billing period**.
ERE_{ct}	is the **emergency reserve event cost** in the **billing period.**
$EREOfftake_{PURxt}$	is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **emergency reserve event trading periods** in the **billing period**.

Schedule 8.3
Technical codes

Technical Code B – Emergencies

5B An **ancillary service agent** must, as soon as reasonably practicable following a request by the **system operator,** inform the system operator of its available **emergency reserve** using a method or form agreed with the **system operator**.

6 Actions to be taken by the system operator in a grid emergency

(1) If an **unsupplied demand situation**, or insufficient generation and **frequency keeping** gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

(a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure there is sufficient generation and **frequency keeping**:

(b) request that a **purchaser** or a **connected asset owner** reduce **demand**:

(c) require a **grid owner** to reconfigure the **grid**:

(ca) **activate emergency reserve**:

(d) require the **electrical disconnection** of **demand** in accordance with clause 7(20):

(e) take any other reasonable action to alleviate the **grid emergency**.

(2) If insufficient transmission capacity gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

(a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure that the available transmission capacity within the **grid** is sufficient to transmit the remaining level of **demand**:

(b) request that an **asset owner** restores its **assets** that are not in service:

(c) request that a **purchaser** or **connected asset owner** reduces its **demand**:

(ca) **activate emergency reserve**:

(d) require the **electrical disconnection** of **demand** in accordance with clause 7(20):

(e) take any other reasonable action to alleviate the **grid emergency**.

(3) If frequency is outside the **normal band** and all available **injection** has been **dispatched**, the **system operator** may require the **electrical disconnection** of **demand** in accordance with clause 7(20) in appropriate block sizes until frequency is restored to the **normal band**.

(4) If any **grid** voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1), and is sustained at or below that limit, the **system operator** may require the **electrical disconnection** of **demand** in accordance with clause 7(20) in appropriate block sizes until the voltage is restored to above the minimum voltage limit.

(5) The **system operator** may, if an unexpected event occurs giving rise to a **grid emergency**, take any reasonable action to alleviate the **grid emergency**.

7 Load shedding systems

[…]

(7) To avoid doubt, the **demand** calculated to comprise **automatic under-frequency load shedding** blocks must be net of any **interruptible load** **or emergency reserve** procured by the **system operator**.

[…]

(17) The **system operator**, each **connected asset owner**, each **grid owner** and each relevant **retailer** must, to the extent reasonably practicable, co-operate to ensure that any **interruptible load** or **emergency reserve** contracted by the **system operator** that could affect the size of an **automatic under-frequency load shedding** block is identified to assist the **connected asset owner** or the **grid owner** to meet its obligations in subclauses (1) to (9).

9 Obligations of generators and ancillary service agents to take independent action

(1) The following independent action is required of **generators** and **ancillary service agents** during the occurrence of extreme variations of frequency or voltage at the **points of connection** to which their **assets** are connected (such extreme levels of frequency or voltage are deemed to constitute a **grid emergency** and require a fast and independent response from each **generator** and each **ancillary service agent**):

[…]

(2) For the purpose of subclause (1), **ancillary service agent** does not include a person in respect of that person's provision of **emergency reserve**.

Schedule 13.3AA
Managing an unsupplied demand situation in the dispatch schedule

3 Adjusting expected profile of demand for demand that was unable to be supplied

(1) As soon as practicable after the **system operator** instructs the **electrical disconnection** of **demand** in accordance with Schedule 8.3, Technical Code B, clause 6(1)(d) or 6(2)(d), or the **activation** of **emergency reserve** in accordance with Schedule 8.3, Technical Code B, clause (6)(1)(ca) or 6(2)(ca), the **system operator** must—

(a) calculate and record the **demand** limit for each relevant GXP; and

(b) record the Short-Term Load Forecast values for the relevant load forecast regions for all available 5-minute market intervals in the future, being the linear interpolation across time of the load forecast prepared under clause 13.7A.

