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Consumer Interests Winter 2023

We appreciate the opportunity to respond to the Authority's issues paper.

Last month, the system operator published a Market Insights Paper that analysed the winter peak capacity challenges experienced in 2021 and 2022 and explored the potential size and shape of the peak capacity challenge in 2023. The Paper explored two core issues around the recent winter peak capacity challenges: peak demand growth and the reduced availability of generation. The system operator's analysis of the 2023 peak capacity challenge identified an impending risk of insufficient supply to balance peak demand, especially in low wind conditions. To ensure continued security of supply for consumers, this risk must be addressed before winter 2023. Transpower will continue to support the Authority's consultation on measures for winter 2023 and believes that the development of an operationally integrated ancillary service product is the most effective mechanism available to address the key concerns ahead of winter 2023. We have reviewed the working design of the product proposed by the CEO forum and support its development and implementation. We outline in this letter potential options to introduce the product by winter 2023.

Peak Demand Growth

The system operator observed a 2% peak demand growth in both 2021 and 2022. In the context of the 20 highest daily peaks observed in 2022, this represents an increase of 138 MW of demand per year - enough generation capacity to meet the average demand of approximately 138,000 homes. To put the peak demand growth into a broader context, in the last 10 years, New Zealand's top 10 largest peak demands all occurred in the past two winters and six out of those 10 occurred in 2022.

This peak demand growth resulted in numerous low-residual situations in 2021 and 2022. The system operator issued 11 low-residual CANs in 2021 and 13 in 2022. Three of the low-residual situations in 2021 triggered a grid emergency, with a further two in 2022. The increased number of low-residual situations in 2021 and 2022 demonstrates peak demand growth that is not sufficiently balanced by existing generation *availability*.

Reduced Availability of Generation

Increased Intermittent Generation

Total installed wind generation in New Zealand increased from ~689 MW in 2019 to ~1,040 MW in 2022. Because there are no underlying fuel costs associated with wind generation, it is generally offered into the market at $0.01 per MWh and is, therefore, early in the order of dispatch. This means increased installed wind generation capacity is increasingly displacing thermal generation from the offer stack. However, wind generation is intermittent and relies on a variable source. It cannot flex to meet demand if the underlying source is missing. The grid emergency on 9th August 2021 saw forecast wind generation for the evening peak drop 194 MW (39%) in the 3 hours preceding the evening peak. This unanticipated change in expected available capacity meant other generation which might have been available was not offered.

Intermittent generation is set to increase by winter 2023, with the system operator expecting ~103 MW of additional wind generation capacity and ~16 MW of solar generation capacity commissioned. This increase does not necessarily contribute to peak system capacity on a reliable basis. It also increases the risk that an unexpected reduction in wind and solar resources impacts balancing the system in real time.

Reduced Thermal Generation

Thermal generation has underlying fuel costs that impact its commercial viability. Approximately half the thermal generation units in New Zealand are relatively old, and expensive to operate and maintain, in comparison to newer renewable generation. Compounding the issue is that of the ~2,000 MW of thermal generation capacity in New Zealand, ~1,100 MW is from slow-start units, which typically take 6 – 12 hours to start generating. The limited flexibility and operational costs of thermal generation units means there is often limited commercial incentive for them to be offered if the expected market conditions in that time horizon are insufficient for them to cover their costs. This is particularly the case with wind generation offered at near-zero prices. The result is that such units cannot be started-up in time if the need arises closer to real-time (e.g. if demand increases and/or intermittent generation decreases, or offered generation does not perform as expected).

2022 was New Zealand's wettest ever winter resulting in increased amounts of low-priced hydro generation offered into the market. An abundance of low-priced hydro-generation drives the spot price down, which has a corresponding effect on the commercial viability of thermal generation, in the same way low-cost wind generation does. The system operator observed the Huntly Rankine units were offered out of the market much more regularly in 2022 where spot prices were lower than in previous winters. Once offered out, these units cannot be started-up in time if the need arises closer to real-time. If another wet winter occurs in 2023 (i.e. the continuation of the La Nina weather pattern beyond the 3-month continuation forecast by NIWA), similar market conditions are expected.

