

Submission form (DG-related Code changes)

Please email your submission to: connection.feedback@ea.govt.nz by 5pm, Tuesday 6 October 2026

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Questions on distributed generation-related Code change proposals

Questions	Comments
Q30. Do you agree the Code should be amended so the 10kW default export limit also applies to Part 1 applications? Please explain your views.	Yes. We support extending the 10kW default export limit to Part 1 applications, and more generally support a consistent approach across Part 1 and Part 1A as part of Part 6 of the Code. The policy intent should apply consistently to all small-scale DG applications up to 10kW, unless a network study demonstrates that a lower export limit is required. This will reduce the risk of applicants being directed into Part 1 and receiving a more conservative export outcome without clear technical justification. However, this should note that with this approach the Authority also accepts a degree of first-mover advantage: customers who prioritise or can afford solar investment may secure available hosting capacity before those who cannot. The Authority should acknowledge this equity implication and consider it further in future work on export allocation, congestion management and access to flexibility services.
Q31. Do you agree the Code should be amended so that distributors cannot limit their approved inverter lists to only communicating smart inverters or use their COPS to mandate smart inverters or flexible/dynamic export limits? Please explain your views.	Strongly disagree. We do not support amending the Code to prevent distributors from limiting approved inverter lists to communicating smart inverters or from using COPS to require smart inverters or flexible/dynamic export limits where this is part of a clear, standardised approach. Especially when Flexibility and Affordability are one of the 4 big strategic priorities of the Authority. In our view, providing clarity now on standardised product requirements and open-standards-based communications is a better long-term approach than preserving a broad non-communicating inverter pathway that may need to be unwound later. The Authority should remove the objective of preserving non-communicating inverters, as this would create an unnecessary legacy issue. The Authority to remain consistent with the Australian market and remain aligned with Clean Energy Council's approved solar inverter list – this is consistent with EECA's strategic direction as well. The cost difference between smart communicating inverters and non-communicating inverters is insignificant in the larger scheme of a solar or DER investment, particularly when compared with the long-term value of future-ready equipment. As reflected in the ENA's published position on this topic, New Zealand should avoid creating a fragmented market where different distributors adopt different inverter communication requirements, or where customers install equipment that cannot participate in future flexible export, dynamic operating envelope, visibility, orchestration, or emergency management services. The outset of market development is the right time to set a nationally consistent direction, because it gives manufacturers, installers, retailers, aggregators, distributors, and customers clear expectations about the capabilities required. We support a move toward smart communicating inverters based on open standards, particularly the Australian market (where most of our solar OEMs come from), CSIP-AUS / IEEE 2030.5, rather than proprietary or distributor-specific approaches. This would support interoperability, reduce bespoke integration costs, align New Zealand with the Australian market and supply chain, and enable customers to access future flexibility services without needing early equipment replacement. This is also more consistent with the direction of DSO development, where visibility and controllability of distributed energy resources will be needed to manage network capacity efficiently and equitably. A clear open-standards pathway is likely to produce better long-term consumer outcomes than allowing ongoing installation of non-communicating devices that cannot support future network and flexibility needs. A move towards non smart inverters is directly contradicting Authority's Flexibility strategic priority and its published position in the DSO roadmap.
Q32. Do you agree the Code should be amended to allow distributors to 'build in' an extra 10% DG penetration when doing	Disagree. We do not support introducing a 10% DG penetration buffer as an interim build-in to network studies. While we understand the intent to reduce repeated reassessments, this risks creating a partial and somewhat arbitrary solution that may be difficult for customers and installers to understand. It may also reduce export access for current applicants without a clear enduring allocation framework. The proposal could also lead to inefficient cost socialisation. Reserving additional network capacity for hypothetical future DG may bring forward network

