Submission to the Electricity Authority

Reforming network pricing for distributed generation to promote efficient investment

Field	Details
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Capacity	Individual respondent
Standing/submitter context	Individual respondent based in Melbourne, Australia, with an interest in comparative electricity-market implementation, distributed-energy policy and climate-energy regulation.
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Key message

The practical test for success is whether efficient distributed generation and storage become easier to connect, price and finance where they reduce long-term system costs, while genuine incremental network costs are transparently allocated.

The Authority should finalise the DGPP reforms so they deliver efficient investment in distributed generation and storage, not opaque one-way cost recovery from injection connections. To achieve that, the final framework should:

1. **Make incremental cost an anchor — and require distributors to show their working** to applicants through cost drivers, capacity triggers and assumptions.
2. **Recognise measurable network benefits as well as costs** so cost-reflective pricing does not become one-way cost recovery.
3. **Protect first movers through stronger pioneer arrangements** where early projects fund shared injection capacity.
4. **Make non-discrimination a headline obligation** where independent and distributor-affiliated projects may compete.
5. **Create standardised pathways for common or low-risk connections** so efficient projects are not deterred by avoidable transaction costs.
6. **Monitor outcomes, not only formal compliance**, including benefit recognition, pioneer-scheme use and comparable treatment.

The practical test for success is whether efficient distributed generation and storage become easier to connect, price and finance where they reduce long-term system costs, while genuine incremental network costs are transparently allocated.

Executive summary

This submission supports the Electricity Authority’s proposal to reform the distributed generation pricing principles. The current framework was designed when distributed generation was less common and when the central concern was preventing excessive charges for distributed generation connections. The current challenge is broader: distribution pricing now needs to allocate costs and benefits efficiently in a system with growing solar, batteries, storage, electrification and network-capacity constraints.

These reforms concern requirements for how lines companies develop and explain their pricing methodologies, not direct price-setting. That distinction matters: the Authority should set clear obligations for methodology, disclosure, benefit recognition and monitoring while leaving distributors enough discretion to reflect local network conditions.

The final reform should avoid two failure modes. First, it should avoid continuing arrangements where injection-related costs are under-allocated to distributed generation and recovered from consumers as residual payers. Second, it should avoid over-correction, where cost-reflective injection pricing becomes one-way cost recovery and deters efficient distributed generation or storage that provides measurable network value.

Cost-reflective pricing should therefore be understood as pricing linked to real, evidenced and materially attributable network cost drivers, not as a mechanism for recovering sunk, residual or poorly explained network costs from distributed generators.

A level playing field also requires applicant-facing transparency. Where a regulated monopoly distributor allocates incremental costs to an injection connection, the burden of justification should sit with the distributor, not with the applicant. Methodology disclosure, applicant-facing cost explanations, materiality thresholds and monitoring are all expressions of that principle, subject to appropriate protection for genuinely confidential or security-sensitive network information.

This submission makes six recommendations.

#	Recommendation	Purpose	Mechanism	Actor	Trigger/threshold	Timing	Why adoptable
1	Reframe incremental cost as an anchor, with transparent methodology, applicant-facing cost-disclosure safeguards and causal-link requirements.	Improve cost allocation while preventing sunk, residual or poorly evidenced costs from being relabelled as incremental costs.	DGPP amendment plus methodology disclosure, applicant-facing cost explanations and causal-link requirements.	Distributors, monitored by the Authority.	Where an applicant is charged incremental injection-related costs.	From commencement.	Supports the Authority's proposed direction while reducing implementation risk.
2	Require symmetrical treatment of incremental costs and measurable network benefits.	Prevent cost-reflective pricing from becoming one-way cost recovery.	Guidance and monitoring on how benefits are identified and recognised.	Distributors and Authority.	Where an injection connection creates measurable, material network benefits.	From implementation, with later review.	Aligns with the Authority's recent negative-charge / peak-injection policy direction.
3	Strengthen pioneer arrangements for injection-related capacity works.	Reduce first-mover disadvantage and position-in-queue problems.	Expanded pioneer scheme rules, published scheme information and review.	Distributors, monitored by Authority.	Where an early project funds identifiable capacity that later injection connections may use.	From commencement, with post-implementation review.	Directly targets a problem identified in the consultation paper.
4	Make non-discrimination a headline implementation obligation.	Ensure pricing does not favour distributor-owned or affiliated generation over independent projects.	Comparable-treatment monitoring, information-access requirements and methodology transparency.	Distributors and Authority.	Where comparable independent and distributor-affiliated projects seek access, pricing, capacity or pioneer-scheme treatment.	From commencement, with first-cycle review.	Matches the Authority's concern that pricing should not favour a lines company's own distributed generation.

5	Create proportionate standardised pathways for common or low-risk injection connections.	Reduce unnecessary transaction friction for efficient projects.	Worked examples, simplified methodologies and standard disclosure expectations for common project types.	Authority and distributors.	Where projects are low-risk, routine or materially similar to worked examples.	Pre-commencement guidance and first pricing-methodology cycle.	Improves usability without removing bespoke treatment for complex projects.
6	Use bounded discretion supported by implementation guidance and targeted monitoring.	Preserve network-specific flexibility while avoiding opaque, inconsistent or overly complex implementation.	Worked examples, dispute pathways, monitoring templates and post-implementation review.	Authority and distributors.	Where distributors apply capacity, congestion, connection or benefit-recognition methodologies under the amended DGPPs.	Pre-commencement and first pricing-methodology cycle.	Preserves flexibility while improving investor confidence and reducing administrative burden.

Scope of this submission

This submission responds to the Electricity Authority's consultation paper, Reforming network pricing for distributed generation to promote efficient investment, updated 21 April 2026, and treats that paper as the controlling document.