(2) After the **system operator** has made an instruction ~~instructed the **electrical disconnection** of **demand**~~ under subclause (1), the expected

profile of **demand** used in the **dispatch schedule**, for the purposes of calculating **dispatch prices**, is—

[…]

(4) The predicted demand referred to in subclause (3) is the amount of **demand** that was expected to be present at a given **conforming GXP** in interval 'i' absent the instruction ~~to **electrically disconnect demand**~~ referred to in subclause (1), estimated at the time of the instruction referred to in subclause (1), calculated as follows:

[…]

Appendix B Concept Consulting Cost Benefit Analysis

Cost Benefit Analysis for Emergency Reserve Scheme
Final report

concept
consulting

About Concept Consulting Group Ltd (www.concept.co.nz)

Concept is one of New Zealand's leading applied economics consultancies. We have been providing high-quality advice and analysis for more than 25 years across the energy sector, and in environmental and resource economics. We have also translated our skills to assignments in telecommunications and water infrastructure.

Our strength is from combining economic & regulatory expertise with deep sector knowledge and leading quantitative analysis.

Our directors have all held senior executive roles in the energy sector, and our team has a breadth of policy, regulatory, economic analysis, strategy, modelling, forecasting, and reporting expertise. Our clients include market participants across the entire utility supply chain, regulators, and governments – both in New Zealand and the wider Asia-Pacific region.

Disclaimer

Except as expressly provided for in our engagement terms, Concept and its staff shall not, and do not, accept any liability for errors or omissions in this report or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions, arising out of or associated with its preparation.

The analysis and opinions set out in this report reflect Concept's best professional judgement at the time of writing. Concept shall not be liable for, and expressly excludes in advance any liability to update the analysis or information contained in this report after the date of the report, whether or not it has an effect on the findings and conclusions contained in the report.

This report remains subject to any other qualifications or limitations set out in the engagement terms.

No part of this report may be published without prior written approval of Concept.

Purpose of this report

The Electricity Authority (**the Authority**) is consulting on introducing an Emergency Reserve Scheme (**ERS**) to both unlock industrial demand flexibility and boost security of New Zealand's power supply ahead of next winter.

The Authority requires independent cost & benefit analysis (**CBA**) for the proposed ERS to understand its benefit relative to alternative options, particularly with regards to the current approach of involuntary load shedding.

The Authority has engaged Concept Consulting (**Concept**) to undertake the CBA.

This report summarises our approach, the options, inputs and assumptions considered in the CBA and the resulting outcomes and conclusions.

Background

In its 31 July 2025 consultation paper on 'Establishing an Emergency Reserve Scheme', the Authority describes the need for an ERS as follows:

The increasing share of intermittent capacity in New Zealand's electricity generation mix is creating challenges for security of supply – especially on cold, still mornings and evenings (known as 'peak capacity risk'). Growth in electricity demand and the declining availability of thermal fuel for generation (especially gas) are exacerbating this risk. The System Operator's assessments of security of supply suggest peak capacity risks will continue until there is sufficient investment in flexible resources, such as batteries and demand flexibility.

Existing market mechanisms provide sufficient price signals for investment in, and operation of, the electricity system to manage peak capacity risk and balance the system under normal conditions. However, in limited circumstances – such as a combination of high demand and a high level of unplanned outages – there is a risk that the market will not balance supply and demand.

An ERS could provide an additional tool for the System Operator to use in periods of acute system stress. It would promote power system reliability and security by helping to manage critical supply shortfalls and could avoid consumers' power being disconnected during emergency events.

Summary

In the CBA we considered three alternative options, that each could maintain the supply-demand balance when there is a forecast supply shortfall. They are:

- **Status quo: involuntary load shedding**
- **Option 1: an ERS allowing for voluntary load shedding**
- **Option 2: interventional investment to cover peak capacity risk**

Our assessment is that option 1, an ERS allowing for voluntary load shedding, has the highest benefit. Over 20 years, its costs are the lowest and >$20million less than continuing with the current practice of involuntary load shedding. The costs of interventional investment is prohibitively high (but included in the options assessment as it could mitigate the risk of involuntary load shedding).

The quantified benefit is dependent on a range of inputs and assumptions, some of which rest quite heavily on judgements, for example about electricity demand growth and the extent to which there will be sufficient generation to always meet demand.

These judgements translate into assumptions around the frequency of possible load shedding events and the volume of unserved demand when an event occurs. We have tested the sensitivity of the ERS quantified benefit to variations in these assumptions (and others) and found it is quite robust. However, a scenario assuming unfavourable outcomes for two or more assumptions can significantly reduce the ERS benefit (and potentially render it negative).

