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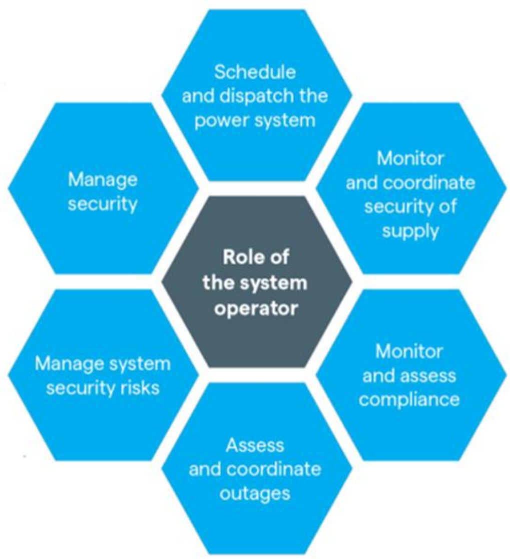
Potential solutions for peak electricity capacity issues

Thank you for the opportunity to respond to the Electricity Authority's (Authority) consultation on potential solutions for ensuring the electricity system has the capacity to meet peak electricity demand. The issues raised in the consultation go to the heart of our role as system operator: to keep electricity supply and demand in balance and manage voltage and frequency on the grid so the power system is stable at all times.[1]

Transpower's·role·as·system·operator¶



The most fundamental responsibility of the electricity industry and its market design, is that supply can meet demand at all times, ensuring the lights stay on and enabling communities, business and industry to thrive across Aotearoa New Zealand. Managing supply and demand, and ensuring a secure and resilient electricity system, is becoming increasingly challenging and important as we transition to greater reliance on variable renewable electricity to support electrification of the economy. Any failure to do so can severely harm consumers, undermining confidence in the electricity industry and the market. This context underpins Transpower's purpose, strategically and operationally, in its roles as both system operator and the owner and operator of the National Grid.

Aotearoa New Zealand's electricity system faces both peak and energy demand challenges. Winter-peak demand is increasing, and there is an increasingly tight supply-demand balance to meet current energy needs. As peak demand grows, additional capacity is needed to meet it, and as the contribution from intermittent generation grows so does the need for other resources to maintain supply when there is no wind or sunshine. Investment in flexible capacity and resources has not kept pace with demand, a situation that became clear during the last two Winters. The tightness of supply-side capacity to meet demand also means it has become increasingly difficult for Transpower and

[1] https://www.transpower.co.nz/system-operator/our-system-operator-role/our-system-operator-role

generators to take the planned maintenance outages that are essential to the longer-term reliability of the electricity system.

We have been fortunate to have healthy levels of rainfall and hydro storage during the last two winters, helping to offset constraints on thermal generation availability, including material unplanned outages in Winter 2023 at Huntly and Stratford power stations. Had these coincided with drier conditions the outcome for households, businesses, and communities could have been very different. Unplanned outages and retirements of existing ageing thermal plant heightens the risk to security of supply.

These are live issues that must be dealt with now and cannot be left for some-time in the future.

We therefore recommend the Authority prioritise (near-term) a review of system security settings, enhanced market outlook monitoring and reporting, and develop one or more preferred backstop measures. We also recommend the Authority investigate an interim ancillary service product that would allow the system operator to procure capacity additional to what is already in the market. Incentivising additional capacity increases the likelihood it will be available when needed. In the meantime, we will continue to collaborate cross-industry, provide information on system risks using our existing tools, coordinate existing resources and do our best to avoid interruptions to power supply.

We agree with the Authority’s problem definition

Our Winter 2024 Outlook paper, published in January 2024, identifies two main risks for the coming winter: the peak capacity challenge, and the ever-present dry-year risk (the energy challenge arising from our wealth of hydro resources but with limited storage capacity):

We also note MBIE’s concerns in its Briefing to the Incoming Minister (BIM) for Energy:

Our most immediate challenge is to ensure sufficient electricity generation to meet peak demand during cold winter mornings and evenings (“firming”). These tight periods can last minutes or hours and are a particular challenge at times when our thermal generators are not already running to provide baseload electricity supply, when the wind drops, or when the weather is colder than forecast.

