1 March 2024

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Dear Electricity Authority,

**Consultation – Potential solutions for peak electricity capacity issues**

Wellington Electricity (**WELL**) appreciate the opportunity to provide feedback on the Electricity Authority's (**EA)** above consultation regarding the proposed solutions to manage peak electricity demand capacity issues on the transmission grid. WELL is acutely aware of the challenges of providing sufficient electricity capacity to meet growing electrification needs. We are forecasting constraints on our own network that we will also have to manage. We agree and support the work programme to manage grid constraints. However, we ask that the EA consider the impact of the proposed solutions on the entire electricity supply chain, including how these changes would impact Electricity Distribution Businesses' (EDB) investment pathways and their ability to manage network supply quality.

**Assessment of demand response incentives**

Under question 2, the paper comments that "there are no technical barriers to demand response participation in the wholesale market". WELL disagrees with this statement and would stress to the EA that the future flexibility will include new services that differ from the established demand response of large commercial users and hot water ripple control.

Traditional demand response has been shifting demand away from congestion periods by offering a cheaper distribution tariff for nighttime electric hot water heating. This works as the network capacity is available which ensures the network operating envelope is not breached. However, when emergency demand is curtailed this cannot be returned automatically and a sequenced approach over many hours is required to preserve quality of supply for connected customers.

The demand response landscape is changing to accommodate small providers who, in the aggregate, could provide a similar or larger response to network or transmission constraints. The same technical challenges will apply for new providers of demand response to coordinate establishing load within network boundaries.

The challenge for smaller flexibility providers, like managed EV charging, is the regulatory and technical changes that are needed before the services can be offered at scale. As highlighted in the most recent *DPP4 Issues paper* submission by the Flexforum[1], key enablers of a service like this lie in the development of EDB low voltage (LV) monitoring and management, improved capacity forecasts, and adapting network operating and planning practises.

While the industry is slowly developing the capability to offer flexibility services, the supporting regulatory changes have yet to be made. We developed an industry EV Connect Roadmap of the changes needed for flexibility services to provide a viable non-wire alternative to building traditional capacity. These changes were summarised in our '*2023 DDA Amendments'*[2], and '*Updating regulatory settings for distribution networks*[3]*'* EA consultations. Changes include Code changes that the EA will need to make to ensure that EDBs can host flexibility services that can be used to respond to grid constraints while maintaining a secure electricity supply.

**Financial Products (Super peaks proposal)**

WELL is concerned that a super peak product would not have sufficient market penetration across enough industry participants, like flexibility providers, who are in their infancy. These providers may not have the sophistication to participate in ASX trading and the forward price discovery process for these types of products. Technical setup and margin requirements may be some reasons that would inhibit these new participants from benefiting and providing the desired outcome.

As the concentration of technologies and distributed energy resources (DER) connect at the ICP level, the benefits from futures trading at the grid exit point (GXP) would be limited to providing risk cover for the larger flexibility providers. Those providing services at an ICP level may not be engaged in the complexity of futures trading and therefore the volatility occurring at ICP level may not be reflected at GXP level, where the super peaks are being traded.

**Evaluation criteria and principles**

We agree with the evaluation criteria as listed on page 30 of the paper, however, when applying the criteria to the proposed solutions, we found it difficult to critically evaluate the suggested options. This is because there is no ranking or skill testing of the criteria to outline which is the most important criteria to focus on. For example, if the solution being in place by winter 2024 is the priority of the industry, then the solutions that achieve this should be given a higher weighting.

Resources need to be prioritised and as the pace of electrification accelerates, there will be further constraints on the industry's ability to keep up. Managing short-term constraints while also investing to meet long-term priorities is an ongoing challenge that is not getting any easier. Since the '*Driving efficient solutions to promote consumer interests through winter 2023'* EA consultation, there was not enough time to implement some of the incentive options before winter 2023, and there was no urgency to have them fast-tracked for winter 2024 either. The EA needs to identify which criteria is the most important so that there is not further delay in the development of a solution.

[1] Flexforum (2023, December). *DPP4 Issues Paper*
[2] Wellington Electricity (2023, November). *Default distributor agreement and consumption data templates*
[3] Wellington Electricity (2023, March). *Updating the Regulatory Settings for Distribution Networks – Submission to Electricity Authority*

**EDB Demand Response Hierarchy**

WELL would like to emphasise to the EA that while they investigate solutions to encourage demand response options, a hierarchy of established demand response across the connected supply chain is still required to preserve a stable electricity supply for customers. The physical operating parameters of the network must be controllable by the party responsible for maintaining quality standards. Accessible demand response (hot water control) is a fundamental tool that we use to maintain network quality. Any interference with this mechanism could result in EDBs not being able to maintain a secure supply, worsening quality performance and increased long-term capex from having to build additional capacity to manage demand volatility.

**Compensation for EDB Demand Response**

Under WRN and GEN scenarios, distributors signal their discretionary demand to the market and shed load as instructed by the system operator (SO). The load shedding using distributors ripple control equipment is not paid for by the whole system even though it contributes to security of the system. Under WRN and GEN situations, discretionary demand does not currently have a recognised value.

