11 April 2025

Electricity Authority
PO Box 10041
Wellington 6143
By E- Mail: taskforce@ea.govt.nz

Re: Cross-submission on Energy Competition Task Force Initiatives 2A, 2B, and 2C

Counties Energy Limited (**CEL**) welcomes the opportunity for cross-submission on the Electricity Authority's (**EA's**) consultation on the Energy Competition Task Force initiatives to provide consumers with more options.

On reviewing submissions from other parties, CEL noted that while most parties supported the intentions of the EA's proposal, common themes emerged, including:

- cost of implementing system upgrades (e.g. billing systems) versus the materiality of network benefits realised. This reinforces the need for the EA's proposal to be principles-based, and not prescriptive, to allow Electricity Distribution Businesses (**EDBs**) to consider the practical challenges with implementation;
- uncertainty as to whether (injection) price signals would materially influence customer behaviour and asset-buying decisions (e.g. purchasing solar + battery), given the relatively low rebate amount likely to be paid, and uncertainty of how long a rebate would continue to be offered;[1] [2]
- mass-market injection not providing a similar efficiency and control as managed flexibility arrangements, contracted flexibility or procured flexibility;
- insufficient time for EDBs to implement by April 2026, given the Default Distributor Agreement (**DDA**) requirement for EDB's to consult with customers (e.g. retailers) on any material price changes, and the possible system upgrades required by some EDBs; and
- risk of cross-subsidisation, if not implemented correctly. This is because requiring EDBs to pay injection rebates would result in EDBs increasing distribution line prices to non-Distributed Generator (**DG**) customers (who are often on lower socio-economic sub-

[1] ERANZ, Submission on the 'Requiring Distributors to pay a rebate when consumers supply electricity at peak times' consultation paper, 26 March 2025, pp 1-2.
[2] Meridian Energy, Requiring distributors to pay a rebate to consumers, 26 March 2025, p 1.

Physical
14 Glasgow Road
Pukekohe 2120
New Zealand

Postal
Private Bag 4
Pukekohe 2340
New Zealand

Energy Reimagined
0800 100 202
countiesenergy.co.nz

groups) to pay rebates to customers who own DG (who are often on higher socio-economic sub-groups).

There were also parties who proposed expanding the scope of the EA's proposal, such as providing injection rebates to also non-mass market customers,[3] requiring a more prescriptive approach,[4] support for consumption-linked tariffs,[5] or mandating injection price signals to all periods when additional generation is needed (e.g. dry years, periods of constrained supply).[6] However, we note that the key risks to EDBs and consumers as outlined in our submission remain an issue under the proposed alternatives.[7] For the additional points raised, our feedback on the key points is discussed below:

EDB-funded rebates outside of peak periods

Several parties submitted that EDBs should pay injection rebates for all periods, including when there is constrained wholesale supply and/or when DG injection can help reduce transmission costs.

Consistent with the EA paper on DG pricing principles,[8] CEL's view is that the current nodal market already provides incentives for DGs to inject when this benefits the wholesale market (e.g. constrained supply during dry years) or helps to reduce costs of transmission network investment (e.g. avoided costs of transmission). This is because New Zealand's nodal pricing reflects the marginal cost of delivering electricity to a certain location. This includes the costs of generation supply (i.e. marginal cost of generation) and transmission costs (e.g. connection charges). Wholesale prices are then passed through to end-customers in retailer tariffs.

CEL considers that if the EA's proposal is extended to also include other times (e.g. off-peak), when there are no benefits to the electricity distribution network from DG injection, this would result in the over-signalling of network benefits, paid for by customers who do not own DG, which potentially increases an EDB's network reinforcement costs that would otherwise not be required. This is not aligned with the EA's distribution pricing principles, which supports "signals to suppliers of energy (via localised generation activity or distributed energy resources) where prices can signal when and where it is efficient for the network to receive energy, and when it is not".[9]