This submission focuses on the proposed reform of distributed generation pricing principles, especially incremental cost, allocation of costs and benefits, capacity pricing, pioneer arrangements, non-discrimination, implementation and monitoring. It does not attempt to resolve wider electricity-market design issues except where they directly affect the implementation of distributed generation pricing.

This submission does not attempt to resolve broader questions about the long-run competitiveness of grid-supplied electricity against behind-the-meter solar, batteries or off-grid alternatives. Those questions matter for the durability of network cost recovery, but they are wider than this DGPP amendment. The narrower point made here is that the proposed rules should avoid creating methodology-driven distortions within the current framework: charges should be transparent, materially cost-reflective, administratively workable and linked to real network cost drivers or measurable network benefits.

Nor does this submission assume that existing grid or network cost-recovery arrangements are inherently efficient; it simply focuses on the narrower question of how the proposed DGPP reforms should operate within the current framework.

I make this submission in my personal capacity as an individual respondent with an interest in evidence-based climate, energy and regulatory policy. I am not a New Zealand distribution-pricing practitioner, lines-company engineer or electricity lawyer. For that reason, this submission focuses on policy design, implementation risk, transparency, incentives and monitoring rather than proposing detailed tariff formulas or legal drafting.

Decision lens

The test for this consultation should be whether the proposed DGPP reforms promote competition, reliable supply and the efficient operation of the electricity industry for the long-term benefit of consumers, consistent with the Authority's statutory objective.

The Authority's statutory objective also includes an additional objective to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. This matters for the DGPP reforms because some injection connections are associated with households and small businesses, and because opaque or poorly explained pricing can affect both investment decisions and consumer confidence.

This submission assesses the proposed reforms against six criteria:

- Efficient investment: whether the rules support efficient entry, connection, operation and investment by injection connections, storage and other distributed resources.
- Efficient cost allocation: whether reasonably identifiable incremental costs and measurable network benefits are allocated in a way that improves total system efficiency rather than merely shifting costs between parties.
- Predictability and investability: whether applicants can understand the likely basis for connection charges, lines charges, benefit recognition and pioneer arrangements before committing capital.
- Non-discrimination: whether comparable independent and distributor-affiliated projects receive comparable treatment in pricing methodology, information access, capacity allocation, timing and dispute pathways.
- Low-friction administrative feasibility: whether common or low-risk injection connections can proceed through standardised, proportionate processes, and whether the framework can be implemented without excessive prescription, transaction costs or compliance costs.
- Capacity to improve over time: whether monitoring and review can identify inconsistent implementation, methodology-driven distortions or failure to recognise measurable network benefits.

This submission does not treat fairness or decarbonisation as freestanding tests. Rather, fairness concerns are relevant where they affect non-discrimination, competitive neutrality, efficient entry or efficient cost allocation. Decarbonisation is relevant in this submission through the Authority's efficiency frame: efficient pricing can help distributed generation, storage and demand-side resources connect and operate where they reduce long-term system costs and improve network use.

The framework should not aim for false precision. Because injection-related costs and benefits can vary by location, time, network configuration and capacity constraint, the Authority should prefer pricing methodologies that are transparent, materially cost-reflective and broadly plausible over methodologies that imply a level of precision that cannot be implemented consistently.

Efficiency should be assessed by reference to long-term system cost and consumer benefit, not by reference to preserving existing cost-recovery patterns.

Problem diagnosis: why current approaches have not been enough

The existing DGPPs were introduced when distributed generation penetration was lower and when the explicit policy concern was that charges for connecting distributed generation could be too high. That original approach solved part of the old problem, but it does not fully solve the current one.

The regulatory problem is therefore not simply that prices may be too high or too low. It is that weak or inconsistent pricing methodologies can produce investment signals that are opaque, difficult to test, and poorly aligned with real network costs or benefits.

A key reason past approaches have not been enough is that residual recovery from consumers is administratively simpler than evidencing incremental cost causation and measurable network benefits for each injection connection. The proposed reform changes the legal framing, but without applicant-facing transparency, proportionate standardised pathways and outcome monitoring, the same administrative path of least resistance may reappear under new wording.

This submission supports the Authority's preferred reform direction over the status quo, while recommending implementation safeguards rather than a more prescriptive or comprehensive redesign of distribution pricing.

Responses to selected consultation questions

Q1. Background and context

I agree with the Authority's background and context summary. Distribution network pricing methodologies now have a larger role in shaping efficient investment because electrification, distributed generation, batteries and storage are changing how distribution networks are used.

A further relevant context point is network investment pressure. Commerce Commission DPP4 material indicates that the DPP4 capex allowance is 37% higher than the DPP3 allowance in real terms. This reinforces the importance of pricing rules that help coordinate efficient investment in distributed generation, storage and network capacity without adding unnecessary implementation burden.

If distributed generation and storage uptake is materially deterred by DGPP pricing methodology, the long-term result may not only be slower distributed-resource investment but also higher network capex than would otherwise be needed, because network upgrades that distributed resources could defer or avoid may be built anyway. The interaction between DGPP design and the Commerce Commission's DPP capex envelope is therefore worth flagging as a forward-work-program issue at the Authority-Commerce Commission interface.

One additional context point is that the Authority's recent distribution-pricing reform work already shows the value of guidance, monitoring and iterative improvement. The lesson for this consultation is that reforming the DGPPs should not stop at changing the wording of the principles. It should include implementation support, methodology disclosure, applicant-facing cost explanations and later review.

