19 May 2026

Electricity Authority
PO Box 10041
Wellington 6143

By email to: distribution.pricing@ea.govt.nz

Dear Electricity Authority team,

Consultation Paper—distribution injection pricing

Electricity Networks Aotearoa (ENA) welcomes the opportunity to make a submission to the Electricity Authority (Authority) on its consultation paper on *Reforming network pricing for distributed generation to promote efficient investment*.

ENA is the membership organisation representing all 28 electricity distribution businesses (EDBs) that distribute electricity across Aotearoa (EDBs represented are listed in Appendix A).

EDBs employ over 7,800 people, deliver energy to more than two million homes and businesses, and have spent or invested $6.8 billion in network assets over the last five years. ENA harnesses members' collective expertise to promote safe, reliable, and affordable power for our members' customers.

1 Introduction

Local networks are becoming a key enabler of decentralised energy. As more households install solar panels, batteries and EV chargers and larger distributed generation is added to distribution networks, lines companies are required to manage increasing complexity from two-way power flows, higher demand and other technical matters not previously required.

As set out in the ENA submission Energy Competition Task Force 2a, 2b and 2c and Authority DGPP issues paper, *ENA members are playing their part in this evolution and are preparing for the ramp-up of [Distributed Energy resources (DER)], and the development of flexibility services. In creating an environment conducive to DER and flexibility services, ENA and its members view distribution prices and an enabling regulatory regime as inextricably entwined, rather than being standalone pillars. Sending the correct price signals, via distribution prices, will play a crucial role in enabling the efficient deployment of DER and adoption of flexibility services.*[1]

Consideration of the distributed generation pricing principles (DGPPs) is an important step in the electrification and energy affordability transition, and we welcome the opportunity to contribute to their development.

As noted in the consultation paper, and discussed throughout this submission, the development of the DGPPs is being progressed in isolation from any confirmed changes to other regulatory settings. There is

[1] ENA, Submission Energy Competition Task Force 2a, 2b and 2c and Authority DGPP issues paper, 26 March 2026. Section 2.

a risk that piecemeal refinement of regulation will create unintended consequences, including perverse incentives. This submission discusses potential consequences for the Authority to consider.

2 Principles-based regulation supported by ENA

The ENA supports the Authority's principles-based approach for allocating costs to distributed generators. As noted in the ENA March 2025 submission, a one-size-fits-all prescription may not suit all circumstances and principles allow flexibility. Principles will allow distributors to respond most effectively to the circumstances and adapt their approach over time.[2]

The Authority should exercise caution where proposed Code amendments extend beyond a principles-based regulatory approach. One example is the proposal to mandate pioneer schemes, which is discussed further in section 4.1 below.

2.1 ENA and IEGA to address uncertainty through guidance

ENA has been working with the Independent Electricity Generators Association (IEGA) to identify areas of alignment and to consider how uncertainty regarding the application of DGPPs can be addressed. ENA and IEGA jointly recommend that industry-developed guidance is the most appropriate means of addressing uncertainty in the application of both the current and proposed regulation.

The collaboration to date has identified areas of agreement, as well as matters requiring further consideration. The areas of agreement most relevant to this consultation are:

- principles-based regulation is the appropriate form of regulation for distributed generation pricing; and
- there is significant value in strengthening a shared understanding of the current DGPPs through clear guidance, including by addressing areas of non-alignment between distributed generators and EDBs and supporting more consistent application across networks.

ENA and IEGA jointly submit that the development of industry guidance would be an appropriate and beneficial approach to support the application of the Authority's current and proposed DGPPs.

Industry-developed guidance would:

- leverage the combined expertise of informed and resourced industry participants;
- strengthen shared understanding among those participants;
- support more consistent application across networks; and
- enable EDBs to represent the interests of other network users in a manner consistent with the principles enacted through the Code.

ENA and IEGA have already commenced development of this industry-led guidance. Appendix B sets out the areas of agreement and matters for further consideration. ENA looks forward to continuing to work with IEGA to develop guidance that is consistent with the Authority's current and proposed DGPPs.

[2] ENA, Submission Energy Competition Task Force 2a, 2b and 2c and Authority DGPP issues paper, 26 March 2025. Section 2.4.

3 Incremental cost principle

The Authority, in relation to incremental cost principle, considers:[3]

a) It remains appropriate to regulate how distributors set charges for injection, to mitigate distributor market power and ensure pricing promotes efficient network usage and investment.

b) Adopting parity between injection and offtake pricing would not promote more efficient operation of the electricity industry, so offtake connections (ie, consumers) should remain residual payers of network costs.

c) The DGPPs should be amended to improve workability, broaden scope for allocating incremental costs and benefits, and position incremental cost as an anchor (not a cap).

3.1 ENA position on incremental cost

ENA supports the review of the DGPPs, including consideration of the incremental cost principle and how it is applied.

It is not clear that the incremental cost pricing principle is an appropriate long-term solution for pricing distributed generation. Questions remain as to whether users should pay for their use of the network regardless of the direction of electricity flow, and about the appropriateness of this approach should generation become the primary driver of a network's activity and constraints.

ENA however supports:

- proposed refinements to the application of incremental cost that increase the ability to charge to an anchor point, as an important improvement on the current position;
- amendments to the DGPPs to improve workability, broaden the scope for allocating incremental costs and benefits, and position incremental cost as an anchor (rather than a cap); and
- the ongoing monitoring and consideration of unintended consequences as the industry continues to evolve.

3.2 Incremental cost definition

The Authority proposes changes to the pricing principles to improve their workability and more clearly endorse a wider range of practices, including alternatives to 'last straw' pricing for network capacity and allocation of cumulative costs and benefits.

ENA supports the changes proposed, noting that:

- the introduction of cumulative costs and programmatic costs to the incremental cost definition provides for these costs to be passed on to all injection connections that contribute to the costs, irrespective of who triggered the cost;
- allowing network injection capacity costs to be included in incremental cost is important to address first mover advantage concerns and to allow EDBs to facilitate efficient distributed generation investment through appropriate price signals. Allowing EDBs to recover costs that have been incurred in anticipation of DG investment will also allow for efficient and mutually beneficial upfront investment;
- providing for the deduction of reasonably identifiable distribution costs is supported as it will allow EDBs to use price to incentivise distributed generation to be located in the network where it will be of most benefit; and

[3] Authority, Reforming network pricing for distributed generation to promote efficient investment, 21 April 2026. Paragraph 4.1.

- we welcome the opportunity to work with IEGA and other stakeholders to develop guidance for the application of the new incremental cost definition.

Appendix D includes drafting notes on the proposed code amendment.

3.3 Transmission charges

The ENA agrees it is appropriate for the Authority to exclude Avoided Cost of Transmission (ACOT) from the scope of this review. The fundamental basis for these payments was tied to the introduction of the 2023 Transmission Pricing Methodology (TPM) and the circumstances surrounding that decision have not changed.

Network pricing must provide the right incentives for connection at the right size and location, ensuring that the avoidance of transmission charges does not distort investment decisions. Grid-scale generation should not be incentivised to choose notionally embedding within a distribution network to avoid contributing to shared transmission costs —a practice known as transmission bypass. This practice provides an artificial commercial advantage that can tilt the build order of projects away from the most economically efficient designs. Effective reform must ensure that investment is driven by actual system benefits and resource availability, rather than charge avoidance.

While considered an area for further reform, the measurable impact transmission bypass is having on grid-scale generation investment decisions should not be ignored.

4 Allocation of costs (and benefits) to network uses

ENA considers that system activities used to manage increasing levels of distributed generation (including distributed energy resource management systems (DERMS) capability, enhanced monitoring/communications, and voltage management tools) should be treated as shared network services where they deliver benefits to multiple parties. Allocation should therefore reflect:

a) causation where costs are clearly incremental to a connection or group of connections, and

b) beneficiary-pays where investments create broader, enduring value (eg, increased hosting capacity, EDB investment in capacity maps allowing for greater visibility for both load and generation access seekers, improved power quality, deferral of traditional reinforcement, and reduced operational risk).

In practice this means:

- Connection-specific or clearly incremental requirements (eg, project-specific studies, protection changes, dedicated comms, bespoke voltage control settings) should be recovered from distributed generators as part of incremental cost.
- Platform and 'common' capability (eg, DERMS platform, network-wide telemetry/visibility, standardised voltage management schemes) should be recovered from the broader customer base where it provides system-wide benefits; where a material portion of the benefit is attributable to a defined class of users (eg, DG above a threshold), a targeted charge can be appropriate.
- Where voltage management actions impose measurable constraints or additional operating costs on a DG connection (eg, curtailment risk, reactive power obligations), any associated costs/benefits should be reflected in connection terms and, where feasible, in prices that signal time/location-specific network conditions.

The Authority's proposed code amendment appropriately identifies the need for cumulative costs and programmatic costs to be considered as part of incremental cost. ENA welcomes the opportunity to work with IEGA and other stakeholders to develop guidance for the application of the new incremental cost

definition, including how to transparently allocate distributed generation related costs between distributed generation users.

The introduction of capacity charging is also supported. Capacity charges will allow EDBs to:

- structure the timing of cost recovery to help to avoid position in queue dynamics;
- manage forecast constraints on the current network through pricing signals; and
- undertake network investment where future needs are identified and then pass costs on to injection customers as the additional capacity is utilised by those customers.

4.1 Mandating Pioneer scheme is not supported

The Authority proposes expanding the 'pioneer scheme' arrangements to apply to injection connections to reduce 'first-mover disadvantage'.

The ENA supports the ability for EDBs to use pioneer schemes where there is a clear benefit. ENA does not support mandated pioneer schemes. There are limited circumstances in which pioneer schemes are likely to be beneficial for injection connections compared with offtake connections, and the administrative burden associated with these schemes is significant.

Due to investment efficiency, distributed generation will typically build solutions that utilise all economically available capacity. This is different to most load customers that may consider location to reduce costs but typically determine load capacity based on other drivers.

Pioneer schemes are only beneficial where network augmentation is required to support new distributed generation, and early movers could otherwise face disproportionate costs.

Distributed generation projects more often than load connections locate to utilise existing network headroom, requiring only minimal investment in the existing network and seldom require investment in assets that would be utilisable by other parties. As a result, mandating pioneer schemes would, in many cases, add process and compliance costs without materially altering investment decisions or pricing signals.

The ENA, accordingly, recommends pioneers schemes are made available for injection connections but not mandated.

4.2 Consumer impact assessment

Appendix A of the Authority's consultation paper includes a qualitative analysis to indicate the impact of reallocating injection related costs. The analysis estimates the near-term impact of reallocating several cost categories – vegetation management, service interruption and emergencies, routine inspections, and benefit-based transmission charges. Table A.2 of the consultation paper sets out an estimated reduction per offtake connection.[4]

While the Authority's discussion on the analysis includes caveats, we believe identified and unidentified shortcomings in the analysis makes it misleading. Although we don't believe it is necessary or beneficial to address the shortcomings it is worth noting that the analysis, by example, does not:

- consider the long-term impact of inefficient investment from inefficient injection pricing signals;
- adequately identify or quantify cumulative and programmatic costs or network benefits that would be transferred to injection connections; and
- adequality consider the expected growth in distributed generation.

[4] Authority, Reforming network pricing for distributed generation to promote efficient investment, 21 April 2026. Appendix A, paragraph A.37.

The ENA supports the application of cost benefit analysis to assess the requirement for change. While the analysis included in the consultation does not adequately identify the benefits, the ENA does not support additional analysis being undertaken as the cost of the analysis would likely exceed the benefit.

The case for change is, however, indisputable, given the current DGPP incentivises inefficient investment decisions, with the associated costs borne by offtake customers.

5 Development occurring in evolving environment

Distributed generation and other technologies connecting to distributed networks are evolving and how they impact and can be utilised to benefit efficient operation of networks is also evolving. As mentioned earlier, ENA therefore supports the application of principles-based rather than rules-based regulation. This will allow flexibility for EDBs to adapt and evolve pricing in response to evolving network needs.

The DGPPs also operate within a broader regulatory context that is evolving.

5.1 Potential unintended consequences

While the ENA supports the evolution of regulations, piecemeal adjustments to regulations heighten the risk of unintended consequences. This section sets out some of the unintended consequences the ENA has identified for the Authority to consider when developing and monitoring the on-going appropriateness of the DGPPs and the Authority's other regulatory mechanisms.