The qualitative assessment (considering non-quantifiable costs and benefits) unambiguously points towards an ERS as the preferred solution, assuming it can be designed in a way that it would not affect incentives for market-driven generation investment and demand response participation in the wholesale market. This is because it would avoid/minimise a range of indirect costs that are difficult to quantify – such as the loss of consumer confidence in the electricity system.

Overall, the quantified and non-quantifiable costs and benefits together indicate there is a strong case for the proposed ERS.

Framework

CBA is a common tool in evaluating the benefit of an investment to the wider public.

In the electricity sector, Transpower uses it to approximate whether its investments in grid enhancements provide and maximise net benefits to consumers – it is defined in Transpower's Input Methodologies for capital expenditure (**the Capex IM**) and referred to as the Investment Test (**IT**).

We have been guided by the Transpower IT due to its long-standing operation and electricity sector familiarity with it. Its key elements are briefly summarised on the next slide.

Where the IT excludes non-electricity market costs and benefits, we include these for completeness in our qualitative assessment. The Authority may discount or omit these costs and benefits if it chooses. This would not, in our assessment, alter the preferred option.

The Investment Test

1. **Objective** – promote the long-term benefit of consumers, based on a robust options assessment.
2. **Decision criteria** – net electricity market benefits (benefits less costs). The preferred solution must have the highest positive expected net electricity market benefit of all credible options considered. It is expressed in present value terms using a social discount rate of 5%.
3. **Cost and benefits** – constrained to those accruing to electricity market participants (ignores any wider economic impacts of infrastructure and potential wealth transfers), assessed against a status quo option.
   - **Costs** – all capex and opex
   - **Benefits** – Reliability benefits (measured at the 'Value of Lost Load' = **VoLL**), system dispatch benefits (generating electricity with the lowest generation costs), loss benefits (lower levels of electrical losses)
4. **Non-quantifiable benefits** – identifies benefits that cannot be quantified (or are hard to quantify) associated with options that have similar net benefits to the option with the highest net benefit (similar is defined as having a net benefit that is within 10% of the project with the highest net benefit).
5. **Scenario analysis** – tests the robustness of results under various electricity demand and generation scenarios (the 'EDGS').
6. **Sensitivity analysis** – tests the robustness of results to discrete changes in key input assumptions. For example, the impact on net benefit from variations in costs (+/- 30%), VoLL (+/- 50%), reliability (+/- 25%), discount rate (3% / 7%).

Options identification

For comparative assessment we considered three policy options – the status quo and two alternatives:

- **Status quo – involuntary load shedding** (or equivalent events* such as System Operator (**SO**) calls to conserve electricity) continues to be the sole means to deal with a shortfall of supply to met demand. The interrupted supply of electricity to consumers is measured at the price they would have been willing to pay – after the event – to avoid the outage. It is approximated through VoLL. There are costs to administer involuntary load shedding – an ongoing cost to enable it as well as a one-off cost when it occurs. These events also impose indirect costs on energy consumers, sector participants and the economy as a whole.
- **Option 1 – An ERS allows for voluntary load shedding.** It would be drawn upon as the last step before involuntary load shedding and hence reduce the need for it (and the associated costs). Its incremental cost would be measured at the price participants in the scheme have contracted for – before the event – with payments comprising an availability as well as activation component. There would also be a cost to the SO administering the scheme. The presence of the scheme (or uncertainty over how it will be deployed) may affect certain generation investment decisions at the margin (hence create an indirect cost).
- **Option 2 – Interventional investment**** **in place of ERS.** This would be investment into more generation, including build capex as well as ongoing capex and opex to keep the plant(s) running. There might be an incremental investment need for transmission and/or distribution, but this is ignored for the analysis (as likely to be much smaller than expenditure into generation).

* For simplification reasons we have treated involuntary load shedding events and SO calls to conserve electricity as equivalent events. While on average more demand might be unserved following a conservation call, VoLL during an involuntary load shedding event is likely to be higher (possibly significantly) due to the indiscriminatory nature of the curtailment, offsetting (but to an unknown extent) the impact from higher demand curtailment following a conservation call.

** Market driven investment in generation would be expected to happen in all options (hence can be ignored for the CBA).

Approach to options assessment

Our options assessment captures quantified and non-quantifiable costs and benefits.

Quantified assessment – focusses on costs (as per previous slide), which are expressed in present value terms, assessed over a 20-year time horizon.