Q2. Workability challenges with defining incremental costs

I agree there are workability challenges with defining incremental costs under the current DGPPs. The current framework is trying to allocate costs in a system where distributed generation can affect connection assets, shared network assets, operating costs, capacity constraints and future investment timing. The proposed reform should therefore avoid assuming that incremental cost can always be measured with exact precision at the level of a single connection.

However, uncertainty should not be a reason to retain weak price signals. At the same time, uncertainty should be recognised honestly. The Authority should avoid creating a framework that requires distributors to prove highly granular incremental cost impacts with unrealistic precision. A better approach is to require methodologies that are transparent, evidence-based and materiality-tested, while accepting that some allocation judgements will necessarily be approximate.

Distributors should publish enough methodology detail to show:

1. Which categories of incremental injection-related cost were considered.
2. How shared or programmatic costs were treated.
3. Whether benefits were assessed as well as costs.
4. What assumptions were used.

5. How estimates can be updated.

6. How disputes or material errors can be corrected.

High-level methodology publication may not be sufficient on its own. Where an applicant is asked to pay incremental costs, the distributor should provide enough project-specific explanation for the applicant to understand the cost categories, assumptions, network constraint, capacity trigger and allocation basis behind the charge. Without that applicant-facing explanation, it may be difficult for the applicant to assess whether the charge is reasonable.

Q3. Under-allocation of costs and benefits

I agree that the current DGPPs can cause costs and benefits to be under-allocated to injection connections. The key design point is that costs and benefits should be treated symmetrically. If injection creates reasonably identifiable incremental costs, those costs should be allocated through transparent pricing. But if injection creates reasonably identifiable network benefits, those benefits should also be recognised.

The Authority's own consultation paper indicates that avoided-cost-of-distribution payments have been rare, with only Top Energy, Electra and FirstLight identified as having made ACOD payments since the DGPPs were introduced. That supports making benefit recognition operational, not merely available in principle.

This is important because cost-reflective pricing can fail if implemented as cost recovery only. A framework that recognises costs more readily than benefits could deter efficient distributed generation or batteries even where they reduce future network costs, defer investment, relieve constraints or support more efficient network use.

This recommendation builds on the Authority's injection-payment requirements, including the 1 April 2026 amendment that clarifies eligibility for negative charges for injection into a distributor's network during peak periods. The same logic – that injection can create network value as well as network cost – should be carried into the DGPP framework for larger and more complex injection connections.

From 1 April 2026, the Electricity Industry Participation Code (Injection Payment Requirements Amendment) Amendment 2026 clarifies which consumers are eligible to receive negative charges for injection during peak periods by specifying an upper limit to a business consumer's connection capacity and the maximum deliverable generation capacity for a consumer's distributed generation. The consultation paper also makes clear that this negative-charge framework is staged. From 1 April 2027, the rate must reflect an estimate of the long-run marginal cost of network offtake capacity. This means the rebate framework is not simply a one-off payment requirement; it is an evolving pricing methodology that should be complemented by the DGPP reforms rather than cut across by them.

The 1 April 2027 LRMC anchor of the negative-charge framework is significant beyond the negative-charge context itself. It suggests a longer-term direction in which both injection-related costs and measurable network benefits are valued by reference to forward-looking long-run marginal cost, not by reference to historical or sunk-cost network spending. The Authority should consider, in its forward work program, whether this LRMC direction should be progressively extended across the broader DGPP framework, so that cost-reflective pricing in practice means efficient forward-looking pricing rather than residual-cost recovery.

In applying this principle, the Authority should give particular attention to whether injection affects costs or benefits at times and locations where the network is constrained. To a first-order approximation, the strongest case for use-based distribution pricing arises where injection or offtake changes peak-capacity requirements, congestion pressure or the timing of network reinforcement. This supports a targeted approach rather than broad assumptions that all injection creates either cost or benefit.

Q4. Whether it remains appropriate to regulate injection pricing methodologies

It remains appropriate to regulate injection pricing methodologies. Distribution networks are monopoly infrastructure, and connection applicants may have limited practical alternatives.

The issue is not whether pricing should be regulated, but how prescriptive the regulation should be. The final framework should regulate core principles and minimum disclosure requirements while allowing distributors some network-specific flexibility. That is preferable to either extreme: fully unregulated negotiation, which risks inconsistent and opaque outcomes, or over-prescriptive pricing rules that cannot handle different network conditions.

Q5. Whether consumers should remain residual payers

Consumers should generally remain residual payers, but the existing residual-payer status should be displaced for an identifiable cost where the distributor can transparently demonstrate that the cost is genuinely incremental, causally attributable to a specific injection connection, and material in size. The burden of justification for displacing residual-payer status should sit with the distributor, not with the connecting party.

The key distinction is between genuine incremental costs caused by an injection connection and sunk, residual or common network costs that distributors may wish to recover but cannot fairly attribute to that connection.

Because distributors hold the cost information needed to make this distinction, the framework should place the evidentiary burden on the distributor to demonstrate a causal link between the charge and the applicant's actual incremental impact on the network, rather than placing the burden on applicants to disprove costs they cannot inspect. This is particularly important for shared, capacity-related and forecast-based cost categories, where the distinction between incremental cost and residual cost is most contestable.

A balanced approach is needed:

1. Injection connections should pay reasonably identifiable incremental costs.
2. Distributors should not over-allocate shared, sunk, residual or common costs to injection connections.
3. Measurable benefits should be recognized.
4. Methodologies should be published.
5. Applicants should receive enough project-specific explanation to test whether charges are reasonable.
6. Outcome monitoring should test whether consumers and investors are both being treated fairly.

This balanced approach is consistent with the Authority's public guide, which notes that under the proposals distributed generators would still be exempt from paying for some specific shared network costs that are paid by everyone else on the network. That caveat is important: the reform should not reverse the problem by over-allocating shared costs to injection connections. It should allocate reasonably identifiable incremental costs while preserving proportionality.