Unlike intermittent generation, which is set to increase by winter 2023, the system operator expects several thermal retirements in the next 18 months. Accelerated thermal generation retirement impacts system flexibility during peak demand periods and decreases the quantity of dispatchable, synchronous generation as a proportion of total generation.

Looking ahead to winter 2023

To understand the potential size and shape of the peak capacity challenge in 2023, the system operator simulated potential market outcomes using peak load days from 2021 and 2022. Given the uncertainty in availability of both slow-start thermal units and wind generation to balance peak demand, the system operator analysed these outcomes against a specific set of slow-start thermal scenarios and wind generation profiles for 2023. The scenarios demonstrate the need for additional flexible capacity during cold days with little or no wind; slow-start thermal units do not offer this flexibility in peak load times unless they are already generating. The risk of insufficient supply to balance peak demand is reduced under increased levels of thermal generation commitment. However, this is dependent on sufficient market signals to provide a commercial incentive for slow-start units to start-up.

Exacerbated in Real-Time

The thermal generation scenarios were developed using 30-minute average load data. However, load variation within a trading period can mean a significant difference between what is forecast as the average demand across the 30-minute trading period and actual demand at 5-minute intervals. The system operator conducted analysis of load variations within each weekday trading period in winter 2022. The analysis demonstrates that real-time load variations can be up to 200 MW greater than the 30-minute average demand. This is a significant difference in the context of the increasing proportion of intermittent generation and the limited flexibility of half the thermal generation capacity. For example, 200 MW of residual generation in the forecast schedules based on the 30-minute average (i.e. outside the low-residual parameters) could end up as 0 MW in real-time based on load variation alone. This means peak capacity requirements could be even greater in real-time than the thermal scenarios demonstrate.

Urgency of Issue

There is less than six months until the start of winter 2023. This is insufficient time to explore all options to solve the issue for winter 2023. The immediate focus should be on what can be implemented in time, with longer-term options developed in parallel to ensure peak capacity challenges are mitigated beyond 2023.

Options

The system operator has engaged with the Authority and industry to explore the options identified and agrees that some of the options should be progressed. However, a significant focus of the Authority’s consultation paper is around improving information available to participants to make efficient contracting and commitment decisions, in particular the provision of additional information by the system operator. While we agree these options should be progressed and have already commenced preliminary work to explore the provision of additional information (as discussed below), we believe the greater focus should be on other operational mechanisms that could be implemented to provide assurance of the reliability of supply. Mitigating the winter 2023 operational coordination issue with further information is insufficient by itself, particularly considering the limited timeframe to resolve the issue. In this context, we believe there is an operational risk that *any* amount of information that can be provided in the limited timeframe to winter 2023 is insufficient to materially address the peak capacity challenge. This is because addressing information gaps will only improve commitment decisions up to a point. It will never be possible to precisely forecast demand or intermittent generation supply, and the system will always be vulnerable to unanticipated events on both the demand and supply side. At the same time, the market would still need to act in response to additional information, considering the respective risk appetites and commercial considerations of participants. The inherent uncertainty in forecasts and risk appetite can still mean insufficient incentives at the right time to commit sufficient resources to balance supply and demand, in which case the system operator's only option is demand management.

Publishing Residual Offer Information

We have agreed with the Authority at an operational level (pending formal approval) for the system operator to provide the calculated residual values from the market schedules to NZX as part of the RTP Phase 4 delivery in April 2023. NZX hosts the WITS website and to centralise (and visualise) all market information it is the logical platform to publish the residuals. The Authority would need to approve the publication of the residual data on WITS by the NZX.

However, publishing this information would only be a partial solution because residual information is only one input among many to the system operator's assessment of capacity adequacy. Moreover, as noted above, this information is still based on forecasts and the provision of this information does not guarantee or incentivise a market response.

