INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

[redacted]

19 May 2026

Network Pricing Team
Electricity Authority
P O Box 10041
Wellington 6143

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

Dear Janet and team,

Re: Consultation Paper - distribution injection pricing

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) proposals to reform network pricing for distributed generation with the objective to promote efficient investment.[1]

The way that the pricing principles are defined and applied will have a substantial impact on the business case for investment in independent distributed generation. Independent distributed generation provides system-wide benefits (firming, capacity, regional resilience, and wholesale competition in a concentration market) and it is important to carefully consider how the changes will impact on incentives for further investment. Over-recovery from distributed generators, or aggregated blunt price signals, risk deterring efficient distributed generation investment and slowing electrification.

The key points of our submission are:

a) The IEGA supports the Authority's decision to continue to use a principles-based approach; to retain the incremental cost principle for distributed generation connections and that load/offtake customers remain the payers of residual network costs after incremental costs are allocated However, we are concerned about the potential scope of the incremental cost principle as our interpretation is that the proposed Code opens the door to cost allocations of shared network costs rather than costs that are strictly incremental
b) The IEGA and ENA have had initial discussions to firm up understandings of the interpretation of the current DGPPs. This work will continue with the aim of improving areas of non-alignment between generation owners and distributors and create guidance that supports a consistent application of the current Code across networks

[1] A Committee of the IEGA has signed off this submission on behalf of members.

c) Any guidance should be developed collaboratively with distributors and generation investors to ensure the expertise and experience within these entities contributes to a durable and transparent methodology. This guidance should be developed and available before the effective date of any Code changes (a 'do it once – do it right' approach)
d) The Pioneer Scheme arrangements should be voluntary (and not mandatory) for generation-only connection assets. Generation investors are commercially incentivised to right-size their connection assets to maximise generation plant output. This creates capacity for new load connections but not necessarily additional generation sites
e) The issue of network injection capacity charges is complicated and not a universal issue across all networks. The IEGA submits that further work and consultation is required before finalising any standard approach to capacity charges
f) The IEGA does not support retrospective application of any of the proposed changes in the consultation paper to existing connection contracts. The cost of renegotiating existing contracts, any unintended consequences and negative impact on investor perceptions outweigh any perceived benefits[2]
g) The IEGA supports the ENA's feedback that the Authority's proposed implementation timeline is too tight. It is in the best economic interests of distributors and distributed generators to allow time so that there is no rework, there is transparency about how the new Code is being applied and to enable a consistent approach across all networks. An effective date of 1 April 2028 is achievable.

The balance of this cover letter elaborates on the above points. This cover letter must be read in conjunction with our response to specific consultation questions is in Appendix 2.

a) Pricing principle and scope

The IEGA supports the Authority's decision to continue to use a principles-based approach; to retain the incremental cost principle for distributed generation connections and that load/offtake customers remain the payers of residual network costs after incremental costs are allocated.

However, the proposal expands the scope of what distributors can consider an 'incremental cost' associated with connecting a generation-only site to a distribution network.[3] Our interpretation is the proposed Code opens the door to cost allocations of shared network costs rather than costs that are strictly incremental. This directly contradicts the Authority's claim that distributors will "still not be able to charge you for more than incremental cost".[4]

Our concern is amplified by the Authority's inclusion of the words "including (but not limited to)" in the pricing principle. It is not clear what other costs the Authority considers may be relevant. If there are other specific types of costs that may be relevant, then the Authority should identify what these

[2] Especially as the reallocation of distributor costs to distributed generation is measured by the Authority at $627,631 in FY25 or 29 cents per ICP in FY25
[3] The Authority describes the advantages of the proposals as enabling distributors to: have more flexibility to introduce lines charges to help recover incremental injection costs; have more flexibility to spread upgrade costs transparently across injection connections; have more flexibility to use pricing to incentivise injection that will reduce costs" (page 3 of consultation paper)
[4] Page 2 of consultation paper

are and provide interested parties with the opportunity to comment on their relevance. Otherwise, that wording should be removed to avoid an unnecessarily broad definition that may be detrimental to efficiency. Our marked-up recommended changes to the wording is:

> (a) the reasonably identifiable distribution costs (which may include transmission costs) incurred by an efficient distributor in providing electricity distribution services to an injection connection, ~~including (but not limited to)~~ which may consist of any or all of the following costs:

The IEGA recommends the Authority reflects on the application of the incremental cost principle across the range of different injection customers connected to distribution networks. The nature of injection connections on distribution networks varies hugely – for example, from existing mass-market connections that choose to add rooftop solar, to investors looking to build windfarms, solar farms, hydro-generators, or grid-scale storage. It is the IEGA's view that the optimal way for costs to be recovered, including the way that costs are signalled, should vary across connection types

It is useful the consultation paper clarifies that the proposals exclude connections where on-site generation (including from a battery or electric vehicle) does not inject power into a distribution network – ie, energy is all consumed 'behind the meter'. We agree that "From a network pricing point of view, these are offtake-only sites and are allocated charges in the same way as an offtake site with no generation".[5]

This means the proposed Code covers offtake connections that also inject.[6]

The Appendix on Terminology states that incremental costs are "the additional costs incurred to serve an additional connection or group of connections". [7] The following table explores the difference in these two types of connections in the context of the distributed generation investments by IEGA members at an additional connection for a generator-only facility:

Attribute	**Group of connections**	**A single additional connection = IEGA member connection**
Size	Likely to be a large group of small connections – such as an urban area where properties have rooftop solar	A single site
Principal activity	Load and generation site - offtake and injection	Generation / injection only
Connection arrangement	Retailer responsible for generation connection	Direct contractual relationship with the Distributor
Access to network	Via existing load connection	Customer-initiated request for connection
Market participation	Retailer purchasing injection volumes	Revenue from the wholesale market
Location in the network	Low voltage	High voltage

[5] Paragraph C.2a. page 67 of consultation paper. This is also explained in footnote 116 pg76 "Existing clause 6B.2(3) sets out how connection pricing should operate for connections that serve both offtake (load) and injection (distributed generation) – ie, offtake needs are priced first and then injection is treated as incremental to offtake needs"

[6]We note the Code drafting is clear that the cost of offtake connection is assessed first and injection costs are incremental

[7] Paragraph C.5f. page 68 of consultation paper

Easy to identify directly attributable costs	No	Yes Connection contract may stipulate costs the generator would be responsible for
Attribution of programmatic and cumulative costs	Distributor to develop a methodology for allocating programmatic costs to groups of connections	Can identify the value of costs directly related to the single generation-site connection
Attribution of shared network capacity costs	Distributors cannot refuse to connect any small-scale generation. These offtake and injection connections have an expectation that capacity will be available to inject using their existing offtake capacity	Connection asset capacity is designed to ensure the generator can inject its maximum output. Any increase in maximum generation output and need for additional connection capacity will only result from an increase in the generator plant capacity – for which the generator is prepared to pay the incremental cost

The IEGA submits the attributes for generation-only sites are clearly more aligned to specific identification and direct attribution of incremental injection costs – which is an efficient outcome.

