Requiring distributors to pay a rebate when consumers supply electricity at peak times - Energy Competition Task Force Initiative 2A

Submission on the Electricity Authority's Consultation Paper

26 March 2025

Aurora ENERGY

Table of Contents

1. Introduction

1.1. Preliminary

1. We welcome the opportunity to submit our views in response to the Electricity Authority's (the Authority's) consultation paper – "Requiring distributors to pay a rebate when consumers supply electricity at peak times".

2. Section 1.2 of this document provides a summary of the key aspects of our feedback, with responses to the submission questions provided in Appendix A.

3. No part of our submission is confidential.

1.2. General Comments

4. Aurora Energy believes in empowering communities with innovative energy solutions that are both practical and forward-thinking. We support the Authority's proposal, noting it aligns with Aurora Energy's commitment to enabling the energy future of our communities. We also expect solar customers to play a critical role in New Zealand's future energy system.

5. While we support the Authority's proposal, we also believe there are several key challenges that must be addressed before effective implementation can be achieved:

    - Export pricing must strike a balance between accuracy and simplicity. While tariffs should incentivise efficient exports, overly complex structures may not align with real-time network conditions. Time-of-Use (ToU) tariffs provide broad signals but do not always reflect actual network costs. Ensuring that export tariffs prevent issues like battery dumping and congestion requires careful design.

    - Implementing cost-reflective export tariffs will require significant system and billing upgrades. Current system infrastructures lack the capability to process dynamic price signals and real-time constraints. Advanced tools such as LV monitoring systems and improved billing engines are needed.

    - Export rebates may conflict with the role of flexibility providers, who can coordinate exports to reduce network congestion and ensure that energy is injected at times that provide the most benefit. Individual rebates might not provide the same level of efficiency and control as managed flexibility arrangements. The Authority should clarify whether distributors must offer export tariffs if flexibility providers operate in the same network. A targeted approach, such as offering higher rates for managed aggregation, could improve overall network efficiency.

    - The Authority should provide clear guidance on implementation expectations and realistic timelines. Given that pricing preparations begin in September/October each year and are

largely concluded in December to meet DDA obligations to notify retailers of new prices in January, a delayed decision risks missing the window for inclusion in the upcoming pricing cycle. We encourage the Authority to recognise the structured steps required to have pricing in place by 1 April each year and ensure that any implementation timeline accounts for these constraints. A more realistic and achievable implementation date is 1 April 2027, allowing for a well-planned and effective transition.

6. In the remainder of this section, we expand on key points that we believe are important for the Authority to consider when refining its approach. While we support the Authority's objective, these considerations are intended to address potential gaps in the proposal and ensure that export pricing remains practical, cost-reflective, and does not introduce unintended network inefficiencies.

Challenges in Tariff Design and Implementation

7. Consumer exports should be seen as the counterpart to consumption, both facing similar challenges in tariff design. Developing a truly cost-reflective mass-market tariff for consumption has proven to be a complex task. The variability in electricity demand and supply, influenced by factors such as weather conditions, time of day, and geographic location, means that a one-size-fits-all approach is often insufficient. Therefore ToU tariffs provide broad guidance, but they do not always align with actual network costs. The same issue applies to export tariffs, which may be too simplified to reflect whether exported electricity is reducing peak demand or creating new congestion issues.

8. While the proposal seeks to improve export price signals, its implementation presents practical challenges. Introducing highly granular export tariffs without the necessary data and systems is not practical with the current systems infrastructure and could increase costs for all consumers. A well-calibrated approach must strike a balance between accuracy and simplicity, ensuring that export tariffs provide effective incentives without adding unnecessary complexity. Just as consumption tariffs act as broad signals rather than exact cost reflections, export pricing should be practical, transparent, and aligned with long-term network efficiency goals.

9. It is important to recognise that exporting at the wrong time can either generate costs or fail to deliver any savings. For instance, even during peak periods, if the network is not congested, an injection from rooftop solar will not confer any network benefit. Similarly, if generation is too intermittent and the distributor is required to build capacity to cover 100% of demand, then the distributed generation effectively provides no benefit. This is why export rebates should be limited strictly to peak times.