Transmission and distribution pricing

Network pricing should provide the right incentives for connection at the right size and location. If generators can materially reduce or avoid contribution to shared transmission costs by embedding within a distribution network, investment decisions may be distorted away from the most economically efficient connection design and location. Reform should therefore ensure that any ability to avoid transmission charges does not create an artificial commercial advantage, and that project economics are driven by underlying resource availability and whole-of-system efficiency—not charge avoidance.

Current customer access to injection capacity

When setting capacity charges, EDBs will need to consider future injection needs. Part of that consideration will be how to price existing injection capacity relative to potential future existing offtake customer injection requirements. Current injection capacity—funded by current offtake customers—allocated to new injection customers at incremental cost, potentially leaves existing offtake customers to fund higher-cost capacity when they later seek to inject.

This situation is considered unfair because it can result in costs and benefits being misaligned across customers:

- Existing offtake customers have already paid—through past connection charges and ongoing lines charges—for network capacity that can support injection.
- If that existing capacity is allocated to new injection customers at incremental cost, those new customers benefit from infrastructure they did not help fund.
- Existing customers may later face higher costs if, when they seek to inject themselves, they must fund more expensive new capacity because the lower-cost, existing capacity has already been used.
- This outcome undermines the beneficiary-pays principle and risks cross-subsidisation, where early investment by one group delivers disproportionate costs to existing customers that decide to inject at a later point.

In effect, customers who funded the network first may lose access to the value of that investment, while later users gain access at a lower cost, creating a fairness concern.

Competition between load and generation for the provision of flexibility services

Different pricing principles applied to load and generation risk creating inefficient price signals when sourcing flexibility services. Where load is exposed to time- and location-reflective signals (eg, capacity or congestion-related charges) but generation is constrained to incremental-cost pricing, flexibility providers may face asymmetric incentives. This can distort which resources offer flexibility (eg, demand response versus generation response), where they choose to connect, and how they contract, because the value of relieving a local network constraint is not reflected consistently. Over time, these distortions could increase total system cost and undermine the development of efficient, contestable flexibility markets.

Evolution of congestion and other polices

The ENA notes that congestion management arrangements across distribution and transmission networks are evolving rapidly, driven by increasing distributed generation, electrification of load, and changing power flows. In response, EDBs are deploying non-traditional tools such as curtailment schemes, active network management, dynamic operating envelopes, and flexibility procurement to manage constraints and maximise utilisation of existing assets. At the same time, related policy development is ongoing, including flexibility service market frameworks, congestion pricing and access arrangements, and transmission pricing reform.

If the DGPPs are amended ahead of clarity on these interacting policy settings, there is a risk of unintended consequences. In particular, pricing signals for load, generation, and flexibility services may become misaligned; congestion management costs and benefits may be allocated inefficiently; and short-term pricing responses may lock in investment or operational behaviours that become inefficient as congestion frameworks mature. This risk is heightened because congestion outcomes are increasingly driven by time- and location-specific operational constraints, while DGPPs remain largely static and connection-focused.

ENA therefore considers it important that the Authority recognises congestion management, flexibility frameworks, transmission pricing, and DGPPs as interdependent components of the regulatory system. Changes to the DGPPs should be implemented cautiously, with ongoing monitoring and flexibility to adapt over time. A principles-based, enabling approach—supported by industry-developed guidance—remains the most appropriate way to manage these interactions and avoid outcomes that may quickly become outdated.

Risk of Code breach

The proposed amendment materially increases the risk of legal challenge and Code breaches for EDBs. Under the current Code, the ‘must not exceed’ requirement provides a clear compliance boundary by allowing EDBs to set charges conservatively below the theoretical threshold of incremental cost. The proposed requirement that charges ‘must reflect a reasonable estimate of incremental costs’ removes that certainty and exposes EDBs to non-compliance risk if, after the fact, another party’s view is found to be the more reasonable estimate.

This is not a minor drafting change. It shifts EDBs from operating within a clear compliance limit to being exposed to retrospective dispute over matters of judgment. That creates regulatory uncertainty, increases the likelihood of challenge, and raises the real prospect of inadvertent Code breaches despite good-faith efforts to comply.

That risk is further amplified by the proposed implementation timeframes, which are not realistic for the introduction of new and untested Code requirements. Refer to section 6.1 below for further discussion. ENA strongly urges the Authority to revise the implementation timeline to allow EDBs sufficient time to develop, test, and apply methodologies before the new requirements take effect.

New 'offtake' term

Using 'offtake' as a concept in Part 6 and 6B risks causing confusion given there is a separate definition of 'offtake' in the Code that is only relevant to grid exit points. It is not clear to us that 'load' cannot be retained as a concept as per previous amendment rounds. The rationale provided in the paper is not convincing - there should be no problem with 'load' covering both the type of connection for process purposes and the use for pricing purposes.

If the concept of offtake is retained for Part 6, we suggest amending the definition of 'offtake' in Part 1 to make clear that it does not apply to this Part., Eg: offtake, except for the purposes of Part 6 and Part 6B, means the flow of electricity from the grid at a grid exit point.

Risk of further unintended consequences

Reviewing and amending the DGPPs at pace creates a risk of unintended consequences. There has been insufficient time through the consultation process to understand all implications. As has been seen with the implementation of other regulatory changes, it is often not until the regulations are in force that consequences can be fully understood.

6 Transition to new regulations

6.1 Timing

The Authority has signalled finalisation of the Code amendments in late 2026 and implementation of the changes in early 2027, with an option to defer lines charge changes until 1 April 2028. ENA does not support this implementation timeframe and raises serious concern if it were to be implemented as proposed.

Establishing or adjusting pricing methodologies requires time and resources, and the Authority must allow sufficient time for these changes to be implemented with proper regard to the pricing principles and each network's specific circumstances. Insufficient implementation time risks inconsistent application across networks, inefficient reworking of pricing methodologies, the emergence of disjointed and inefficient pricing signals for distributed generation over time. It also exposes EDBs to inadvertent Code breaches as discussed in section 5.1 above.

Application of realistic implementation timeframes will facilitate coordination across EDBs and between EDBs connecting parties.

The key steps required before implementation of either connection or lines charge pricing are:

- Develop industry lead guidance that will foster industry buy-in and facilitate consistency across the networks;
- Apply guidance into EDB policies which facilitates the consideration of network specific implications;
- Internal review and approval;
- Adjustment of other line charge pricing to ensure compliance with Commission price-quality path regulations; and
- Notify customers.

Sufficient implementation time will support the development of robust and enduring pricing methodologies and charges, enabling a considered and efficient approach to implementation. Given the proposed requirement for charges to reflect a reasonable estimate of incremental costs, a rushed implementation would expose EDBs to an unacceptable risk of inadvertent Code breaches.

We note that the proposed extension of the 'connection charge reconciliation' is dependent on the implementation of the connection and line charge pricing changes. It cannot be treated as a reporting obligation that can be implemented independently of the changes it is designed to monitor, and not within the unrealistic timeframes proposed in the consultation.

ENA recommends the Code amendments, including the connection charge reconciliation element is made available for application by EDBs but is not mandatory until 1 April 2028. Making the Code amendments available early will allow EDBs to manage the risk of any gaming of changes in pricing from connecting parties.

6.2 Retrospective application to existing contracts

The Authority proposes the updated injection pricing principles would apply to new connection works (including upgrades) and to lines charges for any connection, regardless of when it was built.

ENA does not support the mandatory application of the updated injection pricing principles to lines charges for existing injection customers. Revisiting contracts in a relatively short period—some negotiations have been lengthy and detailed—would be administratively burdensome and inefficient, could undermine investment incentives that have already been agreed and if performed without sufficient consideration, increases an EDBs risk of a Code breech as discussed in section 5.1.

Appendix D includes proposed drafting amendments to ensure current line charge connections are not retrospectively reopened.

7 Conclusion

ENA appreciates the Authority's work on this review and the constructive engagement with stakeholders and looks forward to continuing to work with the Authority to establish regulation that supports efficient investment for the benefit of all electricity network users and contributors.

If you have any questions about ENA's submission please contact Gemma Pascall, Regulatory Manager ( ).

Yours sincerely

Gemma Pascall

Regulatory Manager

Appendix A: ENA Members

Electricity Networks Aotearoa makes this submission along with the support of its members. Listed below are the lines companies represented:

- Alpine Energy
- Aurora Energy
- Buller Electricity
- Centralines
- Counties Energy
- EA Networks
- Electra
- Electricity Invercargill
- Firstlight Network
- Horizon Networks
- MainPower
- Marlborough Lines
- Network Tasman Limited
- Network Waitaki
- Northpower
- Orion New Zealand
- OtagoNet – represented by PowerNet
- Powerco
- Scanpower
- The Power Company – represented by PowerNet
- Top Energy
- The Lines Company
- Unison Networks
- Vector
- Waipa Networks
- WEL Networks
- Wellington Electricity
- Westpower

Appendix B: ENA and IEGA

ENA and the Independent Electrical Generators Association (IEGA) have recently proactively engaged to identify areas of alignment and how uncertainty over application of the current DGPPs can be resolved. The engagement occurred during the Electricity Authority's (EA) consultation period on proposed changes to DGPPs.

The below table B1 summarises matters of agreement and areas for further consideration. The ENA and IEGA jointly present this information as a reflection of how the industry is focused, engaged and best placed to address DGPPs application matters.

Table B1: ENA and IEGA areas of alignment on DPGG

TOPIC AND MATTERS OF ENA/IEGA AGREEMENT	AGREED AREAS FOR FURTHER CONSIDERATION
Regulatory approach - Principles-based regulation is the appropriate form of regulation for distributed generation pricing - Application has been impacted by the lack of clear guidance, resulting in inconsistent implementation across distributed generation operators and EDBs. - Growth in distributed generation in recent years has further highlighted the need for clearer guidance and more consistent implementation across distributed generation operators and EDBs.	- ENA and IEGA agree there is significant value in strengthening shared understanding of the current DGPPs through clear guidance, addressing areas of non-alignment between DG and EDBs, and supporting more consistent application across networks.

Incremental cost
- ENA and IEGA support the use of incremental cost as the appropriate basis for (determining the minimum) charging distributed generation connections, with the objective that new DG connections are subsidy-free and impose no additional costs on existing load customers.
- Incremental cost should include the following categories
  ○ Incremental connection assets
  ○ Operational and maintenance of incremental connection assets
  ○ Return on and of capital (EDB-owned assets)
  ○ Transmission-related benefit-based charges identified via the TPM for embedded generation
  ○ Voltage management impacts – both costs and benefits from DG
  ○ GXP-related assets that are required to connect the DG
  ○ Connection application processing
	- Development of clear, practical guidance to support consistent calculation of incremental cost.
	- Standardise policies and methodologies across EDBs wherever possible to reduce inconsistent outcomes.

TOPIC AND MATTERS OF ENA/IEGA AGREEMENT	AGREED AREAS FOR FURTHER CONSIDERATION
Allocation of costs (and benefits) - whether mandating Pioneer schemes is necessary and would have a net benefit for efficient pricing	- how the costs and benefits of systems activities (eg, DERMS, monitoring/communications, and voltage management) are best allocated between the connecting DG party and other network users, including how any shared, network-wide benefits are recognised

Appendix C: Response to Authority questions

Questions	Comments
Q1. Do you agree with the background and context summary above? Why? Is there additional background, evidence, or context relevant to the proposals in this paper?	Additional background, evidence, and contextual material are provided throughout this submission to illustrate how current arrangements operate in practice. These observations are directly relevant and should be taken into account by the Authority when reviewing and setting regulatory arrangements.
Q2. Do you agree there are workability challenges with defining incremental costs under the current DGPPs? Why, why not? Are there any additional challenges not discussed above?	ENA agrees there are workability challenges with defining incremental costs under the current DGPPs and supports review and amendment of the current DGPPs.
Q3. Do you agree the current DGPPs cause costs and benefits to be under-allocated to injection connections, which can cause the issues listed above? Why?	ENA agrees that the current DGPP's can cause costs and benefits to be under-allocated to injection connections. Whether under-allocation has occurred is dependent on individual circumstances.
Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?	ENA supports the use of pricing principles to regulate injection pricing methodologies. Principles-based regulation, supported by industry-developed guidance, can provide clarity while remaining flexible and able to evolve as the operating environment evolve. ENA cautions against adopting rules-based regulation in this instance, as it risks reducing flexibility and creating unintended consequences (refer sections 2 and 5.1).
Q5. Do you consider that consumers should remain residual payers? Why? Are there any additional economic concepts that should be considered in our reform of the DGPPs?	It is not clear that the incremental cost pricing principle is an appropriate long-term solution for pricing distributed generation. ENA however agrees that: - proposed refinements to the application of incremental cost to increase the ability to charge to an anchor point is an important improvement on the current position; - the DGPPs should be amended to improve workability, broaden scope for allocating incremental costs and benefits, and position incremental cost as an anchor (not a cap); and - unintended consequences must continue to be monitored and considered as the industry evolves.