The experience from Winter 2023 highlights the challenges that need to be managed to avoid interruption to power supply during system peak demand this winter. Last year there were periods where supply balances were low, including during the second highest ever daily peak. The industry had around 700 MW of generation on long-term (unplanned) outage which increased the reliance on available generation in the system, operating or committed to the market. While more assets were committed to the market, the lower physical capacity available on the power system meant electricity supply was more vulnerable to any further asset failure.

Despite improvements in handling low residual and insufficient generation events, we agree with the Authority that these situations will remain a challenge.[2] We are expecting and planning for another challenging winter in terms of ensuring the peak capacity requirements are met. As we have raised in various submissions and forums, we are concerned that without further tools available it will be difficult to keep the system secure in the face of unanticipated events. However, we agree with the Authority that given the limited changes made in the last 12 months, options for addressing peak

[2] https://www.ea.govt.nz/news/general-news/review-of-low-residual-and-insufficient-generation-events/

electricity capacity issues in "the short-term are limited to coordinating resources already in place or in the process of being implemented."

Broadly, we consider the Authority's consultation paper to ask the right questions. We agree the operational coordination issue is the most pressing in the near-term, and support the Authority's view that options to assist capacity now must not hinder mid and long-term investment signals for flexibility. More generally we support the Authority making its decisions, mindful of how best to apply scarce resources (its own and that of participants) given all the other future-focussed and enabling work waiting to be done – including by Transpower in its role as system operator.

We support the Authority's intention to progress work on lowering barriers for BESS and demand-side flexibility participation

The Authority has correctly identified the need to trade-off competing priorities: the certainty new products might bring, internationally proven unintended consequences of out-of-market capacity mechanisms, the time required to bring a new product to market, the expected acceleration in flexibility resource investments, and the opportunity cost of resourcing a relatively complex project.

A clear priority for the industry is to identify and remove barriers to participation of new technologies and the demand-side, the benefits of which are not limited to its potential to mitigate peak electricity capacity issues. We agree the Authority should prioritise this work, and more generally support Code review processes focussed on transitioning to regulations that recognise system impacts (benefits and costs) regardless of the technology causing them.

Investment in system operator tools, processes and resources will be required for implementation of the initiatives the Authority currently prefers. We are available to help the Authority understand what is required as it progresses its project.

We recommend the Authority prioritise a review of system security settings, with Transpower progressing enhanced market outlook and development pipeline reporting

Transpower considers that the Authority should progress the following workstreams aimed at addressing peak capacity risk:

(i) review of scarcity prices and security of supply settings
(ii) enhancing system operator assessment of and reporting on market outlook and risks, and
(iii) information on industry development pipeline – enhancing Transpower's connection pipeline reporting.

Review of scarcity prices and security of supply settings

The scarcity prices and security of supply settings, specified in the Code, are key to enabling our work as system operator to efficiently inform a market response to peak electricity capacity issues (as well as energy issues). Tight market conditions heighten the importance of ensuring they are fit-for-purpose, taking into account the changing risks, economics and community expectations for electricity from across the economy.

Our 2023 paper Evolving Security of Supply explains the importance of prioritising a review of the security of supply settings underpinning our Security of Supply Annual Assessment analysis. The Authority's review would progress implementation of MDAG recommendation 16 (Scarcity pricing parameters)[3] to set appropriate scarcity pricing to signal the increased value of electricity and the benefits that flexible resources provide e.g. batteries, peaking generation and demand response. As system operator we are available to help the Authority progress this review.

Enhancing system operator assessment of and reporting on market outlook and risks

We consider there needs to be improved market outlook reporting and monitoring of market risks, to assess if the market is delivering as expected and inform a market response. As system operator, we could work to enhance the monitoring of risks and provision of information about them to inform a market response. However, we are not currently funded to conduct this work.