We are not expecting payment for supporting transmission and generation security where we have not shed load. This applies similar logic to the paper's example of uncleared offers or dispatchable also not being paid for.

**Beneficiaries of demand response**

A distributor may make their controllable load available to the ancillary services market and earn a market price where dispatched for reserves. Where distributors use demand response for their own network security the amount of generation required in the stack is reduced without requiring a dispatch through energy or reserves. This would have contributed to a lower spot price and the demand response is not recognised in this situation.

There is an incentive for distributors to maintain their demand response equipment (for their own network security) but this is paid for solely by their own customers. Other customers who benefit from a lower spot price around the country are not contributing to the upkeep of these systems and leads to unequal share of the cost of demand response equipment.

**Operating limits for distribution compared to transmission and generation constraints**

The WRN and GEN discretionary demand response offers are used to relieve transmission constraints where demand exceeds asset capacity or security criteria. The same responsibility needs to be considered at the distribution level. Examples from Australia are most relevant for comparison where DER at the distribution level has required operating envelopes for ICP participants to ensure network security and stability ahead of their market trading (i.e. the kW injection from inverters is curtailed to ensure the stability of both distribution and transmission systems as directed by the distribution system operator).

This is a requirement that has been adopted by the market so distribution stability controls allow connectivity to be maintained without a loss of supply. It has developed through these controls to also allow increased injection periods where capacity exists in the distribution network so customers are rewarded from the prior periods of constraint.

All demand responses must understand the network limits and the requirements for further network investment for DER to build be used to offset new generation i.e. they are incentivised to build new generation where it is more efficient to do so than to use demand response. If demand response negatively impacts the operation of the distribution network, then safeguards need to be in place so that operating limits are preserved so all customers receive a reliable supply.

If you have any questions regarding our comments above, please contact chloe.sparks@welectricity.co.nz.

Many thanks,

Chloe Sparks

| Submitter | Wellington Electricity Lines Limited |
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| **Questions** | Comments |
| **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?** | No Comment. |
| **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?** | We agree in part to the assessment of incentives for demand response and have elaborated on specifics above. |
| **Q3: Other than financial incentives, what are the other barriers to entry for demand response participation in the wholesale market that you have identified?** | Elaborated on above. |
| **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?** | WELL agree that the Authority should focus on identifying and lowering barriers for BESS and demand-side flexibility to participate in the wholesale and ancillary services markets provided the stability of the distribution network is not compromised.<br><br>The reasons outlined in the paper indicate that BESS technology and market integration are even further in their infancy than flexibility services. The challenges around integrating BESS characteristics with the current market design appear to be more substantial than demand-side flexibility participation. For this reason, WELL believe demand-side flexibility is more valuable for managing the current peak capacity challenges in the short term and this is where the EA should focus on first. |

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| **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?** | Elaborated on above. |
| **Q6: Do you agree that a standard product for financial 'super peak' hedges is required?** | Elaborated on above. |
| **Q7: What factors do you think we should consider in the design of such a product?** | No Comment. |
| **Q8: Do you agree with our assessment of the risk for the medium to long term?** | WELL agree with the risks in the medium and long term, however we believe that the short-term criticality of producing a solution, outweigh the risks in the long term. The same peak capacity constraints were consulted on before winter 2023 and any drive to accelerate a solution for winter 2024, was not implemented then and may continue to be delayed. |
| **Q9: Do you think it would be beneficial to create a new integrated standby ancillary service? What is your view and why?** | No comment. |
| **Q10: How should the costs for a standby ancillary service be allocated?** | No comment. |
| **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?** | No comment. |

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| **Q12: How should deficit (scarcity) standby residual be priced in relation to scarcity energy and scarcity reserve prices?** | No comment. |
| **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?** | WELL agree with the issues for procuring additional resource out of the market and, when comparing against the principles as elaborated above, it is difficult to weigh the issues against each other if there is not a prioritised list of benefits. |
| **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?** | WELL agree that there are protocols in place when needing to manage emergency demand response. The issue is that the current providers are not compensated for providing this service and therefore are not investing in the technology to develop more availability. The lower distribution tariff for our ripple control customers (emergency disconnect) is already costed into our network prices. How would another incentive cut across this construct and negatively impact this service to distributors?. |
| **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?** | WELL believe this suggestion would undermine economic principles if uncleared generation and uncleared dispatchable demand is paid without providing a service. |
| **Q16: What do you consider to be an appropriate scaling factor to determine the price for residual and why?** | WELL believe any payments for residual would need to send a strong event price signal. This would encourage a larger pool of demand response from those who traditionally would not risk providing interruptible load through the reserve market. Those who currently provide reserve, would still be encouraged to maintain offering reserve because of the more consistent returns in that market. |
| **Q17: What is your view on the factors the Authority should consider when valuing the costs associated with a standby ancillary service?** | Ensure there is additional resources provided rather than current reserve providers moving into a different service. |

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| **Q18: What other options should be considered to better manage residual supply risk for winter 2024?** | No comment. |
| **Q19: Do you have information on any other international standby ancillary services and their positive impacts? If yes, please share your information.** | No comment. |