Questions	Comments
Q6. Do you consider that reframing the incremental cost rule to a requirement that charges 'must reflect a reasonable estimate of' rather than 'must not exceed' incremental costs is appropriate? Why?	ENA, in conjunction with IEGA, supports the reframing of the incremental cost rule to a requirement that charges 'must reflect a reasonable estimate of' rather than 'must not exceed' incremental costs. ENA and IEGA also jointly support the development of industry-led guidance on the application of the incremental cost rule (refer section 2.1).
Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?	ENA supports the amendments to language and framing. Drafting recommendations are included in appendix D.
Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?	ENA supports a non-prescriptive, enabling approach to capacity pricing. Distribution networks, and the distributed generation connected to them, are complex and evolving. The appropriate pricing approach depends on a range of factors that vary by location and project (eg, existing hosting capacity, forecast demand and generation, operational constraints, and planned reinforcement). A non-prescriptive, enabling approach allows EDBs to manage this complexity and apply capacity charges where it is efficient and proportionate.
Q9. Do you consider that the proposed extension of the pioneer scheme for load connections would help address position-in-queue issues for injection connections? Why?	Pioneer schemes will not always be as relevant for injection connections as they are for offtake connections. A non-prescriptive, enabling approach is recommended for the application of Pioneer schemes as they relate to injection connections (refer section 4.1)
Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?	ENA supports the Pioneer scheme being available for injection capacity but not mandatory. Section 4.1 sets out the reasons why.
Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?	The ENA supports the application of non-discriminatory pricing.

Questions	Comments
Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?	ENA does not support changes in line charges being retrospectively applied to existing contracts. Retrospective application would be administratively burdensome and inefficient, could undermine investment incentives that have already been agreed and if performed without sufficient consideration increases an EDBs risk of Code breaches. Refer section 6.2 for further discussion. There are multiple challenges with secondary networks – the issues specific to the DGPP should be considered alongside wider consideration of the role secondary networks will play into the future.
Q13. Do you agree with the proposed commencement provisions above? Why?	The ENA strongly disagrees with the commencement provisions because the implementation timeline is not achievable. In determining an achievable timeline, the Authority should provide sufficient time for the industry to develop guidance, establish or refine and implement methodologies and pricing schemes plus notify customers.
Q14. Do you have any suggestions for how we can most effectively support successful implementation?	ENA and IEGA jointly recommend industry develop guidance to support the implementation of the regulation. The Authority should allow sufficient time in the implementation process for this collaboration.
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	The timing to implement connection charge reconciliation needs to be considered alongside the development of posted network charges for distributed generation across different network tiers. The reconciliation workbook and associated reporting requirements have only recently been applied to load connections and the workability is still to be confirmed over the coming months – these issues and the processes for submissions and reporting need to be resolved before its application is extended to DGPP. We remind the Authority that the timelines for recent connection pricing reforms were insufficient for its own processes, let alone the EDBs. Reporting requirements were only finalised by the Authority one month prior to implementation, allowing insufficient time for EDBs to develop and update systems in a timely and efficient manner. We would like to see lessons learned from the connection pricing debacle and a more reasoned and thought through project management plan being applied to the DG changes. ENA are very happy to work with the Authority to create a realistic workback plan, with clear milestones for all affected parties.

Questions	Comments
Q16. Do you agree it is appropriate to give distributors relatively wide discretion as to how they implement capacity charges for injection connections? Why?	ENA supports a non-prescriptive, enabling approach to capacity pricing. Distribution networks, and the distributed generation connected to them, are complex and evolving. The appropriate pricing approach depends on a range of factors that vary by location and project (eg, existing hosting capacity, forecast demand and generation, operational constraints, and planned reinforcement). A non-prescriptive, enabling approach allows EDBs to manage this complexity and apply capacity charges where they are efficient and proportionate.
Q17. Do you agree that for larger connections a more bespoke approach that accounts for dependability and mitigates risks such as over-injection or inefficient payments is more appropriate than the prescriptive broad-based approach used for residential and small business consumers? What do you consider such an approach should look like?	ENA supports a non-prescriptive, enabling approach to pricing. Distribution networks, and the distributed generation connected to them, are complex and evolving. The appropriate pricing approach depends on a range of factors that vary by location and project (eg, existing hosting capacity, forecast demand and generation, operational constraints, and planned reinforcement). A non-prescriptive, enabling approach allows EDBs to manage this complexity and apply capacity charges where they are efficient and proportionate. ENA welcomes ongoing dialogue with industry participants and the Authority as pricing methodologies continue to evolve in response to increasing network complexity and connecting parties' needs and offerings.
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	ENA supports the application of industry-developed guidance to inform the design and implementation of capacity charges for injection. Industry-led guidance can draw on practical experience and can continue to evolve as network complexity increases and as connecting parties' needs and offerings change.
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	Generators may currently be incentivised to connect via a distribution network rather than directly to the transmission network, because distribution injection pricing is constrained to incremental cost while transmission pricing is not.
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	Paragraphs 5.6-5.10 of the consultation paper correctly identifies the issue. This is a clear example of how evolution of associated regulation will require the Authority to continue to monitor the effectiveness of the DGPPs regulation as adjustments are made to associated regulations.

Questions	Comments
Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	No, the justification for removing consideration of transmission benefits was considered with the changes to transmission pricing from April 2023. It is not helpful to reconsider this issue now.
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	The ENA identifies in section 5.1 potential unintended consequences the Authority should consider in the reform of DGPPs.
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	ENA believes identified and unidentified shortcomings in the analysis make it misleading. We discuss this further in section 4.2.
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	ENA supports the objectives specified in the consultation paper.
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	ENA supports the proposed amendment to the distribution pricing principles and agrees that benefits will be realised. However, this is not a one-size-fits-all situation: networks are evolving, and that evolution will not occur evenly across all networks. Accordingly, flexibility in implementation is important so costs are not incurred unnecessarily or inefficiently.
Q26. 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 objective in section 15 of the Electricity Industry Act 2010.	ENA supports the proposed amendment, with the proposed refinements set out in this submission, as preferable to the other options set out in Appendix B. It is noted, however, that it is not clear that the incremental cost pricing principle is the appropriate long-term solution for pricing distributed generation and that the Authority should continue to monitor the regime as the industry transitions.
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	Yes.
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	They are not inconsistent but there are areas where consistency could be improved. The application of incremental cost could favour certain technologies, which may have unintended implications for future investment.

Questions	Comments
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	We agree that it is helpful to have mandatory distribution pricing requirements in a single part of the Code, especially when they are relevant to all connections. However, it remains the case that a distributor's dealings with traders under Part 12 are distinct to their dealings with connection applicants, and we have suggested, in appendix D, one amendment (for the avoidance of doubt) to ensure that this distinction between pricing arrangements is clear.
Q30. Do you have any comments on the drafting of the proposed amendment?	Refer Appendix D.

Appendix D: Proposed Code Amendment Drafting

Appendix I Proposed Code amendment

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~~Green strikethrough~~ shows text removed from relocated clauses
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Electricity Industry Participation Code 2010

Part 1
Preliminary provisions

1.1 Interpretation

(1) In this Code, unless the context otherwise requires, —

acquired pioneer scheme means a **pioneer scheme** established by a **distributor** (the **selling distributor**) in accordance with clause 6B.7, where ownership of the whole or part of the **distribution network** to which the **pioneer scheme** relates is transferred to another **distributor** (the **buying distributor**)

buying distributor is defined as set out in the definition of **acquired pioneer scheme**

offtake capacity costing requirements means the **mandatory connection pricing methodology** relating to offtake capacity costs, the requirements for which are set out in clause 6B.5

offtake capacity demand assumption means the design offtake capacity applicable to a given **connection application** and **network tier** as determined by a **distributor** under clause 6B.5(1)(c)

connection, for the purposes of Part 6B, means the physical link between plant or a secondary network ~~between a **consumer installation**~~ and a **distribution network** at a **point of connection** to enable **electrical connection** ~~between the **consumer installation** (or **generating station**) and the **distribution network**~~, and **connect** has a corresponding meaning

connection administration fee means an amount paid by a **connection applicant** to a **distributor** for the administrative aspects relating to **connection** or increasing the security or capacity at a new **point of connection**, including assessing and processing **connection applications** and completing **connection** inspections

connection applicant for the purposes of Part 6B means a person who—

Commented [A1]: Query whether using "offtake' as a concept in Part 6 and 6B risks causing confusion given there is a separate definition of "offtake" that is only relevant to grid exit points. It is not clear to us that "load" cannot be retained as a concept as per previous amendment rounds. The rationale provided in the paper is not convincing - there should be no problem with "load" covering both the type of connection for process purposes and the use for pricing purposes.

If the concept of offtake is retained for Part 6, we suggest amending the definition of "offtake" in Part 1 to make clear that it does not apply to this Part

Eg: **offtake,** except for the purposes of Part 6 and Part 6B, means the flow of **electricity** from the **grid** at a **grid exit point**

(a) applies to a **distributor** to **connect** ~~any **load** owned or operated, or to be owned or operated, by the person~~ to the **distributor's distribution network**, ~~or to a **consumer installation** that is connected to the **distribution network**, including by an **extension**~~; or

(b) ~~is a **consumer**, and~~ applies to a **distributor**—

(i) to increase the security, or change the capacity of, ~~the **load**~~ a **connection** ~~provided to the **consumer** at the **connection** between the **consumer installation** owned or operated by the **consumer** and the **distributor's distribution network**~~; or

(ii) to change to or from a **flexible connection**; and

(iii) includes where any of the **connection applications** in subparagraphs

(i) and (ii) involves allocating additional **network** security or capacity, with or without associated physical works

connection application means an application of the kind described in the definition of **connection applicant**, made in accordance with a **distributor's connection process**

connection charge means—

(a) any price, fee, tariff, charge or other similar monetary impost or cost, or any part of any price, fee, tariff, charge, or other similar monetary impost or cost and that is, either directly or indirectly, imposed, or required, or agreed by a **distributor** in relation to **connection works** for a **connection applicant** or is otherwise applied for the purposes of, or has the effect of, recovering **connection works costs** directly or indirectly from a **connection applicant**; and

(b) excludes any **connection administration fees** or **pioneer scheme contributions**

connection charge reconciliation means a standardised breakdown of **connection charge** components in accordance with clause 6B.11

connection charge reconciliation methodology requirements means the requirements set out in clauses 6B.10 and 6B.11

connection enhancement means a **customer-selected enhancement** or a **distributor-selected enhancement**

connection enhancement cost allocation requirements means the **mandatory connection pricing methodology** set out in clause 6B.4

connection pricing methodologies means the pricing methodologies that each **distributor publishes** setting out how it determines **connection charges** and **connection pricing methodology** has a corresponding meaning

connection process means the process a **distributor** requires a **connection applicant** to follow to establish or improve a **connection**, and may include requirements relating to information, timeframes, **connection charges** and **connection works**

connection revenue life means 30 years for a residential **connection** and 15 years for a non-residential **connection**, unless the **distributor** reasonably believes the **connection** will have a shorter revenue-generating life

connection works means an **extension** or a **network capacity upgrade**

connection works cost means the cost of **connection works**

Consumers Price Index means the Consumers Price Index (all groups) published by Statistics New Zealand or, if that index ceases to be **published**, any measure certified by the Government Statistician as being equivalent to that index