Publishing Sensitivity Schedules

Given the short timeframe to winter 2023, calculating sensitivity schedules using the full market system and WITS integration is not feasible. A partial solution outside the market system could be considered for development, however this would need further investigation for winter 2023 feasibility. We expand on the inherent uncertainties and limitations of this partial solution in our consultation response. The system operator's preference is for a fully integrated market system solution to provide the market with reliable information on potential price sensitivities within the market schedules. We recommend the Authority develop a longer-term plan to enable a fully integrated solution into the market system with WITS publication.

Incentive options

Another focus of the options proposed by the Authority is to better align the incentives of participants with the interests of end-use consumers. We comment on some of the longer-term incentive options in our consultation response, but we would like to address the option to selectively increase existing ancillary service cover to offset increased uncertainty in net demand.

The current frequency-keeping and instantaneous reserve ancillary service products were not designed to be artificially inflated to provide market signals at times when the balance between supply and demand is tight, and altering them could have unintended consequences that impact on the system operator's ability to comply with its principal performance obligations. We are also concerned altering the product may not free up generation for energy as intended and could potentially collapse the real-time energy price or trigger scarcity pricing once the inflated buffer is reached. We expand on these unintended consequences in our consultation response.

New Ancillary Service Product

The system operator agrees we need to increase the quantity of flexible resources to reduce the potential for peak capacity shortfalls in winter 2023. With the limited time to winter 2023, a fully market integrated ancillary service product is not feasible, but an interim solution worth investigating is the procurement of additional capacity outside the market (additional to what is already in the market). Incentivising additional capacity increases the likelihood it will be available when needed. In this context, we support the development and implementation of the product proposed by the CEO forum. The working group established by the CEO forum has consulted the system operator around the design, implementation and operation of the product and we continue to provide support as its feasibility and development is explored.

One option would be to utilise the RTP Phase 4 Dispatch Notification Participation (DNx) mechanism to operationalise the product. Operationalising the product with DNx is a step in the direction of increasing market-signalled demand-side participation. We recognise implementation of DNx for existing participants with controllable load resources would incur unexpected costs on those participants, which could be mitigated with an appropriate incentive arrangement.

To further increase the quantity of available resources, additional controllable resources could be procured, but these resources would not necessarily need to be dispatchable in real-time. Using the RTP enhancements, bids and offers could be submitted electronically (as non-dispatchable) with a high price, to inform the quantity available each trading period but to ensure it does not clear in any schedule (although it may appear as a residual). This would not impede the forward price signal for commitment decisions. If the product was required, providers could alter the price to ensure it cleared in the market (but the product would still be non-dispatchable). In real-time, the system operator could implement the scarcity pricing mechanism introduced with RTP to ensure dispatch prices reflect utilisation of controllable load as a last resort before shedding 'real' load (this scarcity pricing mechanism adds back curtailed load to calculate prices which does not necessarily result in scarcity prices).

Both options would mean deploying tools beyond their design purpose, but they could work as an interim solution pending the investigation of a fully market integrated (longer-term) product. Furthermore, both options would be a positive step in increasing demand-side participation.

What Needs to Happen

The system operator would need to complete detailed design, implementation and operability studies to determine the feasibility of operationalising the product. Given the limited time available prior to winter 2023, and the resources required to not only complete feasibility studies and progress design and implementation, the Authority needs to signal a decision around a new ancillary service product by the end of 2022 or, at the very latest, early January 2023.

The Authority's decision would enable the system operator to commence parallel workstreams around Procurement Plan and Policy Statement changes (while the Authority completes an urgent Code change process), preparing the tender and ancillary service contract documentation, preparing information packs for potential providers and conducting the detailed design and implementation workstreams (including training). Similarly, potential providers (aggregators) would need to commence workstreams around contracting with sub-providers and developing systems to integrate with the market. The CEO forum's working group, including external consultants, has already progressed workstreams to explore the design and operation of the product (including necessary changes to the Code and incorporated documents) and we will continue to support those workstreams. However, it is critical that the Authority signals its support for the product so these workstreams can continue and advance.

