Ref: 25007

11 April 2025

Electricity Authority Te Mana Hiko
Energy Competition Task Force

By email to taskforce@ea.govt.nz

Tēnā koutou

CROSS-SUBMISSION ON CONSULTATION PAPERS FOR TASK FORCE INITIATIVES 2A AND 2B/2C

Unison Networks Limited (**Unison**) is an electricity distribution business operating in Hawke's Bay, Taupō and Rotorua. Centralines Limited (**Centralines**) is a distributor operating in Central Hawke's Bay.

We thank the Electricity Authority (**Authority**) and the Energy Competition Task Force (**Task Force**) for inviting further feedback on the proposed Code changes that support the Package Two initiatives 2A, 2B and 2C and the related submissions.

Summary

Submissions to the Authority and Task Force have highlighted a shared interest in advancing efficient, consumer-centric pricing reform while avoiding inefficient signals or incentives with limited benefits. Electricity Distribution Businesses (**EDBs**) are cautious about driving investment without clear network value. Meanwhile, consumers, particularly those with Distributed Energy Resources (**DER**) and Consumer Energy Resources (**CER**), are seeking to maximise the value and savings from their investments. Pricing principles must therefore focus on benefiting the majority, rather than disproportionately favouring a tech-enabled minority. Any rewards for DER and CER should be grounded strictly in the network value they provide, such as reducing constraints or relieving congestion.

There is broad agreement that retailers play a crucial role in passing through price signals and rebates. Submissions reflected differing views on how this should be managed, with some supporting mandated pass-through or clearer guidelines, while others favour maintaining retailer flexibility. Regardless of the approach, a transparent, effective mechanism is essential to ensure the intended consumer behaviour and overall savings.

Unison and Centralines continue to strongly support the connection and use of DER and CER on a level playing field and are committed to enabling this through principle-based incentives. It is important to recognise that most consumers invest in these technologies not to participate in flexibility markets, but to meet personal or household goals. Our role must be to support and enable this value creation as a priority.

We advocate for a principles-based approach that allows flexibility and relies on the competitive nature of the retail market to deliver suitable pricing options to consumers, rather than mandating specific offerings through regulation. In line with this, we propose separating delivery charges from energy charges to better promote cost reflectivity for both distribution (2A) and energy costs (2B/2C), while still allowing for retail innovation. This separation is critical to achieving greater consumer understanding, encouraging meaningful participation, enhancing retail competition, and enabling simpler, more transparent energy offers—without requiring comparison tools or AI. Separation will also help unbundle energy services and create a level playing field for retail competition at the installation control point (**ICP**) through multiple trading relationships.

To support efficient participation in flexibility markets and unlock the full value stack of DER, it is vital that aggregators are formally recognised as market participants, ensuring access to flexible resources while maintaining system and network security. Lastly, access to data on standard, pay-as-you-go terms and at reasonable cost is essential for distributors to identify where DER delivers locational value and to design appropriate, principle-based incentives to encourage it.

The below table summarises Unison's and Centralines' key points for consideration, how these points were observed by other submissions and our resulting recommendations.

Key points for consideration	Submissions' debate	Recommendation
Direct pass-through via retailers to be eventually mandated, so EDBs' strategic and locational peak export negative prices provide the desired signal.	**Pass-through Transparency and Consumer Impact:** Several submissions voice a concern that retailers may not transparently pass through price signals or rebates to consumers[1], undermining the intended outcomes and possibility benefiting the retailer's margin.[2] **Mandating Pass-through or Transparency:** Some submitters advocate for stronger regulation to ensure rebates or price signals are passed through to consumers, either through mandated pass-through or increased transparency.[3]	In order to send efficient signal and reward the appropriate ICPs for their network contribution, direct pass-through of distribution charges or rebates is necessary. As there is low appetite for this change by retailers, we recommend this must be mandated in the Code.