Q6. Reframing incremental cost as "must reflect a reasonable estimate of" incremental costs

I support reframing the incremental cost rule from a ceiling to a requirement that charges must reflect a reasonable estimate of incremental costs. This is a better fit for the current system because the existing "must not exceed" framing can protect against overcharging but still allow under-recovery and weak price signals.

The phrase "reasonable estimate" is important. It should not be interpreted as requiring exact attribution of every marginal cost to each individual connection. Instead, it should support a proportionate standard: distributors should explain the relevant cost drivers, assumptions, materiality thresholds and treatment of uncertainty, and should show why the resulting charge is broadly aligned with efficient network use.

The word "reasonable" should also have a procedural dimension. An incremental-cost estimate is more likely to be accepted as reasonable if the affected applicant can see the main drivers of the estimate and how those drivers relate to the project's actual network impact. The Authority should therefore expect distributors to provide applicant-facing cost explanations, not only general pricing-methodology descriptions.

The shift from a ceiling ("must not exceed") to a "reasonable estimate" obligation transfers regulatory discretion from a strict bounded test to a judgement-based test. The Authority should make explicit that the new framing does not permit charges materially above a defensible incremental-cost estimate, and that the existing protection against overcharging is preserved as an implicit upper bound on what "reasonable" can mean. Without that clarification, the change could in practice expand the range of permissible charges in both directions, rather than only correcting under-recovery.

Suggested implementation wording:

> Charges should reflect a reasonable estimate of incremental injection-related costs, supported by published methodology, reasonable assumptions, applicant-facing explanation, and a clear explanation of how identifiable benefits have been considered.

Q7. Whether the proposed language and framing would support more efficient pricing

Yes, but only if supported by guidance and monitoring. Language changes can improve the legal framework, but the effectiveness of the reform will depend on how distributors implement the changes in pricing methodologies, connection negotiations and charge reconciliations.

The Authority should therefore support the final amendments with guidance or worked examples covering common project types, such as:

1. Rooftop solar and small-scale batteries.
2. Medium-scale batteries.
3. Larger injection-dominant or export-focused distribution-connected projects, such as solar, wind, batteries or hybrid projects, with guidance on how mixed import/export sites should be treated.
4. Mixed import/export connections.
5. Projects that trigger shared capacity upgrades.
6. Aggregated DER, virtual power plant or flexible export arrangements where network impacts depend on operation, dispatch or dynamic export limits rather than fixed export capacity alone.

Worked examples would reduce uncertainty without requiring the Authority to prescribe every pricing outcome.

The proposed terminology shift from “distributed generator” to “injection connection”, and from “load” to “offtake connection”, is sensible because pricing requirements should turn on what the connection does rather than the technology type. This is particularly important for hybrid connections that combine injection and offtake, such as solar with batteries, farms with embedded generation and load, or secondary-network arrangements where the connecting party may not directly operate generating plant.

Q8. Non-prescriptive approach to capacity pricing

A non-prescriptive approach to capacity pricing is appropriate at this stage, but it should be bounded. Different distributors face different network constraints, and some flexibility is needed.

However, unbounded discretion could create inconsistent, opaque or overly cautious implementation. Distributor discretion should therefore be bounded by:

1. Methodology publication.
2. Applicant-facing explanations.
3. Worked examples.
4. Explanation of capacity constraint assumptions.
5. Explanation of how benefits are valued.
6. Dispute pathways.
7. Monitoring of actual outcomes.
8. later Authority guidance if material inconsistency emerges.

This is also a reason to keep capacity-pricing design proportionate. More granular pricing is not automatically better if it becomes too complex for applicants to understand, too difficult for distributors to administer, or too uncertain to guide investment. The Authority should prefer simple, transparent and reviewable approaches where those approaches produce broadly efficient signals.

Q9. Whether proposed extension of pioneer schemes would address position-in-queue issues

Yes. Pioneer arrangements should be strengthened because they address a real investment-coordination problem. Pioneer schemes should be treated as investment-enabling mechanisms, not only fairness mechanisms. Without effective pioneer arrangements, a first mover may face the full cost of capacity works that later users benefit from. This can encourage projects to delay, undersize or avoid triggering upgrades.

The Authority should ensure pioneer arrangements include:

1. Clear eligibility rules.
2. Publication of active scheme information.
3. Transparent calculation of pioneer contributions and later rebates.
4. Defined scheme duration.

5. Treatment of both extension and capacity costs where relevant.
6. Publication of actual contribution and rebate information where this can be done without disclosing genuinely confidential project information.
7. Review of whether the mechanism reduces stalled or inefficiently scaled projects.

For material shared-capacity works, the Authority should consider a rebuttable default that a pioneer arrangement is available unless the distributor explains why the project does not create identifiable capacity that later users are likely to benefit from. Indicative materiality thresholds, whether expressed in cost, capacity or project type, would reduce inconsistency across distributors while preserving proportionality.

Q10. Whether pioneer schemes should cover network injection capacity

Yes. Pioneer schemes should cover network injection capacity where an early injection project funds capacity that later injection projects can use. The same basic fairness and efficiency problem exists for injection as for other shared network capacity: the first mover may fund shared capacity while later users receive benefits without bearing a fair share.

Pioneer schemes should be materiality-based and administratively proportionate. But where an identifiable capacity investment is likely to support later injection connections, pioneer arrangements should be available under clear published criteria. This does not mean every shared-capacity project must automatically create a pioneer scheme; rather, distributors should have a transparent policy for when a scheme is created, how contributions and rebates are calculated, and how later beneficiaries are treated.

