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Submissions
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by email: taskforce@ea.govt.nz; distribution.pricing@ea.govt.nz
(subject line "Consultation paper — Requiring distributors to pay a rebate when consumers export electricity at peak times")

Submission on ECTF initiatives 2A and Authority DGPP issues paper

Thank you for the opportunity to provide feedback on the Electricity Authority's (the Authority) 12 February 2025 release of:

- Requiring distributors to pay a rebate when consumers export electricity at peak times (the Consultation Paper), and
- Distributed Generation Pricing Principles (the Issues Paper).

For us, these papers cover related issues, so we provide a combined response. Our over-arching comments in this letter are followed by responses to the specific questions provided in the Consultation and Issues papers.

Context and situation

We are evolving into a network of interconnection. Historically we distributed electricity from Transpower's grid to homes and businesses. Alongside this we are now increasing providing an interconnection service, redistributing energy between producers and consumers. Through small and large scale embedded generation, we now regularly reach the point where combined generation exceeds the load on our entire network, and the surplus is fed back to Transpower's grid.

Some forward-thinking advocates visualise an ideal where customers can meet their own energy needs, and where groups of customers can get together and share energy resources. Those that have more energy resources can help those who don't have the options, and different forms of generation can complement each other to collectively meet their community's needs.

The great news is that we already have this interconnection service in place. Our locally owned distribution network links up customers enabling energy sharing. It's worth acknowledging that there's a cost to this service (as there would be for any alternative), and we spend a bit of time thinking about how this cost should be efficiently and equitably shared between users of the service, particularly in areas where we need to bolster the service to allow for the growing demand for interconnection.

A point to note is that the interconnecting service operates as a natural monopoly – it makes sense to have a single provider, as no one will win if we end up with competing network infrastructure in our streets. In lieu of competition, electricity distribution networks are regulated, and appropriately so. We need to ensure that the regulation leads to efficient outcomes, and this means that users of our service need to pay for that service. Customers with generation seek to use our service to get their “product” to users. These generating customers are “users” of our service, and for the most part, they are currently using our service free-of-charge.

Challenges rewarding demand response to address a congestion

Pricing mechanisms are a blunt tool to entice generation or demand response. Our prices apply over broad categories of customers and across wide areas of our network. In many respects, prices reflect longer-term costs of our service to ensure consistency and stability for customers.

Pricing mechanisms are difficult to deploy in a meaningful way because of a number of electricity network realities, which include:

- Our engineers, acting efficiently, will reconfigure the network over time to address congestion, changing open points and moving load both in and out of a congested area to better utilise capacity, sometimes on a seasonal basis. This makes any pricing response volatile, as customers can find themselves within a congested area one day, and outside the congested area the next.

- Sometimes it takes just one large customer to disconnect and a constraint can be alleviated. A pricing incentive can disappear overnight, without warning.

- In some situations it will take just one new large customer to force a network solution to address a constraint. In this situation, once we are committed to an upgrade, any pricing incentive to address the congestion can disappear overnight, without warning.

In our experience, the level of volatility in the availability of credits will not sit well with customers looking to make an investment in distributed generation. Those that elect to size their investment to provide export capability, will not appreciate an outcome where expected benefits are no longer available.

We are also conscious that pricing incentives need a long lead time to be effective; customers need to be rewarded in advance of the network deferral or avoidance to allow the response to develop. This creates a risk for our customer base that funds these incentives, as there’s no guarantee that the benefits will eventuate.

A more nuanced and targeted approach can be taken if the demand or generation response is attracted via a flexibility arrangement. We see this as an operational expense instead of a refund or rebate of charges. The arrangement more transparently competes with the network solution and can be targeted at times, areas and situations where a real benefit is provided.

A pricing and flexibility package could work in tandem, but we’d need to be careful that the combined reward didn’t exceed lead to higher costs for our customers than the network solution that we are looking to avoid or delay.

We are of the view that, as an industry, we should promote and develop flexibility service options, rather than blunt pricing incentives.