a network study, that may lead to parts of networks qualifying for export limits below 10kW? Please explain your views.	investment or constrain the use of existing capacity, with those costs ultimately shared across the wider customer base. This risks increasing inequity, particularly where customers who cannot afford to invest in solar or other DG are required to contribute toward costs or capacity provisions that primarily benefit customers who can. This would be inconsistent with the broader effort to keep electricity and network services affordable for all consumers. Rather than adding a halfway measure, the Authority should keep the approach simple and transparent: lower export limits should be justified by current network conditions through a clear network study, and any future capacity allocation or congestion management framework should be developed properly through a nationally consistent process. That framework should explicitly consider cost allocation, equity, efficient use of existing hosting capacity, and the overall impact on affordability
Q33. Do you agree that a 10% allowance (as an interim measure) reduces the need for frequent network assessment. If not, what alternative level of allowance or approach should the Authority consider and why?	No. A 10% allowance may reduce reassessment frequency in some cases, but it is not the right solution. It introduces another assumption into the process and may be seen as reserving capacity without a clear policy basis for how that capacity should be allocated. A simpler approach would be to require export limits below 10kW to be based on current, documented network constraints, and to prioritise development of an enduring framework for hosting capacity, congestion management, flexible and dynamic exports, and fair capacity allocation.
Q34. Do you agree the Code should be amended to explicitly require distributors to offer both Part 1A and Part 1 DG application processes? Please explain your views.	Yes. We support making it explicit that distributors must offer both Part 1A and Part 1 processes where applicable. This will improve consistency across distributors and ensure applicants can access the streamlined, lower-cost Part 1A pathway when their proposed DG meets the relevant criteria. Clear publication of both pathways, including eligibility requirements and fees, will also help installers and customers submit complete applications. At the same time, consistent access to these pathways does not resolve the broader first-mover issue, where customers able to invest earlier in DG may obtain available export capacity ahead of later applicants.
Q35. Do you agree the Code should be amended to make it clear distributors cannot extend timeframes for Part 1A applications, but should not be penalised by the time taken by the applicant to remedy a deficient application? Please explain your views.	Yes, for current application volumes. Counties Energy can manage the proposed Part 1A timeframe settings at the volumes currently being experienced, and we support clarifying that distributors should not be penalised for time taken by applicants to remedy incomplete or inaccurate information, provide access for inspection, or pay relevant fees. The Code should clearly define when the clock stops and restarts, and distributors should retain records of these dates for transparency and monitoring. However, this position may need to be revisited if there is exponential uptake of small-scale DG, particularly if automation is not yet in place to process applications quickly and reliably. In that scenario, it would be difficult for Counties Energy, and likely any distributor, to keep up with tight statutory timeframes. Deemed approvals caused by expired timeframes could have negative engineering consequences if applications are approved by default before appropriate technical checks, network capacity assessment, phase balancing, protection considerations, or export limit settings have been completed. The Authority should therefore monitor uptake closely and consider whether future volume thresholds, automation readiness requirements, or alternative processing arrangements are needed before the risk of default approvals becomes material.
Q36. Do you agree with the objectives of the proposed amendments? If not, why not?	Partly. We agree with the objectives of the proposed amendments in relation to consistent access to Part 1 and Part 1A processes, efficient connection processes, and ensuring lower export limits are technically justified. However, the Authority should remove objective 6.1(b). Preserving the ability for distributed generators to continue using non-communicating inverters would create an unnecessary legacy issue and may delay the development of standardised, interoperable flexible export capability. The cost difference between smart communicating inverters and non-communicating inverters is insignificant in the larger scheme of a solar or DER investment, particularly when weighed against the long-term cost of stranded assets, reduced network visibility, and future retrofit or replacement requirements. The Authority should place greater weight on setting clear national product and communications requirements now, based on open standards such as CSIP-AUS / IEEE 2030.5, so that new DER installations are future-ready from the outset. We also support keeping Part 1A efficient, but the objective should recognise that very tight statutory timeframes and deemed approvals may become problematic if uptake increases exponentially before automation is in place. The Authority should also be clear that the proposed approach to export capacity allocation may advantage customers who are able to move first and invest in solar earlier. This should be addressed through future work on fair and efficient access to constrained export capacity, including flexible and dynamic export arrangements that can allocate headroom more equitably over time.