This should include updating system operator information provision to the market. Currently we provide the Security of Supply Annual Assessment, New Zealand Generation Balance (NZGB) planning tool, Electricity Risk Curves, System Security Forecast, and an annual winter outlook (Winter 2024 Outlook). These can be enhanced to provide more detailed and/or more regular information to the market. It should also include implementation of Tranche 1 MDAG recommendation 15 (Seasonal outlook report),[4] which can be progressed without amendment to the Code.

We can complete some initial work with our current level of resource and funding. However, we would not be able to move faster or provide more extensive enhancement with our current resourcing and funding levels. For example, we are currently working to systemise (code) tools supporting look-back analysis of real-time market outcomes to enable more efficient, robust and lower opportunity cost provision of information about the factors leading to Low Residual situations, including near-misses. In contrast, it would require additional resources and funding to systemise SOSA analysis to allow more frequent (than annual) updates.

Information on industry development pipeline – enhancing Transpower's connection pipeline reporting

Transpower, as the owner and operator of the National Grid and the system operator, is well placed to lead and progress implementation of MDAG recommendation 17 (Information on development pipeline).[5] Transpower already holds much of the information anticipated: demand trends and outlook, project development pipeline, and projected energy/capacity margins. As MDAG notes, Transpower's connection enquiry pipeline has significantly improved the visibility of generation and load projects and we could engage with stakeholders to better understand what information would help them to make high quality contracting and investment decisions.

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[3] MDAG final recommendations report: Scarcity pricing parameters (Recommendation 16) – Update the security standard and associated settings for the spot market to ensure they properly reflect the value of reliability to consumers. These have not been updated for many years. In addition, consider indexing shortage values (like Australia) and undertake further updates where required. If the parameters are set too low, the system will be less reliable than consumers want (and vice versa).

[4] MDAG final recommendations report: Seasonal outlook report (Recommendation 15) – The Authority to publish quarterly briefings on current and expected market conditions (akin in concept to the quarterly reports published on the primary sector) with a view to regularly calibrating public and political expectations in relation to the wholesale electricity market.

[5] MDAG final recommendations report: Information on development pipeline (Recommendation 17) – Collate and publish comprehensive and regular updates on the demand trends and outlook, project development pipeline, and projected energy/capacity margins.

Enabling the future market needs investment in system operator tools and processes

Our system operator tools were designed for an era of coordinating a few large participants. But that is the industry of the past. The future is many more participants, including much smaller capacity resources that are more widely distributed, and with greater complexity. And this future is arriving faster than had been anticipated, for example:

- we have about 65 new Interruptible Load sites since 2019
- in 2023 we supported the entry into the market of two new entrant generation owners (Lodestone and New Power Energy[6]), the first utility-scale BESS, the first utility-scale solar farm, and also the first demand side aggregator offering energy, and
- we also set-up five new generation connections last year, not including the change in dispatch type to an existing generator - the most in one year since 2005, if not since the establishment of the wholesale electricity market.

Through this period of change and increased volume, we need to ensure our existing obligations are maintained, whether this be in maintaining our principal performance obligations (PPOs), supporting the broader Code obligations or maintaining our enduring relationships. Investing in the system operator tools and processes will be necessary to maintain the appropriate service levels, requiring new capabilities over and above those invested in historically.

On 26 January 2024, the Authority published its decision allowing system operator discretion to approve wide-area aggregations of demand-side load to bid at single GXPs. This rule change will help demand-side participation and deliver benefits for consumers through greater levels of competition in the market. However, the extent to which system security can accommodate such aggregations will be limited, with the current market system dispatch processes (to remain manageable) also constraining disaggregation to many GXPs. Trials have proven that even quite small quantity aggregations leads to uncertainty in network modelling that reduces system stability. The increasing complexity of the system operations from this change will require investment to ensure benefits can be delivered to consumers.

