26 March 2025

Networks and System Change Team
Electricity Authority
By email: distribution.pricing@ea.govt.nz

Tēnā koe,

Distributed Generation Pricing Principles – Issues Paper

We welcome the opportunity to respond to the Electricity Authority (**Authority**)'s issues paper on the Distributed Generation Pricing Principles (**DGPP**).

Decarbonisation through electrification is important and urgent. As we have argued in our submissions on connection pricing, the problem that justifies reform is not about efficiency alone, just as it is not only about decarbonisation and fairness. It is about enabling a least-cost equitable energy transition in the most efficient way possible. We welcome the Authority's clarity that DGPP reform is required to remove barriers to efficient electrification rather than tilting the playing field. This will build consensus and support in the industry that reform is necessary and urgent.

Rather than running this as a separate process, it would be more efficient and effective for the Authority to repeal specific pricing principles for Distributed Generation (**DG**) and merge the work to clarify how the existing 2019 distribution pricing principles apply to DG into a single workstream that combines its *Network connections project* and *Distribution connection pricing* work to ensure that all barriers to timely and efficient DG connection are addressed.

Our summary observations on the Issues Paper are:

All distribution pricing principles should be consistent	• Current DGPPs deliberately tilt the playing field to support DG, as a result, the DGPPs increasingly cause wider inefficiencies • A least cost transition will be enabled by harmonising the DGPPs with the Authority's distribution pricing principles • We support the Authority's Option 4, by repealing the DGPPs and aligning to the Distribution Pricing Principles, as they should be consistent
Decarbonisation depends on efficient DG connection	• Timely and efficient network access for DG is a key enabler for decarbonisation • DG connection pricing is only one barrier to efficient network access • Resolving issues with funding connections is equally important

Flexibility tenders complement distribution pricing	• Distribution pricing should provide broad long-run marginal cost signals • Flexibility tenders sharpen these signals and can be more targeted at deferring specific investments • Pricing and flexibility are complementary, not alternatives

We link these observations to the Authority's questions in section 4 below.

We are always keen to meet with the Authority to discuss and develop the ideas in our submissions. In the meantime, if you have any questions or would like to talk further on the points we have raised, please contact Emma Wilson (Emma.Wilson@powerco.co.nz).

Nāku noa, nā,

EWilson

Emma Wilson
Head of Regulatory, Policy and Markets
POWERCO

1. All distribution pricing principles should be consistent

We support the Authority's consistency in driving distribution pricing reform using its 2019 distribution pricing principles[1] and the guidance it has provided to EDBs in how to implement them[2]. The DGPPs are inconsistent with these principles and the problems with them can easily be addressed by applying the 2019 distribution pricing principles to both load and generation, rather than having specific provisions for DG.

As the Authority's issues paper clarifies[3], the policy intent behind the incremental cost limit in the DGPPs was a political initiative from 2006 to stimulate investment in DG by deliberately tilting the playing field to support DG connections. Similar to the 2004 low user fixed charge regulations[4], the motivation behind the policy was well-intended but mandating inefficient distortions to distribution pricing as a means of implementing it has had adverse consequences. It increasingly presents a barrier for customers for a least cost transition to an expanded low-carbon electricity system.

During the early years of their effect, electricity demand in New Zealand was relatively static. DG investment rates were low and largely served to replace supply from existing generation either at the end of plant life or where new generation was cheaper. Small scale DG connections, such as behind-the-meter residential and commercial solar were on shared connections where costs not borne by generation were small and largely borne by the same customer through demand charges.

In the period to 2050, a key lever for efficient decarbonisation in New Zealand will be the repowering of activities that currently use fossil fuels with renewable electricity.

While the DGPPs have resulted in inefficiencies and issues raised by the Authority[5], we anticipate larger inefficiencies as DG investment rates increase during this phase of growth if the DGPPs are not reformed. In particular:

- to date most DG has been on mixed (load & supply) connections, but in future there will be larger generation-only connections which may increase costs for load-consumers if investors benefit from the artificial advantage for DG[6], and
- increasingly we'll get large DG connections which would be more efficient on the transmission network but are incentivised to embed in the local network to avoid transmission timeframes and cost.