Each option's benefit is expressed in terms of its total cost difference to the status quo. It is therefore referred to as the relative benefit.

Qualitative assessment – focusses on costs that cannot reliably be quantified, or where quantifying these costs would be very difficult/time-consuming. It is important to ensure these costs fall not within the scope of VoLL. While we would usually apply a tick box analysis to show the relative benefit of all options compared to the status quo (similar to Transpower's approach), we considered such a (more rigorous) approach unnecessary, as the qualitative assessment unambiguously points towards an ERS as the preferred solution.*

Combining results from quantified and qualitative assessments – we assume an equal weighting between quantified and non-quantifiable costs and benefits to reduce the risk of forecast error or incorrect assumptions in the quantified assessment. We note that pursuing a high-level of accuracy in the assumed weighting is unlikely to yield noticeable benefits as both the quantified and qualitative assessments derive the same conclusion.

* assumes policy is specifically designed to avoid affecting market-driven generation investment decisions and demand response participation in the wholesale market.

Quantified assessment

Inputs and assumptions – Unserved demand

Inputs	Assumption/Source	Description	Base case	Sensitivities
Event	Modelling assumptions are guided by the August 2021 situation that resulted in involuntary load shedding	'Event' describes a situation where demand is curtailed due to insufficient electricity supply	n/a	n/a
Electricity winter demand	System operator (SO) 2025 SOSA until 2034, extrapolated to 2065	Electricity demand from April to September	Medium	Low/High
Peak demand factor	SO 2025 SOSA	Peak demand relative to average winter demand	1.4	1.3/1.5
Electricity demand unserved per event	Per August 2021 event	The volume of unserved demand per event	0.6%	0.2%/1%
Event duration	Per August 2021 event	Start to end (time) when demand is curtailed	1.5 hours	1hour/2hours
Event frequency	-> See next slide	Likelihood of an event occurrence in any given year	Difficult transition	Historical trend/Very difficult transition

Event frequency

A key input to the quantified assessment is the event frequency – i.e. the likelihood in any given year of one event occurrence (= a situation where demand is curtailed due to insufficient electricity supply). While historically these events have been rare, it is more likely than not that going forward - at least during a time of transitioning to a new steady state – the event frequency will increase and might even settle at a higher than historical rate. This is due to the increasing proportion of intermittent generation and expected decreasing proportion of 'firm' generation.

However, forecasting the event frequency with enough certainty is difficult, as this is informed by underlying demand growth, the 'peakiness' of demand and the speed at which new (and the type of) generation is commissioned. This is evident in the 2025 annual SOSA, for example, which indicates a high level of future supply uncertainty and changing consumption patterns*. In the quantified assessment, this uncertainty is accounted for by means of three different scenarios (-> next slide), covering a wide range of different outcomes. These consider, for example:

- **Recent historical trends** - increased supply intermittency and demand peakiness, thermal plant retirement, little / no new peaking generation, emergence of batteries as alternative to peaker plants.
- **Generation uncertainty** - likely further retirement of thermal generators (TCC), likely ratio intermittent : firm increases, possible grid scale batteries 'replace' firm generation decline, likely reliability of remaining thermal plant will decrease as plant ages / caution on reinvestment, likely generation + battery build slower than assumed by the Authority/Transpower.
- **Demand uncertainty** - likely to grow, possibly slower than assumed in SOSA, impacted by fossil fuel availability, speed of electrification and EV uptake
- **Peak demand** - likely to grow, but pace and scale are uncertain – potential to (a) increase (demand growth + EV uptake, low smart charge penetration), (b) flatten (moderate smart charger penetration), (c) decrease (high smart charger penetration)

*6 of the 12 highest historical peaks have occurred in 2025 and peaks increasing fall in shoulder seasons when slow start thermal generation is less likely to be operating.