Q11. Non-discriminatory pricing requirements

I support the proposed non-discriminatory pricing requirement. A pricing-specific non-discrimination requirement would strengthen confidence that independent investors are not disadvantaged relative to distributor-owned or affiliated projects.

This issue has practical significance because the Authority’s public guide notes that the Government has signalled an intention to change the law to allow lines companies to own more generation connected to their own networks, increasing the threshold from 50MW to 250MW. If ownership rules change in that direction, pricing non-discrimination becomes more important, not less.

If the threshold for distributor involvement in generation connected to its own network is increased from 50MW to 250MW, the non-discrimination obligation, methodology transparency, comparable timing and access-to-information safeguards in this submission become more important. The DGPP reforms should therefore be monitored alongside any ownership-rule change, because pricing safeguards and ownership settings interact in practice.

The issue is not distributor ownership itself; it is whether pricing methodology, timing, information access and capacity allocation are demonstrably comparable between affiliated and independent projects.

Non-discrimination should be monitored in practice. The Authority should monitor whether comparable independent and distributor-affiliated projects receive comparable treatment in:

1. Methodology assumptions.
2. Timing.
3. Access to capacity information.

4. Pioneer scheme treatment.
5. Charges or rebates.
6. Dispute outcomes.
7. Bespoke arrangements.

A level playing field also depends on comparable access to cost information. Independent generators should not be left with less practical ability than distributor-affiliated projects to understand, challenge or respond to incremental-cost assumptions. Non-discrimination should therefore be assessed not only by final charges, but also by access to information, timing, methodology explanations and the opportunity to test assumptions.

Q12. Application provisions

I broadly support application provisions that avoid retrospectively unsettling existing arrangements, while still ensuring the new framework applies to future pricing and future connections in a clear and predictable way. Retrospective application could damage investor confidence and create avoidable disputes. However, indefinite grandfathering could preserve inefficient pricing signals.

The Authority should make clear which elements apply to new connections, new pricing methodologies, amended arrangements and existing connections at later review points.

Q13. Commencement provisions

I support the Authority's proposed staged commencement: changes applying to connection charges from 1 February 2027, and changes applying to lines charges, including negative prices, from 1 April 2027 with an option for distributors to defer to 1 April 2028.

This staging is sensible because it allows connection-charge changes to take effect earlier where they relate to new applications, while aligning lines-charge changes with distributors' annual tariff-setting cycle. It also gives distributors time to update pricing methodologies, systems, retailer communications and customer-facing material.

The one-year deferral option for lines charges is a reasonable safeguard against implementation pressure. However, the Authority should monitor whether the deferral is used disproportionately by distributors with high distributed-generation activity. If deferral is concentrated in those networks, it could delay the benefits of the reform where they are most needed.

Q14. Supporting successful implementation

Successful implementation will require more than amending the DGPPs. The Authority should support implementation through:

1. Guidance on estimating incremental injection costs.
2. Guidance on identifying and recognising benefits.
3. Worked examples for common connection types.
4. Minimum content expectations for pricing methodology disclosures.
5. Minimum expectations for applicant-facing incremental-cost explanations, including the cost categories, assumptions, capacity trigger, allocation basis and any confidentiality limits.

6. Materiality thresholds or examples showing when more detailed incremental-cost analysis is required and when a simpler standardised approach is sufficient.
7. Expectations for pioneer scheme information publication.
8. Guidance on proportionate standardised pathways for common or low-risk injection connections.
9. Monitoring templates.
10. A time-bound post-implementation review.

Guidance should be available ahead of the effective date of the new rules so distributors, applicants and representative bodies can minimise rework and develop reasonably consistent approaches before pricing methodologies are updated. The Authority should involve representatives of both distributor and distributed-generator interests in preparing implementation guidance, including representation from distributor peak bodies and independent distributed-generator interests, while retaining responsibility for the final guidance.

Where a distributor’s pricing methodology change materially changes the charges, rebates or cost allocation faced by injection connections, the methodology should explain whether the change reflects a real change in network costs, a real change in measurable network benefits, a changed capacity constraint, improved data, a changed assumption, or a methodological artefact. This would help applicants, retailers, consumers and the Authority distinguish genuine network-cost signals from methodology-driven changes in pricing outcomes.

A limited Australian comparison is instructive. In the National Electricity Market, the AEMC’s 12 August 2021 final determination on access, pricing and incentive arrangements for distributed energy resources recognised export services as part of distribution services and enabled export pricing arrangements. The reform also showed that cost-reflective export pricing can face legitimacy risks if consumers perceive it as a penalty on distributed energy, even where transition protections are included. The lesson is not that New Zealand should copy or avoid the NEM framework. It is that two-way pricing needs clear regulatory guidance, applicant-facing and consumer-facing explanation, transition arrangements and oversight so export pricing is understood as an efficiency tool rather than a blunt penalty on distributed energy.

Q15. Effective monitoring and reporting

Monitoring should focus on actual outcomes, not only formal compliance. The Authority should monitor:

1. Whether distributors publish clear injection-pricing methodologies.
2. Whether methodologies explain both costs and benefits.
3. Whether applicants receive enough information to assess the reasonableness of incremental-cost charges.
4. Whether benefit recognition becomes more common where justified.
5. Whether pioneer schemes are used.
6. Whether connection projects still stall or withdraw because of shared upgrade costs.
7. Whether independent and affiliated projects receive comparable treatment.
8. Whether disputes increase or decrease.
9. Whether methodology quality improves over time.

10. Whether common or low-risk connection types are able to proceed through proportionate standardised pathways.
11. Whether applicants report improved ability to understand and test incremental-cost explanations.
12. Whether monitoring identifies any need for further guidance on storage, flexible export, aggregated DER or VPP arrangements.