Time-bound rebates are challenging

We have considerable experience applying dynamically signalled credits for a generation response. In situations where these are to address peak loads, the duration of such a signal can vary significantly from one peak season to the next, as loading levels are driven by external influences, like weather. This raises a number of challenges:

- There may be no need to issue a signal in some years (and we have experienced dissatisfied customer responses where they have not been given the opportunity to benefit from credits).
- There may be extended calls for generation response in other years, where high loading levels persist in response to weather. This can easily increase the cost of the response to a level where it exceeds the cost of a traditional network solution, placing an undue burden on customers.

In our experience, customers that are dissatisfied with the returns that they receive tend to become disillusioned with the interaction. This can have impacts that reach far beyond the transaction in question, and can influence how the customer might respond to future options and incentives.

Where we know that the outcome for customers may be volatile, we think we should be careful about how we promote and attract customers. Publishing and applying rebate prices will not always provide the opportunity for the level of interaction that is needed explain the risks to customer.

Pricing can't distinguish certainty of response

Providing a time-bound energy credit will reward customers for periods where they are able to respond to a signal. However, congestion is only alleviated if a response is available throughout a period of congestion. Of particular note:

- It would not be efficient for a network operator to reward day-time solar driven export when a signal to an equivalent evening peak might go unanswered.
- It would not be efficient to reward battery driven export that regularly contributes during the first few hours of a signalled peak, but lacks the capacity to continue contributing where the peak extends beyond this duration.

Peaks are addressed with kW not kWh

A better way to structure an incentive is to let the generating customer address the duration risk, and apply a kW-based credit for the minimum contribution during signalled periods (or the combined minimum contribution from a group of customers). This approach ensures that customers are rewarded on a basis that is consistent with the extent to which they actually address the congestion.

That is, kWh (volume) based credits are crude, and will lead to situations where payments are made (at the expense of other customers) where no benefits are derived. Unfortunately, an alternative approach of basing credits on the rate of export (kW-based) is far more complex to measure, apply, and a lot harder for the customer to understand.

Standard network sizing vs efficient network sizing

We currently build our low voltage network to standard sizing levels. We find this to be the most efficient approach where customer demands can vary over the life of the network, because the cost to retrofit additional capacity vastly exceeds the initial cost of installation. While the initial customer might have access to energy alternatives, future customers at the premise might seek electrical solutions.

As the uptake of solar and battery and EV charging technology continues, we see a future where these appliances come and go from properties. It certainly isn't efficient for us to increase and reduce the size of the cables in the ground as these changes occur.

Overall, we think that the introduction of generation technology will increase the tiers of our network where standard sizing becomes the most efficient approach, rather than reducing it. Then, in terms of network infrastructure, we are of the view that the benefits of distributed generation will only manifest in the upstream network, at the zone substation, subtransmission and national grid level.

Noting that the Electricity Authority has regulated to preclude any benefits to exporting generators at the national grid level (and even charge additional amounts to large generators that meet network load that previously was delivered via the grid), this leaves a relatively small set of network assets where generating customers might usefully contribute and benefit from a rebate scheme.

Concluding remarks

Thank you again for the opportunity to provide feedback. If you have any queries regarding these comments, please feel free to contact me on [redacted] or at [redacted]

[redacted]

Alex Nisbet
Pricing & Regulatory Manager

Responses to questions from Issues paper — Distributed Generation Pricing Principles

Submitter	EA Networks

Questions	**Comments**
Q1.Do you have a view on the definition of incremental cost that is contained in the Code? Should it be more tightly defined to include only network costs and to exclude consequential costs relating to factors such as frequency keeping and voltage support? Would this lead to more timely generation build and lower energy costs?	It appears odd to ask about changes to the definition of incremental cost when the basis of the consultation is to remove the concept. Certainly, where distributed generation brings about costs that are consequential, these costs should not be borne by the wider customer base. In our situation, a particular issue has arisen in terms of our harmonic allowances. Both load and generation contribute to our harmonics, and “use up” the available allowance as they connect. The amount that is “used up” generally relates to the size of the generator (rather than any export limit), so the Authority’s move to focus on export capability is concerning. Once we are at or near our harmonic limit, the only way to connect further load or generation is to pay for mitigation. This can either be mitigation at the point of generation, or often it might be more efficient to provide a centralized mitigation at another location in the network (effectively mitigating the background harmonics to allow a polluting generator to connect and operate). Even when we are not near our harmonic limit, a connecting generator will use up some of the allowance that would otherwise be available for future load customers. Noting that our network has been built and maintained by funding from load customers, it is incongruous that this network capability, which is needed by load customers, might instead be given to generation customers free-of-charge. We roundly reject the notion that generators should get a free-ride on consequential costs. Of course this would encourage more generation and drive lower energy costs, but any inappropriate subsidy would do that. It’s not clear why such a suggestion would be made.