Inputs and assumptions – Event frequency

Scenario	Assumption	Description	Event frequency
Historical trend	Assuming the event frequency observed in the more recent history will continue	Since ~ 2008 there have been three load shedding events, including a SO call to conserve electricity (2011, 2021, 2024). This implies a return period of once per six years, however more weight is assigned to 2020+ events.	~ once every three years
Difficult transition **Base case**	Assuming the future will look **different** from the past.	An increase in load shedding or equivalent events as margins tighten with growing demand, thermal retirement and lagging generation build, exacerbated by an only moderate penetration of smart chargers initially, easing from early 2030s but remaining higher than historical due to lower ratio of firm to intermittent in future generation mix.	Once every year to 2030, then a declining annual likelihood (75% to 2035, 50% from 2035)
Very difficult transition	Assuming the future will look **very different** from the past	High demand growth, ratio peak to energy remains constant or increases, generation build is slower than assumed, erratic inflows of recent years persist, gas availability continues to fall, some battery investment but less than assumed.	Three times per year to 2030, easing to two per year to 2035 and then settling at one event per year

Inputs and assumptions – ERS

Inputs	Assumption/Source	Description	Base case	Sensitivities
Set up costs	Concept estimate	One-off SO costs to set up an ERS	Cost redacted for confidentiality reasons	+/-50%
Fixed administration costs	Concept estimate	Fixed annual SO costs to administer an ERS	Cost redacted for confidentiality reasons	+/-50%
Variable administration costs	Concept estimate	Per event SO costs to administer an ERS	Cost redacted for confidentiality reasons	+/-50%
Load participating in an ERS	Per Electricity Authority, kept flat over time as participation rate means there is a significant surplus	Maximum load participating in an ERS	170 MW	+/-50 MW
Price paid to load	Concept high-case	Price paid to participating electricity consumers	$5k/MWh	+/-$3k/MWh
Generation participating in an ERS	Concept estimate, kept flat over time (drawn upon before load)	Maximum off-market generation participating in an ERS (eg, diesel generators)	10 MW	+/- 10 MW
Price paid to generators	Concept estimate (includes a cost margin to incentivise participation)	Price paid to off-market generators participating in an ERS	$1k/MWh	-

Inputs and assumptions – Others

Inputs	Assumption/Source	Description	Base case	Sensitivities
VoLL	$20k/MWh	Value of lost load (=economic value of involuntary load shedding)	$20k/MWh, inflated to 2025	+/-50%
CPI	Concept estimate	Inflation factor to convert real 2025 inputs into nominal figures	2%	-
Discount rate	As per requirements for the Transpower Investment Test	Converts forecast nominal cash flows into present values	5%	3%/7%
Administration costs involuntary load shedding	Concept estimate	Fixed and variable annual SO costs to administer involuntary load shedding	Cost redacted for confidentiality reasons	-
Interventional expenditure	Concept estimate, peaker plant (OCGT). 50% of the plant(s) will be allocated to accommodate peak demand	One-off build capex and ongoing operating and maintenance expenditure	100 MW in 2028, 50 MW in 2040	-