[1] MainPower and Marlborough Lines submission – Q9, p.3
[2] Horizon Energy submission – Q6, p. 6
[3] Waipa Networks submission – Para 3, p.1

Key points for consideration	Submissions' debate	Recommendation
Access to low-voltage (**LV**) network data will be crucial in assessing the effectiveness of negative prices and ensuring their optimal design.	**Accurate Allocation of Rebates:** Several submitters highlight that LV network data is essential to ensure rebates are accurately allocated to ICPs that provide genuine network benefits. [4] **Understanding Network Benefits:** Alpine Energy notes that visibility of DG data, including LV data, is important for evaluating how consumer exports contribute to network outcomes.[5] **Quantifying Network Benefits:** Horizon Networks states that in order to identify and quantify where small-scale DG is providing network benefits, they need access to half-hourly (**HHR**) smart meter data, which will give EDBs the necessary visibility.[6] **Limitations of Simpler Data:** Aurora Energy points out that currently, cost-reflective mass-market billing is limited to time-of-use (**ToU**) periods using relatively simple EIEP1 data, and a full-scale rollout of export tariffs reflecting real-time constraints would require more sophisticated data such as HHR data (EIEP3).[7]	We urge the Authority to implement the necessary regulation to provide EDBs access to HHR data in order to allow successful and efficient implementation of targeted export rebates and to support the broader goal of leveraging distributed generation for network benefits. Currently, several barriers hinder access to this essential data. These include excessive minimum term lengths for data access agreements, a lack of transparency around pricing, particularly where consumers may effectively be paying twice, given that smart meter infrastructure has already been funded through retailer led meter deployment; and the absence of standardised terms and conditions across different Metering Equipment Providers (**MEPs**). The lack of adequate LV network visibility, which is compounded by these access issues, has been a significant concern raised by multiple EDBs regarding both the practicality and fairness of the proposed rebates.

[4] Northpower submission – Para 5, p. 1
[5] Alpine Energy submission – Para 11, p. 2
[6] Horizon Energy submission – Para 13, p. 2
[7] Aurora Energy submission – Para 2, p. 5

Key points for consideration	Submissions' debate	Recommendation
A clear and transparent mechanism must be established to coordinate the coexistence of flexibility aggregators and negative charges on the same network.	**Coordinated and Targeted Flexibility:** Aggregators can schedule exports in response to network constraints, enabling targeted flexibility services that can help defer or avoid costly network upgrades. Unlike individual households, they can pool resources and provide a more reliable and predictable response, ensuring demand-side management is effective and aligned with network needs. [8] Contracted flexibility with an aggregator provides a higher level of certainty and assurance for EDBs when considering deferring network investment.[9] **Maximising Network Benefits:** Arrangements through flexibility providers and aggregators are likely to maximise benefits to networks. By coordinating exports across many sites, they can control when and how much energy is exported, reducing network strain and optimising for network needs. On the other hand, export at peak by individual households is likely to be inconsistent and unreliable, offering limited benefits to networks. The small and unpredictable nature of individual exports contrasts with the coordinated and reliable responses that aggregators can provide.[10] **Need for Clear Frameworks and Support:** EDB submissions recommend that the Task Force should prioritise establishing clear regulatory frameworks for Virtual Power Plants (**VPP**) and bring aggregators into the Electricity Industry Act 2010 as Industry Participants.[11]	Aggregators, including retailers, will be important intermediaries in enabling the participation of DER and CER to provide flexibility services for a range of purposes. It is important that regulation ensures these resources can access the full value stack, and that regulated pricing approaches do not impede this. At the same time, there must be appropriate regulation of aggregators and VPP operators to ensure that these resources are available to provide flexibility services across the full value stack. This includes ensuring they are offered, dispatched, and operated in a way that does not undermine system security, including at the local distribution network level. We also recommend the Task Force and the Authority develop a clear guidance to provide higher value to aggregators through EDB payments in order to incentivise individual ICPs signing up with aggregators and VPPs.