Potential backstop options should be investigated

We consider it would be prudent for the Authority to explore and develop backstop options(s) ahead of time. The transition brings increasing supply and demand uncertainty and lumpy risks (e.g. thermal retirement) and developing and implementing new market settings takes time.

Developing backstop option(s) now would prevent having to design something on-the-fly if it is needed at short-notice.[7] As an example, our ability to rapidly implement the winter 2023 initiatives was in large part because we had already explored options for sensitivity schedules and wind-forecast publication. When these were required to be delivered at pace, the initial thinking had already been done. The ancillary service product developed by the CEO forum is a potential backstop option, as are the Authority's interim options:

- Option 1: Contracts for out-of-market resource (which is similar to the CEO forum option)
- Option 2: Out-of-market tender for emergency demand response
- Option 3: Provide payments to participants to commit their resources to the market: we consider sub-option (a), paying for the next 200MW in the merit order, is the most promising.

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6 We are in discussion with four other new entrant generators we expect to commission within the next 12-18 months.

7 The Authority has suggested *the further analysis and development required* to develop *could take a number of years*.

While the Authority has outlined that it does not favour the option of a standby ancillary service, we think that exploring these options further would be pragmatic and a 'least regrets' approach to risk management.

The appendix attached to this letter provides our detailed response to the Authority's questions.

Yours faithfully,

Chantelle Bramley
Executive General Manager Operations

Appendix: Responses to the Electricity Authority's questions

Question	Transpower response
Q1: Do you agree with the principle that the winter capacity margin should be based on the trade-off between the cost of the hours of reserve or energy shortfall and the cost of the peaking generation needed to mitigate it? Do you have any other suggestions on factors the Authority should consider and why?	We recommend the Authority prioritise (near-term) a review of SOSA system security settings, including the winter capacity margin and the winter energy margins (and scarcity prices). These settings are key to enabling our work as system operator to efficiently inform a market response to peak electricity capacity issues and energy issues. Tight market conditions heighten the importance of ensuring they are fit-for-purpose, taking into account the changing risks, economics and community expectations for electricity from across the Aotearoa New Zealand economy. The winter capacity and winter energy margins were last reviewed in 2017. The need for a review has been raised in submissions to the SOSA, which we have relayed to the Authority. Our market insight (Evolving security of supply assessment in New Zealand) outlines some of the issues of changing risks, economics and expectations and the potential impacts on security of supply in Aotearoa New Zealand. In addition to reviewing the margins, we consider that it would be useful for additional information to be provided for market participants to better understand the quantity and duration of shortfalls that are 'accommodated' within the settings of the current margins (the North Island winter capacity margin setting is currently 630-780MW). The current winter capacity and winter energy margins focus on the average outcomes with no visibility on the size, duration, frequency and timing of potential shortfall events. These additional dimensions are important for conveying to consumers and wider industry stakeholders the potential system risks implied by the standards, especially given the increasing consequences of shortages as additional segments of the economy are being electrified. This information can help set consumer and market participant expectations, increase public and political confidence and also provide a valuable feedback loop to the Authority, who sets these standards, if the cost/risk trade-offs need to be re-considered to reduce the variance of potential shortfall outcomes. This is also covered in our market insight (Evolving security of supply assessment in New Zealand).
Q2: Do you agree with our assessment of the incentives for demand response? If not, what is your view? Are there other criteria that the Authority should consider?	Consideration should also be given to the extent to which there may be potential barriers to demand-side participation. We believe the use of pilots and trials is an effective way to understand these issues. As an example, the Ara Ake winter innovation pilot[8] highlighted some important operational considerations for the update of flexible DER such as the impact of aggregation across the network on operational security. MDAG have also recommended the use of pilots and trials to standardise demand-side flexibility interfaces and systems and protocols.