A least cost transition will be enabled by harmonising the DGPPs with the Authority's distribution pricing principles. Given the above, we support the Authority's Option 4, a comprehensive overhaul of the DGPPs,

[1] https://www.ea.govt.nz/industry/distribution/distribution-pricing/
[2] https://www.ea.govt.nz/documents/299/Distribution_pricing_practice_note.pdf
[3] *Distributed Generation Pricing Principles Issues paper*, Electricity Authority. February 2025. 1.2-1.4
[4] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (SR 2004/272) (as at 01 April 2024) Contents – New Zealand Legislation
[5] *Distributed Generation Pricing Principles Issues paper*, Electricity Authority. February 2025. Section 2
[6] *Distributed Generation Pricing Principles Issues paper*, Electricity Authority. February 2025. 2.12-2.15

rather than developing new DGPPs. Given the policy intent – to remove barriers to efficient investment in DG – a least cost transition would be supported by repealing the DGPPs and developing guidance as to how the pre-existing 2019 distribution pricing principles apply to DG connections in their absence.

As these pricing principles are worded generally and apply to both injection and offtake. It would be helpful if the Authority clarified how EDBs should apply them to DG connections of different sizes and in different circumstances (mixed/dedicated connections). This could be done by updating the *Distribution Pricing: Practice Note* in much the same way that Appendix C of the *Second Edition v 2.2* is a practice note on *Transmission charge pass-through*.

2. Decarbonisation depends on efficient and timely DG connection and is not just about price

As we have mentioned in previous submissions, DG pricing is not a standalone problem, and to truly support efficient decarbonisation in New Zealand, you cannot think about this in isolation, but rather the Authority needs to consider price, non-price and solve issues to access to capital together. As we emphasise in our cross-submission[7] on the Authority's *Distribution connection pricing proposed Code amendment:*

> The problem that justifies connection reform is not about efficiency alone, just as it is not only about decarbonisation and fairness. It is about enabling a least-cost equitable energy transition in as efficient way as possible.
>
> Clarifying that the problem is removing barriers to efficient electrification rather than tilting the playing field will build consensus and support in the industry that connection reform is necessary and urgent.

The same is true of the DGPPs, they are inefficient – which is a problem in itself – but also compounded issues of decarbonisation and fairness. Reform should address all 3 types of issues, not efficiency in isolation. In our main submission[8] on the Authority's *Distribution connection pricing proposed Code amendment* we emphasise the importance of the open access regime on electricity networks in New Zealand:

> *EDBs in New Zealand offer open access to their networks. This means access seekers are free to connect on equal terms and share available network capacity. Unlike some access regimes in other jurisdictions, connected parties do not reserve network capacity to the exclusion of others.*
>
> *EDBs anticipate future capacity needs and augment their networks to meet forecast demand for injection and offtake. All connected parties benefit from this and so wider network augmentation costs to meet network growth are socialised proportionately just like the sunk costs of the existing network. Cost reflective distribution pricing ensures that the proportionate allocation of sunk and augmentation costs is efficient.*[9]

This is particularly true as we decarbonise through electrification and timely and efficient network access for DG is a key enabler for decarbonisation. Just like the low-user fixed charge limit, the incremental cost limit in the DGPPs

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[7] https://www.ea.govt.nz/documents/6400/Powerco_cross_submission_connection_pricing_and_process_Redacted.pdf

[8] https://www.ea.govt.nz/documents/6343/Powerco_DCP_-_Submisisons_2024_i7uSvux.pdf

[9] Ibid 52 and 53

makes it impossible for EDBs to signal the long run marginal cost of network augmentation consistently across injection and load connections. The incremental cost limit in the DGPPs means that access seekers will not be making efficient decisions about their demands for new export hosting capacity – whether as new connections or augmentation.

While efficient pricing is an important component of a network access regime, it is only one barrier to efficient network access and non-price frictions can create bottlenecks that lead to inefficient investment decisions by access seekers – this is the scope of the Authority's *Network connections project – stage one* consultation.

We explain in our submissions on the *Network connections project*[10] and *Distribution connection pricing* that, while we understand why the Authority has considered price and non-price issues separately, these must be considered together as a package to avoid duplication of interventions and limit the potential for any perverse outcomes.

This should include repealing specific pricing principles for DG and merging the work to clarify how the existing 2019 distribution pricing principles apply to DG into a single workstream that combines the *Network connections project* and *Distribution connection pricing* work to ensure that all barriers to timely and efficient DG connection are addressed.

3. Flexibility tenders complement distribution pricing

The Authority's issues paper,[11] discusses the relationship between distribution pricing and "contracting". We see a clear relationship between the two but they have different roles, and should be used for different purposes at a different level of granularity over different time periods.