[8] Aurora Energy submission – para 13, p. 6
[9] Counties Energy submission – para 5, p. 5
[10] ENA submission – para 2, p. 18
[11] Orion submission – para 6.b, p. 2

Key points for consideration	Submissions' debate	Recommendation
Principles to stay out of the Code.	**Flexibility and Easier Amendments:** Principles outside the Code allow for easier and more flexible amendment by the Authority if required in the future. The electricity sector is undergoing rapid transition, and a principles-based approach provides the adaptability needed to respond to evolving export tariffs and current implementation challenges.[12] Keeping the principles outside the Code allows for a more flexible and adaptive approach.[13] **Opportunity for Learning and Refinement:** Keeping the principles as guidance allows the Authority to work closely with EDBs and leverage lessons learned from previous trials using injection price signals. A voluntary approach would allow the Authority and distributors to observe real-world outcomes and refine the proposal accordingly.[14] This enables an iterative refinement based on observed data and experiences. **Preventing Premature Codification:** The Authority should only consider including the principles in the Code if voluntary uptake proves ineffective. This allows for a period of observation and assessment before making them mandatory.[15]	Many EDBs strongly support keeping export rebate regulation outside the Code to preserve flexibility for managing market and technology changes. A voluntary, principles-based approach, rather than mandatory obligations, supports learning, refinement, and adaptation. This is particularly important where practical challenges remain, and where flexibility has worked well in other successful non-Code frameworks. We believe a full, coordinated review, similar to the Authority's proposed review of the Distributed Generation Pricing Principles (**DGPPs**), is essential. This review should also ensure alignment with broader Distribution Pricing Principles, particularly regarding fair contribution to shared network costs and effective DER integration. Since the 2A proposals fall within the scope of the DGPPs, their implementation should not proceed in isolation.

[12] ENA submission – para 2.4, p. 6
[13] Aurora Energy submission – Q7, p. 10
[14] Network Tasman submission – para 4, p. 1
[15] Waipa Networks submission – Q7, p. 4

Key points for consideration	Submissions' debate	Recommendation
Later implementation date such as 1 April 2027 required.	**Insufficient time for planning, system development, and consultation:** Distributors require time after the final decision to model network impacts and determine how benefits will be realised.[16] Preparing new pricing methodologies occurs between September and December each year to meet contractual and regulatory deadlines for notifying retailers of new prices in January. Given that internal pricing activities do not take place between January and April, it is unlikely that there will be sufficient time to reflect a final decision made in early 2026 for the 2026/2027 pricing year.[17] A more realistic and achievable implementation date is **1 April 2027**, allowing for a well-planned and effective transition **Need for clear guidance:** Distributors need clear guidance on implementation expectations and realistic timelines from the Authority.[18] Guidance needs to be issued and finalised before implementation can start.[19] The lack of clear implementation guidance makes the proposed timeframe unrealistic.. It is unreasonable to expect distributors to start implementing system changes from a draft decision. **Alignment with retailer readiness:** Retailers should have time to reflect these changes in their retail packages so that the benefits can pass through to consumers. If retailers cannot implement associated changes (like time-varying buy-backs) by 1 April 2026, then the 2A requirements on distributors should also be delayed to align with retailers' capability.[20]	Unison and Centralines are aligned with many other submissions that 1 April 2026 implementation date is unrealistic and agree that the earliest feasible implementation date is 1 April 2027 depending on when the Authority and Task Force reach a final decision and provide the necessary guidance.

[16] Aurora Energy submission – Q8, p. 10
[17] Horizon Energy submission – para 12, p. 2
[18] Firstlight Network submission – Q8, p. 2
[19] Horizon Energy submission – Q5, p. 6
[20] Aurora Energy submission – para 22, p. 8

Key points for consideration	Submissions' debate	Recommendation
Later implementation date such as 1 April 2027 required (cont.)	**Data requirements:** Some distributors do not currently receive HHR meter data for most of their mass-market ICPs, including those with distributed generation. As a result, they do not have the information required to quantify the benefits for the 2026/27 pricing year, making the proposed timeline unrealistic.[21] Allowing time to analyse data is crucial before designing alternative pricing approaches. **Phase out of Low Fixed Charge regulations:** The proposed rebate potentially represents a wealth transfer to customers with DG from customers without DG. Delaying the implementation until after the phase out of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC) is suggested.[22] The low user fixed charge will not be removed until 1 April 2027, and export rebates should evolve in the same way.[23] **Need for consultation:** Under the Default Distributor Agreement (DDA), EDBs are contractually required to consult with retailers on any tariff structure changes several months before the start of the pricing year. [24] Implementation timelines should ensure the time required for this consultation is taken into account	