Q2. Do you agree with the problems with the incremental cost limit identified in this section? Why or why not? Do you have a view on the relative importance of the problems identified?	We, we agree with the problems identified. A significant further issue is that the incremental cost restriction encourages us to limit any capacity added, as any capacity added in advance of an approach from a distributed generator must be given to them to use free-of-charge. This can lead to an inefficient piecemeal reinforcement approach solely to avoid costs inappropriately falling to our load customers.
Q3 Do you agree circumstances have changed significantly since the DGPPs were introduced, including that there are now far fewer impediments to distributed generation than in the early 2000s?	For us, we have now reached the point where the capacity to host export from generation has been fully utilised in some areas of our network. In these areas, it is now the incremental cost approach itself that is acting as acting as a barrier to further connection of distributed generation. This aside, the evolution and standardisation of inverter technology has addressed many of the impediments, and connection of distributed generation has become a mainstream activity.
Q4 Do you agree with the assessment of the current situation and implications of incremental cost pricing? If not, why not? What if any other significant factors should the Authority be considering?	As noted above, the incremental cost approach effectively prevents networks from forward planning and asking all access seekers to contribute to the next upgrade. This creates a hard-stop where such an upgrade is required, which we have observed to skuttle DG proposals. Having been required to give existing capacity away free-of-charge, the cost barrier of upgrades is difficult to address. The incremental cost restriction led us to this situation, but removing it will not provide a resolution.
Q5. Do you agree these are the appropriate options to consider?	Yes, however, we note the additional option that we suggest in response to question 6 below.
Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?	An additional option for consideration might be to align the regulation with that applied for load customers. We often see situations where a customer has aspects of both load and generation, and where the approaches diverge, it can give rise to considerable uncertainty as to the approach that should be taken. Fundamentally, network upgrades or reinforcement to accommodate new load or generation are not different, and a consistent pricing approach should provide efficient outcomes.
Q7. Will new aggregator business models emerge to solve the problem?	No, we don't think that aggregators will solve the funding cost for connection of distributed generation. Aggregators are well placed to resolve issues with and enhance benefits associated with the operation of distributed generation, but this is largely a separate issue to the restriction imposed by the current incremental cost requirement.

Q8. Are distribution price signals alternative to, or complementary to contracting?	As noted above, they can be complimentary, but it is important that a response is not over-rewarded via funding from both mechanisms. We think that flexibility contracting can provide a more nuanced and targeted approach, whereas pricing signals provide a blunt tool that may not provide the benefits needed to support the incentive.
Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?	In the absence of alignment with the pricing principles for load, we think that a comprehensive overhaul (option 4) would provide the most efficient outcome.
Q10. Do you agree with the Authority's tentative view on a solution? In particular: • Should efficient price signals be sent through a revised set of pricing principles? • Would voluntary guidelines or mandating through the Code be the best approach? • Should we rely on the distribution pricing principles outside the Code or codified new pricing principles for DG? Why?	Like pricing principles for load, we consider that a consistent set of principles could effectively operate for generation. Establishing voluntary guidelines (together with reporting of the degree of alignment) will provide the most efficient outcomes, as it will allow local situations to be accommodated, where appropriate. Including provisions in the Code risks a repeat of the very outcome we have reached with the incremental cost approach, and the situation we observed with ACOT requirements. We think that a principles-based approach will better support the innovation, evolution and adaptation that we are seeing in the distributed generation space.
Q11. Are there any unintended consequences from removing the existing DGPPs? • Do you agree with the risks we have identified, and our assessment of them? • Do you think there are any other risks we should consider associated with the removal of the DGPPs? • Do you have any information that would allow the Authority to better assess such risks?	Although not unintended, some less intuitive impacts might be: • Some customers may see prices fall as common costs are more equitably shared across a wider user base. • More efficient large scale (or grid scale) generation solutions will become a comparatively more attractive option, leading to lower overall energy costs for customers