Distribution pricing should provide broad long-run marginal cost signals, and as the Authority explains:

> *The primary role of efficient pricing is to correctly signal the most efficient use of the existing network and, where appropriate, to reflect the cost of future network investments or the application of non-network investments – the latter either by the distributor, its end-users, or other participants. By encouraging more efficient use of and investment in electricity networks, efficient distribution pricing leads to relatively lower prices for electricity consumers in the long-term. Promoting efficient electricity infrastructure investment will be particularly important as New Zealand electrifies its transport fleet and industrial processes over the next 30 years to support its transition to a low-emissions economy*[12].

And that

> *We expect to see that options analysis of future investment include alternative pricing structures to delay or avoid investment.*[13]

Our Asset Management plan outlines how we will continue to meet the changing needs of our customers and communities over the next 10 years. It sets out how we intend to meet those needs as efficiently as possible, both

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[10] Powerco submission EA Network Connections Project Stage 1 20 Dec 2024.pdf

[11] *Distributed Generation Pricing Principles Issues paper*, Electricity Authority. February 2025. Section 3 and question 8

[12] *Distribution Pricing: Practice Note. Second Edition v 2.2,* Electricity Authority. October 2022. 8

[13] Ibid. 69

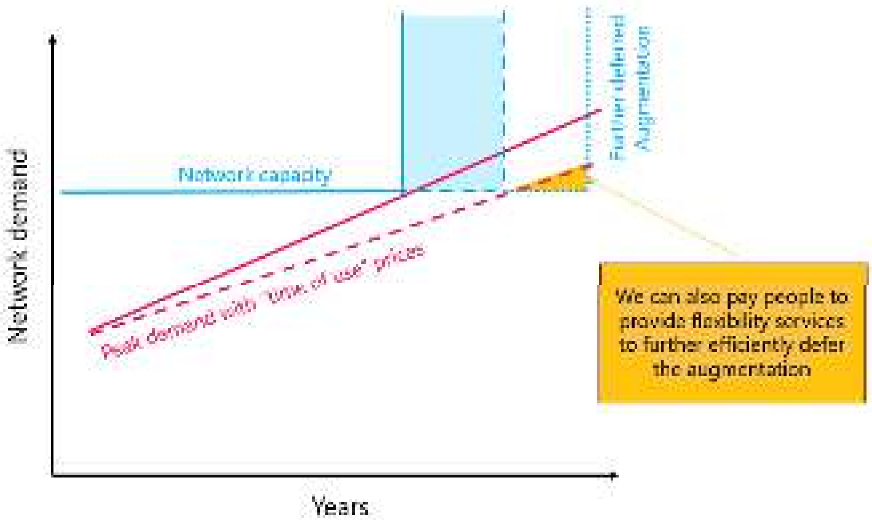
by investing in new and replacement larger assets, increasing the capacity of existing resources and through non-network solutions where possible.

We have to build our electricity network to handle the maximum loads (or generation export) that occur on them at any time but in many cases, those peaks only last for a few hours every year. Traditionally we have had to increase this "hosting capacity" of the network to make sure we can meet new load and generation requirements, by building and replacing physical assets - wires, transformers, substations and the like.

To defer these investments, we use variable prices in peak periods to signal the cost of the local planned investment in each region. The amount of money we are allowed to charge by the regulator is capped so we forecast what we expect to recover through peak prices and recover because most of our costs are fixed, we recover most of the balance through fixed (mainly daily) charges and low off-peak variable prices.

What this means in practice is that we can avoid or at least defer spending money on physical capacity upgrades by reducing the size of the network peaks. This is achieved when our customers or their agents respond "flexibly" to peak prices by injecting electricity into the network (from a local generator or a battery) or reducing local demand in the congested part of the network (illustrated by figure 1 below).

Figure 1. How prices and flexibility can further defer network spend



The falling cost and improving capability of new technologies to control demand and store or generate electricity means that the opportunity for us to do this economically is improving all the time. Sunk cost pricing is inevitably broad given the time period over which long run marginal costs are signalled.

However, in addition to price signalling, we can also use flexibility tenders in parallel to sharpen these signals which are more granular. Powerco have been trailing the use of flexibility tenders[14], and over the next decade we will refine and align how pricing and flexibility tenders work together to defer investment, each working over different time horizons, as shown in the figure below. DG should be no different from any other connection.