Industry Collaboration and Supporting the Authority

We strongly support the Authority's consultation on options to mitigate the winter 2023 and beyond peak capacity challenges. We support the investigation of longer-term market options but given the urgency to winter 2023 the industry needs to move quickly to implement an interim solution to provide assurance around reliability of supply. We believe the development of the product proposed by the CEO forum, namely a new non-market integrated ancillary service product, will provide this assurance and is a positive step in the right direction given the time constraints.

We will support the Authority to achieve this outcome. Given the resources and effort required to deliver this outcome, we would want to engage with the Authority as early as possible to discuss resourcing, funding and the potential reprioritisation of other workstreams.

We answer the specific consultation questions in the appendix.

Yours faithfully,

Alison Andrew
Chief Executive

Appendix

Questions	Transpower (system operator) response
1. Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?	While we agree operational coordination has become more challenging, we believe the issue is principally whether other operational mechanisms that increase the quantity of flexible resources should be implemented to reduce the potential for peak capacity shortfalls in winter 2023 and beyond. In this context we have reviewed the working design of the product proposed by the CEO forum and support its development and implementation.
2. Do you agree that the factors in paragraphs 4.10 to 4.63 create information challenges or misaligned incentives, and that these make it hard to achieve optimal commitment actions? If not, what is your view and why?	We do not believe the winter 2023 peak capacity issue is limited to information challenges or misaligned incentives. We have already outlined in our Market Insights Winter Review Paper the impact on peak capacity of a combination of factors and the challenges those factors will create in 2023, which demonstrate the need for additional flexible capacity.
3. Do you agree that it is prudent to examine options to address information and incentive gaps identified above? If not, what is your view and why?	There will always be scope to provide more information. However, addressing information gaps will only improve commitment decisions up to a point. It will never be possible to precisely forecast demand or intermittent generation supply, and the system will always be vulnerable to unanticipated events on both the demand and supply side. There is currently no incentive to make sufficient standby capacity available to mitigate information shortfalls and unanticipated events. At the same time, the market would still need to act in response to additional information, considering the respective risk appetites and commercial considerations of participants.

	Given the timeframe to winter 2023, the option that best addresses the provision of additional flexible capacity is the development of an operationally integrated ancillary service product to supplement improvements in the provision of information.
4. Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria that the Authority should consider?	Transpower agrees with the criteria as high-level objectives, but considers more specific evaluation criteria need to be considered, including: Timeliness: • Given the limited timeframe, solutions should be feasible for winter 2023 (including design and implementation of operational processes, IT systems for the system operator and participants, training etc). • This may mean considering options that might be interim steps to a longer-term solution. Effectiveness/Certainty: • How certain is the solution to address the peak capacity issue. • How likely is the solution to bring additional resources into the market during the times it is needed. • Can the solution operate within existing tools? If not, timeliness considerations above apply. Risks: • Risks of unintended consequences (already captured by the Authority at 5.3(c)). • How much impact does the option have on tools, processes, and the risk of adverse consequences. • "Out-of-market" solutions to address urgent/near-term risks could be transition-only (have a sunset date) to reduce any risk of long-term unintended consequences on market efficiency. Transition to long-term solution:

	• Where possible, provide transition path to longer-term market solutions (desired end-state). Cost/Resources: • What is the cost/resource requirements of implementing the solution. • What other projects/developments might need to be delayed as a result
5. What if any other options should be considered to better manage residual supply risk for Winter 2023?	Transpower has engaged with the Authority and industry to explore the options identified. We support the development and implementation of the new (non-market integrated) ancillary service product proposed by the CEO forum. Provided the selection of one or more options is progressed with absolute urgency (especially a new ancillary service product), we do not propose any additional options. We strongly encourage the Authority to consider short-term transitional solutions to longer-term market integrated solutions, especially the development of a non-market integrated ancillary service product.
6. Do you think it would be beneficial to publish the residual offer information used by the system operator when calculating Grid Warning and Emergency Notices? If not, what is your view and why?	We have agreed with the Authority at an operational level (pending formal approval) for the system operator to provide the calculated residual values from the market schedules to NZX as part of the RTP Phase 4 delivery in April 2023. NZX hosts the WITS website and to centralise (and visualise) all market information it is the logical platform to publish the residuals. The Authority would need to approve the publication of the residual data on WITS by the NZX. However, publishing this information would only be a partial solution because residual information is only one input among many to the system operator's assessment of capacity adequacy. Moreover, as noted above, this information is still based on forecasts and the provision of this information does not guarantee or incentivise a market response.
7. Do you think it would be beneficial to provide sensitivity case spot price forecasts in forward schedules, as well as central forecasts? If not, what is your view and why	This could provide additional information to participants of potential price risks. However, the provision of this additional information does not guarantee a market response. Given the reduced timeframe to winter 2023 a full market system development solution with WITS publication is not feasible. Only a partial solution outside the market schedules (similar to the Sensitivity Schedules trial in 2020) can be considered for development, however this needs further investigation for winter 2023 feasibility as the infrastructure used in the system operator