Q12. Do you agree market and regulatory settings provide efficient incentives for DG reducing or avoiding transmission costs? What, if any, other significant factors or options should the Authority consider?	No. When distribution businesses connect larger scale distributed generation their transmission charges are increased (despite using the grid less). We certainly understand why preventing a reduction in transmission costs might be economically warranted, but where a distributed generator meets demand that would otherwise be met by the grid, it is very difficult to comprehend why this should attract additional charges.

Responses to questions from Consultation paper — Requiring distributors to pay a rebate when consumers export electricity at peak times

Format for submissions

Submitter	EA Networks

Questions	Comments
Problem definition	
Q1. Do you agree with the problem definition above? Why, why not?	No. As mentioned in our introduction, a growing proportion of an electricity network is most efficiently provided using a standard-sizing approach (because the cost to increase or decrease capacity as customer needs change is prohibitive). We do not agree that the load driven future cost estimate can be offset to the extent indicated. Further, while network investment will be required to meet growing demands, the higher utilisation should mean that "unit costs" for energy delivery (that is, prices) should reduce. Stating that "$20 billion will need to be invested every decade" is certainly a provocative statement, but another angle might be to say that prices for network services are likely to reduce as costs are spread over more users and greater usage. If generating customers are rewarded at a level that reflects the cost of network investment that's avoided, then other customers will be no better off, and the net result may be that we have encouraged the development of bespoke generation that (currently) costs around three times the amount that grid scale generation costs. We don't see how this outcome can be beneficial for our economy. We shouldn't ignore what we learnt through the industrial revolution. Meeting energy needs at scale is vastly more efficient, less polluting and more enduring than bespoke home-based solutions.
Proposed solution: principles-based rebates	
Q2. Do you agree with these principles? Why, why not?	No. Our "standard contracts" reach far beyond the mass market level. We have commercial, industrial and large irrigation customers on standard contracts. For these larger customer, standard demand and capacity based pricing approaches prevail, and our network tends to be sized to meet their capacity needs. When customers at this scale meet their own energy demands, constraints tend to be alleviated, and rewarding export beyond this level (even in a constrained area)

	would not normally provide additional network benefits. We think it would be more appropriate to cap the principle using a connection capacity limit of (say) 50kVA, or 69 kVA (which equals 100A per phase and is the point up to which standard "whole current" metering can be used). In terms of the principle for payments (part (b)(iii)), it would be useful to make it clear that payments may reflect the duration or consistency of response.
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?	Yes, subject to our response to question 2 above and if a blanket obligation is to apply, then limiting this to mass-market customers is appropriate. For larger customers a flexibility contract with a more targeted arrangement is more appropriate.
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)?	Yes. We often see a mix of generation, and we are not in a position to rank each as flexible or inflexible. Solar is often installed with varying capacity of batteries, and diesel generation often has a fuel based limited run-time. The consultation paper states that inflexible generation "is unlikely to inject at times that benefit the network". However, we would be concerned if the infrequent times that it does inject during a peak did attract a credit as this would not provide a durable network benefit. This can occur as a correlated response which could lead to significant rebates where no network benefit is derived. For example, a congested area of a network might peak in response to customer behaviour during cold temperatures. Where these temperatures occur on a cold frosty morning, solar may contribute significantly, but where they occur when a cloudy cold front moves through, solar will not make the same contribution.
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	Yes, the indicative guidance points capture the range of issues that we would need to consider when setting rebates, in particular: • The trade-off between focussed and longer durations of fixed-time rebate windows, • Setting the rebates at some level below the cost of the network solution, • Stable rebate signals being more likely to attract a response, • The ability to close off rebates (or lower the rebate level) where a sufficient response has been attracted, and the ability to cap the level of injection that attracts a rebate. We do note that paying a rebate in advance of the anticipated need for a network solution comes with some risk. There will be situations where rebates are provided over a period of time but the network solution is required regardless (for a variety of