If generation-only sites are allocated any costs that are not incremental then the cost includes an allocation of the 'shared / residual costs' of the shared network. The IEGA is concerned about if the new pricing principles led to costs associated with residential solar, for example, being smeared across all injection connections. If an allocation of residual costs is recovered though injections then these costs are instead recovered through a usage charge, which has the effect of artificially depressing the amount of electricity used. The Authority also states: "Allocating residual costs to producers would flow through to higher wholesale and retail electricity prices for consumers".[8]

Generation-only investors will typically take the distribution network cost at a particular location into account when determining where to build new generation. This contrasts with the case of load customers (whether residential or commercial) who choose to inject from an existing location – typically the decision in that case is whether to inject or not and at what volume or when, rather than whether to relocate their place of residence or business according to the distribution network injection costs. As a result, the most efficient and effective pricing constructs and signals will likely differ across injection connection types.

A more 'average' allocation of (incremental)[9] programmatic and cumulative costs to low voltage combined offtake and injection sites is consistent with the Authority's approach when developing the negative rebate for injection during peak periods (as defined by distributors) being available only to residential and small business consumers with a 45kVA cut off.

The following table shows the customer groupings of ICPs with distributed generation greater than 10kW and the growth in ICP connections in the year to 31 March 2026.[10] Residential and SME ICPs made up 67% of the new connections. The current incremental cost pricing principle has been interpreted as enabling a distributed generation injection charge for offtake customers with generation: Northpower has an 'Export Generation' delivery charge of $0.01/kWh applied to all

[8] Paragraph 4.8 of consultation paper
[9] These concepts are vague and seem beyond the definition of 'incremental'
[10] Source: EMI website installed distributed generation dataset

offtake customer groups in the 2026/27 pricing year. In the same period, Counties Energy removed their Injection charge which had been $0.0103/kWh for mass market and $0.0114/kWh for Major TOU customers.

Total Distributed generation >10kW	ICP count		Incr in ICP connections in 12 mths to 31-3-26	% total new ICPs	MW connected at 31/3/26	Incr in MW in 12 months to 31-3-26	% total MW added
	31/03/2025	31/03/2026					
Residential	2,182	3,191	1,009	42%	64	27	14%
SME	1,759	2,359	600	25%	96	25	13%
Commercial	1,316	1,644	328	14%	210	51	27%
Industrial	1,236	1,680	444	19%	1,394	83	45%
Total DG >10kW	6,493	8,874	2,381		1,764	186	

The underlying question is who is creating or benefiting from the programmatic and cumulative costs the Authority is proposing be allocated to any size of distributed generation.

b) Industry collaboration to improve application of the current DGPPs

The IEGA and ENA has had initial discussions to firm up understandings of the interpretation of the current DGPPs. This work will continue with the aim of improving areas of non-alignment between generation owners and distributors and create guidance that supports a consistent application of the current Code across networks.

The IEGA and ENA agree that real value is attainable from creating clear guidance, improving areas of non-alignment between generation-only site owners and distributors and working towards consistent application of the incremental cost principle across networks. The IEGA and ENA have agreed this should be done through an initiative by some or all of IEGA/ENA/EA and should cover:

- what activities / costs can reasonably be counted as incremental
- how incidence of a particular cost is established for each generator
- how any costs are quantified and substantiated / evidenced.

The plan is that this work to improve implementation of the current Code should proceed at pace. It could inform further detail and guidance for changes, if any, the Authority decides to make to the DGPPs. Appendix 1 includes a table that lists the current areas of alignment on the current DGPPs and areas that the IEGA and ENA agree require further consideration.

c) Guidance

As the experience with the current incremental cost principle in the DGPPs demonstrates, interpretation of the proposed ‘incremental injection cost’ principle is likely to differ across distributors and across different types of generation connections.

If there are changes to the DGPPs, the IEGA submits it is imperative that the Authority endorse / facilitate an industry working group to develop guidance. The IEGA and ENA have the expertise and practical experience to reach conclusions that will improve areas of non-alignment between generators and distributors and create consistent and transparent application of the principles across networks. This will maximise utilisation of existing assets, improve the efficiency of generation and network investment and ensure a durable solution.

This guidance must be developed and available before the effective date of any Code changes to enable efficient implementation of any new rules (a 'do it once – do it right' approach).

d) Pioneer Schemes

The IEGA does not support a mandatory requirement for distributors to arrange a pioneer scheme for each generation connection. Setting up a pioneer scheme should be a decision taken jointly between a generation-only investor and the distributor. As discussed above a generation investor is commercially incentivised to right-size its connection assets to maximise output from its generation plant.

e) Concept of consuming network injection capacity and capacity charges

The Authority is also proposing giving distributors the option to charge new and existing generation connections for the cost (if any) of consuming network injection capacity.

The issue of network injection capacity charges is complicated. Limited 'free' injection capacity is not a universal issue across all networks.[11] The IEGA submits that further work and consultation is required before finalising any standard approach to capacity charges.[12] This includes valuing both the costs and benefits of generation location so locations where additional distributed generation could help support network operations are also signalled.[13]

There are two important 'facts' that underpin the issue of connection charges and 'use' of capacity:

- paying connection charges does not confer any capacity rights to the payer on the specific directly attributable connection asset or other parts of the distribution network. Clause 6B.22 states:

  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.

)

[11] A graph in Appendix 3 shows the distributed generation MW as a percentage of maximum coincident peak demand for each network for the year ended 31 March 2025. There are 6 networks where this ratio is greater than 20% and 20 networks where the ratio is less than 10%. This ratio would change temporally and regionally within networks but demonstrates there are network specific circumstances.