System and Billing Upgrades Are Essential for Accurate Export Tariffs

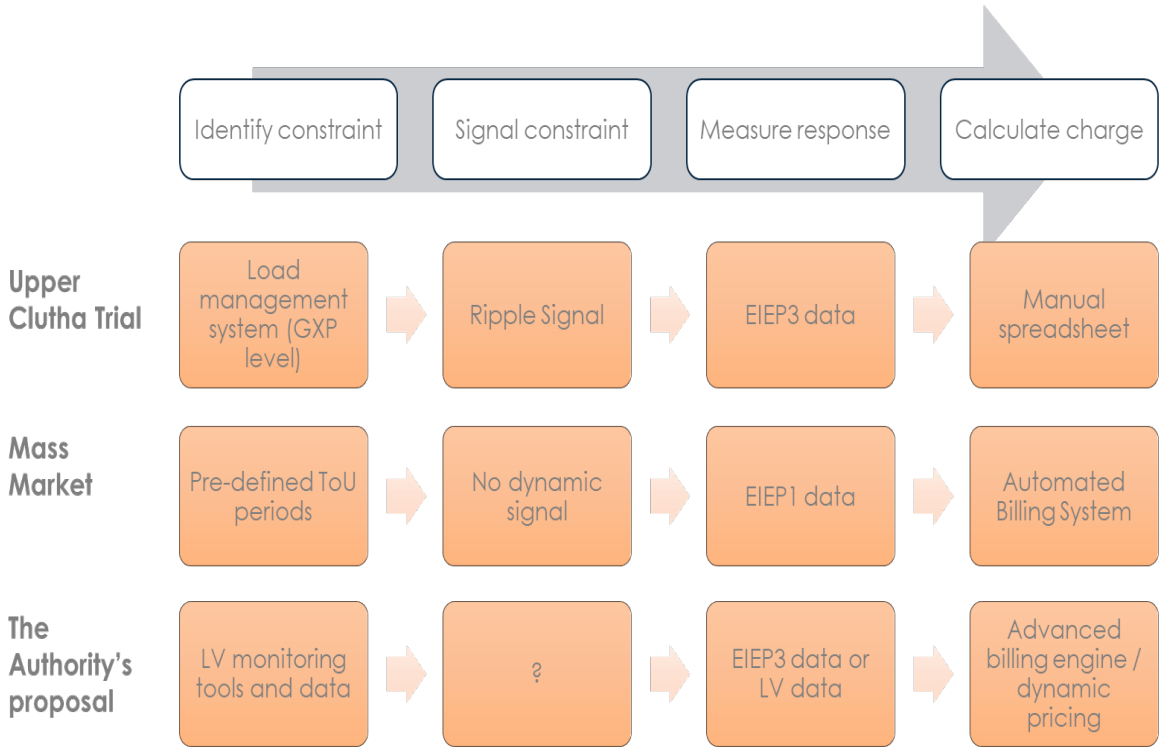
10. Building on the above points about targeted rebates and real-world constraints, the billing process in figure 1 illustrates how we currently manage charges for mass-market customers and how we have managed charges for our flexibility services arrangement with Solar Zero in the Upper Clutha region of our network. Figure 1 also indicates what might be needed to fully implement the Authority's proposal. At present, cost-reflective mass-market billing is limited to ToU periods with no dynamic signalling, using relatively simple EIEP1 data and automated billing systems. The Upper

Clutha solution which Aurora Energy started in RY25, has required more granular signalling (e.g. ripple control signals) and the use of EIEP3 data, but still relies on manual billing methods.

By contrast, a full-scale rollout of export tariffs that accurately reflect real-time network constraints would require more sophisticated tools and data - such as low-voltage (LV) monitoring systems to identify local constraints, dynamic signals to inform consumers when and how much to export, and a more advanced billing engine capable of handling complex pricing structures. These technology upgrades could be costly, and the Authority has not yet fully addressed how distributors can reconcile what is economically desirable with what is practically achievable given current systems.

Although we support the Authority's overarching aims, we believe it is critical to acknowledge the gap in current system capabilities and carefully consider the cost and complexity of implementing such measures at scale. In particular, the Authority should further examine billing system capabilities and data availability (e.g., half hour reconciliation data) - both of which are pivotal in determining whether an export tariff can be deployed in a way that is fair, accurate, and does not create disproportionate administrative burdens for distributors and retailers. Achieving this goal will require substantial time and investment.