[8] Ara Ake, Innovative pilot shows Virtual Power Plants can play an important role in managing winter peaks, February 2024

Question	Transpower response
	Another important factor in increasing incentives is spot price accuracy and reflecting scarcity. The current energy and reserve scarcity prices are in need of review. We currently see generator offer prices exceeding the reserve scarcity price of $3,000/MWh. Dispatchable Demand/Dispatch Notification Load have a limited operational scope, for participants who are predominately influenced by spot prices. Other potential demand-side flexibility service providers who are either not responsive to wholesale price signals, or have significant process constraints, are unlikely to engage in Dispatchable Demand/Dispatch Notification Load. We are wary that updating bid/offer parameters to reflect ramping or reactivation constraints on the demand side could require significant market system investment to reflect these constraints within the market scheduling and dispatch process. Transpower in its role as the system operator would need to be involved to help understand the impact of these issues on the scheduling and dispatch systems. Other alternatives might also become feasible such as an ahead market which would increase the notification time for demand-side participation. Some constraints and other factors that might restrict this participation are discussed in our response to Q3.
Q3: Other than financial incentives, what are the other barriers to entry for demand response participation in the wholesale market that you have identified?	The wholesale market relies on five-minute nodal dispatch to ensure security of the system in real-time. This requires generation and load to respond to five-minute dispatches whilst respecting transmission system constraints. This is a necessary part of the current market design to align spot price signals and physical operation of the system. The physical constraints on consumers' operations might restrict their ability to respond to real-time price signals. Bidding of demand by node would be required to ensure the market dispatch is aligned with the physical state of the power system (including transmission flows). This granularity is needed to maintain operational integrity of the dispatch process which is a key part of the system operator's ability to ensure system security. There would be greater uncertainty/volatility in the demand (and therefore potential demand response) with more granular regions which might limit uptake and participation in the spot market. While some aggregation might be possible,[9] maintaining operational integrity of the dispatch process is paramount for the System Operator. Load parties might find it more cost effective to respond to price signals (without bidding into the market). If this demand response is not bid into the market, it is not visible to the market which will result in increasing 'errors' in the load forecast and therefore the price forecasts from the market schedules. This could also have flow on costs for other services such as frequency keeping.

[9] Transpower submission, Dispatch notification enhancement and clarifications, September 2023

Question	Transpower response
Q4: Do you agree that the Authority should focus its resources on identifying and lowering barriers for BESS and demand side flexibility to participate in the wholesale and ancillary services markets? If so, where do you think the Authority should focus first?	We recommend the Authority prioritise (near-term) a review of system security settings, enhanced market outlook monitoring and reporting, and develop one or more preferred backstop measures. We also recommend the Authority investigate an interim ancillary service product that would allow the system operator to procure capacity additional to what is already in the market. Incentivising additional capacity increases the likelihood it will be available when needed. In the meantime, we will continue to collaborate cross-industry, provide information on system risks using our existing tools, coordinate existing resources and do our best to avoid interruptions to power supply. We also recognise that working to identify and remove barriers to participation of new technologies and the demand-side is a clear priority for the industry, the benefits of which are not limited to its potential to mitigate peak electricity capacity issues. We agree the Authority should prioritise this work, and more generally support Code review processes focussed on transitioning to regulations that recognise system impacts (benefits and costs) regardless of the technology causing them.
Q5: Do you agree that any solutions should satisfy these principles? If not, what is your view and why? Are there other principles that the Authority should consider?	No. We do not consider that the revised principles help identify policy solutions which best satisfy the Authority's statutory objective(s). There are a number of problems with the evaluation criteria, including that they confuse problem definition/policy solutions with evaluation criteria e.g. if the evaluation criteria is "improve the information available to customers and operators" then tautologically the only policy solution will also be to "improve the information available to customers and operators". The commentary in the 'principle' that this would "make efficient contracting and commitment decisions" is a high-level evaluation of the policy option not a principle or evaluation criteria and should be removed. While we recognise, and emphasise in our submissions, the urgency of adopting policy options that would provide a short-term 'fix' to peak-demand risk, we are cautious about using a principle or evaluation criteria that the solution can be adopted within a year particularly when the Authority's own review process is slower than this. For example, the Authority has rejected options in both its consultation papers such as introduction of a capacity market or market for ancillary services partly on the basis they could not be adopted within a year, but if it had progressed these after the first consultation, they could have been implemented prior to the 2024 winter. It is also unusual that principles or evaluation criteria to determine which options would best promote the Authority's statutory objective include the statutory objective itself. This suggests each of the principles (a) to (f) has the same status as the statutory objective (principle (g)) rather than the statutory objective sitting above the principles. This is highlighted vividly in respect of options such as option 3(a) which the Authority has determined would meet the