[12] Each distribution network is attempting to manage its own injection capacity – limited by the size of its individual network. With only 7 networks having a peak demand over 200MW (see graph in Appendix 3), individual network size may be limiting and complicating the opportunities for distribution network connected generation.

[13] Referred to in Appendix F of the 'Improving information on high-voltage network capacity' consultation paper

- distributors' approach to the Code relating to connection of generation is that the distributor <u>must</u> connect any applicant when the application meets the connection and operation standards. This is creating congestion issues in some parts of some distribution networks.

These facts are important to the consideration of capacity charges.

The definition of 'network capacity cost' is "*the cost of offtake or injection capacity <u>for shared network elements</u> (ie, beyond the dedicated assets used by a connection). May be assessed in terms of the cost of adding capacity, or the cost of consuming capacity that may one day need to be expanded*" [emphasis added]. The definition allows for costing of "shared network elements" which must, by definition, be beyond the scope of the incremental costs of connection. Allocation of shared or residual costs to new and existing generation contradicts the Author's position that "*allocating residual costs to producers would flow through to higher wholesale and retail electricity prices for consumers*" and that offtake customers should remain the payer of residual costs.[14]

The IEGA submits that the current incremental cost approach drives very significant efficiencies by directly signalling the costs that will result from a generator connecting to a specific location on the network. Price signalling in this way minimises the costs that are added to the system through generation connection (there is no cross-subsidisation by other network customers). Generators have the incentive to select a location where there is already sufficient capacity to accommodate their injections. We query whether using congestion pricing / capacity charges to signal a location where there is sufficient capacity is any more efficient for generation-only sites than the current incremental cost rule (given the pioneer scheme is proposed to address the first mover disadvantage situation).

The IEGA queries whether it is most economically efficient to deal with a congestion issue using the 'pricing' of connection (eg capacity charges) or to provide information (and incentives) to locate in other parts of the network. The Authority's proposals to improve visibility of distributors generation and load hosting capacity will assist with achieving efficient location selection. We note many distributors already have detailed informative maps on their websites.

Who uses the distribution network and who pays for it?

The consultation paper states "*This paper focuses on distribution network pricing methodologies, which deal with cost allocation between network users* [offtake and injection] *and between types of charges*."[15]

The IEGA submits the Authority has failed to identify transmission grid connected generators as 'users' of distribution networks – they are 'producers' and inject electricity into distribution networks via GXPs.

Distributors recovered $2,921 million in line charge revenue in the year to 31 March 2025 for providing electricity distribution services. This revenue recovered the cost of the assets and activities needed to deliver the 35,596.97GWh of electricity entering the distribution network system for supply to consumers' connection points in the same period. Electricity supplied via GXPs from transmission grid connected generation was 31,004.03GWh. The balance of 4,592.94GWh of electricity delivered to

[14] Paragraph 4.8 of consultation paper
[15] Page 10 of consultation paper

ICPs was supplied by distributed generation.[16] Therefore, on average 87% of the electricity distributors deliver to their ICPs comes from transmission grid connected generation and 13% from generation plant connected to distribution networks.

Distribution networks are constructed to ensure electricity can be delivered to supply demand and meet peak demand. The Authority is clear that "*Network capacity planning is based on 'after-diversity' maximum demand …* ".[17] That is, distributors design the capacity of a distribution network to reflect the current and forecast future demand from customers connected to the network and this cost is recovered from offtake customers. Hosting capacity for generation is a function of the physical capacity of the wires as well as the current level of demand.

Generation-only sites connected to distribution networks are commercially incentivised to maximise output from their generation plant from day one. They are not in a position to hold back generation in anticipation of an increase in demand over the next several years or network planning period. If a network is experiencing demand growth and the distributor invests in capacity to serve this demand growth this demand will be met by transmission grid connected generation. Put another way, generation-only distributed generation does not expect or anticipate that distributors will plan expansion in the shared network to accommodate new generation-only sites.

If injection capacity is the capacity needed to supply demand at a point in time the proportion of GXP supplied electricity to locally supplied electricity could range between 0% and 100%. This ratio differs in different parts of the network – depending on the location and concentration of local generation. Generation connected to a distribution network displaces electricity supplied via the GXP from the transmission grid. Appendix 4 includes a number of scenarios and numbers to further explain this point.

It is well known that distributors do not charge transmission grid connected generators for their electricity distribution service of delivering their electricity to distribution network connected ICPs.

Any proposal to include recovery of programmatic and cumulative costs from distribution network connected generators (or any costs above directly attributable incremental costs of connection) results in this distributed generation paying more than transmission grid connected generation for the electricity distribution delivery service. The distributed generator is facing costs that put it at a competitive disadvantage to transmission grid connected generators who are using the same service at no cost.

The Authority's position is that regulating pricing methodologies promotes the Authority's main statutory objective of promoting both competition and efficient operation of the electricity industry.[18] Any proposal for distributed generation to pay more than its incremental directly attributable cost for connecting to distribution networks does not promote competition. Distributors provide an electricity distribution delivery service to both transmission grid connected generators and distribution network connected generators – any charges must apply to both producers using this service.

The Authority appears convinced that the proposed incremental injection pricing principle will result in distributed generation paying only incremental costs – the IEGA is unconvinced, especially as the

[16] Source: Schedule 9e(ii) on System demand from the Commerce Commission's Information Disclosures dataset
[17] Footnote 26 page 18 of consultation paper
[18] Paragraph 4.5 of consultation paper

principle requires only a 'reasonable estimate' to be determined. We agree with the Authority that the principle, resulting methodologies and implementation must be monitored to ensure the approach

> *"continu[es]ing to mitigate the risk of distributors allocating residual costs to producers (which would inefficiently increase the cost of distributor-connected production and weaken its ability to compete with Transpower-connected production)"*[19]

f) Retrospective application of proposed changes

The IEGA does not support retrospective application of any of the changes proposed in the consultation paper to existing generation connection contracts. The cost of renegotiating existing contracts, any unintended consequences and the negative impact on investor sentiment outweigh any perceived benefits. Significant investment has already been sunk in long-life generation assets connected to distribution networks and any new allocation of distribution costs to existing plant undermines investment incentives and returns.

g) Implementation timeline

The IEGA agrees with the ENA that there are serious ramifications if the Authority proceeds with its proposal to have distributors' entire line charges adjusted for any change to the DGPPs on 1 April 2027 when final decisions might only be published in late 2026.