[21] Horizon Energy submission – Q7, p. 7
[22] MainPower and Marlborough Lines submission – Q8, p. 3
[23] Powerco submission – Q8, p. 7
[24] Counties Energy submission – Q8, p. 10

Key points for consideration	Submissions' debate	Recommendation
2BC – Regulation in competitive market not advisable.	**Market Competition Should Drive Offerings:** Several EDB submissions argue that the retail electricity market is already competitive, with numerous retailers offering a variety of pricing plans, including ToU options and export tariffs for DG customers.[25] They contend that if consumers demand these types of plans, the competitive market will naturally respond by providing them.[26] Mandating these offerings is seen as unnecessary intervention in a functioning market. **Risk of Stifling Innovation and Hampering Flexibility Providers:** Some submissions express concern that regulating retail offerings could have unintended consequences that stifle demand and innovation from flexibility providers and aggregators.[27] They worry that prescriptive regulations might limit retailers' ability to create innovative pricing structures and services that could better serve consumers.	We advocate for a principles-based approach that allows flexibility and relies on the competitive nature of the retail market to deliver suitable pricing options to consumers, rather than mandating specific offerings through regulation. We propose separating delivery charges from energy charges to better promote cost reflectivity for both distribution (2A) and energy costs (2B/2C), while still allowing for retail innovation. This approach aligns with several of the Authority's objectives and initiatives, including: • Enhancing consumer understanding and participation. • Enabling direct comparison of retail energy offers without the need for tools or AI (e.g., Powerswitch lists over 17,000 separate retail price plans, which is excessive for a commodity service and contributes to consumers being on the wrong plan, failing to switch, or misunderstanding their bills, with many believing the fixed component is the lines charge).

25 ENA submission – "Summary of Key ENA Views", p. 9
26 ENA submission – para 6, p. 14
27 ENA submission – para 2.3, p. 5

Key points for consideration	Submissions' debate	Recommendation
2BC – Regulation in competitive market not advisable (cont).		• Enabling responses to price signals and incentives to address localised network congestion. • Providing a transparent, level playing field for competition at the ICP level, which would be hindered by a model where incumbent retailers bundle line charges and rebates.
2BC - If regulation is introduced, it should apply consistently across all retailers rather than targeting only a subset.	**Potential for Uneven Impacts and Competitive Disadvantage:** Applying regulations to only some participants in the retail market could negatively impact competition and unevenly affect EDBs. [28] For example, mandating TOU for only a subset of retailers could create an unlevel playing field.[29]	We recommend removing the 5% market share limit for any regulation impacting retailers.

Conclusion

In conclusion, while the goal of promoting efficient use of the distribution network through export rebates is widely supported, submissions highlight that achieving this requires a strategic, targeted, and data-informed approach. Broad-based rebates risk inefficiency, cross-subsidisation, and unintended investment signals, whereas locational and time-specific pricing, enabled by robust data access and regulatory frameworks, can better align incentives with actual network benefits.

Mandating pass-through of signals to end consumers, supporting aggregator participation, and maintaining a flexible, principles-based regulatory approach outside the Code are essential for success. Moreover, a realistic implementation timeline, such as 1 April 2027, is necessary to allow EDBs, retailers, and other stakeholders to prepare effectively.

Ultimately, a balanced and principles-based approach that allows flexibility and relies on the competitive nature of the retail market to deliver suitable pricing options to consumers will be key to unlocking the full value of distributed generation for New Zealand's electricity networks. Separation of delivery charges from energy charges will better promote cost reflectivity, while still allowing for retail innovation. This separation is critical to achieving greater consumer understanding, encouraging meaningful participation, enhancing retail competition, and enabling more transparent energy offers.

[28] ENA submission – "Summary of Key ENA Views", p. 9
[29] ENA submission – para 7, p. 14

Separation will also help unbundle energy services and create a level playing field for retail competition at the ICP through multiple trading relationships.

Nā māua noa, nā

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