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Driving efficient solutions to promote consumer interests through winter 2023

1. This is Vector's submission on the Electricity Authority's (Authority) consultation paper titled *Driving efficient solutions to promote consumer interests through winter 2023.*

2. We share industry concerns over security of supply in Winter 2023, and are pleased to see that this issue has been prioritised by the Authority. We appreciate the Authority's responsiveness to these concerns.

We support the parallel development of a new, temporary ancillary service product

3. Clearly, something has changed in the market in the past two years. The risks to consumers' security of supply, and of collateral damage to the overall industry, are now too great to ignore.

4. We therefore support the progression of a new ancillary service product to address this risk, in parallel to the Authority's more fulsome consideration of market enhancements. We have been part of the group of industry participants developing this proposal, and support the joint submission the group made to this effect.

5. Developing a new service product will carry implementation costs. If the product proves not to have been particularly necessary (because demand for its use is low, or supply is plentiful) then the overall costs to consumers of the procurement will be limited. If the costs are high, this will signal that the product was in fact required. The development and procurement of the new product seems a small price to pay, in the scheme of things, relative to the potential costs of non-supply – including direct costs, in the case of any event itself, and indirect costs due to the fall-out of such an event.

Incentives on generators to provide accurate forecasts must be strengthened

6. We noted the Authority's commentary on wind forecasting accuracy and incentives, and were concerned about the (average) positive bias in the forecasts. Such behaviour, if it is indeed systematic, is likely to under-signal the need for slow-start thermal plant, and reduce their ability to respond when they are genuinely needed. The fact that the over-forecasts can be in the order of several hundred MW must, in and of itself, be having a material impact on generator commitment and hence system security.

7. In our submission to the Authority's Market Development Advisory Group in March 2022, we noted that, as has been analysed extensively overseas, non-dispatchable renewable generators may not be exposed to the whole-of-system costs of their intermittency or forecasting errors. At the moment, depending on ownership and contracting arrangements, they are unlikely to face the full cost that these errors, and their intermittency overall, impose on the system and on consumers.

8. Other jurisdictions do impose system balancing costs on the parties causing those costs, as ours does in limited cases – including when a failure by a large generator triggers reserves. The Authority notes, in para 5.43(a) of the consultation paper, that there appear to be reasonable grounds to revisit ancillary service cost allocations. The Authority should explore

whether there is a missing mechanism here that is creating a potential cost and risk to consumers. This is becoming more urgent as a larger number of renewable investment commitments are being made – it would be preferable from investors' perspective to be aware of these costs before they finalise their commitment.

9. Further, the Authority should investigate and convince itself that none of the forecast inaccuracy is in fact tacit market manipulation. We understand that in at least one example overseas, over-estimated wind forecasts have been used as a mechanism to displace competitors' slow-start thermal and bring on fast-start thermal owned by the wind generators themselves. We make no assertions, nor have any evidence to suggest, that any such strategic over-forecasting for portfolio reasons is occurring in New Zealand. However, the possibility exists, and it is therefore worth the Authority, through its monitoring function, assuring itself that no such behaviour is occurring.

Distributors' ripple control should not be treated as a free option

10. The ripple control owned and operated by electricity distribution businesses (EDBs) should not be treated as a free, costless option by the System Operator (SO). Much like distributed generation, which effectively provides the same benefit to system security, these assets require constant ongoing re-investment, have multiple purposes, and should be compensated for the role they play. Any distributed generator providing emergency support would be compensated for providing that service (through the increased energy revenue it earns), and demand response should be similarly recompensed.

Concluding remarks

11. Again, we appreciate the urgency with which the Authority is now addressing winter 2023. As an aside, we would have expected the Authority's Security and Reliability Council (SRC) to have been providing advice to the Authority Board on system security in winter 2023. We would be interested to know what advice the SRC has given.

12. Our answers to the specific questions posed are appended to this letter. Please contact me at james.tipping@vector.co.nz if you have any questions on any of the content of this submission.