CPI movement means, for the purposes of Part 6B, the percentage movement in the **Consumers Price Index** for the 12-month period ending on 31 March in the previous calendar year

customer-owned assets means ~~any **assets** whose ownership does not transfer to a **distributor**, such that a **consumer** will retain responsibility for its operation, maintenance and renewal, or disposal~~, for the purposes of Part 6B, any **assets** forming part of a **connection** which are not owned by a **distributor** and for which the **distributor** is not responsible for their operation, maintenance and renewal, or disposal

customer-selected enhancement means any enhancement to the **relevant minimum scheme** requested, and agreed to in writing, by a **connection applicant**

dedicated assets means any **assets** owned or operated by a **distributor** that were built for one or more **connections** for the same person (for example, where two **connections** are provided under a single **connection application**) and are not subsequently used to support another person's **connection**

disclosure year, for the purposes of Part 6B, means the 12-month period in which information disclosures are required of a **distributor** under section 53C of the Commerce Act 1986 and, if no such year is specified or if more than one 12-month period applies to the **distributor** under those information disclosure requirements, means the 12-month period ending on 31 March of the year a disclosure relates to

distribution network capacity means the capacity of a **distribution network** to convey **electricity** under a range of load and **generation** conditions in accordance with **reasonable and prudent operating practice**

distributor-selected enhancement means any enhancement to the **relevant minimum scheme** chosen by a **distributor**

EDB ID determination means the *Electricity Distribution Information Disclosure Determination 2012* [2012] NZCC 22, and any amendment of this determination

EDB IMs means the *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26, and any amendment of this determination

electricity lines services has the meaning given in section 54C of the Commerce Act 1986

extension means—

(a) works or operating arrangements to:

(i) provide a **connection**; or

(ii) increase the security or capacity of:

(A) a **connection**; or

(B) any **assets** owned or operated by a **distributor**

that do not increase the capacity of the **shared network**; or

(b) an **extension-like upgrade**; or

(c) **incremental transmission works**; but

(d) does not include works or operating arrangements associated with **customer-owned assets** or work covered by a **connection administration fee**

extension cost means the cost of an **extension**

extension-like upgrade means works or operating arrangements that increase the capacity of the **shared network** that—

(a) substantially benefit only the **connection applicant** and the **distributor** reasonably considers this is likely to remain the case; and

(b) do not meet the threshold to use an estimate in clause 6B.5(2)

first pioneer is defined as set out in the definition of **pioneer**

flexible connection means an arrangement whereby a **connection applicant's** export or import of **electricity** through the **connection** is managed (often through real-time control) based upon principles of available security or capacity agreed to in writing with the **distributor**

incremental injection costs, for the purpose of Part 6B, means:

(a) the ~~reasonable additional~~ reasonably identifiable **distribution** costs **(which** may include ~~any reasonable additional~~ transmission costs but excludes any **connection administration fee**) ~~that an efficient **distributor** would incur~~ incurred by a **distributor** in providing **electricity distribution** services to ~~**distributed generation**~~ an **injection connection**, including (but not limited to):

(i) costs attributable to the specific **injection connection**; and

(ii) cumulative costs, being a share of costs attributable to **injection connections** generally (for example, system operations and network support opex or transmission costs); and

(iii) programmatic costs, being a share of costs that are difficult to attribute to a

Commented [A2]: As for offtake pricing, it should be clear that administration costs are excluded from connection pricing calculations (and can be charged separately as per comments below).

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specific **injection connection** due to being part of a wider programme of work but are attributable to a group of **connections** (for example, vegetation management or other network opex); and

(iv) **network injection capacity costs** reasonably attributable to the injection connection; minus

(b) the reasonably identifiable **distribution** costs (which do not include any transmission costs) that ~~an efficient~~ a **distributor** ~~would be able to avoid~~ avoids as a result of ~~the **electrical connection** of the **distributed generation**~~ providing **electricity distribution** services to the **injection connection**, including (but not limited to):

(i) benefits attributable to a specific **injection connection**; and

(ii) cumulative benefits, being a share of benefits attributable to **injection connections** generally; and

(iii) capacity benefits, being an estimate of the benefit of freeing up **network offtake capacity**

incremental cost estimate means an estimate of the incremental cost of a **connection** calculated in accordance with clause 6B.11(2)

incremental distribution revenue estimate means the portion of an **incremental revenue estimate** relating to distribution line charge revenue

incremental opex scaling factor means the scaling factor calculated in accordance with clause 6B.11(5)

incremental revenue estimate means an estimate of the incremental revenue from a

connection calculated in accordance with clause 6B.11(3)

incremental transmission cost means an estimate of the cost of **incremental transmission works** including—

(a) a change in transmission charges due to a benefit-based charge adjustment event under paragraph 81(1)(e), (g), (h), (i) or (l) of the **transmission pricing methodology**; or

(b) new transmission charges relating to a high-value post-2019 BBI (as those terms are defined in the **transmission pricing methodology**)

incremental transmission revenue estimate means the portion of an **incremental revenue estimate** relating to pass-through of transmission charges

incremental transmission works means, in relation to a **connection**, **works** to establish a new **grid** connection, increase security or capacity of **grid connection assets** or otherwise alter **grid connection assets** to accommodate the new or altered **connection**

Commented [A3]: This should be limited to network injection capacity costs attributable to the application - proposed drafting inserted.

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injecting party means, for the purposes of Part 6B, a party who injects, or proposes to inject, **electricity** into a **distribution network** at an **injection connection**

injection connection means a **connection** at which **electricity** is injected into a distribution network

injection pricing principles means the requirements that must be applied by **distributors** and **injecting parties** that are **participants** in subpart 3 of Part 6B

~~**load**~~**offtake connection** means, for the purposes of Part 6B, any **connection** to a **distribution network** ~~or to a **consumer installation**~~ that consumes **electricity**

localised historical cost recovery means an allocation of historical **distributor-selected enhancement** costs or historical network development costs to subsequent **connections** that benefit from the works to which those costs relate

mandatory connection pricing methodologies means the pricing methodologies set out in subpart 2 of Part 6B that each **distributor** must use for determining **connection charges** and **pioneer scheme contributions** and **mandatory connection pricing methodology** have corresponding meanings

minimum flexi scheme means **connection works** that deliver a **flexible connection** at lesser cost than the **minimum scheme**

minimum scheme means the least-cost solution for any **connection works** provided by a **distributor**, including for security and firmness of capacity, in accordance with the

distributor's connection and operation standards and network connection standards as defined in the **distributor's distributor agreement** or a different standard if agreed to in writing between the **connection applicant** and the **distributor**

net incremental cost means **incremental cost estimate** less the **incremental revenue estimate** for a **connection**

network injection capacity cost means the cost of consuming or adding ~~injection~~**injection** capacity in the **shared network** (other than **extension-like upgrade** costs)

network offtake capacity means the capacity for **electricity** to flow from a **shared network** to meet offtake demand from **connections**

network offtake capacity cost means the cost of consuming or adding **network offtake capacity** ~~capacity in the shared network~~ (other than **extension-like upgrade** costs)

network capacity upgrade means—

(a) works or operating arrangements to—

(i) provide a **connection**; or

(ii) increase the security or capacity of—

Commented [A4]: As per comments above, consider whether load (or something else) might be a better concept than offtake. From a strict legal perspective, the offtake terminology is workable, but may cause confusion given the specific use of offtake in the transmission setting. We understand that the EA is wishing to convey that a connection can be priced for both offtake and injection, but it seems to us that retaining load as the concept will not undermine that objective.

Commented [A5]: We have red underlined the highlighted drafting in these definitions to make clear which drafting is new rather than amended.

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(A) a **connection**; or

(B) any **assets** owned or operated by a **distributor**; that increase the capacity of the **shared network**; and

(b) for the avoidance of doubt, includes—

(i) operational changes made by the **distributor** that are required to provide the **connection** or to increase security or capacity; and

(ii) allocation of additional network security or capacity to the **connection**, even where this does not involve physical works or a change to a person's right to capacity on a **distributor's distribution network**; but

(c) does not include—

(i) **extension-like upgrades**; or

(ii) works or operating arrangements associated with **customer-owned assets** or work covered by a **connection administration fee**

network cost contribution means the difference between the **connection charge** for a **connection** and the **net incremental cost** of that **connection**

network costing zone means the part of a **distribution network** to which a common **posted capacity rate** applies

network tier means any one of the following components of a **distribution network**:

(a) sub-transmission line:

(b) zone substation:

(c) high voltage feeder:

(d) distribution substation:

(e) low voltage mains

nominal capacity increment means an amount of added capacity corresponding to the assumptions used to derive a **posted capacity rate**

operating cost loading means estimated incremental operating costs associated with a

connection, where the estimate is either—

(a) zero if the **consumer** or **consumers** at the **connection** will pay **posted tariffs**; or

(b) if the **consumer** or **consumers** at the **connection** will not pay **posted tariffs**, a reasonable assessment of incremental operating costs associated with the **connection**—

(i) including costs associated with operating and maintaining new **assets**; and

(ii) excluding **transmission** charges; and

(iii) expressed as the present value of future costs

pioneer means—

(a) the **connection applicant** referred to in paragraph (a) of the definition of **pioneering connection works** (the **first pioneer**); and

(b) any **connection applicant** who subsequently **connects** to the **pioneering connection works** or **vested pioneering works** (a **subsequent pioneer**) and—

(i) who makes a **pioneer scheme contribution** of more than the amount of $25,000 in December 2025 dollar terms, adjusted each year by the **CPI movement**, or a lesser amount specified by the **distributor**; and

(ii) is determined by the relevant **distributor** to be a **subsequent pioneer** under clause 6B.7(1)(b); and

(c) any other person to whom the status of **first pioneer** or **subsequent pioneer** has transferred in accordance with clause 6B.8(6)

pioneering connection works means **connection works** ~~**an extension**~~ where—

(a) the portion of the cost of the **connection works** ~~**extension cost**~~ initially met by a **connection applicant** is more than the amount of $50,000 in December 2025 dollar terms, adjusted each year by the **CPI movement**, or a lesser amount specified by the **distributor**; and

(b) the **connection applicant** has not opted out of applying a **pioneer scheme** to the **connection works** ~~**extension**~~ by agreeing in writing with the relevant **distributor** that the **connection works** ~~**extension**~~ should not form part of a **pioneer scheme**; and

(c) for an **extension**—

(i) it is feasible that other parties may seek to **connect** to all or part of, or make use of, the **extension** at a later date; but

~~(d)~~(ii) excludes an **extension** where the **extension costs** are established using posted connection charges; and

~~(e)~~(iii) excludes any portion of **extension cost** relating to a benefit-based charge adjustment event as defined in the **transmission pricing methodology**; and

(d) excludes a **network capacity upgrade** where **network offtake capacity costs** are established under clause 6B.5 or any similar approach applied by a **distributor** in respect of **network injection capacity costs**

pioneer scheme means—

(a) an arrangement that covers any part of a **distributor's network** or the

distributor's grid connections that comprises **pioneering connection works**, and includes an **acquired pioneer scheme**; and

(b) a **vested pioneer scheme**

pioneer scheme contribution means a payment to be made by a **connection applicant** to a **distributor**—

(a) determined in accordance with clause 6B.8; and

(b) any similar legally binding obligation put in place for any **connection works** built or established for a single **consumer** prior to 1 April 2026

pioneer scheme policy means a policy **published** in accordance with clause 6B.9

pioneer scheme pricing methodology requirements means the **mandatory connection pricing methodologies** set out in clauses 6B.6 to 6B.9

posted offtake capacity rate means the estimated average cost per capacity unit that is **published** by a **distributor** for a **network capacity upgrade** in respect of offtake capacity for a given **network tier** and **network costing zone**, where the rate may be set to zero if the **distributor** reasonably considers there is no foreseeable need within the **distributor's** applicable **network** planning horizon for such a **network capacity upgrade**

posted connection charge means a **connection charge** that is **published** by a **distributor** that applies to any **connection** of a type that meets requirements specified by the **distributor**

posted extension rate means a unit rate that has been **published** by a **distributor** for use in building up **extension cost** estimates for **connections** that meet requirements specified by the **distributor**

posted tariff means a price or rate schedule **published** by a **distributor** that sets out standard charges for use of a **distribution network**

real estate development means the development of land for the purpose of on-selling including its development in one or more of the following ways:

(a) subdivision:

(b) the construction of commercial or industrial premises (or both):

(c) the construction of multiple new residential premises

rebate means any disbursement, credit or deduction made to a **pioneer** by a **distributor** in accordance with clause 6B.8(5)

relevant minimum scheme means a **minimum scheme** or, if a **connection applicant** requests it and the **distributor** can reasonably supply it, a **minimum flexi scheme**

selling distributor is defined as set out in the definition of **acquired pioneer scheme**

shared network means any part of a **distribution network** that is not **customer-owned assets** or **dedicated assets**

start date, for a **pioneer scheme**, means the date the first **pioneer** for the **pioneer scheme** made its first **connection charge** payment in relation to the **pioneering connection works** or the **vested pioneering works** subject to the **pioneer scheme**

subsequent pioneer is defined as set out in the definition of **pioneer**

vested pioneer scheme means an arrangement that covers any part of a **distributor's network** where a ~~**consumer**~~ **connection applicant** carried out or funded works that were initially owned by ~~**the consumer**~~ the applicant and the **distributor** to whose **network** the works were **connected** agreed to take ownership of the works and that those works should form a **pioneer scheme**

vested pioneering works means the works carried out or funded by ~~**a consumer**~~ a **connection applicant** as referred to in the definition of **vested pioneer scheme**.