Monitoring should also test whether the framework is becoming too complex. A pricing reform can fail not only by under-allocating costs or ignoring benefits, but also by creating methodologies so granular that smaller applicants, retailers or consumers cannot understand the basis for charges. The Authority should therefore monitor usability and predictability as well as formal cost-reflectivity.

Review milestone: after the first pricing-methodology cycle under the amended DGPPs, the Authority should review whether distributor methodologies are clear enough to compare, whether measurable benefits are being recognised where justified, whether pioneer arrangements are being used for shared capacity works, whether comparable independent and distributor-affiliated projects are receiving comparable treatment, and whether standardised pathways are reducing friction for common or low-risk connections.

Monitoring should be proportionate and targeted. The Authority need not replicate a full scorecard-style assessment immediately if resources are constrained; an initial focused review of methodology quality, applicant-facing cost explanations, benefit recognition, pioneer scheme use, standardised pathway availability and comparable treatment would be sufficient to identify whether further guidance is needed.

Q16. Wide discretion in capacity charges for injection connections

I support relatively wide distributor discretion only if it is paired with strong disclosure and review. Capacity pricing is network-specific, and distributors are best placed to understand local constraints. But discretion should not become opacity.

The Authority should require distributors to explain:

1. When capacity charges apply.
2. How injection capacity is measured.
3. How coincidence with network constraints is assessed.
4. How shared capacity costs are allocated.
5. How benefits are offset.
6. How pioneer schemes interact with capacity charges.
7. How applicants can challenge unreasonable assumptions.

Q17. Larger connections and bespoke approaches

For larger connections, a bespoke approach is generally more appropriate than broad prescriptive rules. Larger projects are more likely to have site-specific network impacts, different dependability characteristics, and greater potential to influence future capacity investment. However, bespoke treatment should still be transparent and non-discriminatory.

This is also consistent with the Authority's public guide, which says rewarding larger-scale distributed generation is more complex and that a targeted approach is needed to ensure larger distributed generators do not create more costs or receive rebates when they do not create cost savings.

The Authority should require distributors to document the reasons for bespoke treatment and ensure that comparable projects are treated consistently unless differences are justified by evidence. Bespoke treatment should not become the default for routine or low-risk projects that could proceed through a standardised pathway.

Q22. Other matters

The Authority should explicitly design the reform around predictable implementation failures. The key risks are:

Failure mode	Why it matters	Design response
One-way cost recovery	Costs are allocated but benefits are ignored.	Require methodologies to address costs and benefits.
First-mover disadvantage	Efficient early projects may stall or undersize.	Strengthen pioneer arrangements.
Opaque discretion	Investors cannot predict connection costs.	Publish methodologies, applicant-facing explanations and worked examples.
Insufficient applicant-facing cost transparency	Applicants may be unable to assess whether incremental-cost charges are reasonable, even where distributors publish high-level methodologies.	Require project-specific explanations of cost categories, assumptions, capacity triggers and allocation basis, subject to confidentiality safeguards.
Cost shifting in either direction	The framework could either leave consumers paying for costs caused by injection connections, or allow distributors to recover sunk, residual or common network costs from injection connections without a clear causal link.	Require transparent applicant-facing explanations of cost categories, assumptions, capacity triggers, benefit treatment and causal links to actual network impacts.
Distributor self-preference	Independent projects may lack confidence in fairness.	Monitor comparable treatment.
Reactive dispute-only oversight	Problems may persist unless someone has capacity to challenge.	Add proactive monitoring and review.
False precision and excessive complexity	Incremental-cost analysis may become too granular, inconsistent or difficult for applicants to understand, increasing transaction costs without improving efficient decisions.	Use materiality thresholds, worked examples, transparent assumptions and simpler standardised approaches where appropriate.
Transaction friction for low-risk connections	Efficient projects may be deterred by bespoke processes even where network impacts are routine or low-risk.	Create proportionate standardised pathways for common or low-risk connection types.

Beyond these failure-mode design responses, the Authority should consider three specific forward-work-program items raised in section 5 of the consultation paper: further oversight of capacity pricing if voluntary distributor practice produces materially inconsistent outcomes; addressing the transmission bypass incentive that arises where distribution-connected generation faces materially different transmission cost exposure than transmission-connected generation; and reviewing the existing restriction on recognising transmission benefits if evidence emerges that injection delivers material, measurable transmission-cost reductions.

These are forward-work-program matters rather than immediate recommendations for this Code amendment. They should be revisited after the first post-implementation review, once the Authority has evidence on how distributors have applied the updated DGPPs.

Q23. Consumer impact analysis

The consumer impact analysis should be interpreted with care because it is indicative. The DGPP Consumer Impact Analysis workbook estimates the impact of allocating certain distribution and transmission costs, currently allocated only to offtake customers due to the existing distribution pricing principles, to injection connections. It describes the analysis as indicative and based on what could have been allocated had the proposal applied in recent years.

The Authority's 21 April 2026 correction to Appendix A clarified that, under the proposed changes, benefit-based transmission charges are typically the only transmission charge component that could be reallocated to distributed generators; transmission connection charges would not typically be reallocated. This submission reads the consumer-impact analysis on that corrected basis.

The model description identifies four cost categories considered for reallocation:

- Distribution vegetation management costs.
- Distribution routine and corrective maintenance and inspection costs.
- Distribution service interruption costs.
- Transmission benefit-based charges related to injection, excluding those related to adjustment events.