Figure 1: Cost reflective pricing in practice



11. A key enabler for implementing cost-reflective export tariffs is access to LV data. Currently, there is a limited visibility of LV network conditions, making it difficult to manage constraints in real time or provide accurate price signals. To support the effective rollout of dynamic export pricing, the Authority should take proactive steps to promote access to LV data on reasonable terms. Improved

access would allow distributors to make more informed decisions about network management, enhance the efficiency of energy exports, and support the integration of distributed generation into the grid. Without this, there is a risk that pricing structures could be based on incomplete information, leading to inefficiencies or unintended consequences.

12. Some billing challenges may be mitigated by utilising an intermediary flexibility provider, and as an interim measure, export tariffs could be applied during winter only, linked to ToU consumption tariffs (for example, at 50% of a peak tariff), offering a practical, targeted solution.

Interaction with Aggregator-Led Demand Response

13. The Authority's proposal to introduce export rebates raises an important question regarding its interaction with aggregator-led demand response. Direct rebates for individual mass-market consumers might not be fully reflective of network benefits, as managed flex arrangements with aggregators can often provide more efficient and coordinated demand-side management. Achieving a targeted network response often requires an intermediary. Aggregators can pool resources and provide a more reliable and predictable response, ensuring that demand-side management is both effective and aligned with network needs.

14. The Authority acknowledges that export rebates should be applied sparingly, given that the circumstances in which mass-market exporters provide genuine network benefits are limited. If customers are already capturing significant value from these rebates, there might be little room left for additional flexibility services. This leads to a core question: should distributors be required to offer solar export tariffs if a flexibility provider is operating on the network, and how would this requirement change if multiple providers exist, offering consumers a choice? One possible solution could be to offer flex providers a better export rate than mass-market residential exporters.

15. Ultimately, it may be more effective for distributors to contract directly with flexibility providers, rather than relying on direct export rebates. This could be a balanced solution, ensuring that export pricing remains targeted, avoids regressive cost increases, and does not stifle the development of efficient demand-side management solutions in New Zealand.

16. We align with the Authority's stance that export tariffs should not mirror consumption tariffs, and we have some additional reasons for this.

- **Discourage Battery Dumping at the Beginning of a Congestion Period:** When stored energy is released all at once at the start of a congestion period, it can create significant issues. It can lead to sudden spikes in supply that the network may not be able to handle efficiently, potentially causing instability and requiring additional infrastructure to manage these peaks. Encouraging solar households to first offset their own household demand before exporting genuine surplus stored energy back to the grid can prove to be more cost-effective. Additionally, if households export all their battery storage early and then recharge during the congestion period, it can exacerbate congestion issues towards the end of a congestion period, particularly if the congestion period extends beyond 2 hours, which is the typical time it takes for a battery to discharge. Therefore,

prioritising household consumption over exporting helps maintain network stability and efficiency.

- **Recognise the Value in Aggregation:** Aggregation and coordination of energy exports by flexibility providers can optimise the export of energy from multiple sources, ensuring network benefits and support are maximised during period of network congestion. Allowing room for a higher rate to be paid to those exporting via a flexibility provider would be a means of reflecting this added value. Consideration should also be given to operating envelopes and managed households to ensure effective and beneficial coordination.

- **Alignment with LRMC Assumptions:** We suggest that export tariffs should align with Long-Run Marginal Cost (LRMC) assumptions. The LRMC differential should serve as the starting point for setting export tariffs, ensuring they reflect the true cost and value of energy exports over time.

Additional Considerations

17. It is also important to address barriers such as the current Low Fixed Charge (LFC) and effective constraint signalling. Without the ability to signal and respond appropriately, even the best-designed price signals will fail to deliver their intended benefits.

18. Currently, there is a lack of economic studies to determine the appropriate discount rate for export tariffs. We ask that the Authority provide clear guidance on this matter by commissioning or drawing on robust economic analysis. This would help ensure that export tariffs are set at levels that accurately reflect network benefits while remaining cost-effective and fair for consumers.

19. The tax implications of solar export rebates have not been addressed in the consultation paper. It remains unclear whether the export of electricity to the network is a taxable activity, for both income tax and GST purposes. While the quantum of these rebates may be relatively small, the tax treatment could have implications for both consumers and distributors, particularly in terms of compliance and reporting.

20. Aurora Energy also prefers a negative tariff over a rebate, particularly in the context of potential symmetrical tariffs.