The industry must be given time to develop guidance so that both distributors and generation investors understand the consequences of any new methodology and to ensure a durable and consistent approach across NZ. 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 and exposes distributors to inadvertent Code breaches.

Concluding remarks

In summary, we strongly recommend that the proposed amendments to the Code be revised to more tightly define incremental costs, so that the new definitions do not enable broad allocations of costs or the inclusion of speculative costs. We are also concerned that the proposed changes may allow an averaging or smearing of costs across quite different types of injection connections or areas – allocated smeared costs to generation-only sites will place these generators at a competitive disadvantage to transmission grid connected generators.

[19] Paragraph B8.a of consultation paper

The IEGA appreciates the engagement we have had with your team during the consultation process. However, given the importance of the DGPP to investment decisions on distributed generation or other forms of injection, the IEGA submits that the Authority should take the time needed to develop, refine and test the DGPPs, which may well require further consultation and engagement than the current process.

We would appreciate the opportunity to discuss this formal submission with you as well.

Yours sincerely

[redacted]

Ben Gibson
Chair

Appendix 1: ENA and IEGA areas of alignment on DGPPs

Electricity Networks Aotearoa (ENA) and the Independent Electrical Generators Association (IEGA) recently engaged proactively to identify areas of alignment and to explore ways to resolve uncertainty regarding the application of the current distributed generation pricing principles (DGPPs). This engagement occurred during the Electricity Authority's consultation period on proposed changes to the DGPPs.

The Table below summarises the matters on which ENA and IEGA are aligned, as well as areas identified for further consideration. ENA and IEGA present this information as evidence of an industry that is focused and constructively engaged and well placed to work collaboratively to address DGPP application matters.

ENA and IEGA areas of alignment on DGPP

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 charging distributed generation connections, with the objective that new DG connections are subsidy-free and impose no costs on existing load customers.
- Incremental cost should include the following categories
    o Incremental connection assets
    o Operational and maintenance of incremental connection assets
    o Return on and of capital (EDB-owned assets)
    o Transmission-related benefit-based charges identified via the TPM for embedded generation
    o Voltage management impacts – both costs and benefits from DG
    o GXP-related assets that are required to connect the DG
    o 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.

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 2 – Response to questions

Name	
Organisation	**IEGA**

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?	The background and context are useful but the Authority could be clearer about the problem definition and what distributed generation it is proposing to regulate. The consultation paper is clear that EDB offtake consumers that have generation entirely for their own supply are excluded / the proposed pricing principle does not apply. The impact assessment implicitly assumes DG less than or equal to 10kV is already paying its full incremental injection cost because the reassignment of costs to DG only includes ICPs with generation greater than 10kV. Is this the correct interpretation? In our view it is possible to differentiate between generation-only sites (such as IEGA members' generation) and offtake/injection combined sites. Using a range of criteria to identify these two groups enables clearer identification of the source of components of incremental injection costs. For example, the incremental costs from connecting a generation-only site are more identifiable / directly attributable than costs created by groups of smaller combined offtake and injection sites. Note that about two-thirds of the new DG connections of more than 10kW in the year to 31 March 2026 were residential and small business.
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?	In submissions on the Authority's issues paper, the IEGA and ENA requested the Authority hold a joint workshop to discuss the perspectives from both sides of the generation connection contract regarding how to interpret, implement and be consistent about the scope of 'incremental costs' under the current Code. The EA attended a recent joint ENA/IEGA initial discussion. There is alignment on a number of components of incremental cost, and the discussion identified areas for further consideration – see Appendix 1. As discussed in our cover letter, these discussions to improve the application of the current DGPPs will continue.

Questions	Comments
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?	The Authority has provided no specific examples to substantiate the claim that "*the cumbersome approach to estimating incremental costs means most injection connections are likely subsidised by consumers*".[20] The IEGA acknowledges that the new TPM is allocating to distributors (Transpower's customer) Benefit-based Charges for electricity injected onto the transmission grid. It is appropriate that distributors pass on this cost to DG connections – and it would be useful if there was a standard methodology for this 'pass-through'. If interpreted correctly, the Authority's impact assessment therefore indicates the level of subsidy – or the benefit from reallocating programmatic and cumulative costs to connections with generation greater than 10KV - is 27 cents per ICP per annum for connections without generation or $627,631 per annum.[21]
Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?	The IEGA agrees it remains appropriate to regulate connection charges. We agree with the Authority's analysis that due to their monopoly position, "*distributors can dictate how charges are determined – ie, distribution pricing is not restrained by competition*" and "*connection applicants are vulnerable to hold-up risk and inefficient risk transfer, because they commit significant resources ahead of securing a connection. If pricing methodologies are not regulated, these risks can chill investment*" [22] The proposal is not to regulate 'pricing methodologies' but to provide a pricing principle that individual distributors can interpret and incorporate into their own pricing methodologies. The IEGA submits that any changes to the Code should create clear and transparent information about distributors' methodologies and charges[23] and encourage a consistent approach across all networks.

[20] Paragraph 3.15
[21] Page 55
[22] Paragraph 4.4 of consultation paper
[23] The IEGA does not support requiring a connection reconciliation methodology for generation connections

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?	Yes, the IEGA agrees offtake consumers should remain residual (non-incremental) payers of distribution network costs as this is the most efficient and appropriate approach. Distributors can recover these residual costs from electricity consumers through charges that are not directly linked to usage (for example, daily fixed charges) and which do not distort the volume of electricity consumed. If an allocation of residual costs is recovered though injections then these costs are instead recovered through a usage charge, which has the effect of artificially depressing the amount of electricity used. As stated by the Authority: • this is consistent with the Transmission Pricing Methodology (footnote 44) • allocating residual costs to producers would flow through to higher wholesale and retail electricity prices for consumers (para 4.8(b)) • electricity producers are also generally more responsive to network costs, so it is less distortionary (ie, more efficient) to allocate residual costs to consumers (para 4.9) • "injecting parties are electricity suppliers, so cost allocation and price structures impact efficient operation of the electricity sector, including by influencing the cost, build timing, location, connection level, and operation of new generation and storage" (para 4.4) • "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" (para 4.1(b)) The key issue is the scope of what is an 'incremental cost' and therefore what is left as a 'residual cost'. The consultation paper and proposed Code wording is confusing about this. Residual costs are described as: residual costs – costs remaining to be allocated after the primary allocation method(s). For distribution injection pricing, this refers to remaining costs <u>after incremental costs are allocated</u> [emphasis added] Part 1 of the Code has the following definition of incremental costs: the reasonable additional costs (which include any reasonable additional transmission costs) that an efficient distributor

would incur in providing electricity distribution services to distributed generation

It's unclear if this definition is being removed.