	Sensitivity Schedules trial in 2020 has been disestablished. If this partial solution is proposed by the Authority, the system operator would need to undertake an assessment on potential resources required for a winter 2023 delivery. This might impact the delivery of other system operator projects. We also note this partial solution will have some inherent uncertainties in its design. First, it will not involve re-running the Simultaneous Feasibility Test (SFT) and Reserve Management Tool (RMT) applications (which are used in the calculation of forecast prices in the market system). So the actual price movements (given a change in net demand) could be different from the calculated price sensitivities. Secondly, a partial solution which could be implemented by winter 2023 would be limited by its inability to incorporate advanced powerflow calculations, resulting in sensitivity solutions with higher inaccuracy, and not have the rigorous support arrangements enjoyed by our critical systems. The system operator's preference is for a fully integrated market system solution to provide the market with reliable information on potential price sensitivities within the market schedules. There should be a longer-term plan to enable this to be implemented as a fully integrated solution into the market system with WITS publication. When this option was explored with the Authority several years ago, the approximate costs and timeframes for investigation and implementation were ~$1.7m and 16 months.
8. Do you agree that cross-industry work on improving the quality of intermittent generation forecasts is unlikely to be available for Winter 2023? If not, what is your view and why?	In July 2022, the system operator submitted a Code change proposal to the Authority to require intermittent generation to update offers every 2 hours based on a demonstrated resource forecast model (with the persistence model reduced to 1 hour). The proposal was rejected, as the Authority had commenced its own project to improve the accuracy of intermittent generation forecasts/offers. Any large scale improvement in the quality of intermittent generation forecasting will depend on the outcome of the Authority's project. We do not believe the cost of a resource model would place a material financial burden on participants, but would lead to material improvements in forecast information. Accordingly, we encourage the Authority to progress this project with urgency.

9. Do you agree that the system operator should procure an external wind forecast and ask participants to review their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why	Subject to funding, the system operator could procure an external resource forecast (wind and solar) so that it can better assess potential uncertainties. However, there is a difference between advising the market of significant differences (as per the consultation paper) and asking participants to review their offers (as per the question). Asking participants to review their offers might assume the resource forecast model used by the system operator is more accurate than the information available to generators, which may not necessarily be the case. If the system operator procured an external resource forecast, it might be more appropriate for the Authority's market monitoring function to monitor market behaviour alongside this forecast.
10. Do you agree that the availability and use of 'discretionary' demand control (such as ripple control not used for instantaneous reserves) should be clarified? If not, what is your view and why	We agree that real-time visibility and use of "discretionary" demand not used for interruptible load should be improved. A practical first step for winter 2023 could be to look at improving the visibility and use of discretionary demand from larger distributors initially (e.g. >100 MW peak load), with smaller distributors to follow in subsequent years. However, improving the visibility does not necessarily mean it could be integrated with our exiting SCADA/market tools by winter 2023 (i.e. it would only improve our manual instructions to participants). Nor does visibility guarantee availability or performance. Offering these resources via the market (Dispatch Notified Participation) would provide better visibility of these resources to the market and integrate with the market solution and is, therefore, our preference.
11. Do you agree that work should be undertaken on a new integrated ancillary service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?	We support the development of an operationally integrated ancillary service product. We have outlined some options for how this product could be procured and operationalised in our cover letter within the available timeframe to winter 2023. This product could work as an interim solution pending the investigation of a fully market integrated (longer-term) product. We agree the development of a fully market integrated ancillary service should be investigated for future implementation.
12. Do you agree that selectively increasing ancillary service cover	We do not agree this option is appropriate.