CBA results – Costs and (relative) benefits

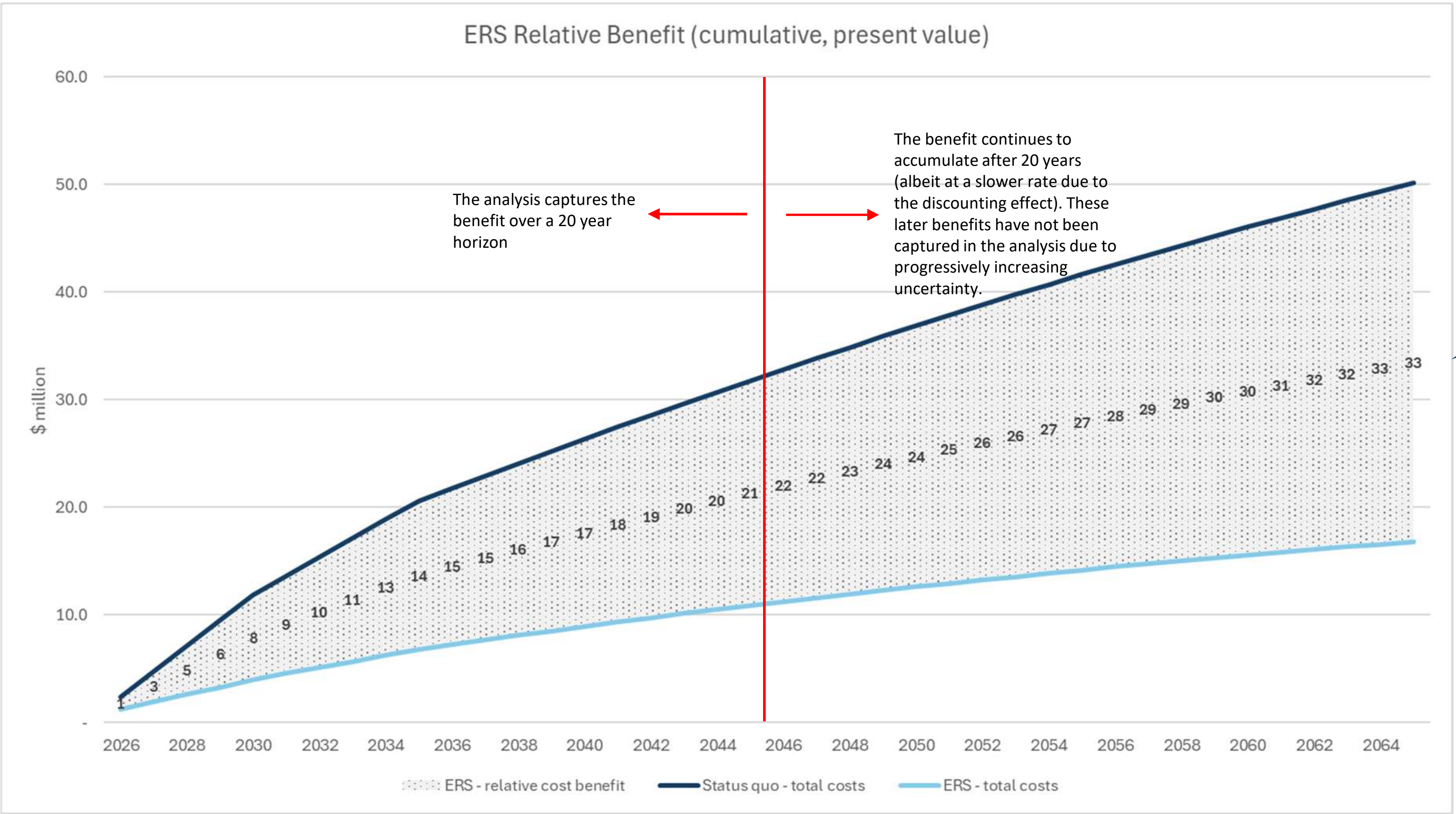
Option	Assumption/Source	Value
Status quo - involuntary load shedding	Total costs – present value	$32 million
	Total benefit – present value	zero
Option 1 – An ERS allows for voluntary load shedding	Total costs – present value	$11 million
	Total benefit – present value	+ $21 million
Option 2 – Interventional investment to cover peak capacity risk	Total costs – present value	$172 million
	Total benefit – present value	- $141 million

The status quo option has a zero benefit because it assumes continuing with the current practice of involuntary load shedding, i.e. nothing would change

Option 1 has the highest relative benefit, i.e. its costs are lower by $21 million in present value terms than the costs of the status quo option