Part 6

Distributor agreements, arrangements, and other provisions

Commented [A6]: This appears to be an incorrect heading. Should it be "Connection to Distribution Networks"?

6.1 Contents of this Part

This Part specifies—

(a) a framework to enable the connection and continued connection of **distributed generation** to a **distribution network** if consistent with a **distributor's connection and operation standards** required under clause 6.2C; and

(b) in Schedule 6.1, processes (including time frames) under which **applicants** may—

(i) connect **distributed generation** to a **distribution network**; or

(ii) continue an existing connection of **distributed generation** to a **distribution network** if the connection contract for the connection—

(A) is in force and the **applicant** wishes to extend the term of the connection contract; or

(B) has expired; or

(iii) continue an existing connection of **distributed generation** to a **distribution network** that is connected without a connection contract if the **regulated terms** do not apply; or

(iv) change the **maximum export power**, **nameplate capacity**, inverter model, **electricity** producing components within the connected **distributed generation**, or fuel type of connected **distributed generation**; and

(c) in Schedule 6.2, the **regulated terms** that apply to **distributed generation** in the absence of a connection contract; and

(d) in Schedule 6.3, a default dispute resolution process for disputes related to this Part and subparts 2 and 3 of Part 6B; and

(e) ~~in Schedule 6.4, the **distributed generation** pricing principles to be applied for the purposes of this Part; and~~

(f) in Schedule 6.5, prescribed maximum fees.

6.3 **Distributors must make information publicly available**

- (1) The purpose of this clause is to require each **distributor** to make certain information publicly available to enable the approval of **distributed generation** under Schedule 6.1.
- (2) Each **distributor** must make publicly available, free of charge, from its office and Internet site,—
  - (a) forms for applications under Schedule 6.1; and
  - (b) the **distributor's connection and operation standards**; and
  - (c) a copy of the **regulated terms**, together with an explanation of how the **regulated terms** will apply if—
    - (i) approval is granted under Schedule 6.1; and
    - (ii) the **distributor** and the **distributed generator** do not enter into a connection contract; and
  - (d) a statement of the circumstances in which **distributed generation** will be, or may be, curtailed or interrupted from time to time in order to ensure that the **distributor's** other **connection and operation standards** are met; and
  - (da) a list of all locations on its **distribution network** that the **distributor** knows to be subject to **export congestion**; and
  - (db) *[Revoked]*
  - (dc) the **maximum export power** threshold and the **export limits assessment methodology for distributors** and the **bespoke export limits assessment**

Commented [A7]: We have proposed edits to make it clear that administration fees can be recovered consistently for both types of connection. Specificaly, we propose drafting to make clear that Schedule 6.5 does not apply to or limit other **connection administration fees**. Such fees are excluded from **connection charges** (and therefore pricing calculations) and distributors seek further clarity that they are entitled to recover administration fees for both injection and offtake connections. Drafting amendments have therefore been proposed at clauses 6.3 and 6B.2.

methodology for distributors used to determine that threshold, for locations at which the **distributor** has set a **maximum export power threshold**; and

- (e) a list of any fees that the **distributor** charges under Schedule 6.1, which must not exceed the relevant maximum fees prescribed in Schedule 6.5. For the avoidance of doubt, nothing in Schedule 6.5 limits any other **connection administration fee** which the **distributor** may require from a **connection applicant**; and
- (f) a list of the makes and models of inverters that the **distributor** has approved for connection to its **distribution network**; and
- (g) the **distributor's** contact information for any enquiries relating to the connection of **distributed generation** to its **distribution network**.

- (3) The application forms referred to in subclause (2)(a) must specify the information, including any supporting documents, that must be provided with an application under Schedule 6.1.

~~(f)~~

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Commented [A8]: The scheme of Part 6 and 6B is to exclude connection administration fees from the calculation of charges (ie it is excluded from the definition of connection charges), which we agree with. The proposed edits are to make it clear that administration fees can be recovered consistently for both types of connection.

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~~**6.9 Distributed generation pricing principles**~~

~~Schedule 6.4 applies in accordance with~~

~~(a) clause 19 of Schedule 6.2; and~~

~~(b) clause 4 of Schedule 6.3.~~

Schedule 6.2 cl 6.6

Regulated terms for distributed generation

~~*Pricing*~~

~~**19 Pricing principles**~~

~~Charges that are payable by the **distributed generator** or the **distributor** must be determined in accordance with the pricing principles set out in Schedule 6.4.~~

Schedule 6.3 cl 6.8

Default dispute resolution process

1 Application of this Schedule

This Schedule applies in accordance with clauses 6.8 and 6B.~~12~~27 of this Code.

4 Application of ~~distributed generation~~ injection pricing principles and mandatory connection pricing methodologies to disputes

(1) In determining a dispute under clause 6.8 or clause 6B.27, the **Authority** and the **Rulings Panel** must:

(a) apply the **injection pricing principles** or the **mandatory connection pricing methodologies**, whichever is applicable;

(b) if the **Authority** or the **Rulings Panel** considers that relevant charges have been calculated in a manner which is not consistent with either the **injection pricing principles** or the **mandatory connection pricing methodologies**, whichever is applicable, make such directions as the **Authority** or the **Rulings Panel** thinks fit to ensure that the **distributor** recalculates the charges so that they are so consistent.

~~(1) The **Authority** and the **Rulings Panel** must~~

~~(a) in relation to a dispute under clause 6.8, apply the **distributed generation** pricing principles set out in Schedule 6.4 to determine any **connection charges** payable in respect connections of **distributed generation**; and~~

~~(b) in relation to a dispute under clause 6B.12 , require a **distributor** to determine any **connection charges** payable in respect of **connections** of **load** in a manner specified by the **Authority** or the **Rulings Panel** that is consistent with the **mandatory connection pricing methodologies**.~~

(2) Subclause (1) applies if—

(a) there is a dispute under Part 6 or Part 6B of this Code; and

(b) in the opinion of the **Authority** or the **Rulings Panel** it is necessary or desirable to apply subclause (1) in order to resolve the dispute.

Commented [A9]: Given clauses 1 and 4(1) refer to disputes under clause 6.8, the reference to Part 6 should be retained here. The alternative is to delete clause 4(2)(a).

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~~Schedule 6.4 cl 6.9~~

~~Distributed generation pricing principles~~

1 This Schedule sets out the pricing principles to be applied for the purposes of Part 6 of this Code in accordance with clause 6.9 (which relates to clause 19 of Schedule 6.2 and clause 4 of Schedule 6.3).

Compare: SR 2007/219 clause 1 Schedule 4

Clause 1: amended, on 23 February 2015, by clause 69 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

2 The pricing principles are as follows:

Charges to be based on recovery of reasonable costs incurred by distributor as a result of connecting the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs

(a) subject to paragraph (i), connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the distributed generation:

(b) when calculating **incremental costs**, any costs that cannot be calculated must be estimated with reference to reasonable estimates of how the **distributor's** capital investment decisions and operating costs would differ, in the future, with and without the generation:

(c) estimated costs may be adjusted ex post. Ex post adjustment involves calculating, at the end of a period, what the actual costs incurred by the **distributor** as a result of the **distributed generation** being **electrically connected** to the **distribution network** were and deducting the costs that would have been incurred had the generation not been **electrically connected**. In this case, if the costs differ from the costs charged to the **distributed generator**, the **distributor** must advise the **distributed generator** and recover or refund those costs after they are incurred (unless the **distributor** and the **distributed generator** agree otherwise):

Capital and operating expenses

(d) if costs include distinct capital expenditure, such as costs for a significant **asset** replacement or upgrade, the connection charge attributable to the **distributed generator's** actions or proposals is payable by the **distributed generator** before the **distributor** has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the **distributor** is not obliged to incur those costs until that payment has been received:

(e) if **incremental costs** are negative, the **distributed generator** is deemed to be providing network support services to the **distributor**, and may invoice the **distributor** for this service and, in that case, the **distributed generator** must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):

(f) if costs relate to ongoing or periodic operating expenses, such as costs for routine **maintenance**, the connection charge attributable to the **distributed generator's** actions or proposals may take the form of a periodic charge:

(g) *[Revoked]*

(h) after the connection of the **distributed generation**, the **distributor** may review the connection charges payable by a **distributed generator** not more than once in any 12-month period. Following a review, the **distributor** must advise the **distributed generator** in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

(i) if multiple **distributed generators** are sharing an investment, the portion of costs payable by any one **distributed generator**—

(i) must be calculated so that the charges paid or payable by each **distributed generator** take into account the relative expected peak of each **distributed generator's** injected generation; and

(ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the **distributor** must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating **distributed generation**, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

(k) if a **distributed generator** has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other **distributed generators**, the **distributor** must refund to the **distributed generator** all connection charges paid to the **distributor** under paragraph (i) by other **distributed generators** in respect of that investment:

(l) if there are multiple prior **distributed generators**, a refund to each **distributed generator** referred to in paragraph (k) must be provided in accordance with the expected peak of that **distributed generator's** injected generation over a period of time agreed between the **distributed generator** and the **distributor**. The refund—

(i) must take into account the relative expected peak of each **distributed generator's** injected generation; and

~~(ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:~~

~~(m) no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 36 months from the initial connection of that **distributed generator**:~~

~~*Non-firm connection service*~~

~~(n) to avoid doubt, nothing in Part 6 of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for. **Distributors** must **maintain** connection and **lines** services to **distributed generators** in accordance with their **connection and operation standards**.~~

Part 6B

Distributor pricing methodologies, information requirements and other requirements

Subpart 1—General

6B.1 Contents of this Part

This Part specifies—

(a) **mandatory connection pricing methodologies** which are the pricing methodologies that must be applied by **distributors** in relation to ~~**consumers'** **connection charges**~~ and **pioneer scheme contributions** in respect of **offtake connections**; and

(b) information requirements for **distributors** in relation to access to **distribution networks**; and

(ba) **injection pricing principles** which are requirements that must be applied by **distributors** and **injecting parties** that are **participants** in respect of **injection connections**; and

(c) application of the dispute resolution process in Schedule 6.3 to the requirements under subpart 2 and 3 of this Part where **connection applicants** or **injecting parties** are **participants** and enhancement of the processes available to non-participants; and

Commented [A10]: Given the amendments to broaden the relevant connection definitions, it should be made clear that this applies to offtake connections - ie it is the companion to new (ba) - proposed drafting inserted.

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(d) other requirements related to **distribution network** pricing.

Subpart 2—Mandatory connection pricing methodologies

6B.2 Application of this ~~Part~~subpart

(1) This ~~Part~~subpart does not apply to—

(a) any **connection application** received by a **distributor** prior to 1 April 2026; or

(b) a **distributor** in respect of the **distributor's** ownership or operation of a secondary network; or

(c) existing **connections**~~**load connected**~~, or a **connection applicant** seeking to **connect** load, to a secondary network.