	reasons). The consultation paper does not appear to acknowledge that the requirements will, in some situations, lead to higher costs for consumers.
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	The guidance could be enhanced to specify that kW based and seasonal rebates may be used to target beneficial injection. In the absence of this guidance, generators may expect that a kWh-based rebate is an appropriate mechanism.
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?	Inserting a mandated requirement in the Code at the outset may come with unintended consequences that might better be discovered and addressed through a less prescriptive approach. Distributed generation, flexibility services and network solutions are evolving rapidly. We have observed that Code previsions can significantly outlast their usefulness, and we are concerned that this could occur with this proposal. We think and initial voluntary principle (together with an assessment against that principle) would be a useful step in advance of a mandated Code requirement.
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.	We think that an implementation date of 1 April 2026 (next year) is tight, and would lead to inefficient solutions. It will require quite some work across various disciplines to identify areas of congestion and which customers might alleviate such congestion, establish the generation support that might provide deferral, establish the value of deferral, and convert this into a pricing option. We generally consult with retailers on changes to the structure of our tariffs around September in advance, so this leaves very little time to establish how we might efficiently reward generation support.
Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?	The guidelines should make it clear that, if a cost-reflective price based incentive is provided, there is no additional funding available to reward a contracted flexibility approach. This is because the additional cost of the contracted flexibility would then exceed the costs being avoided or deferred. The presence or mandating of a pricing option may act to prevent the development of more targeted flexibility contracts.
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?	No. The wealth transfers will be proportional to the uptake. If the proposal leads to significant incentives, then the uptake may also be significant, and the wealth transfer may be more than minor. As noted above, pricing incentives are a blunt tool. While they may drive cost savings in some situations, in other situations

	they will increase costs. It is not clear to us that the uncertain benefits outweigh the certain costs (in addition to the transaction costs).
Alternative option: prescribed rebates	
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?	A prescriptive approach is more likely to lead to situations where incentives are provided and no benefit is derived. This would lead to higher costs for customers. A principles-based approach would allow specific circumstances to be taken into account, and pricing incentives can be provided where benefits are more quantifiable, and alternative flexibility contracts might be adopted where these provide a better outcome.
Alternative option: consumption-linked injection tariffs	
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 tariff would not be sufficiently targeted. In line with the pricing principles, we aim to recover our residual costs in a way that least distorts behaviour. We also aim to share our residual costs between consumers in a fair and equitable way. Volume based pricing approaches are a very equitable way of sharing residual costs and are widely accepted by customers. We anticipate de-weighting volume based pricing to address the distorting responses, but (noting that all pricing options have distorting influences) we think that volume pricing will always be part of the mix for recovery of residual costs. We also note that the TPM residual costs are entirely recovered from us on a volume basis. On this basis, linking an export price to the load-based volume price would simply exacerbate the distorting influence that we are trying to address.
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?	As noted above, injection rebates should not match consumption charges. We are not aware of any safeguards to address situations when the injection itself might lead to network costs (that may not have been anticipated at the time of initial connection). We are not sure that we have observed this yet, but it certainly could occur in the future if a correlated injection response was effectively incentivised.
Regulatory statement	

Q14. Do you agree with the objective of the proposed amendment? If not, why not?	We agree with the objective that customers should be appropriately rewarded for DG that provides network benefits. We don't agree with the presumption that this reward should be provided via pricing. We think that flexibility contracts (including via aggregators) would provide a much more nuanced and targeted approach for rewarding injection that addresses network constraints. Pricing solutions are not practicable, carry a high transaction cost, are not targeted enough and will lead to rewards being applied where there is no corresponding network benefit.
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	It is not clear to us that the benefits will outweigh the costs. What we can say is that the costs borne by our customers will be real and apparent, but the benefits will be uncertain.
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.	Of the options presented, yes, we consider that a principles-based approach is preferred. However, as noted above, we think that a pricing solution may hinder the development of a more effective flexibility services market.

Proposed amendment Code drafting	
Q17. Do you have any comments on the drafting of the proposed amendment?	Not reviewed.