On that basis, the analysis appears useful as an indicative estimate of direction and scale, but it should not be treated as a complete measure of long-term consumer benefit. The Model Results Summary indicates an overall total charge reallocation of approximately $1.34 million annually and an overall annual average charge reduction per offtake ICP of approximately $0.59. This suggests the direct average modelled bill impact may be small in absolute terms, while the policy significance lies more in improving allocation, incentives and future investment signals than in immediate average bill reductions.

The small average modelled reduction per offtake ICP suggests that the reform should not be justified primarily as a near-term bill-reduction measure. Its stronger justification is dynamic efficiency: better long-term investment signals for distributed generation and storage, reduced inefficient subsidies, more transparent capacity-cost allocation and improved use of network capacity.

The benefits assessment should also consider long-run behavioural responses. If pricing reform is perceived as an opaque attempt to recover sunk or residual network costs from prosumers, it may encourage inefficient bypass, undersized connections or behind-the-meter investment that avoids network charges rather than lowering total system cost. This is another reason to keep the framework transparent, capacity-focused and linked to real cost drivers and measurable benefits.

The Authority should therefore monitor whether the reforms reduce inefficient subsidies without deterring efficient distributed generation and storage. If implementation evidence shows that the reforms deter projects that provide measurable network benefits, the Authority should adjust guidance or monitoring expectations.

Q24. Objectives of the proposed amendment

I agree with the objectives of the proposed amendment. The objectives appropriately focus on improving distributed generation pricing so costs and benefits are more efficiently allocated. The final amendment should also make clear that implementation quality, methodology transparency, applicant-facing cost explanations and monitoring are central to achieving those objectives.

Q25. Whether benefits outweigh costs

I agree that the benefits of the proposed amendments are likely to outweigh the costs if the final framework includes the safeguards recommended in this submission. The benefits are strongest where the reform improves cost allocation, recognises measurable network benefits, reduces first-mover disadvantage, improves applicant-facing transparency and improves confidence that pricing is non-discriminatory.

The costs and risks are more likely to arise if implementation is opaque, inconsistent, overly complex or perceived as a way to recover residual network costs from prosumers without a clear link to real cost drivers. For that reason, the benefit-cost judgement depends heavily on implementation guidance, methodology disclosure and proportionate monitoring.

A reform that mainly protects existing cost-recovery structures, rather than improving efficient long-term price signals, could increase inefficient bypass risk and reduce confidence in the legitimacy of the framework.

Q26. Preferred option

I broadly agree that the proposed amendment is preferable to retaining the status quo, provided it is implemented with transparent methodologies, applicant-facing cost explanations, symmetrical cost-benefit recognition, pioneer scheme safeguards, standardised pathways where appropriate and monitoring. Retaining the current framework would not adequately address under-allocation, capacity-pricing and first-mover issues identified in the consultation paper.

The Authority has already refined its position from the February 2025 issues paper, which considered no change, modifying the DGPPs, removing the DGPPs, or a comprehensive overhaul. The current, more targeted proposal appears appropriate because it addresses the main under-allocation, benefit-recognition, position-in-queue and capacity-pricing issues without attempting a comprehensive overhaul that could increase implementation risk during a period of high investment in distributed generation and storage.

Q27. Section 32(1) of the Act

I do not provide a legal opinion on compliance with section 32(1) of the Electricity Industry Act 2010. From a policy perspective, the Authority’s Appendix B reasoning is sound on the points that matter most: the proposed amendments remain focused on how distributors set charges rather than direct price prescription; they continue to mitigate distributor market power; they preserve consumers as residual payers for residual costs; and they address the increasing risk that consumers cross-subsidise injection connections.

The main residual section 32(1) risk is not the design of the amendments themselves but implementation. If distributors apply the rules inconsistently, materially over-allocate costs to injection, or under-recognise measurable benefits, the amendments may not promote efficient operation and investment in practice. The methodology-disclosure, applicant-facing cost-explanation, monitoring and benefit-recognition recommendations in this submission therefore support the Authority’s section 32(1) reasoning rather than sitting outside it.

Q28. Consistency with distribution pricing principles

The preferred high-level settings for injection pricing appear broadly consistent with the distribution pricing principles if they are implemented proportionately. Cost-reflective pricing, transparency, benefit recognition and non-discrimination are consistent with efficient pricing. However, consistency will depend on whether distributors apply the settings in a way that recognises both incremental costs and measurable benefits and explains project-specific cost allocation clearly enough for applicants to understand.

Q29. Consolidating distribution pricing methodology requirements into Part 6B

I support consolidating distribution pricing methodology requirements into Part 6B if it improves clarity and consistency. Consolidation should make it easier for distributors, distributed generators, retailers and consumers to understand where pricing methodology obligations sit and how they interact.

The Authority should ensure that any consolidation does not obscure the specific obligations applying to distributed generation pricing, including applicant-facing cost explanations, benefit recognition, pioneer scheme treatment, standardised pathways for common or low-risk projects, and non-discrimination.

Q30. Drafting comments

I do not make detailed drafting comments. At a high level, the drafting should ensure that:

- Incremental costs and measurable network benefits are both addressed.
- Distributor methodology disclosure obligations are clear.
- Applicant-facing cost explanation expectations are clear.
- Pioneer scheme obligations are practical and reviewable.
- Non-discrimination requirements are capable of being monitored.
- Standardised pathways for common or low-risk connection types are possible.
- Commencement and application provisions avoid unnecessary retrospectivity while preventing indefinite preservation of inefficient pricing signals.

For terminology, see the response to Q7. The same logic should be reflected in final drafting: pricing obligations should turn on what a connection does, not only on the technology label attached to it.

The Authority should ensure the final drafting and guidance explain how connections that switch between injection-dominant and offtake-dominant operation over time are treated.