(2) For the avoidance of doubt—

(a) this ~~Part~~subpart applies in addition to ~~Part 6~~ subpart 3 ~~and applies to all **connection applications** for **load**~~ and, if there is any inconsistency between this ~~Part~~subpart and ~~Part 6~~subpart 3, this ~~Part~~subpart prevails;

(b) a **connection applicant** who is not a **participant** is not required to comply with this Part and cannot be subject to the enforcement measures set out in the **Act** or the Electricity Industry (Enforcement) Regulations 2010 for failing to comply with this ~~Part~~subpart;

~~(b)~~(c) this subpart does not limit any **connection administration fee** which a **distributor** may require from a **connection applicant**.~~.~~

(3) If ~~an application under Part 6~~ a **connection** application is for ~~includes~~ both offtake ~~**load**~~ and ~~**distributed generation**~~**injection**—

(a) both the **connection enhancement cost allocation requirements** and the **capacity costing requirements** must be applied to the offtake ~~**load**~~ component of the application before ~~Part 6~~subpart 3 is applied to the ~~**distributed generation**~~**injection** component of the application; and

(b) the **pioneer scheme pricing methodology requirements** and **connection charge reconciliation methodology requirements** must be applied to the **connection** as a whole.

Connection pricing methodologies

6B.3 Distributors must comply with mandatory connection pricing methodologies

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(1) Each **distributor** must apply the **mandatory connection pricing methodologies** in subclause (2) in setting **connection charges**, including in the calculation of quoted charges and application of such charges, the allocation of costs to persons, and in otherwise recovering or allocating **connection works costs**.

(2) The **mandatory connection pricing methodologies** are:

(a) the **connection enhancement cost allocation requirements** in clause 6B.4:

(b) the **offtake capacity costing requirements** in clause 6B.5:

(c) the **pioneer scheme pricing methodology requirements** in clauses 6B.6 to 6B.9:

(d) the **connection charge reconciliation methodology requirements** in clauses 6B.10 and 6B.11.

(3) Despite subclause (1), a **distributor** is—

(a) not required to apply the **pioneer scheme pricing methodology requirements** in respect of **real estate developments**; and

(b) in respect of any **connection** covered by a large connection contract as defined in the **EDB IMs,** required to apply the **connection charge reconciliation methodology requirements** only.

(4) A **distributor** must not refuse to **connect** a person to the **distributor's distribution network** for the purpose of avoiding compliance with the **mandatory connection pricing methodologies**.

Connection enhancement cost allocation requirements

6B.4 Connection enhancement cost allocation requirements

(1) Subject to subclauses (2) to (4), each **distributor** in determining the **connection charges** that it requires a **connection applicant** to pay for or in respect of an **offtake connection** or any increase in offtake security or **capacity** at a **point of connection** or for an **asset—**

(a) must determine those **connection charges** on the basis of the **relevant minimum scheme**, unless the **connection applicant** agrees in writing to modifications to the **relevant minimum scheme**; and

(b) if modifications are made to the **relevant minimum scheme**, must allocate only the **customer-selected enhancement** costs to the **connection applicant**, in addition to the costs of the **relevant minimum scheme**; and

(c) must not allocate any **distributor-selected enhancement** costs to the **connection applicant**.

(2) If a **connection applicant** and **distributor** agree in writing that the **distributor** does not need to determine the cost of the **relevant minimum scheme**, the **distributor** does not need to determine charges in accordance with subclause (1).

(3) If a **connection applicant** and **distributor** agree in writing to an alternative allocation of **connection enhancement** costs than set out in subclause (1), the **distributor** does not need to determine charges in accordance with subclause (1).

(4) If a **distributor publishes posted connection charges**, it may use those charges to determine the charges under subclause (1), instead of applying subclauses (1)(a) to (1)(b), where the **connection** is of the type and meets the requirements specified by the **distributor** for the **posted connection charge**.

(5) If a **distributor publishes posted extension rates**, it must use those rates to determine the costs under a **relevant minimum scheme** or for any **customer-selected enhancement** costs, where the **connection works** are of the type and meet the requirements specified by the **distributor** for the **posted extension rate**, unless otherwise agreed in writing with the **connection applicant**.

Offtake c~~C~~apacity costing requirements

6B.5 Offtake c~~C~~apacity costing requirements

(1) If a **distributor** intends to include or includes **network offtake capacity costs** (in whole or in part) in the charges payable by a **connection applicant** for or in respect of any **connection works**, it must—

(a) determine a **posted capacity rate** for each **network tier** and **network costing zone** in respect of which it charges for **network offtake capacity costs** for each current **disclosure year** and the following four **disclosure years** on an annual rolling basis; and

(b) not revise the **posted capacity rates** and **nominal capacity increments published** under paragraph (a) for the current **disclosure year** and the following **disclosure year** except to correct errors; and

(c) determine the **capacity demand assumption** for each **network tier** and **network costing zone** to which each **connection application** that it receives relates having reasonable regard to any relevant information provided by the **connection applicant**; and

(d) use the **posted capacity rate** and **capacity demand assumption** applicable to each **network tier** and **network costing zone** to which the **connection application** relates to calculate the **network offtake capacity costs**.

(2) If the **capacity demand assumption** determined by a **distributor** for a **network tier** (other than **distribution** substations and low voltage mains) is greater than 80% of the **nominal capacity increment** for that **network tier**, the **distributor** may use estimated capacity upgrade costs for that **network tier** instead of the **posted offtake capacity rate** in the calculation under subclause (1)(d).

(3) If the **distributor** determines that the estimated cost per unit to add offtake capacity at a **network tier** is more than 150% or less than 80% of the applicable **posted offtake capacity rate** for that **network tier** and **network costing zone**, the **distributor** may use the estimated rate instead of the **posted offtake capacity rate** in the calculation under subclause (1)(d).

(4) This clause does not apply to any **connection application** received by a **distributor** prior to 1 April 2027.

(5) Subclause (1)(b) does not apply with respect to **posted offtake capacity rates** and **nominal capacity increments** for the **disclosure year** ending 31 March 2028.

Pioneer scheme pricing methodology requirements

6B.6 Distributors must develop a pioneer scheme policy

(1) Each **distributor** must develop a **pioneer scheme policy** by 1 April 2026.

(2) The **pioneer scheme policy** must set out how the **distributor** will apply the requirements in clauses 6B.7 and 6B.8, including how it will—

(a) determine whether a **pioneer scheme** exists; and

(b) determine the matters in clause 6B.7(1)(b) and (3); and

(c) otherwise administer **pioneer schemes**.

6B.7 Requirements for a pioneer scheme

(1) For the purposes of clause 6B.6, this clause and clause 6B.8—

(a) a **pioneer scheme** continues from its **start date** until the expiry date set by the **distributor**, which must be not less than 7 years from the **start date**, unless each **pioneer** to the **pioneer scheme** and the **distributor** agree in writing that the scheme shall cease at an earlier date; and

(b) a **distributor** may determine which persons, other than the **first pioneer**, are **subsequent pioneers**.

(2) For the purposes of this clause and clause 6B.8, a **distributor** must—

(a) determine whether a **pioneer scheme** exists in accordance with this Part and its pioneer scheme policy; and

(b) record the location on its **network** that the **pioneer scheme** covers.

(3) Each **distributor** must determine for each **pioneer scheme** additional or more detailed pricing methodologies to those set out in clause 6B.8 specifying how it will, in a way that is consistent with clause 6B.8,—

(a) administer and collect **pioneer scheme contributions**; and

(b) determine and apply **rebates**; and

(c) determine which persons are eligible for **rebates**.

(4) A **distributor** must treat all **connection applicants** that **connect** to **pioneering connection works** or **vested pioneering works** as subject to the relevant **pioneer scheme**.

(5) If a **pioneer scheme** is an **acquired pioneer scheme**, the **purchasing distributor**—

(a) must not change any aspect of the matters determined for the **pioneer scheme** by the **selling distributor** or the **pioneer scheme policy** for that scheme set by the **selling distributor**, unless each **pioneer** to a **pioneer scheme** and the **distributor** agree in writing to a change; and

(b) **must** continue to administer, and comply with, those requirements and that **pioneer scheme policy** in complying with this clause and clauses 6B.8 and 6B.9.

6B.8 Determining connection charges, contributions and rebates for pioneer schemes

(1) From 1 April 2026, where there is a **pioneer scheme**, the **distributor** must, in determining **connection charges** and, where applicable, any other charges, for—

(a) the **first pioneer** to the scheme, comply with subclause (2); and

(b) for each **subsequent pioneer** to the scheme and each other **connection applicant** that **connects** to the **pioneering connection works** or **vested pioneering works** covered by the scheme, comply with subclause (3).

(2) The **distributor** must, in determining the **connection charges** and any other charges payable by the **first pioneer** to a **pioneer scheme—**

(a) from the time that any other **pioneer** or other **connection applicant connects** to the **pioneering connection works** or **vested pioneering works** covered by the scheme, apply a **rebate** determined in accordance with subclause (5); and

(b) otherwise comply with its **pioneer scheme policy** and the matters determined under clause 6B.7; and

(c) determine the costs of the **pioneering connection works** or **vested pioneering works** in accordance with subclause (4)(a).

(3) The **distributor** must, in determining the **connection charges** and any other charges payable by each **subsequent pioneer** or other **connection applicant** that **connects** to the **pioneering connection works** or **vested pioneering works** covered by a **pioneer scheme—**

(a) comply with the **pioneer scheme contribution** requirements set out in subclause (4); and

(b) in the case of a **subsequent pioneer**, from the time that any other **pioneer** or other **connection applicant connects** to the **pioneering connection works** or **vested pioneering works** covered by the scheme, apply a **rebate** determined in accordance with subclause (5); and

(c) otherwise comply with its **pioneer scheme policy** and the matters determined under clause 6B.7.

(4) The **pioneer scheme contribution** is to be determined as follows:

(a) in determining the costs of the **pioneering connection works** or **vested pioneering works**—

(i) the **distributor** must use the actual costs if these are known to the distributor;

(ii) if the actual costs are not known to the **distributor** (for example, if the **pioneering connection works** or **vested pioneering works** were constructed or contracted by a person other than the **distributor**), the **distributor** may use its estimated costs of the works;

(iii) if the **distributor** is using information provided by the **consumer** who constructed or paid for any **vested pioneering works**, the **distributor** must be reasonably satisfied that the information is accurate;

(iv) the **distributor** must exclude the costs of any **connection enhancement** or equivalent costs in respect of **vested pioneering works**;

(v) the **distributor** must include the costs incurred by a **pioneer** under any other **pioneer scheme** covering any part of the **distributor's network** that the **pioneering connection works** or **vested pioneering works** directly **connect** to:

(b) the **distributor** must apply straight-line depreciation to the costs of the **pioneering connection works** or the **vested pioneering works** that the **pioneer scheme** relates to determine the present-day value of those costs each time it calculates **pioneer scheme contributions**, using a depreciation period of 20 years:

(c) the **distributor** must take into account ~~distance (along an **extension**) and capacity~~, in respect of each **connection** ~~**consumer installation**~~ which a **pioneer** or **connection applicant** ~~that~~ **connects** to **pioneering connection works**:—

(i) where the **pioneering connection works** are an **extension**, the distance of the **connection** along, and its use (through **injection** or offtake) of the capacity of, that **extension**; and

(ii) where the **pioneering connection works** are a **network capacity upgrade**, the **connection's** use (through **injection** or offtake) of the capacity added by that **network capacity upgrade**; and

(d) **pioneer scheme contributions** must not be collected if the **pioneer scheme contribution** would be less than the amount of $1,000 in December 2025 terms adjusted each year by the **CPI movement** after deducting any fee to cover the reasonable costs of administering the scheme, or of a lesser amount specified by the **distributor**.

(5) The **rebate** due to a **pioneer** must be determined in a way that—

(a) shares any **pioneer scheme contribution** received by a **distributor** among all **pioneers** covered by the **pioneer scheme** proportionate to the extent to which each **pioneer** has met the costs of the **pioneering connection works** or the **vested pioneering works**; and

(b) shares any amount received by a **distributor** under clause 6B.5 that relates to a **network capacity upgrade** that was paid for by a **pioneer** or **pioneers**, among all **pioneers** covered by the **pioneer scheme** proportionate to the extent to which each **pioneer** has met the costs of the **network capacity upgrade**; and

(c) after deducting any fee to cover the reasonable costs of administering the scheme.