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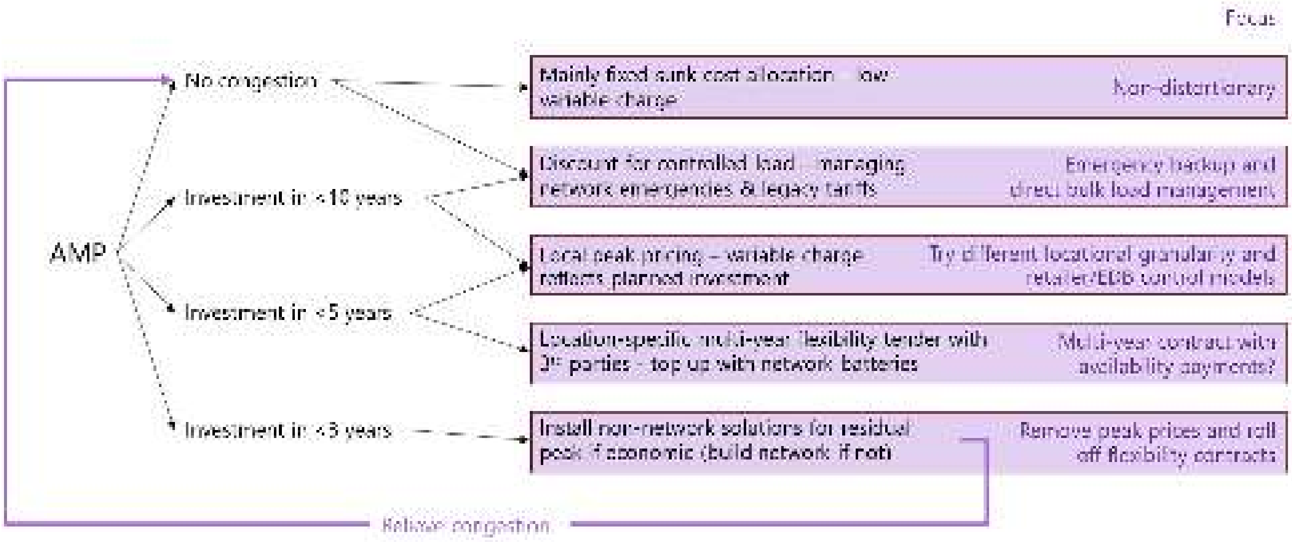
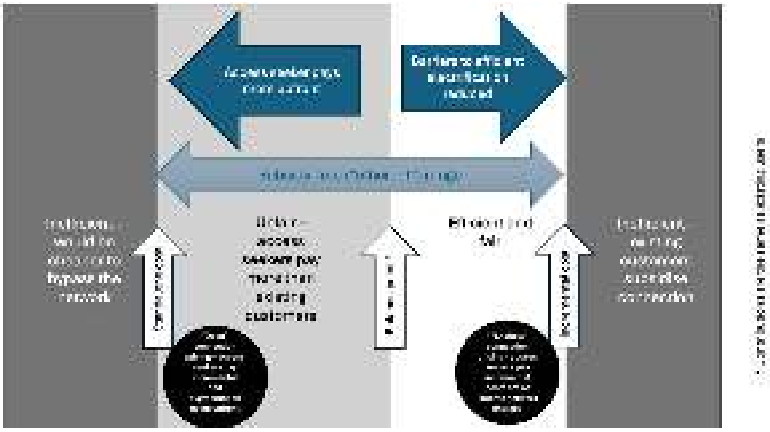
[14] For example: tendering process for network support to the Coromandel Region

Figure 2. Investment deferal cycle



4. Responses to the Authority's questions

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?	In our submission on the EA's connection pricing reform proposals we discuss the efficient range.  We further discuss how regulation should be proportionate to the harm it is addressing and the implications for different sizes of connection[15]. It's less a question of defining "incremental cost" than pricing small connections at the shallow end of the efficient range and larger connections closer to the balance point.
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?	Yes – and it's getting worse as we note in section 1 above.

[15] *Powerco's submission on Authority's Distribution Connection Pricing Consultation*. Sections 2, 3 and 4