Question	Transpower response
	statutory objective but has rejected because it does not satisfy most of the other criteria (only one). We question the efficacy of evaluation criteria which conflicts with the Authority's statutory objective.
Q6: Do you agree that a standard product for financial 'super peak' hedges is required?	Transpower supports hedge market reform and development of products that allow electricity generators and retailers to manage their wholesale market/spot risk. It is clear from submissions to the Authority and MDAG that independent suppliers would consider such products to be useful and essential. The MDAG analysis raised this as a potential solution that could have benefit. The MDAG analysis also noted this product could be transitional as spot price spikes could become less correlated with peak demand periods as increased intermittent renewable generation enters the system (see para B29 of the MDAG paper[10]). This highlights the importance of evolution and development of the hedge market and hedge market products rather than relying on static settings. If hedge market reform is prioritised and given the necessary resourcing, it could be in place by winter 2025 (but not in time for winter 2024). The Authority should draw on experience with these types of issues and products in other jurisdictions e.g. in relation to the Australian National Electricity Market (NEM)/the ACCC inquiry into the NEM.
Q7: What factors do you think we should consider in the design of such a product?	No comment. This is a matter for market participants who need/would be impacted by the products to consider.
Q8: Do you agree with our assessment of the risk for the medium to long term?	Aotearoa New Zealand's electricity system faces both peak and energy demand challenges. Winter-peak demand is increasing, and there is an increasingly tight supply-demand balance to meet current energy needs. As peak demand grows, additional capacity is needed to meet it, and as the contribution from intermittent generation grows so does the need for other resources to maintain supply when there is no wind or sunshine. Investment in flexible capacity and resources has not kept pace with demand, a situation that became clear during the last two winters. The tightness of supply-side capacity to meet demand also means it has become increasingly difficult for Transpower and generators to take the planned maintenance outages that are essential to the longer-term reliability of the electricity system. We have been fortunate to have healthy levels of rainfall and hydro storage during the last two winters to offset constraints on thermal generation availability, including material unplanned outages in winter 2023 at Huntly and Stratford power stations. Had these coincided with drier conditions the outcome for households, businesses, and

[10] MDAG, Price discovery in a renewables-based electricity system - Final recommendations paper, December 2023

Question	Transpower response
	communities could have been very different. Unplanned outages and retirements of existing ageing thermal plant heightens the risk to security of supply. In the longer-term, the SOSA shows the capacity margins falling below the capacity security standard until sufficient investment in flexible resources (such as batteries) are made. To reduce the risk to the market these investments would need to be made before the retirement of existing resources otherwise there would be a step reduction in system resource capability. This is discussed further in our response to the Authority's consultation on Ensuring an Orderly Thermal Transition (here).
Q9: Do you think it would be beneficial to create a new integrated standby ancillary service? What is your view and why?	Yes. A new standby capacity service would alleviate the risk of needing to resort to involuntary load control, which is costly, operationally risky and does not meet consumers expectations for reliability of their electricity supply. The standby service could provide security against two system risks: (a) the risk of insufficient offered capacity during peak periods and (b) the risk of sudden unpredicted loss of intermittent generation (IG) capacity. While (a) is likely remedied by other means as has been considered in the Authority's analysis, (b) is ultimately unable to be completely mitigated without some sort of operating reserve. A standby ancillary service would provide incentives for (a) investment in flexible resources and (b) allocating resources with flexible capability for this standby capacity service. The need for this flexibility is arising from the increasing uncertainty in forecast supply and demand (IG and demand response not signalled). There would also be benefits in providing incentives for reducing uncertainty in forecasts which could be achieved by cost allocation of this service. See our response to Q10. MDAG in its final recommendation paper on Price discovery in a renewables-based electricity system has assessed the need for a standby ancillary service as part of its future market design recommendations (recommendation 6).
Q10: How should the costs for a standby ancillary service be allocated?	We consider causer-pays appropriate for standby ancillary services and for other ancillary services. Causer-pays would help manage inefficient increases in need (requirement) for this ancillary service.
Q11: How should the residual requirement be set? Should it be an operational setting or dynamically calculated? If it is dynamically calculated, what factors should be considered in the calculation?	The residual need will be dependent on the uncertainty of supply and demand which will change depending on system conditions (intermittent generation and demand uncertainty). Thus, a dynamic determination will be more reflective of the flexibility required to manage the uncertainty. We recommend considering a dynamic requirement based on a forecast uncertainty measure (FUM). This approach has been developed successfully by Australian Electricity Market Operator (AEMO) and provides for a systematic approach to minimising the standby capacity requirement. It also embraces procuring a quantity of standby capacity