(5A) If a rebate is unable to be paid to a **pioneer** because the **pioneer** cannot be located after a reasonable attempt has been made by the **distributor** do so—

(a) the **distributor** must take reasonable steps to repay the corresponding amount of **pioneer scheme contributions** already collected to those that paid it, in proportion to their contribution; and

(b) the **distributor** may retain any amount that cannot be repaid in accordance with paragraph (a); and

(c) **pioneer scheme contributions** that would have been paid to the missing **pioneer** under the **pioneer scheme** must no longer be collected.

(6) A **distributor** must determine whether and in what circumstances the status of **first pioneer** or **subsequent pioneer** may transfer to a different person or persons (for example, where the status is to be apportioned between multiple people).

(7) This clause does not apply to a **pioneer scheme** entered into before 1 April 2026.

6B.9 Distributors must publish information on pioneer schemes

(1) Each **distributor** must—

(a) **publish** its **pioneer scheme policy**, which must include how it will;—

(i) determine **pioneer scheme contributions**; and

(ii) administer and collect **pioneer scheme contributions**; and

(iii) determine and apply **rebates**; and

(iv) determine which persons are eligible for **rebates**; and

(v) distribute **funded asset rebates** it receives in accordance with clause 29 of the **transmission pricing methodology** relating to **incremental transmission works** to **pioneers**; and

(vi) determine whether and in what circumstances the status of **first pioneer** or **subsequent pioneer** may transfer to a different person or persons; and

(b) make each **connection applicant** aware of the existence of the **pioneer scheme policy**;

(c) **publish** the **details** of each **pioneer scheme** it administers, applying the requirements in clause 6B.7, including the following information:

(i) the part of its **network** that the **pioneer scheme** covers:

(ii) the **start date** of the **pioneer scheme**:

(iii) the expiry date of the **pioneer scheme**:

(iv) the relevant opening value(s) of the **pioneering connection works**, **vested pioneering works**, or parts of these works covered by the **pioneer scheme**.

(2) Subclause (1)(c) does not apply to a **pioneer scheme** entered into before 1 April 2026.

Connection charge reconciliation methodology requirements

6B.10 Distributor must provide connection charge reconciliation on request

(1) If requested by a **connection applicant** during the **connection process**, or as otherwise required under subclause (2), a **distributor** must provide a written **connection charge reconciliation**.

(2) A **distributor** must, when providing a quote for the **connection charge** or **connection charges**, in respect of any **connection works**, either—

(a) provide a written **connection charge reconciliation**; or

(b) notify the **connection applicant** of their right to request a written **connection charge reconciliation** under this clause.

(3) If requested by the **Authority**, a **distributor** must—

(a) provide information on **connection charge reconciliation** amounts to the **Authority**; and

(b) if requested, provide sufficient information under paragraph (a) to enable the **Authority** to understand how the **distributor** determined those amounts; and

(c) provide the information requested under this subclause in the form, manner, and at the time and/or frequency specified by the **Authority**.

6B.11 Connection charge reconciliation requirements

(1) A **connection charge reconciliation** must show:

CC = (IC - IR) + NC

where

CC is the **connection charge** or **connection charges**

IC is, for offtake connections, the **incremental cost estimate** and for injection connections is the **incremental injection costs**.

IR is the **incremental revenue estimate**

NC is the **network cost contribution**.

(2) For **offtake connections**, a **distributor** must assess the **incremental cost estimate** under subclause (1), and show this assessment in the **connection charge reconciliation**, in accordance with the following formula:

IC = EC + CSE + NOCC + ITC + LHCR + OCL

where

IC is the **incremental cost estimate**

EC is the **extension cost** of the **relevant minimum scheme**, excluding any **incremental transmission cost**

CSE is the **customer-selected enhancement** costs, if any

NOCC is the **network offtake capacity cost** of the **relevant minimum scheme** calculated in accordance with clause 6B.5, including in respect of a **connection application** received by a **distributor** prior to 1 April 2027 as though that clause applied to the **connection application**

ITC is the **incremental transmission cost**, if any

LHCR is the **localised historical cost recovery**, if any

OCL is the **operating cost loading**, if any.

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(3) A **distributor** must assess the **incremental revenue estimate** under subclause (1), and show this assessment in the **connection charge reconciliation**, in accordance with the following formula:

$IR = IDR + ITR$

where

IDR is the **incremental distribution revenue estimate**

ITR is the **incremental transmission revenue estimate**.

(4) A **distributor** must assess the **incremental distribution revenue** and **incremental transmission revenue** estimates, and show this assessment in the **connection charge reconciliation**, by—

(a) estimating revenue from **electricity lines services** (excluding **connection charges** and **connection administration fees**) the **distributor** will receive in respect of the **connection** in the first **disclosure year** (or part **disclosure year**) following the **electrical connection** of the **connection** or the completion of the **connection works**, whichever is later; and

(b) estimating revenue for subsequent **disclosure years** by adjusting the estimate derived under paragraph (a) for—

(i) change from part-year to full-year, if applicable; and

(ii) forecast changes in demand at the **connection** (if any); and

(iii) forecast changes in revenue per **connection**, in real terms, for any years for which the **distributor** has a reasonable revenue path forecast; and

(iv) forecast changes in tariff structures or levels for any years for which the **distributor** has a reasonable price path forecast; and

(c) discounting the estimates under paragraph (b) to their present value using—

(i) a duration from the beginning of the first full year of operation equal to the **connection revenue life**; and

(ii) a discount rate equal to the most recent available mid-point estimate of vanilla WACC (being the weighted average cost of capital) made by the Commerce Commission in accordance with the **EDB ID determination** made under Part 4 of the Commerce Act 1986 less an adjustment to remove inflation consistent with inflation projections for the year ahead from the most recent Monetary Policy Statement published by the Reserve Bank of New Zealand at the time of that mid-point estimate of vanilla WACC; and

(d) for **incremental distribution revenue** relating to offtake only, and only where **the incremental cost estimate** includes an **operating cost loading** which is zero, multiplying the amount derived after the application of paragraph (c) by the **distributor's incremental opex scaling factor** calculated in accordance with subclause (5).

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(5) A **distributor** must calculate its **incremental opex scaling factor**, and show this calculation in the **connection charge reconciliation**, in accordance with the following formula: formula:

$$OSF=1-\frac{ASO}{AEDR}$$

where

OSF is the **incremental opex scaling factor**

ASO is the average selected opex, being the average value over the five most recent available **disclosure years** of the sum of a **distributor's**—

(a) operational expenditure relating to service interruptions and emergencies as defined in the **EDB ID determination**; and

(b) operational expenditure relating to vegetation management as defined in the **EDB ID determination**; and

(c) operational expenditure relating to routine and corrective maintenance and inspection as defined in the **EDB ID determination**; and

(d) any costs, other than an amount or charge payable to **Transpower**, described in clause 3.1.2(1)(a) of the **EDB IMs**

AEDR is the average electricity distribution revenue, being the average value over the five most recent available **disclosure years** of a **distributor's** distribution line charge revenue (excluding revenue relating to pass through of electricity transmission costs)

and where all values must exclude goods and services tax and be expressed in real terms (with a common base year).

(6) A **distributor** may further adjust the calculation of the amounts of the *CC*, *IC* and *IR* in subclauses (1) and (2), as applicable, to recognise differences in the timing of cashflows using a discount rate for each year consistent with the rate determined in subclause (4)(c)(ii).

(7) A **distributor** must treat in-kind contributions consistently as between *CC* and *IC* (either both zero or both the same estimated value).

~~*Disputes about the application of this Part*~~

~~**6B.12Disputes between distributors and connection applicants that are participants**~~

~~(1) If there is a dispute between a **connection applicant** that is a **participant** and a **distributor** about the application of any of the **mandatory connection pricing**~~

~~**methodologies**, either **participant** may commence the default dispute resolution process in Schedule 6.3 at any time.~~

~~(2) Subclause (1) does not apply to disputes about the following clauses:~~

~~(a) Clause 6B.5(1)(a) to (b) (requirements relating to **network capacity costs**);~~

~~(b) Clause 6B.6 (requirement to develop a **pioneer scheme policy**);~~

~~(c) Clause 6B.7 (requirements for a **pioneer scheme**);~~

~~(d) Clause 6B.9 (requirement to **publish** information on **pioneer schemes**);~~

~~(e) Clause 6B.10(3) (requirement to provide information to the **Authority** on **connection charge reconciliation** amounts).~~

~~**6B.13 Disputes between distributors and connection applicants that are not participants**~~

~~(1) If a **connection applicant** that is not a **participant** is in a dispute with a **distributor** about the application of this Part, other than a dispute about any of the clauses listed in clause 6B.12(2), and has notified the **distributor** of the dispute, the **distributor** must attempt to resolve the dispute in good faith.~~

~~(2) For the avoidance of doubt, nothing in this clause prevents the **connection applicant** from reporting a breach or possible breach of this Code under regulation 9 of the Electricity Industry (Enforcement) Regulations 2010 or from making a complaint to the **distributor** under regulation 5 of the Electricity Industry (Enforcement) Regulations 2010 at any time.~~

Subpart 3—Injection pricing principles

6B.14 Injection connection pricing principles

This subpart specifies the **injection pricing principles**, being:

(a) the **incremental injection cost** requirements in clauses 6B.16 and 6B.17:

(b) the payment and security requirements in clause 6B.18:

(c) the review restriction in clause 6B.19:

(d) the tariff requirements in clause 6B.20:

(e) the non-discrimination requirements in clause 6B.21.

6B.15 Application of this subpart

(1) The following **participants** must comply with the **injection pricing principles**:

(a) **distributors**; and

(b) **injecting parties** that are **participants**.

(2) Nothing in this subpart, other than clause 6B.20, applies to—

(a) a **distributor** in respect of the **distributor's** ownership or operation of an **embedded network** that conveys less than 5 GWh of **electricity** per annum; or

(b) an **injecting party** when the **injecting party** wishes to connect or has an **injection connection** connected to such an **embedded network**.

(3) A **distributor** and an **injecting party** do not need to comply with this subpart, other than clauses 6B.20 and 6B.21, if they enter into an agreement that will result in the **distributor** receiving incremental revenues that will cover the **incremental injection cost** of the **connection**.

(4) In assessing subclause (3):

(a) future cashflows must be discounted using a discount rate consistent with the rate determined in 6B.11(4)(c)(ii); and

(b) **incremental injection cost** must include estimates of:

(i) the cost (if any) of consuming network **injection** capacity; and

(ii) contributions to programmatic and cumulative costs (if any).

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Incremental injection costs

6B.16 Charges must reflect incremental injection costs

Charges in respect of an **injection connection** must reflect a reasonable estimate of **incremental injection costs**.

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6B.17 Negative incremental injection costs

(1) If **incremental injection costs** are negative, the **injecting party** is deemed to be providing network support services to the **distributor** and may invoice the **distributor** for this service.

(2) An **injecting party** that invoices a **distributor** for providing network support services in accordance with subclause (1) must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax).

Payment and security

6B.18 Distributors may require payment or security

(1) A **distributor** may **require** payment or security from an **injecting party** before incurring or committing to incur any costs of **connecting** an **injection connection** that constitute distinct capital expenditure, such as costs for a significant new asset, asset replacement or upgrade.

(2) If a payment is required under ~~S~~subclause (1), ~~only applies when the **distributor**~~ then when making~~s~~ a reasonable effort to facilitate the **connection** of the **injection connection**, a **distributor** is not obliged to incur those costs until that payment has been received..

Review of charges

6B.19 Review of charges

(1) A **distributor** may review the charges payable in respect of an **injection connection** not more than once in any 12-month period.

(2) A **distributor** must advise affected customers in writing of any change in the charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect.

~~(2)~~(3) For the avoidance of doubt, nothing in this clause applies to charges payable under a **distributor agreement** under Part 12.

Tariffs for residential and certain business consumers

6B.20 Payments for injection

(1) A **distributor's** pricing methodology must, for any **price category** that has eligibility criteria that are designed to target residential consumers, or business consumers with a connection capacity of 45kVA or less, include a negative charge for **injection** of **electricity** into the **distributor's network** that:

(a) applies at times when offtake demand in the region where the **ICPs** in that **price category** are located is likely to~~, on average and over time,~~ drive future **network offtake capacity** investment; and

(b) is based on either—

(i) the long-run marginal cost of **network offtake capacity** ~~peak demand~~ that can, on average and over time, be avoided by **injection** that occurs at the times identified in paragraph (a) from **ICPs** in that **price category**; or

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Commented [A15]: It is not clear why this qualifier is required or how it applies. The intent stated in the paper is to relax the requirement that payment "must" be made in advance. Existing clause 2(d) also relaxes the distributor's requirement to make reasonable endeavours until the payment is received. So this appears to be a mis-translation of the existing requirement. Amendments suggested.