21. We support the introduction of new principles, but it would be crucial to allow a sufficient implementation timeframe before assessing distributors against those principles. This will ensure that the necessary systems and processes are in place to achieve the desired outcomes effectively and efficiently.

22. We consider it would be more appropriate to introduce the principles with effect from 1 April 2027 because:

    – Distributors will need time once the final decision has come out to model the network to identify where benefits will be realised and how these benefits will be achieved;

- The Authority should take the time following its final decision to develop and provide distributors with clear guidance on the extent of consultation required to implement changes related to new price categories and methodologies for calculating location-specific rebates;
- Distributors will need time to then consult with consumers and key stakeholders on those changes;
- Distributors will need time to implement the changes and incorporate them into prices and pricing methodologies, the preparation of which will next occur between September and December 2025 in order to meet contractual and regulatory deadlines for notifying RY27 prices. Internal activities to set prices do not take place between end of January and April each year so distributors would only have until December 2025 practically to reflect any final decision; and
- Retailers should have time to then reflect these changes in their retail packages so that the benefits can pass-through to consumers.

23. Implementing the new principles from 1 April 2027 is a more realistic and achievable date. The Authority has on several occasions introduced tight implementation timelines for decisions and we strongly encourage it to take heed of the practical steps associated with implementation on this occasion. We believe it would be unreasonable to expect distributors to start the process of implement system changes from a draft decision.

Appendix A. Consultation Questions – Requiring distributors to pay a rebate when consumers supply electricity at peak times

Q1. Do you agree with the problem definition above? Why, why not?

Generally, Aurora Energy agrees with the problem definition provided by the Authority. However, we recognise a significant gap between what is practically achievable and what is economically desirable.

Q2. Do you agree with these principles? Why, why not?

We generally agree with the principles set forth by the Authority. However, as previously mentioned, the aggregation and coordination of energy exports by flexibility providers can optimise the export of energy from multiple sources, maximising network benefits and supporting the network during congestion.

Q3. Do you agree that the principles should only apply to mass-market consumers, or should they apply to larger consumers and generators also? Why, why not?

We agree that the principles should apply to mass-market residential customers. However, it is also important to provide distributors with the flexibility to establish bespoke arrangements with larger customers. As discussed above large customers and aggregators have the capability to export significant amounts of energy during periods of network congestion, which can greatly benefit the overall stability and efficiency of the network. By allowing for tailored agreements, distributors can better manage and optimise the export of energy from these larger sources, ensuring that the network can handle the additional load effectively. This approach not only maximises network benefits but also supports the goal of reducing congestion and improving the reliability of the electricity supply.

Q4. Do you agree the principles should apply to all mass-market DG, including inflexible generation (noting that the amount of rebate provided will still be based on the benefit the DG provides)?

We support the application of the principles to all mass-market DG, including inflexible generation, such as solar without batteries.

Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?

As stated above, generally we agree with the direction of the guidance.

Q6. Are there any additional issues with the principles where guidance would be particularly helpful?

As discussed earlier, the Authority should take proactive steps to promote access to LV data on reasonable terms. This access is crucial for enabling distributors to make informed decisions about network management and optimisation. By providing access to LV data, the Authority can facilitate better planning, enhance the efficiency of energy exports, and support the integration of distributed generation into the grid.

Additionally, the Authority should provide guidance on an appropriate discount rate for export tariffs. This guidance is essential to ensure that export tariffs accurately reflect the long-term value and benefits of distributed generation to the network.

Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?

Aurora Energy believes that the principles should be outside the Code. While we support the introduction of these principles, it is crucial to recognise the practical limitations in achieving them. Incorporating them within the Code at this stage could impose unrealistic expectations and burdens on distributors. By keeping the principles outside the Code, we allow for a more flexible and adaptive approach, giving distributors the necessary time to develop and implement the required systems and processes effectively. This approach ensures that the principles can be gradually integrated in a way that is both practical and achievable.

Q8. Do you agree with the proposed implementation timeline for this proposal? If not, please set out your preferred timeline and explain why that is preferable.

While we acknowledge the Authority's objective of providing consumers with more options to manage energy bills, the practical constraints of implementation have not been fully considered.

- Distributors require time after the final decision to model network impacts and determine how benefits will be realised. This also includes time for consultations with customers and stakeholders.
- Preparing new pricing methodologies occurs between **September and December each year** to meet contractual and regulatory deadlines for notifying RY27 prices. 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 RY27 pricing.