Question	Transpower response
	on the basis of many different system attributes which influence the need (principally, uncertainties in wind forecast, solar forecast, cloud cover, demand). We are mindful that this would require additional development. An interim step could be to have a fixed requirement based on offline calculations.
Q12: How should deficit (scarcity) standby residual be priced in relation to scarcity energy and scarcity reserve prices?	Deficit standby residual should be priced below Instantaneous Reserves (IR) scarcity. The energy and reserve scarcity prices should also be reviewed given the increased value of electricity in the Aotearoa New Zealand economy. The review of these scarcity prices is seen as a key input to improve the incentives for flexible resources in the market and was also signalled by the Authority in its Winter 2023 paper. MDAG have also highlighted the importance of scarcity pricing parameters and recommends updating these (recommendation 16).
Q13: Do you agree with our assessment of the issues associated with procuring additional resource out of market? If not, what is your view and why?	We consider it would be prudent for the Authority to explore and develop backstop options(s) ahead of time. The transition brings increasing supply and demand uncertainty and lumpy risks (e.g. thermal retirement) and developing and implementing new market settings takes time. Developing backstop option(s) now would prevent having to design something on-the-fly if it is needed at short-notice.[11] As an example, our ability to rapidly implement the winter 2023 initiatives was in large part because we had already explored options for sensitivity schedules and wind-forecast publication. When these were required to be delivered at pace, the initial thinking had already been done. The ancillary service product developed by the CEO forum is a potential backstop option, as are the Authority's interim options: • Option 1: Contracts for out-of-market resource (which is similar to the CEO forum option) • Option 2: Out-of-market tender for emergency demand response • Option 3: Provide payments to participants to commit their resources to the market: we consider sub-option (a), paying for the next 200MW in the merit order, is the most promising. While the Authority has outlined that it does not favour the option of a standby ancillary service, we think that exploring these options further would be pragmatic and a 'least regrets' approach to risk management.

[11] The Authority has suggested *the further analysis and development required* to develop *could take a number of years*.