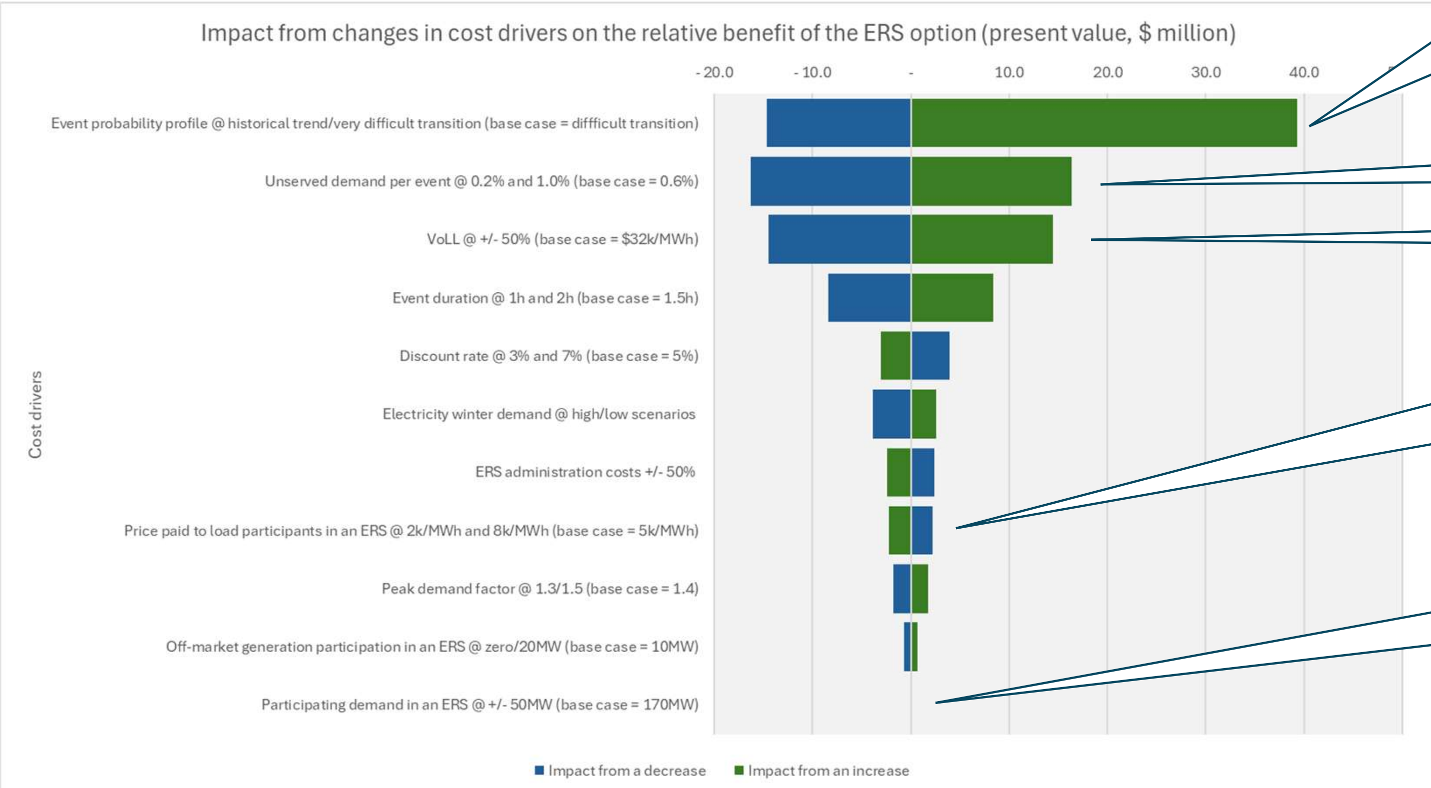
Option 2 has the lowest relative benefit, i.e. its costs are higher by $141 million in present value terms than the costs of the status quo option (even when including in the analysis only 50% of the build, operating and maintenance costs)

CBA results – Build up of ERS benefit



This shows the cumulative build up of the ERS benefit over 40 years

CBA results – Sensitivities



The ERS benefit is very sensitive to changes in event frequency assumptions. When assuming these would continue to follow historical trends, the benefit would reduce by $15m. When assuming a higher frequency ('very difficult transition'), the benefit would increase by almost $40m.

The volume of unserved demand per event also has a high impact on the ERS benefit.

And so does VoLL!

The price paid to load participants in an ERS has a much smaller impact on the ERS benefit. In fact, it could be as high as VoLL before the ERS becomes break-even with the status quo.

170 MW of participating load means even +/- 50MW would have no impact on the ERS benefit (i.e. only a fraction of the 170 MW would be drawn upon in a typical event)

Conclusion – quantified assessment

- The ERS benefit is quite robust – none of the above uncertainties alone have the potential to make it negative.
- Even the most impactful sensitivity – a significant reduction in the volume of unserved demand by event – would not totally offset the ERS benefit of $21m.
- A scenario assuming unfavourable outcomes for two or more assumptions could *potentially* render the ERS benefit negative.

Qualitative assessment

Summary

- The key unquantified risk (cost) is that the ERS scheme's presence or operation negatively affects generation investment (especially firm generation). This is important because even a small change in generation investment (especially if firm) could increase/decrease the number of load-shedding/ERS events.
- A secondary risk to address is its potential impact on demand response participation in the wholesale market.
- We understand from the Authority that these risks are well understood and that an express objective is to design the ERS to mitigate the risks.
- The non-quantified benefits are primarily avoiding indirect costs associated with a less reliable power supply. The loss of consumer confidence, incident and post incident costs, and, New Zealand's reputation and attractiveness to foreign visitors and investors. In our opinion, these benefits are potentially very material, especially if – as we assess is likely – the risk of involuntary load-shedding events is increasing.
- On the basis the scheme does not negatively affect generation incentives, it is very likely that non-quantified benefits from introduction of the ERS exceed non-quantified costs.