Yours sincerely

J. Tipping

Dr James Tipping
GM Market Strategy / Regulation

Appendix – answers to consultation questions

Question	Response
Q1. Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?	Agree. We are pleased to see the Authority include analysis of generator unit commitment challenges in its problem definition, not just changes to load behaviour.
Q2. 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?	Agree.
Q3. 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?	Agree, but options should be examined in a considered manner to avoid unintended consequences. Further, this area should not be focussed on at the expense of the other options – including development of new ancillary service products.
Q4. 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?	No.We feel the risks to reliability of supply in 2023, and the risks of collateral damage to the sector (and its consumers), are worthy of including for consideration. If supply in 2023 were to be compromised, the risk of ill-considered, reactive intervention would increase, which would be unlikely to be in the long-term interests of consumers. Further, it would dent consumer and stakeholder confidence at the very time the sector is wanting to embrace its key role in decarbonisation.
Q5. What if any other options should be considered to better manage residual supply risk for Winter 2023?	We want to ensure that the industry-led development of a security solution is prioritised in the options.
Q6. [A] 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?	Agree. To make these events more transparent, the Authority could also consider requesting the SO produce some standard reporting on what has led to the residual dropping below specific thresholds, and the actions that it has taken to maintain security. For example, the SO could report on whether the situation was driven by an unplanned generation outage, transmission outage, surge in load, an over-forecast of generation, etc, and the actions it requested parties to take.
Q7. [B] 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?	Agree. This option would be useful. We suggest including sensitivities to multiple variables, including temperature, wind, and loss of non-intermittent generation (N-1).
Q8. [C] 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?	We have no view on the amount of work required for this option. As per our cover letter, we do believe this should be prioritised, along with an examination of the incentives parties have to ensure the accuracy of their forecasts.

Q9. [D] 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?	Agree. This would be a good initial step towards making intermittent generators more responsible for the accuracy of their forecasts. As we noted in our submission to MDAG earlier in the year, different types of generators bring different kinds of benefits and impose different costs on the system. A lack of firmness in wind generators' forecasts can impose costs on the system in terms of efficient dispatch and system balancing, but the wind generators themselves are not necessarily directly exposed to those costs. The Authority could consider reviewing cost allocations for ancillary services in light of the changing supply mix.
Q10. [E] 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?	Firstly, we believe there needs to be greater appreciation and understanding of the costs required to be incurred by EDBs to maintain ripple systems. While we do not feel that ripple, as a tool, is fit for a post-RCPD future in which granularity of control becomes paramount, it will still be an important lever for some time. Attention needs to be paid to how the system transitions to new, smart, ICP-addressable hot water management. The Authority and industry should recognise that access rights to the management of hot water load have been clarified in clause 5 of the Default Distributor Agreement (DDA). We agree that the use of discretionary demand control in emergencies should be clarified. Its participation in the wholesale market via either instantaneous reserves or the new Dispatch Notification (DN) product when that comes online in 2023 should be encouraged. It is not clear, however, how long it would take for those EDBs not already participating to build the capability to do so. We suspect that making use of the DN product is not high on many EDBs' (or even other parties') priority lists at this time. This will make it clearer for generators to know when they should commit to generate. It also removes the ability for the SO to call for hot-water control as a free option. As such, if system security does get to the point where the SO requires EDBs to drop load, EDBs will have to go straight to dropping feeders, as the hot water load will already have been dispatched off by the market.

Q11. [F] 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 a new ancillary service for 2023 and agree with the desire for its integration with the market. Realistically, to be ready by winter 2023, we may have to target a product that operates along the same lines as frequency keeping (i.e. with operational integration, rather than market integration).
Q12. [G] Do you agree that selectively increasing ancillary service cover should be considered as an interim option for Winter 2023? If not, what is your view and why?	No, this option should not be explored further. Increasing cover of existing services may just lead to having more plant on standby and fewer resources at the SO's disposal. The cost of frequency keeping is currently not signalled in the spot price. The product is intended as a balancing service and is unlikely to provide additional capacity. The cost of reserve is integrated, but only triggered by under-frequency. Also, over-procurement of reserve risks an over-frequency event as too many resources respond, potentially causing generation to trip.
Q13. [G] If increased cover from an existing ancillary service at times is pursued further as an option for Winter 2023, what are your views on whether to utilise frequency keeping or instantaneous reserve, and why?	See answer to Q12. We do not support this approach.
Q14. [H] 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?	Agree. This option should not be rushed, to avoid intended consequences. The Authority would need to assure itself that the contract market is sufficient to enable retailers to manage that risk, before imposing additional obligations on them.
Q15. [I] 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?	We have no view on the amount of work required to implement this option. We support an update to the values in due course reflecting the cost of involuntary load reduction or reduced system security.
Q16. [J] 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?	We have no view on the amount of work required to implement an ahead market, but we support this option being investigated further in due course. It would help develop the market for demand response.
Q17. [K] Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored further for Winter 2023? If not, what is your view and why?	Agree.
Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	Agree, but note our answer in Q10 in relation to option E. However, this should not be taken to the extent of excluding development of a multi-hour winter peak product – we support that product being developed.

Q19 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?	No. Option F should be pursued, but not option G (see our answer to Q12 above).
Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	Agree. See our answers to each related question.
Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?	The Authority needs to account for the greater, long-term risks to consumer benefits if there were to be a supply shortfall in winter 2023. Such a shortfall would increase the risk of intervention, which is not in consumers' long-term interests.