Now the proposed pricing principle is

> the reasonably identifiable distribution costs (which may include transmission costs) incurred by a distributor in providing electricity distribution services to an injection connection, including (but not limited to):
>
> - costs attributable to the specific injection connection; and
> - cumulative costs; and
> - programmatic costs; and
> - network injection capacity costs.

The IEGA is seriously concerned that the broad definition of incremental cost will result in distributed generation paying costs of the shared network (shared / common costs). Distributors provide electricity distribution services to both distribution and transmission grid connected generators. Distributed generation will be at a competitive disadvantage if it pays any of the shared / common costs of distribution networks when transmission grid connected generators are not billed by distributors for the same service.

The IEGA considers it important that these costs are:

(1) sufficiently tightly defined to avoid broad allocations, in accordance with the Authority's view that residual costs are not recovered from injection connections
(2) do not include speculative costs
(3) do not include general overhead costs

Discussing each of the cost categories:

Attributable costs - The IEGA understands that "attributable costs" would include costs such as those of dedicated assets (for example transformers or lines) that are required to connect injection connection. We recommend the addition of the word "directly" in the definition so it reads as follows:

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

We note that other types of costs that could be considered attributable are costs incurred on the shared network directly because of and triggered by a particular generation connection. As discussed further below regarding capacity costs, the IEGA is comfortable with the current approach where these attributable costs are recovered from the new injection connections. In any case, it is important that there is no doubling up of such costs across the attributable costs and network injection capacity cost components of the definition of incremental costs.

Cumulative costs - The IEGA considers it important to ensure that the term 'cumulative' is sufficiently well-defined that only those costs that are incremental to injection are included, rather than broad allocations. The IEGA would be concerned if general allocators were used to allocate broad types of costs such as system operations and network support opex. We suggest that the definition of cumulative costs be amended to avoid broad allocations – recommended amendments:

(ii) cumulative costs, being an estimate of ~~a share of~~ costs attributable to injection connections ~~generally~~ (for example, specific types of system operations and network support opex that are reasonably expected to be driven by injection connections or transmission costs that are higher are a result of supplying injection connections); and

Programmatic costs: It appears that these types of costs are associated with operating and maintaining the assets that are required as a result of injection connections. We recommend being more specific about this in the definition – for example:

(iii) programmatic costs, being a share of costs that are difficult to attribute to a 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 specific types network opex associated with operating and maintaining assets that are incremental to injection connections); and

Capacity costs: The Authority's consultation paper and proposed Code amendment provide little clarity on exactly how capacity charges would be calculated or applied. However, the Authority does state that the network injection capacity cost has a corresponding meaning to the network offtake capacity cost.

It appears the Authority proposes to allow distributors to either charge new generation connections for the actual cost of adding capacity in the shared network, or to instead apply a charge that is based on the cost of consuming shared network capacity that may one day need to be expanded. Essentially this provides an averaged approach to incremental costs (Average Incremental

Questions	Comments
	Cost), where distributors would estimate costs of potential future network upgrades and then unitise those costs by the amount of capacity that the upgrades would provide. Connecting parties then pay a capacity rate regardless of whether their individual connection will trigger a network upgrade. The appropriateness and usefulness of an average capacity cost approach will be highly dependent on how it is implemented. In the IEGA's view, the concern that the Authority has with the current approach is more likely to be relevant when applied to load customers who want to start injecting from their existing location, such as a residential or commercial electricity consumer installing rooftop solar to their existing connection. In many such cases the cost of connecting electricity injection will not be a driver of where the customer is located (residential customers will not generally factor in the cost of electricity injection connection into the decision of where to live). As a result, efficiency losses from applying capacity charges for average incremental capacity cost for mass market customers are likely to be limited. However, the situation is very different for larger generators. The IEGA considers that the current approach drives very significant efficiencies by directly signalling the costs that will result from a generator connecting to a specific location on the network. Price signalling in this way minimises the costs that are added to the system through generation connection. Generators have the incentive to select a location where there is already sufficient capacity to accommodate their injections. If capacity charges are applied beyond mass-market connections, then this needs to be done in a way that preserves signals about where the network is and isn't constrained so that generators that connect to parts of the network which can accommodate significant generation do not have to pay any upfront capacity charges when connecting. The issue of network injection capacity charges is complicated. Limited 'free' injection capacity is not a universal issue across all networks. The IEGA submits that further work and consultation is required before finalising any standard approach to capacity charges. This includes valuing both the costs and benefits of generation location so locations where additional distributed generation could help support network operations are also signalled.

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?	The proposal is a pricing principle. Distributors will have discretion about how to interpret and implement this principle (and how long the 'anchor' is). See also our answer to Q6. The greatest gain could be made by continuing discussion about interpretation of the current pricing principle – reaching consensus about what is and what isn't an incremental cost. The IEGA / ENA has initiated this discussion which will be continued at pace. The Authority should be wary of the uncertainty created by the more open-ended principle based on what is 'reasonable'. This can be addressed by distributors and generators working together, with the Authority, to develop guidance on: • what activities / costs can reasonably be counted as incremental • how incidence of a particular cost is established for each generator • how any costs are quantified and substantiated / evidenced.
Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?	It is unclear if the proposed amendments to language and framing will support more efficient pricing. See also answer to Q6. The IEGA notes the Authority has removed the work "efficient" and replaced it with "reasonably identifiable". While we consider the wording "reasonably identifiable" to be an acceptable addition, there is no need to drop the term "efficient". Efficiency is a key goal of the Authority and the IEGA finds it surprising that the need for efficiency would be specifically removed from the DGPP. We submit that any refinement to the existing definition of incremental costs should still include the concept of efficiency.
Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?	The IEGA submits the proposal to include recovery of possible **future** shared network capacity expansion as a component of the incremental cost for generation connection will negatively impact efficient investment in distributed generation. This is discussed in more detail in the cover letter (and answer to Q6).
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?	See section c) in the cover letter. There may be instances where the location of a load/offtake pioneer scheme is attractive to a generation-only investor. Injecting close to load is economically efficient and the generation-only investor should be prepared to contribute to the cost of the load/offtake connection assets subject to a pioneer scheme.