Q37. Do you agree the benefits of the proposed amendments outweigh their costs?	Partly. We agree that several of the proposed amendments are likely to have benefits that outweigh their costs, particularly the amendments supporting consistent Part 1 and Part 1A processes. However, we do not consider the benefits of preserving a non-communicating inverter pathway have been adequately established. In our view, this proposal risks creating unnecessary legacy issues, delaying standardisation, reducing near-term investment certainty, and increasing long-term integration costs. The cost difference between smart communicating inverters and non-communicating inverters is insignificant in the larger scheme of a solar or DER investment, and should be weighed against the benefits of future-ready capability. We also do not support the proposed 10% DG penetration buffer, as it risks adding complexity and reducing customer export access without a clear enduring allocation framework. On Part 1A timeframes, the benefits are reasonable at current application volumes, but the cost assessment should recognise the future risk that exponential uptake, without sufficient automation, could lead to deemed approvals before necessary engineering checks are complete. The costs of allowing continued installation of non-communicating inverters should be considered more explicitly. These include reduced network visibility, reduced ability to offer flexible or dynamic exports, potential stranded equipment, inconsistent customer experiences, and higher costs later if equipment needs to be replaced or retrofitted to support future DSO services. A nationally consistent open-standards approach would provide clearer market signals and is likely to reduce implementation costs over time.
Q38. Do you have any feedback on the Authority's assessment of the costs and benefits and the balancing of these as set out in this paper, including any evidence of quantified costs and benefits?	The qualitative assessment is broadly reasonable for the process-related amendments, but it understates the strategic cost of delaying standardised smart inverter requirements and the future operational risk associated with very high application volumes. The assessment should remove any assumed benefit from preserving non-communicating inverters, as this would create an unnecessary legacy issue and may require future retrofit or replacement. The cost difference between smart communicating inverters and non-communicating inverters is insignificant in the larger scheme of a solar or DER investment, particularly when compared with the long-term benefits of interoperability, visibility, and participation in future flexibility services. The assessment should consider the long-term costs of continuing to install non-communicating DER equipment, including reduced ability to manage constrained networks, delayed development of flexibility markets, higher integration costs, and the risk of inconsistent distributor-specific approaches. It should also recognise that tight Part 1A timeframes and deemed approvals are manageable at current volumes, but could create engineering risk if uptake accelerates before distributors have automated application assessment, network capacity checks, phase balancing, protection checks, and export limit setting processes in place. The Authority should also recognise the benefits of aligning with open standards, particularly CSIP-AUS / IEEE 2030.5, given the overlap between New Zealand and Australian inverter, battery, EV charging, and aggregator supply chains. A clear national signal would support product availability, conformance testing, interoperability, and more efficient implementation across the sector.
Q39. Do you agree the proposed amendments are 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.	Partly. We agree the proposed amendments are preferable to relying on guidance alone for the Part 1 and Part 1A process matters, because the issues relate to clear obligations and customer entitlements that should be reflected in mandatory Code drafting. However, we disagree with the proposed approach of preventing distributors from requiring communicating smart inverters or flexible/dynamic export capability through approved inverter lists or COPS, and we do not support objective 6.1(b). This approach appears directly contradictory to the direction established in the Authority's Roadmap for the future of distribution system operation in New Zealand. The Roadmap expects distributors to make significant progress toward implementing DSO functions and identifies improved network visibility, system interoperability, standardised flexibility market operation, and better coordination of consumer energy resources as critical capabilities. These outcomes will be difficult and more costly to achieve if the Code simultaneously preserves the continued installation of non-communicating DER that cannot be readily monitored, coordinated or incorporated into flexible export arrangements. Although the Roadmap is not itself a committed programme of regulatory intervention, the direction of travel is clear and should be reflected consistently across the Authority's regulatory work programme. Our preferred approach is for the Authority to provide a clear national direction now for standardised smart inverter capability based on open communications standards, particularly CSIP-AUS / IEEE 2030.5, with appropriate transition arrangements. This would better support the Authority's statutory objective by promoting efficient operation of the electricity industry for the long-term benefit of consumers. It would reduce fragmentation, support future flexibility services, improve network visibility and controllability, and reduce the risk of early DER investments becoming stranded or unable to participate in future export arrangements. Given the cost difference between communicating and non-communicating inverters is insignificant in the context of the overall investment, preserving a non-communicating pathway is not preferable to creating a future-ready national standard.