should be considered as an interim option for Winter 2023? If not, what is your view and why?	These ancillary service products were not designed for this purpose and altering them could potentially have some unintended consequences. For example: • If insufficient offers are provided in response to the increased requirements, scarcity could be reached earlier (i.e. scarcity will be triggered if there is a shortfall in meeting the increased requirements). • For instantaneous reserves, if the additional requirements are met by additional interruptible load being offered (i.e. in addition to IL already offered as reserves) rather than additional generation, then the product might not free up generation for energy as intended. • For instantaneous reserves, artificially inflating the reserves could potentially trigger an over-frequency event due to the over-procurement of reserves relative to the risk. • If the requirement is specified as an increased frequency keeping (FK) requirement then it would need a process to ensure the additional generation (due to the increased FK requirement) is released into the energy market when it is needed. This could be achieved by collapsing the increased FK band to the "normal" size in real-time when this additional capacity is needed, however this may collapse the energy price. Collapsing the real-time energy price would reduce the price incentives in real-time and impact the market response for future situations. Similar, 'release' and price collapse issues apply should instantaneous reserve requirements be increased. • Increasing the ancillary service requirements will increase the operational requirements and procedures for the system operator's control room and any near-real-time adjustments of the requirements would likely be at a time when staff and resources are focussed on managing the tight capacity situation, which could potentially increase operational risks. • The pool of certified resources to provide this increased requirement might be relatively small. This could have potential competition impacts for this artificially increased requirement.
13. If increased cover from an existing ancillary service at times is pursued further as an option for	See previous response.

Winter 2023, what are your views on whether to utilise frequency keeping or instantaneous reserve, and why?	
14. Do you agree the option of requiring retailers to make compensation payments to customers affected by forced power cuts should not be explored for Winter 2023? If not, what is your view and why?	The system operator is unclear if this option would be beneficial.
15. Do you agree that reviewing the default pricing in the Code to apply in energy and reserve shortfalls should not be explored for Winter 2023? If not, what is your view and why?	The scarcity pricing values should be reviewed as soon as practical to ensure these remain fit-for-purpose.
16. Do you agree that an hours-ahead market should not be explored for possible adoption for Winter 2023? If not, what is your view and why	An hours-ahead market would provide greater certainty ahead of real-time. However, this option would require significant policy development, market system development and operational procedure changes and is not a feasible solution for winter 2023. We believe that an hours-ahead market should be investigated for further development as part of the future market design.
17. Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored further for Winter	This option should be explored as an interim measure for winter 2023 (see our response to question 11).

2023? If not, what is your view and why?	
18. Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	A: See response to Q6. B: See response to Q7. D: See response to Q9. E: See response to Q10.
19. Do you agree that options F and G should be assessed further to determine if they are likely to have net benefits? If not, why not?	F: See response to Q11. G: See response to Q12.
20. Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	C: See response to Q8. H: See response to Q14. I: See response to Q15. J: See response to Q16. K: See response to Q17.
21. What if any other matters should be considered when assessing options to better manage residual supply risk for winter 2023?	The Authority's proposed information options are still dependent on a positive market response (i.e. unit commitment) for the options to be successful. The system operator does not believe artificially adjusting existing ancillary service products is a prudent solution due to the inherent characteristics of those products. However, the development of a new ancillary service product on a short-term basis for winter-2023 is encouraged. We have reviewed the working design of the product proposed by the CEO forum and support its development and implementation However, it would require significant work to fully explore its implementation and operation and, as such, any decision on it should be progressed with accelerated urgency. A short-term product could provide a useful platform to explore the benefits of a long-term co-optimised ancillary service product.