Questions	Comments
Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?	See section c) in the cover letter.
Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?	The government decision (yet to be implemented) that distributors can invest in generation up to 200MW in their own network makes the following non-discrimination in the arm's length rules irrelevant. **3D Duty not to discriminate in favour of business B** Business A must not, in providing services or benefits, discriminate in favour of business B or the customers, suppliers, or members of business B. The IEGA queries whether the proposed non-discriminatory pricing requirement is sufficiently broad: 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, including whether the **distributor** has an ownership interest or a beneficial interest in that customer. It appears the Code only applies if the generator connecting to the distribution network is already a 'customer' of the distributor. When does the generator become classified as a 'customer'? Pricing discussions between the distributor and generator will start well in advance of a connection being commissioned. From the above proposed Code it is hard to see how this provision provides the safeguards the Authority describes in para 4.42 of the consultation paper, namely: *"The principle would refer to 'charges', so would apply to both up-front (connection) and ongoing (lines) charges for both injection and offtake. It would prohibit taking ownership into account, but not other factors (such as congestion, pioneer or cost recovery schemes, required extension works, or when an application is made) and would prevent a distributor from taking ownership into account when determining the required level of prudential security but not the acceptable form (eg, whether a parent company guarantee is satisfactory)."* The IEGA submits that non-discrimination should be assessed not only by final charges, but also by access to information, timing, methodology explanations and the opportunity to test assumptions relating to charges.

Questions	Comments
Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?	See section f) in the cover letter regarding retrospectivity. Are the restrictions on opting out (whereby a distributor must demonstrate revenue from the connection is expected to cover its incremental cost) for the benefit of the generation connecting party – or for the Authority? Carrying over the current application of DGPPs to certain secondary networks makes sense.
Q13. Do you agree with the proposed commencement provisions above? Why?	No, the IEGA does not agree with the proposed commencement provisions. See section g) in the cover letter.
Q14. Do you have any suggestions for how we can most effectively support successful implementation?	Yes, see section c) in the cover letter.

Questions	Comments
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	The Authority monitoring should focus on actual outcomes (and not just formal compliance) as well as useability and predictability. The Authority maybe proposing changes that improve cost-reflectivity but if it is too complex for injection customers to understand or feel confident the connection charges are 'reasonable' this could discourage generation investment. The reconciliation requirements are cumbersome and time consuming for distributors (and maybe highly theoretical). Our preference is for strong guidance about: • what activities / costs can reasonably be counted as incremental • how incidence of a particular cost is established for each generator • how any costs are quantified and substantiated / evidenced and a consistent approach across distributors to applying the incremental injection cost principle (a standard methodology). This approach can provide confidence to generation investors that the charge is a 'reasonable estimate' of incremental costs. Paragraph 4.68 in relation to monitoring and disclosures states: "While the disclosure obligations refer to pricing for 'consumers' and 'consumer groups', the relevant definitions describe 'consumption of electricity lines services' so encompass connection and lines charges for injection. Accordingly, we would expect distributors to update (and expand, if necessary) their pricing disclosures to cover how they are implementing amended injection pricing principles (in their connection and lines charges)." The definition of electricity lines services (s54C of the Commerce Act) is specific that "none of the following are electricity lines services: .... (c) conveying electricity (other than via the national grid) only from a generator to a local distribution network or from a local distribution network to a generator." Does this make a difference to the Authority's expectations or implementation?

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?	The IEGA does not agree that distributors should be allowed wide discretion to determine how capacity charges for injection connections are calculated and when they are applied. As discussed in section e) in the cover letter (and answer to Q6), considerably more analysis and consultation are required before introducing any injection capacity charge. The IEGA's recommendation for a collaborative industry-led approach to developing guidance for the current and proposed incremental pricing principle includes detailed consideration of how best to manage injection capacity – both physical limits and costs. Given the discussion in paragraphs 5.2 to 5.5 of the consultation paper, the IEGA suggests it is premature to include 'network injection capacity costs' as a component of the incremental cost pricing principle for connecting generation at this stage.
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?	See section e) in the cover letter and our response to Q16 above. We agree an approach for larger injection connections can be developed that mitigates the risks of over-injection or inefficient payments. What that solution looks like at this stage is probably similar to a Non-Traditional Solution provided by any source that can reliably defer distribution network investment.
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	See answer to Q16
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	It's not clear from the description what the difference is between a 'local grid connected (LGG)' (point B) and 'distributed (DG)' (point C). The IEGA agrees there is a lot of related work underway. A clear problem definition and further analysis is needed to understand the potential for inefficient bypass and then develop a solution.

Questions	Comments
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	We request further information about the "connection charge distortion issue" before offering any solution to address this issue. As stated in answer to Q19, there is a lot of related work underway. A clear problem definition and further analysis is needed to develop a solution.
Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	As discussed in the IEGA submission on the Energy Competition Task Force 2026 work programme, distributed generation can provide benefits that defer transmission as well as distribution investment. The IEGA will engage with the Task Force as it progresses any work on this topic.
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	Section f) in the cover letter discusses the topic of who uses the distribution network and who pays for the distributors' electricity distribution service.
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	At a high level, the benefit from removing any subsidisation of DG>10kv is very small, at 27cents per ICP per year or $629,631.27 per annum according to the Authority's impact assessment. If the proposals are implemented and generation connections pay their incremental costs - and therefore there is no cross-subsidisation - the amount that is reallocated to generation is a one-off step change. This is the limit on the level of reallocation to generation regardless of how much generation is connected in the future. Efficiency gains from the proposed changes are difficult / impossible to estimate but the hope is these gains exceed the estimate of 27 cents per ICP per year.
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	No comment
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	No comment

Questions	Comments
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.	As discussed in the cover letter, the IEGA's position is that further work and collaboration between ENA and IEGA could achieve a more durable and consistent application of the current DGPPs.
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	No comment
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	No comment
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	This could make the Code easier to follow – see feedback on the current drafting in answer to Q30.
Q30. Do you have any comments on the drafting of the proposed amendment?	

Definition of incremental cost

There is already a definition of incremental cost in Part 1 of the Code. Recommend the Authority review whether this is still relevant.