We strongly encourage the Authority to provide clear implementation guidance and realistic timelines, ensuring alignment with industry processes.

Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?

As noted by the Authority, the benefits to mass-market consumers from the proposed rebates may not be substantial. Additionally, without granular visibility of network

constraints, distributors may struggle to ensure that these rebates effectively support congestion periods. A flexibility provider, capable of managing and optimising network support during congestion times, would likely offer a more effective solution. This approach would ensure targeted and efficient network support, addressing congestion issues more reliably than the proposed rebates alone.

Q10. Do you agree the proposal will lead to relatively minor wealth transfers in the short term, and will lead to cost savings for all consumers in the longer term?

We agree that requiring distributors to reward mass-market consumers for their injection would reduce the net revenue recovered by distributors. To recover their maximum allowable revenue (MAR) as set by the Commission, distributors are likely to increase their charges that apply to all customers. This could be achieved by adjusting the distribution tariffs, which would spread the cost of the rebates across the entire customer base.

However, we believe that the proposal will lead to relatively minor wealth transfers in the short term. As mentioned by the Authority's analysis, the short-term impact per ICP is expected to be minimal, with an average monthly increase in charges being less than $0.01 due to the small number of consumers with DG systems initially receiving rebates.

In the longer term, as more consumers invest in DG systems, the network will benefit from reduced peak demand and deferred infrastructure investments. This will result in significant cost savings for all consumers, leading to lower electricity prices.

Q11. Do you agree that more prescriptive requirements to provide rebates will be less workable than a principles-based approach, and therefore should not be preferred? Why, why not?

We agree that more prescriptive requirements to provide rebates will be less workable than a principles-based approach. Prescriptive requirements lack the flexibility needed to accommodate the unique conditions of different networks, leading to inefficiencies and potential misalignment with actual network benefits.

Q12. Do you agree that a consumption-linked injection tariff would not be sufficiently targeted, and therefore should not be preferred? Why, why not?

We agree that a consumption-linked injection tariff would not be sufficiently targeted and therefore should not be preferred. This approach could over-incentivize injection where it does not provide network benefits, leading to inefficiencies and potential additional network costs such as voltage management issues, where excessive injections during low demand periods can cause voltage fluctuations, requiring investment in voltage regulating equipment.

However, due to the current lack of access to LV visibility data, this approach could serve as an interim solution until more precise data becomes available.

Q13. If this approach was progressed, do you think:

a) injection rebates should perfectly mirror consumption charges?

b) there are sufficient safeguards in place that would allow distributors to avoid over-incentivising injection to the extent that it incurs additional network costs?

a) No, the rebates should not perfectly mirror the consumption rates. We suggest that export tariffs should align with LRMC assumptions. The LRMC differential should serve as the starting point for setting export tariffs, ensuring they reflect the true cost and value of energy exports over time.

b) As previously mentioned, distributors can offer more favourable export rates to flexibility providers compared to mass-market residential exporters. This is because flexibility providers can deliver targeted network support during periods of congestion.

Q14. Do you agree with the objective of the proposed amendment? If not, why not?

We generally agree with the objective of the proposed amendment.

Q15. Do you agree the benefits of the proposed amendment outweigh the costs?

Aurora Energy believes in empowering communities with innovative energy solutions that are both practical and forward-thinking. We support the Authority's proposal, as it aligns with our commitment to enabling the energy future of our communities. We also see Solar customers playing a critical role in New Zealand's future energy system. This said, we also understand that export pricing mechanisms have practical limitations, particularly in their ability to provide precise price signals that reflect real-time network conditions. It is crucial to strike a balance between accuracy and simplicity to ensure that export tariffs provide effective incentives without adding unnecessary complexity. While the benefits of the proposed amendment may become significant in the long term, they are unlikely to be substantial in the short term.

Q16. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objectives in section 15 of the Electricity Industry Act 2010.

As discussed earlier, the principle-based approach is preferable, however, there is a lot of work that needs to be done before its implementation. We also believe that consumption-linked injection tariffs and a principles-based approach are not mutually exclusive. For example, use consumption-linked injection tariffs as a baseline for setting export tariffs. Then, apply principles-based adjustments to account for specific network conditions, such as local constraints and peak demand periods. This ensures that tariffs are both cost-reflective and adaptable to changing conditions.

Q17. Do you have any comments on the drafting of the proposed amendment?

We have no comments at this time.