Questions	Comments
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?	During the early years of their effect, electricity demand in New Zealand was relatively static. DG investment rates were low and largely served to replace supply from existing generation either at the end of plant life or where new generation was cheaper. Small scale DG connections, such as behind-the-meter residential and commercial solar were on shared connections where costs not borne by generation were small and largely borne by the same customer through demand charges. We expect to see more and larger generation-only connections as we use renewable electrification to decarbonise in the years to 2050. If the DGPPs remain unaltered, there is a risk that some of this generation will connect at lower cost on distribution networks even though they would be more efficient on the transmission network.
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?	Yes but as we discuss in section 2 above, pricing is only one barrier to timely and efficient DG connection – issues with non-price barriers and funding connections are equally important. Rather than running the DGPP reform as a separate process, it would be more efficient and effective for the Authority to repeal specific pricing principles for DG and merge the work to clarify how the existing 2019 distribution pricing principles apply to DG into a single workstream that combines its *Network connections project* and *Distribution connection pricing* work to ensure that all barriers to timely and efficient DG connection are addressed.
Q5. Do you agree these are the appropriate options to consider?	Yes – noting that the Authority should merge the work to clarify how the existing 2019 distribution pricing principles apply to DG into a single workstream that combines its *Network connections project* and *Distribution connection pricing* work.
Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?	Rather than developing <u>new</u> DGPPs, the policy intent – to remove barriers to efficient investment in DG – would be supported by repealing the DGPPs and developing guidance as to how the pre-existing 2019 distribution pricing principles apply to DG connections in their absence. These pricing principles are worded generally – so apply to both injection and offtake. It would be helpful if the Authority clarified how EDBs should apply them to DG connections of different sizes and in different circumstances (mixed/dedicated connections) but this could be done by updating the *Distribution Pricing: Practice Note* in much the same way that Appendix C of the *Second Edition v 2.2* is a practice note on *Transmission charge pass-through*.
Q7. Will new aggregator business models emerge to solve the problem?	Agree that retailers and their agents ("aggregators") will respond to distribution prices and flexibility tenders in new ways. This won't solve the problem of efficient DG pricing in its entirety.

Questions	Comments
Q8. Are distribution price signals alternative to, or complementary to contracting?	As we detail in section 3 above, we see a clear relationship between the two but they have different roles, and should be used for different purposes at a different level of granularity over different time periods: • Distribution pricing should provide broad long-run marginal cost signals • Flexibility tenders sharpen these signals and can be more targeted at deferring specific investments • Pricing and flexibility are complementary, not alternatives
Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?	At the highest level we support the Authority's Option 4: comprehensive overhaul of the DGPPs. Rather than developing new DGPPs however, the policy intent – to remove barriers to efficient investment in DG – would be supported by repealing the DGPPs and developing guidance as to how the pre-existing 2019 distribution pricing principles apply to DG connections in their absence.
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?	As we discuss in section 1, above the Authority can address the issues it identifies by repealing the DGPPs and developing guidance as to how the pre-existing 2019 distribution pricing principles apply to DG connections in their absence. These pricing principles are worded generally – so apply to both injection and offtake. It would be helpful if the Authority clarified how EDBs should apply them to DG connections of different sizes and in different circumstances (mixed/dedicated connections) but this could be done by updating the *Distribution Pricing: Practice Note* in much the same way that Appendix C of the *Second Edition v 2.2* is a practice note on *Transmission charge pass-through*.

Questions	Comments
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?	No

Questions	Comments
12. 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?	Noting our comments about the complementarity of distribution pricing and flexibility tenders in section 3 above, DG may have a similar role for transmission. Transpower is incentivised to demonstrate that it has discovered the most prudent and efficient means of meeting grid injection and demand, including non-transmission solutions, under the Commerce Commission's individual price quality path ("IPP") for the Grid Owner. As the Authority's Innovation and Participation Group noted in their review of the Transpower Demand Response Programme: *Transpower has shown real candour in explaining the limited opportunity that DER offers for deferring or avoiding transmission investment given that most NZ transmission assets are built to N-1 or higher levels of security – which means that all operating assets are duplicated or more than duplicated so that the system continues to supply load uninterrupted if a single asset fails. This duplication allows Transpower to operate Special Protection Schemes where the loading of circuits close to capacity are reduced by splitting flows across the duplicate assets – increasing the risk of non-supply for a proportion of the load but at low probability and for short periods of time which is almost always cheaper than buying transmission alternatives from flexibility portfolios based on DER or larger resources.*[16] Where EDBs tender directly for flexibility as outlined in section 3 above, it is likely that the distribution peaks which flexibility providers are offering to lower will be coincident with transmission grid peaks. Transpower will only need to contract directly with flexibility providers if transmission and distribution congestion periods diverge. This is similar to Powerco's observation that spot market peaks currently coincide with network peaks from our winter 2024 retailer hot water control trial[17].

[16] Review of the Transpower demand response programme, IPAG. July 2021. p. 6

[17] *Opportunities for the use of ripple and smart meter-controlled circuits for managing peaks*, Powerco and Vector. October 2024 slide 2 in October SRC papers