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(ii) for the pricing year beginning 1 April 2026, the difference between the peak charge and off-peak charge for consumption of **electricity** for **ICPs** in that **price category**; and

(c) has regard to transaction costs, consumer impacts, uptake incentives and network stability.

(1A) Despite subclause (1), a negative charge for **injection** of **electricity** is not required to be offered or paid under this clause in respect of any **injection connection** ~~**distributed generation**~~ with maximum deliverable generation capacity of more than 45kW in total across three phases.

(2) A payment resulting from subclause (1) may be met by way of a credit against any amount owed to the **distributor** by the **distributor's** customer.

(3) A **distributor's** pricing methodology must disclose:

(a) how any long-run marginal cost in subclause (1)(b)(i)—

(i) has been calculated; and

(ii) has been converted into a negative charge for **injection** (including any adjustment to account for the specific characteristics of **injection**); and

(b) how any differential between the peak charge and off-peak charge in subclause (1)(b)(ii) has been converted into a negative charge for **injection** (including any adjustment to account for the specific characteristics of **injection**); and

(c) the form of the negative charge and the time periods or circumstances in which it applies; and

(d) any important assumptions relied upon.

(4) A **distributor** must not use charges from a regulated distributor tariff option (as defined in regulation 4 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004) for the purposes of subclause (1)(b)(ii).

(5) This clause applies—

(a) to **distributors'** pricing methodologies that apply on and after 1 April 2026; and

(b) despite anything contrary in any agreement or the **regulated terms**.

No discrimination in setting charges

6B.21 No discrimination in setting charges

Charges in respect of **injection connections** must be set in a way that does not discriminate on the basis of the ownership of, or beneficial interests in, a customer,

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including whether the **distributor** has an ownership interest or a beneficial interest in that customer.

Other provisions

6B.22 Code does not create property rights unless contracted for

To avoid doubt, nothing in Parts 6 or 6B of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for.

6B.23 Distributors must comply with connection and operation standards

Distributors must **maintain connection** and **lines** services in respect of **injection connections** in accordance with their **connection and operation standards**.

6B.24 Transitional provisions

(1) Clauses 6B.16 to 6B.19 and clauses 6B.21 to 6B.23 apply to:

(a) an application to **connect** an **injection connection** that has a **maximum export power** of more than 10 kW where any final application is received, or the **distributor** issues a decision to not require a final application, on or after 1 ~~February 2027~~April 2028; and

(b) an application to **connect** an **injection connection** that has a **maximum export power** of 10 kW or less received on or after 1 ~~February~~ April 2028~~7~~.

(2) Until the dates specified in subclause (1)(a) and (b), **distributors** and **injecting parties** ~~must~~ may:

(a) comply with the distributed generation pricing principles in Schedule 6.4 of the Code immediately before the commencement of this subpart in respect of the relevant **injection connection**; or

~~(2)~~(b) Apply clauses 6B.16 to 6B.19 and clauses 6B21 to 6B.23.

(3) A **distributor** is not required to comply with this subpart, other than clause 6B.20, to the extent that compliance would require the **distributor** to change the pricing methodologies the **distributor** uses to set lines charges before 1 April 2028.

(4) Despite subclause (3), this subpart does not apply to or affect the rights, powers or obligations of a **connection applicant** or **distributor** under a written agreement entered into between that **connection applicant** and **distributor** for an injection connection that is entered into before this subpart enters into force.

~~(3)~~

Commented [A17]: Dates amended to reflect practical reality of transition to implementation ie providing industry - wide guidance and standardisation of implementation.

Commented [A18]: Despite need to extend the deadline for mandatory application of these clauses we acknowledge that some distributors may be prepared to move early and wish to retain the possibility of

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Commented [A19]: Distributors have been engaged in negotiating injection contracts. Some of these negotiations have been lengthy and detailed and distributors do not wish to reopen those contracts which have been mutually agreed to date. Drafting to carve out existing agreements proposed.

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Subpart 4—Other requirements

Pass-through of settlement residue

6B.25 Distributors must pass-through settlement residue

(1) The purpose of this clause is to allocate **settlement residue** to customers in proportion to the transmission charges paid by those customers in respect of each **connection location.**

(2) A **distributor** that is paid any amount of **settlement residue** under clause 14.35A(l) of Part 14 must, on a monthly basis, allocate and pay this amount to its customers that pay **lines** charges directly to the **distributor** ("distribution customers") in accordance with a methodology developed under subclause (3).

(3) Each **distributor** to whom subclause (2) applies must develop a methodology for allocating **settlement residue** to its distribution customers that gives effect to the purpose described in subclause (1) and reflects the information provided to the **distributor** by **Transpower** under clause 14.35A(6) of Part 14.

(4) A **distributor** must publish the methodology developed under subclause (3), including an explanation of the rationale for the methodology.

(5) A **distributor** must publish annually a breakdown of payments made under subclause (2) by **connection lōcation** and type of distribution customer (for example retailer, direct ~~generation~~ **injection** customer, direct ~~load~~ offtake customer).

(6) From time to time the **Authority** may prescribe the form that the annual breakdown of payments must take when **distributors** publish this breakdown of payments under subclause (5).

(7) A **distributor** may adjust any payment made under subclause (2) to correct for a previous overpayment or underpayment under that subclause or to adjust for any amount of negative **settlement residue** or **settlement residue** processing costs the **distributor** is charged by a **grid owner**.

(8) A payment required under subclause (2) may be met by way of a credit against any amount owed to the **distributor** by the customer.

(9) This clause applies to **settlement residue** paid to a **grid owner** in respect of any **trading period** on or after 1 April 2023.

Distributors must charge in accordance with time-varying pricing plans where offered

6B.26 Distributors must charge in accordance with time-varying pricing plans where offered

(1) Subject to subclause (2), if a **distributor** offers one or more **time-varying pricing plans**, it may only charge a customer on a **standard contract** in accordance with that plan or plans, and may not charge that customer in accordance with any plan that is not a **time-varying pricing plan.**

(2) A **distributor** is not required to comply with subclause (1) in respect of any premises that does not have a **smart meter**.

(3) This clause applies on and after 1 April 2026.

Disputes about the application of mandatory connection pricing methodologies and injection pricing principles

6B.27 Disputes between distributors and connection applicants or injecting parties that are participants

(1) If there is a dispute between a **connection applicant** or **injecting party** that is a **participant** and a **distributor** about the application of any of the **mandatory connection pricing methodologies** or the **injection pricing principles**, either **participant** may commence the default dispute resolution process in Schedule 6.3 at any time.

(2) Subclause (1) does not apply to disputes about the following clauses:

- (a) Clause 6B.5(1)(a) to (b) (requirements relating to **network offtake capacity costs**):
- (b) Clause 6B.6 (requirement to develop a **pioneer scheme policy**):
- (c) Clause 6B.7 (requirements for a **pioneer scheme**):
- (d) Clause 6B.9 (requirement to **publish** information on **pioneer schemes**):
- (e) Clause 6B.10(3) (requirement to provide information to the **Authority** on **connection charge reconciliation** amounts):
- (f) Clause 6B.20 (requirement to make payments for certain injection).

6B.28 Disputes between distributors and connection applicants or injecting parties that are not participants

(1) If a **connection applicant** or **injecting party** that is not a **participant** is in a dispute with a **distributor** about the application of subpart 2 or 3 of this Part, other than a dispute about any of the clauses listed in clause 6B.27(2), and has notified the

distributor of the dispute, the **distributor** must attempt to resolve the dispute in good faith.

(2) For the avoidance of doubt, nothing in this clause prevents the **connection applicant** or **injecting party** from reporting a breach or possible breach of this Code under regulation 9 of the Electricity Industry (Enforcement) Regulations 2010 or from making a complaint to the **distributor** under regulation 5 of the Electricity Industry (Enforcement) Regulations 2010 at any time.

Part 12A

Distributor agreements, arrangements, and other provisions

12A.3 Distributors must pass-through settlement residue

(1) The purpose of this clause is to allocate **settlement residue** to customers in proportion to the transmission charges paid by those customers in respect of each **connection location.**

(2) A **distributor** that is paid any amount of **settlement residue** under clause 14.35A(1) of Part 14 must, on a monthly basis, allocate and pay this amount to its customers that pay **lines** charges directly to the **distributor** ("distribution customers") in accordance with a methodology developed under subclause (3).

(3) Each **distributor** to whom subclause (2) applies must develop a methodology for allocating **settlement residue** to its distribution customers that gives effect to the purpose described in subclause (1) and reflects the information provided to the **distributor** by **Transpower** under clause 14.35A(6) of Part 14.

(4) A **distributor** must publish the methodology developed under subclause (3), including an explanation of the rationale for the methodology.

(5) A **distributor** must publish annually a breakdown of payments made under subclause (2) by **connection location** and type of distribution customer (for example retailer, direct generation customer, direct load customer).

(6) From time to time the **Authority** may prescribe the form that the annual breakdown of payments must take when **distributors** publish this breakdown of payments under subclause (5).

(7) A **distributor** may adjust any payment made under subclause (2) to correct for a previous overpayment or underpayment under that subclause or to adjust for any amount of negative **settlement residue** or **settlement residue** processing costs the **distributor** is charged by a **grid owner**.

(8) A payment required under subclause (2) may be met by way of a credit against any amount owed to the **distributor** by the customer.

(9) This clause applies to **settlement residue** paid to a **grid owner** in respect of any **trading period** on or after 1 April 2023.

12A.5 Distributors must charge in accordance with time-varying pricing plans where offered

(1) Subject to subclause (2), if a **distributor** offers one or more **time-varying pricing plans**, it may only charge a customer on a **standard contract** in accordance with that

plan or plans, and may not charge that customer in accordance with any plan that is not a **time-varying pricing plan**.

(2) A **distributor** is not required to comply with subclause (1) in respect of any premises that does not have a **smart meter**.

(3) This clause applies on and after 1 April 2026.

12A.7 Payments for injection

(1) A **distributor's** pricing methodology must, for any **price category** that has eligibility criteria that are designed to target residential or business consumers with a connection capacity of 45kVA or less, include a negative charge for injection of **electricity** into the **distributor's network** that:

(a) applies at times when demand in the region where the **ICPs** in that **price category** are located is likely to, on average and over time, drive future network investment; and

(b) is based on either—

(i) the long-run marginal cost of peak demand that can, on average and over time, be avoided by injection that occurs at the times identified in paragraph

(a) from **ICPs** in that **price category**; or

(ii) for the pricing year beginning 1 April 2026, the difference between the peak charge and off-peak charge for consumption of **electricity** for **ICPs** in that **price category**; and

(c) has regard to transaction costs, consumer impacts, uptake incentives and network stability.

(1A) Despite subclause (1), a negative charge for injection of **electricity** is not required to be offered or paid to any **distributed generation** with maximum deliverable generation capacity of more than 45kW in total across three phases.

(2) A payment resulting from subclause (1) may be met by way of a credit against any amount owed to the **distributor** by the **distributor's** customer.

(3) A **distributor's** pricing methodology must disclose:

(a) how any long-run marginal cost in subclause (1)(b)(i)—

(i) has been calculated; and

(ii) has been converted into a negative charge for injection (including any adjustment to account for the specific characteristics of injection); and

(b) how any differential between the peak charge and off-peak charge in subclause (1)(b)(ii) has been converted into a negative charge for injection (including any adjustment to account for the specific characteristics of injection); and

(c) the form of the negative charge and the time periods or circumstances in which it applies; and

(d) any important assumptions relied upon.

(4) A **distributor** must not use charges from a regulated distributor tariff option (as defined in regulation 4 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004) for the purposes of subclause (1)(b)(ii).

(5) This clause applies—

(a) to **distributors'** pricing methodologies that apply on and after 1 April 2026; and

(b) despite anything contrary in any agreement or the **regulated terms**.