Non-quantifiable costs – investment impact (1)

The main cost or risk is that the ERS affects incentives for generation investment. This risk arises from:

- the presence of the scheme and that uncertainty over how it will be deployed will affect certain generation investment decisions at the margin. For example, introduction of the scheme could introduce uncertainty, increase risk and cost of capital and therefore the willingness, timing and scale of investment in peaking (an potentially other) generation, battery investment.
- how the scheme is actually deployed in practice, with potential for more discretionary or 'out of merit order' deployment which risks uncertainty and or distorting price signals.

In reaching our overall conclusion (see summary slide), we have discounted this cost assuming – following the Authority's lead – that an ERS can be designed in a way it would not affect incentives for market-driven generation investment.

We note, however, that even a well-designed ERS may not mitigate this risk entirely. This is because simply its existence may dampen investment incentives at the margins – at least initially until its practical application gives assurance to market participants it is working as intended.

Non-quantifiable costs – wholesale market impact (2)

There is also a risk that the presence of the ERS reduces incentives for parties with demand-response capability to participate in the wholesale market. We consider that the design of the ERS lowers this risk because:

- the ERS includes an "additionality" requirement that would exclude "participation by those for which other mechanisms are more appropriate" including "price sensitive load that would otherwise be used in the absence of an ERS".
- the ERS is only expected to be utilised infrequently, so those willing to reduce demand more frequently will likely make more money by participating in the wholesale market.

For the purposes of this CBA, we assume that this risk is not material due to these design factors above. However, we note that over time, these risks may increase if:

- as participants become more accustomed to reducing their demand at certain times, it becomes more difficult to assess additionality (i.e. whether or not they would still respond if the ERS was not in place).
- the ERS becomes used more frequently, increasing the potential revenue from the ERS (compared to the value of actively participating in the wholesale market).

Unquantified benefits (costs avoided if ERS prevents involuntary load shedding)

	Cost description	Category	Beneficiary	Comment
1	Loss of consumer confidence in the electricity system and the consequential costs of this. For example, investment in back-up generators, citizen discontent.	Consumer confidence	Electricity market / broader society	Expect discontent to escalate with event frequency.
2	The cost / risk of consequential events, for example, loss of supply to medically dependent customers, failure of back up supply to essential services (hospitals, civil emergency, traffic systems, communications and water services).	Disruption	Electricity market / broader society	High impact, possibly low probability, risk escalates with event frequency.
3	Reputational damage to New Zealand as a modern economy with reliable public infrastructure. This may impact tourism, foreign direct investment, credit ratings and the cost of capital for New Zealand investors.	NZ reputation	Broader society / electricity market /	Small change has potentially significant impact.
4	Costs to electricity consumers from a general lack in demand side flexibility/capability amongst electricity consumers.	Consumer confidence	Electricity market	It is assumed an ERS would enhance the willingness to participate in demand response programmes.
5	Costs to participants such as Transpower, distributors, retailers to communicate with customers, the media and stakeholders, for urgent call outs and to power restoration.	Transaction costs	Electricity market	An involuntary load-shedding event may disrupt normal operations for those affected for hours or even days.
6	Financial and opportunity costs to Transpower, regulatory authorities and other parties for post-event inquiries, compliance or other investigations.	Transaction costs	Electricity market	Opportunity cost likely larger than financial cost (which would be ~$.5m+ for 2021 like event).

Appendix C Format for submissions

Submitter	

Questions	Comments
Q1. Do you support the Authority's proposal to amend the Code to establish an emergency reserve scheme?	
Q2. Do you have any comments on the drafting of the proposed amendments?	
Q3. Do you consider any further Code amendments are required to establish the emergency reserve scheme as outlined in section 5?	
Q4. Do you see any unintended consequences in making the proposed amendments?	
Q5. Do you agree with the objective of the proposed amendment? If not, why not?	
Q6. Do you agree the benefits of the proposed amendment outweigh its costs? Please provide evidence to support your view.	
Q7. Do you agree the amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's objectives in section 15 of the Act.	
Q8. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act? If not, why not?	