[3] Sustainable Energy Association New Zealand (SEANZ), SEANZ Taskforce Submission – New ways to empower electricity consumers. 26 March 2025.
[4] Rewiring Aoteroa, Submission to Energy Competition Task Force, 26 March 2025.
[5] Ibid.
[6] Lyttelton Energy Transition Society, Energy Competition Task Force Initiatives 2a, 2b and 2c. 26 March 2025.
[7] Counties Energy, Submission on Energy Competition Task Force Initiatives 2A, 2B and 2C. 26 March 2025.
[8] The Electricity Authority, Distributed Generation Pricing Principles – Issues paper, 12 February 2025, p 23.
[9] The Electricity Authority, Distribution Pricing: Practice Note, Second Edition v 2.2, 2022. October 2022. para 13

Symmetrical export tariffs

Several parties submitted that symmetrical export tariffs would be preferred, as it provides a simpler approach for consumers to understand. While we support greater simplicity and fair cost-reflective pricing for consumers, we consider the main risk of this approach is that it may incentivise additional DG investment that does not correspond to a network benefit.

This is a risk some EDBs are already facing, as currently, the ability for EDBs to absorb excess export generation is likely to be lower than the ability to absorb additional demand on parts of the network. This is because electricity distribution networks have traditionally been designed to support growing electricity demand but are facing challenges in hosting DG capacity, to support increasing export generation on electricity distribution networks.

If symmetrical prices are applied, this could result in over-rewarding export generation, higher than the net benefit that it provides.[10] Given the evolving state of many electricity distribution networks, and their transition towards more cost-reflective pricing, CEL's view is that perfectly symmetrical export tariffs would not be workable at this stage.[11]

Using contracted flexibility with injection price signals

Some parties submitted that contracted flexibility could work together with injection price signals. While we agree in principle with using both resources together to manage network costs, it is important for EDBs to implement in a way that doesn't create undue distortions to investment or operational decisions, and the benefits it achieves.

CEL considers that, if both tools are used, EDBs should consider the use case for each resource in context to their own networks, how both resources can work together, and whether the combined effect achieves the intended effect. The main risk to avoid is over-rewarding flexibility (i.e. rewards that don't correspond to a network benefit) as this results in inefficient pricing and cross-subsidies between customers.[12]

For this reason, CEL supports the Electricity Engineers' Association's (**EEA's**) view that a principles-based, rather than a prescriptive approach is preferred, to reflect the differences in EDB's local network conditions, such as topology, constraint patterns, and available flexibility.[13] This would allow EDBs to determine the best tool, or combination of tools, to use within the context of their

---

[10] For example, if 'herd behaviour' occurs, encouraging more mass market customers to inject energy beyond a level that benefits an electricity distribution network

[11] This is assuming that DG capacity is concentrated in certain areas of an electricity distribution network. If there is even dispersion of generation capacity across the electricity distribution network, DG may not necessarily cause significant additional network reinforcement or augmentation costs on EDBs.

[12] Ofgem provides useful context to consider how price and non-price flexibility can be used to manage electricity distribution networks. Refer to https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/summer_2019_-_working_paper_-_links_with_procurement_of_flex_note_final_nd.pdf

[13] Electricity Engineers' Association, EEA Submission – Consultation Paper – Requiring distributors to pay a rebate when consumers supply electricity at peak times. 26 March 2025. p 3

network and the value that this provides. If a prescriptive approach is mandated, this could increase costs for some EDBs where injection price signals may be the sub-optimal choice.

Concluding comments

CEL reiterates its support for the underlying intentions of the EA's proposal. However, as discussed above, if the EA's proposal is mandated for all EDBs, there may be practical issues with implementation, and net costs incurred by some EDBs. As both Orion and Powerco have already implemented (network-wide) injection rebates for its mass-market customers (from April 2025), we also consider the need for regulatory intervention to be low.

CEL recommends that, as an alternative, the EA publish its proposal as guidance only at this stage. This would allow it to work with EDBs and industry to understand key lessons from current (and upcoming) EDB trials using mass market injection and other flexibility tools, and to understand the network benefits this achieves.

CEL would be happy to discuss any aspect of our submission further.

Yours sincerely

[redacted]

Marcus Sin
Senior Regulatory Manager