Question	Transpower response
Q14: Do you think it would be beneficial to create an out -of -market tender for emergency demand response? If not, what is your view and why?	Yes, particularly if the mechanism is understood to be temporary pending development of other market enhancements (such as improvements to wind forecasting, embedding Winter 2023 longer-term initiatives, updating scarcity pricing, hedge market development and removing barriers to batteries and demand response). The benefit of such an approach is that it can be used to address the short-term capacity issue. We see this option as being similar to the Code amendments to clarify use and availability of discretionary demand control (Option E) when a tight capacity situation is forecast by the System Operator, especially if this is targeted to demand-response that would not otherwise be bid into the market in the short-term. Another benefit of this approach is that it would increase the knowledge and experience of demand-side participants bidding into the spot market, thus providing greater industry experience for future demand-side flexibility (DSF) development and uptake. Adopting a sunset clause would help mitigate or avoid longer-term unintended outcomes.
Q15: Do you think it would be beneficial to provide payments to resource providers for any uncleared generation and/or dispatchable demand? If not, what is your view and why?	Yes. Providing payments to uncleared resources that are flexible provides greater incentives and certainty for these resources to be available. The capacity shortfall risk arises when there are insufficient resources offered into the market because the expectation is prices are going to be too low. A combination of unexpected events unfolding (drop in intermittent generation, increased demand, generation tripping) can result in tighter capacity closer to real-time with insufficient resources in the supply stack to meet the energy and reserve requirements. The residual is an indicator of the ability to manage these unexpected events. Paying for the residual is an "insurance" payment for these unexpected events. We agree that setting the price for this would be important (if done out of market) and consider that some further work should be done to explore this as an interim option. As an example, a price could cover fixed costs for the resources in the residual. Doing so reduces the 'regret' of the resource being offered into the market but not being dispatched. If the resource is dispatched it would be paid at the spot price. Providing resources greater certainty in their ability to recover fixed costs, even if they are not dispatched but are part of the residual, would reduce their 'regret' of not being dispatched and increase the residual which is needed to cater for unexpected events. Adopting a sunset clause would help mitigate or avoid longer-term unintended outcomes.
Q16: What do you consider to be an appropriate scaling factor to determine the price for residual and why?	Further work is warranted in this area. See our response to the previous question.

Question	Transpower response
Q17: What is your view on the factors the Authority should consider when valuing the costs associated with a standby ancillary service?	The current market settings need to reflect the changing economics, expectation, and risks of the power system. While 22 hours of energy and reserve shortfall is accommodated in the current security of supply standards, this is just an average. In some instances, deeper and longer demand and reserve shortfalls are considered 'acceptable' under the current settings. Greater education and visibility around this is needed. The market settings need updating to ensure the current market is fit-for-purpose to deliver the right investments at the right time. These are discussed in our market insight (Evolving security of supply assessment in New Zealand). In the interim and under the current environment the system is capacity constrained. Events can occur that are unexpected (e.g. plant outages, increased load, forecast uncertainty) which can impact the ability to balance supply and demand. In the transition to a future state where there is increased investment of flexible resources (batteries, peaking generation and demand response) and while the market settings are being updated there could be steps that could be applied in the transition to increase the "insurance" on the system. Ideally this would be fully co-optimised in the market, but time is critical. We would need to explore interim solutions that can ensure additional resources are available to the market (system operator) to dispatch in real-time to manage this period increasing uncertainty with tight capacity margins. Sunset clauses on these interim options would help reduce longer-term unintended outcomes. We would like to see further work on Option (1) (which is similar to the CEO forum option), (2) and 3(a) and their feasibility to be implemented as an interim option until the market provides sufficient investment to reduce this risk. The cost allocation of this service should also be considered as part of this work.
Q18: What other options should be considered to better manage residual supply risk for winter 2024?	We are expecting and planning for another challenging winter in terms of ensuring the peak capacity requirements are met. As we have raised in various submissions and forums, we are concerned that without further tools available it will be difficult to keep the system secure in the face of unanticipated events. However, we agree with the Authority that given the limited changes made in the last 12 months, options for addressing peak electricity capacity issues in "the short-term are limited to coordinating resources already in place or in the process of being implemented." We continue to seek opportunities to improve the information we provide to and receive from the market, and the processes and tools we use to coordinate and inform a cross-industry response to tight system conditions. We think options that improve the quality of information in the forward market schedules (up to 7 days ahead) will provide better information to the system operator in assessing the upcoming security risks, and also provide better information to market participants on future market conditions. We have not been able to identify any other option that could be ready in time to help better manage residual supply risk for winter 2024.

Question	Transpower response
Q19: Do you have information on any other international standby ancillary services and their positive impacts? If yes, please share your information.	No comment.