Implementation roadmap

Phase	Timing	Action	Responsible actor	Output	Risk controlled
Immediate	Final decision/Code amendment	State in the final decision paper and Code amendment explanation how cost-benefit symmetry, methodology disclosure, applicant-facing explanation, standardised pathways and non-discrimination expectations will be implemented.	Authority	Final decision and amendment explanation	One-way cost recovery; scope uncertainty
Pre-commencement	Before 1 February 2027/1 April 2027	Prepare guidance with distributor and distributed-generator representative input.	Authority, with input from distributor peak bodies and independent distributed-generator interests	Implementation guidance and worked examples	Rework; inconsistent distributor implementation

Implementation	First pricing-methodology cycle	Require distributors to update methodologies with injection-cost and benefit treatment.	Distributors	Published methodologies and applicant-facing cost explanations	Opaque pricing; investor uncertainty
Early monitoring	First post-implementation review	Review methodology quality, benefit recognition, applicant-facing explanations, pioneer scheme use, standardised pathway availability and comparable treatment.	Authority	Monitoring report or targeted assessment	Weak implementation; self-preference
Adjustment	After evidence of implementation issues	Issue further guidance or amend requirements if material inconsistency appears.	Authority	Guidance / further reform pathway	Inconsistent or ineffective practice
Fallback review	Fixed review date	Assess whether first-mover disadvantage and cost/benefit under-allocation have improved.	Authority	Public review findings	Reform not delivering real outcomes

Risks and safeguards

This table summarises the failure-mode analysis in Q22 in a shorter form for implementation review.

Risk/objection	Safeguard in this submission
The reform becomes one-way cost recovery from distributed generators.	Require symmetrical treatment of incremental costs and measurable network benefits.
Residual or sunk network costs are treated as incremental injection costs.	Require distributors to explain the causal link between the charge, the network constraint, the capacity trigger and the applicant's actual network impact.
Incremental-cost analysis becomes falsely precise or too complex.	Use materiality thresholds, worked examples and simpler standardised approaches where appropriate.
Distributors retain too much opaque discretion.	Require published methodologies, applicant-facing explanations and monitoring of actual outcomes.
Pioneer schemes become too burdensome or inconsistent.	Make them available under clear published criteria for material shared-capacity works, rather than mandatory in every case.
Monitoring imposes excessive burden on the Authority.	Use a targeted first-cycle review focused on methodology quality, applicant-facing explanations, benefit recognition, pioneer scheme use, standardised pathway availability and comparable treatment.
The submission drifts into transmission pricing reform.	Treat transmission bypass, transmission benefit recognition and capacity-pricing oversight as forward-work-program items, not immediate Code-amendment asks.

Minimum viable fallback

The minimum viable fallback below identifies the smallest package that should be adopted if the Authority does not adopt the full implementation package immediately.

1. Require distributors to publish how they estimate incremental injection costs and identifiable network benefits.
2. Require applicant-facing explanations for project-specific incremental-cost charges.
3. Require worked examples for common project types.
4. Create proportionate standardised pathways for common or low-risk injection connections.
5. Monitor whether benefit recognition and pioneer scheme use increase where justified.
6. Monitor whether non-discrimination works in practice.
7. Commit to a time-bound review of whether the reforms reduce first-mover disadvantage and improve efficient distributed generation investment.

Conclusion

The Authority should proceed with reforming the DGPPs, but the success of the reform will depend on implementation design. The final framework should not simply move from a pro-DG framework to a cost-recovery framework. It should create a fair, transparent and investable pricing framework for a higher-DG, more electrified and capacity-constrained system.

The most durable approach is to combine cost-reflective injection pricing with symmetrical benefit recognition, applicant-facing incremental-cost transparency, stronger pioneer arrangements, non-discrimination monitoring, proportionate standardised pathways, bounded distributor discretion and a clear post-implementation review.

I note the cross-submission deadline of 5pm, 3 June 2026, and would welcome the opportunity to provide clarification on any recommendation or engage with material submissions from other parties at that stage.

Appendix A: Key terms

Term	Meaning in this submission
Distributed generation	Generation or storage connected to a distribution network rather than directly to the transmission grid.
Injection connection	A connection that injects electricity into a distribution network. This term is useful because the proposed reforms focus on what the connection does, not only on the technology type.
Offtake connection	A connection that takes electricity from the distribution network.
Incremental cost	The additional cost reasonably attributable to an injection connection, pricing decision or network use, rather than residual costs shared across the network.
Measurable network benefit	A benefit that can reasonably be identified and explained, such as avoided or deferred network investment, reduced pressure on constrained parts of the network, or more efficient use of capacity.
Pioneer arrangement	A mechanism that allows an early party funding shared network capacity to receive contributions or rebates from later users who benefit from that capacity.
Non-discrimination	Comparable treatment of independent and distributor-affiliated projects unless differences are justified by evidence.
Bounded discretion	Distributor flexibility to reflect local network conditions, combined with methodology disclosure, worked examples, monitoring and review.
Flexible export arrangement	An arrangement where an injection connection's export limit can vary over time according to network conditions, rather than being fixed at a single firm export capacity.
Aggregated DER / virtual power plant	Distributed energy resources coordinated across multiple connections to provide energy, capacity or network-support value that may not be visible at the level of a single connection.

Sources

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7. Electricity Authority, Interpretation of the Authority's statutory objective.
8. Electricity Authority, Electricity Industry Participation Code (Injection Payment Requirements Amendment) Amendment 2026, effective 1 April 2026.
9. Electricity Authority, Decision paper on small business eligibility for export rebates, 20 January 2026.
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14. Australian Energy Market Commission, Access, pricing and incentive arrangements for distributed energy resources, final determination, 12 August 2021.