Definition of incremental injection costs

Extract from the definition:

: "... the reasonably identifiable **distribution costs (which** may include transmission costs) incurred by a distributor in providing **electricity distribution** services to an **injection connection** ... "

The IEGA recommends the Authority review the bolding / reference to defined terms in the above definition. For example:

- 'Distribution costs' is not a defined term
- putting '**(which**' in bold is obviously a drafting error
- 'Electricity distribution' is not a defined term in the Code. If this is meant to be 'electricity distribution services' this is also not a defined term in the Code. It is a defined term in the Commerce Commission EDB Input Methodologies Determination and relies on the definition of 'electricity lines services' which is defined in the Code as having the same definition as in s.54C of the Commerce Act.

Questions	Comments

Structure of Part 6B

The IEGA suggests changes to the structure of this Part so that it is clearer what provisions relate to offtake only, what applies to injection only and what applies to both offtake and injection. Feedback on 68.1 is included below in [ ] and italics – although a more thorough legal review should be undertaken.

6B.1 Contents of this Part

This Part specifies—

(a) *[make subpart 2 all about offtake customers – which includes c6B.25 and 6B.26 on SRAM and TOU pricing respectively]* mandatory offtake connection pricing methodologies which are the pricing methodologies that must be applied by distributors in relation to consumers' offtake connection charges and pioneer scheme contributions *[how should this section be amended to allow for voluntary establishment of pioneer schemes for injection connections? If the pioneer scheme section is to apply to both offtake and injection, we recommend this section goes into a new subpart 4];* and

(b) information requirements for distributors in relation to access to distribution networks; *[this is the reconciliation methodology which applies to offtake customers and should stay in subpart 2]*

(ba) injection pricing principles which are requirements that must be applied by distributors and injecting parties that are participants in respect of injection connections; *[subpart 3]* and

(c) *[include this as a new subpart 4 that includes provisions that relate to both offtake and injection]* 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

(d) other requirements related to distribution network pricing. *[already discussed]*

Comments on specific provisions

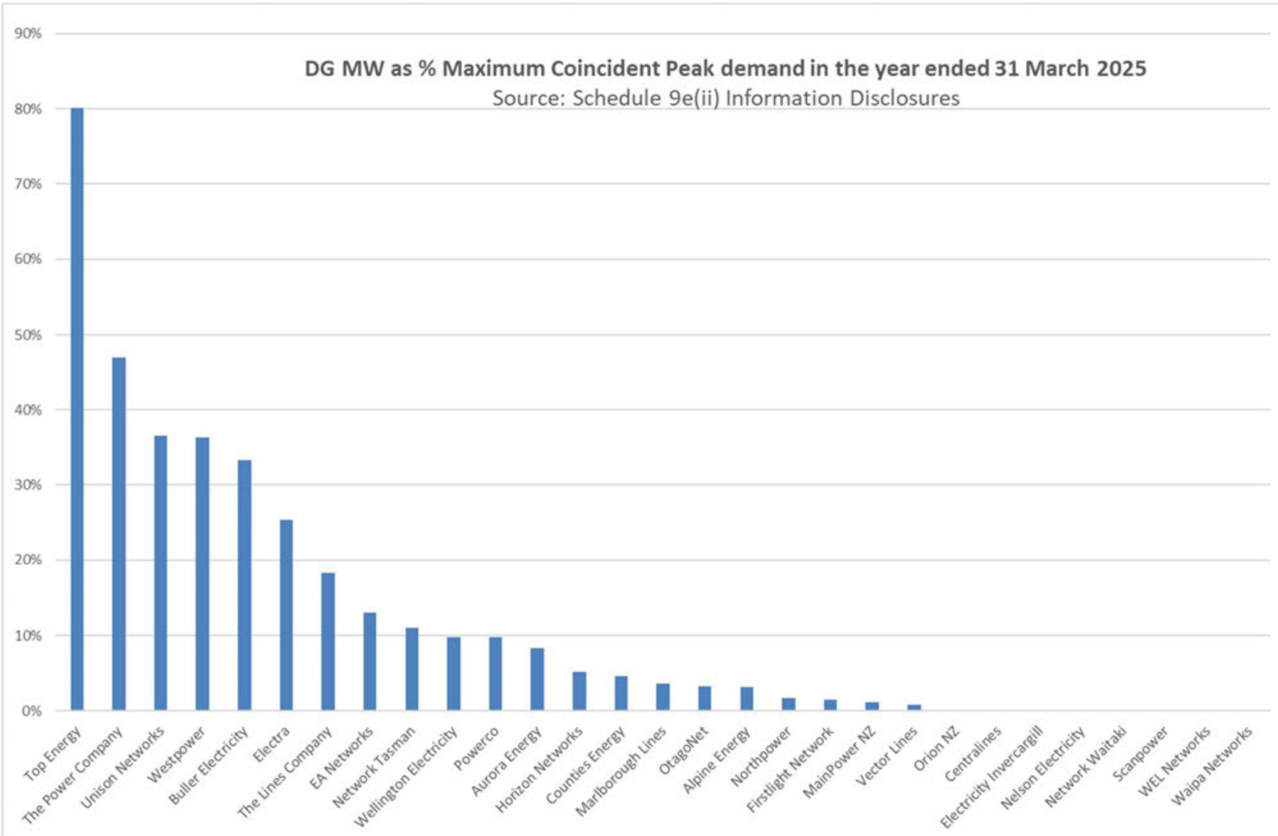
The following definitions rely on clauses that clearly apply to offtake connections only. It would be useful for the definition to be renamed:

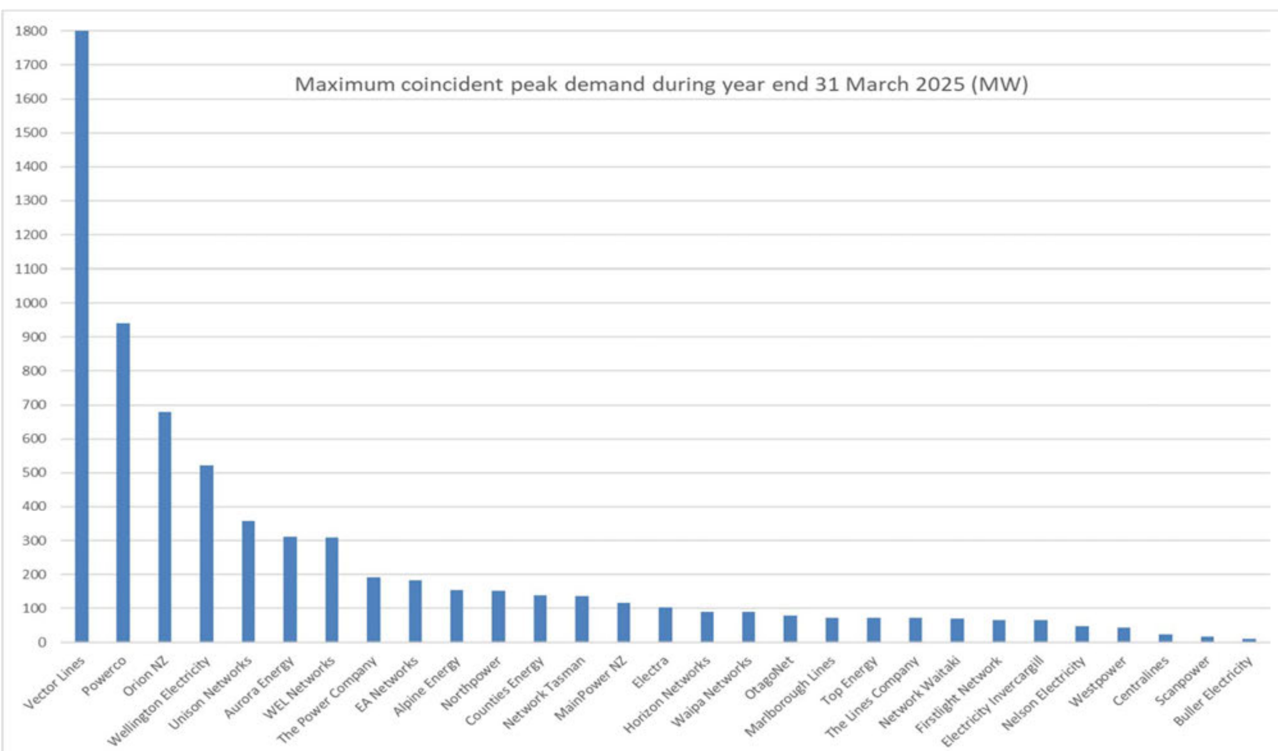
- 'incremental cost estimate' relies on c.6B.11(2); rename 'incremental offtake cost estimate'
- 'incremental distribution revenue estimate' rename' incremental distribution revenue estimate for offtake'
- 'incremental opex scaling factor' relies on c.6B.11(5); rename 'incremental opex scaling factor for offtake'
- 'incremental revenue estimate' relies on c.6B.11(3); rename 'incremental offtake revenue estimate'
- 'Connection enhancement cost allocation requirements' relies on c.6B.4; rename 'Offtake connection enhancement cost allocation requirements'

The definition of 'mandatory connection pricing methodologies' only applies to offtake connection and should include the work offtake: 'mandatory offtake connection pricing methodologies'

6B.15(4)(b) repeats the requirement in clause 6B15(3) that incremental revenue covers incremental injection costs.

Appendix 3: Distributed generation MW as a Percent of Maximum Coincident Peak Demand in the year ended 31 March 2025





Appendix 4: Who creates the need for additional network capacity and who pays for it?

The purpose of including this table is to show who is supplying electricity to meet demand under different scenarios and who pays the cost of the distributor's electricity distribution delivery service.

Just because offtake and distributed generation are both connected to distribution networks, they are not comparable 'customers' of the distributor. To be able to deliver electricity to offtake customers, distributors provide the same service to both transmission grid connected- and distribution network connected generators.

The red boxes in the table overleaf show where the proposed incremental injection cost principle has the potential to impose costs on distribution network connected generators – that are not imposed on transmission grid connected generators despite using the same delivery service from the distributor.

	Demand	**Supply**	
	Load / offtake customers	**Transmission grid connected generators**	**Distribution network connected generators**
Scenario 1: There is NO generation plant connected to a distribution network. The network has been constructed to supply current load of 100GWh per annum and meet peak demand of 50MW			
Who supplies the electricity to meet demand?	100GWh; 50MW	100GWh 100%	
Who pays the distributor for delivering the electricity? - Directly attributable costs	Not applicable	Not applicable	
- Shared / residual / common costs	100%	0%	
Scenario 2: There is NO generation plant connected to a distribution network. There is a trend of growing electricity use and the distributor augments the network to be able to supply an increase in total electricity used of 10GWh and increase in peak demand 5MW in 5 years' time.			
How much electricity is delivered?	110GWh; 55MW	110GWh 100%	
Who pays the distributor for delivering the electricity? - **Directly attributable costs**	Not applicable	Not applicable	
- **Shared / residual / common costs**	100%	0%	

	Demand	Supply	
	Load / offtake customers	Transmission grid connected generators	Distribution network connected generators
Scenario 3: Total electricity used is 110GWh per annum and peak demand is 55MW. A 20MW solar farm constructs a spur line to connect on an 11kV feeder producing 35GWh of electricity. This 35GWh of injection displaces the supply from transmission grid connected generators.			
How much electricity is delivered?	110GWh; 55MW	75GWh	35 GWh
Who pays the distributor for delivering the electricity? - **Directly attributable costs**	Not applicable	Not applicable	Pays 100% of directly attributable cost of connection – under current and proposed Code
- **Shared / residual / common costs**	Amount paid by Load is unchanged if generator is paying any incremental increase in these costs	0%	Proposal is to charge incremental programmatic and cumulative costs. High risk this could include ongoing apportionment of existing shared costs
Scenario 4: Scenario 3 is in place with total electricity used 110GWh per annum and peak demand is 55MW. An offtake customer constructs a new manufacturing plant connected to the distribution network. Energy consumed is 25MWh and peak demand 15MW. As well as the incremental connection assets, the distributor faces increased residual costs There is an increase in supply of electricity from the GXP as the distributed generation is operating at full capacity			
How much electricity is delivered?	135GWh; 70MW	100GWh	35 GWh
Who pays the distributor for delivering the electricity?			
- **Directly attributable costs**	New offtake customer pays the cost of connection	Not applicable	Not applicable
- **Shared / residual / common costs**	New offtake customer pays ongoing residual costs allocated to its customer segment	0%	High risk new generator could face ongoing apportionment of existing shared costs