	We also do not support the proposed 10% DG penetration allowance as an interim measure. Rather than layering in a partial allowance, the Authority should keep the current connection assessment approach simple and develop a proper enduring framework for hosting capacity, congestion management and export allocation. That future framework should consider whether first-in-time allocation remains appropriate as DG penetration increases, given it may disproportionately benefit customers who can afford or prioritise early solar investment.
Q40. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act?	Partly. We agree that the proposed amendments relating to Part 1 and Part 1A consistency, the 10kW default export limit, and Part 1A timeframe clarification are broadly consistent with section 32(1) of the Act at current volumes. These amendments support efficient industry operation, reliable supply, and improved customer access to DG. However, Part 1A deemed approvals could undermine reliable and efficient outcomes if future uptake grows exponentially and applications are approved by default before necessary engineering checks are complete. We also do not agree that preventing distributors from requiring communicating smart inverters, or preserving objective 6.1(b), best supports section 32(1). In our view, a nationally consistent requirement for smart communicating inverters based on open standards would better support efficient industry operation over the long term. The cost difference between smart communicating and non-communicating inverters is insignificant in the context of the overall DER investment, while the long-term benefits of visibility, interoperability and flexibility capability are material. We also do not support the proposed 10% DG penetration buffer, as it introduces an interim assumption rather than a simple, transparent and enduring approach to capacity allocation. A clearer national framework for flexible and dynamic exports, DER visibility, hosting capacity, automation readiness, and congestion management would better support efficient use of network capacity and long-term consumer benefit.
Q41. Do you have any comments on the drafting of the proposed amendments?	We suggest the drafting be revised to avoid preventing distributors from progressing standardised smart inverter and flexible export capability. Clauses 6.3(2)(f), 6.3(4), and 6.3A(3)(c)(iii) should not prohibit distributors from requiring communicating smart inverters or flexible/dynamic export capability where those requirements are based on nationally recognised open standards and are applied transparently through published COPS. Objective 6.1(b) should be removed, as preserving non-communicating inverters would create an unnecessary legacy issue and is not justified by any material cost difference in the context of a solar or DER investment. If the Authority proceeds with a transitional approach, the drafting should make clear that any protection for non-communicating inverters is time-limited and subject to future national requirements for smart inverter functionality, interoperability, and communications standards. The drafting should also distinguish between proprietary or distributor-specific communications requirements, which should be avoided, and open-standards-based requirements such as CSIP-AUS / IEEE 2030.5, which should be encouraged or mandated through a nationally consistent approach. We do not support the drafting that allows a 10% DG penetration buffer. If the Authority wishes to address future capacity allocation, this should be done through a clear enduring framework rather than an interim percentage allowance. We also suggest the Authority clearly identify the start and restart points for Part 1A clock-stop provisions, including fee payment and deficient application information, and consider adding a review trigger or alternative process if application volumes materially increase before automated technical assessment capability is in place. This would reduce the risk of deemed approvals occurring before necessary engineering checks have been completed. We also suggest that drafting for 6.3A (c) (i) of the Code is amended from:

6.3A Limits on maximum export power and installed generation

- (1) A **distributor** must not set a limit on the **nameplate capacity** of **distributed generation** that may be installed at an **ICP** for applications made under Part 1 or Part 1A.
- (2) A **distributor** may set a limit on the **maximum export power** that may be injected into the **network** from an **ICP** (the '**maximum export power** threshold') for applications made under Part 1A, provided the **maximum export power** threshold is not set lower than 10kW except in accordance with subclause (3).
- (3) A **distributor** may set a limit on the **maximum export power** threshold that applies to an **ICP** or group of **ICPs** of lower than 10kW provided the **distributor** has undertaken a **network** study that—
 - (a) shows a lower **maximum export power** threshold is necessary to maintain voltage within the allowable tolerances or **network** safety, including, but not limited to, any issues reasonably likely to affect power quality or reliability, such as thermal constraints, in the section of the **network** that carries **electricity** from the **ICP** or group of **ICPs** to the **network**; and
 - (b) only takes into account **distributed generation** that is connected to, and applications that are being assessed to connect **distributed generation** to, the section of **network** that carries **electricity** from the **ICP** or group of **ICPs** to the **network**; and
 - (c) if the lower **maximum export power** threshold is part of a **dynamic export limit** or a **flexible export limit**—
 - (i) the lower **maximum export power** threshold is only active **during the time periods when the network study has identified that the lower maximum export power threshold is necessary**; and
 - (ii) the **dynamic export limit** or a **flexible export limit** does not operate when the **network** is not constrained.

To: the lower maximum export power threshold is only active during the time periods when, or under the conditions in which, the network study has identified that the lower maximum export power threshold is necessary...

This is to address the requirement that a network study supporting a dynamic/flexible export is required to provide specific times when an export limit below 10kW is justified, which is impractical given the dynamic nature.