Exploring plug-in generation and Code improvements for export limits and connection processes

Issues and consultation paper

8/09/2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

In this combined issues and consultation paper,[1] the Electricity Authority Te Mana Hiko (Authority) seeks your views about:

- issues regarding how the Electricity Industry Participation Code 2010 (Code) applies to plug-in generation, also commonly known as 'balcony solar'
- five proposed Code change clarifications regarding export limits and small-scale distributed generation[2] (DG) connection processes.

As New Zealand moves towards greater electrification and uptake of DG, the Authority has been progressively improving the efficiency of the rules on connecting to distribution networks under our Network connections project.[3] This work supports our main statutory objective to promote the efficient operation of the electricity industry for the long-term benefit of consumers.

Stage one of the project involved a suite of rule changes to make the application process to connect to networks easier, faster, more equitable and consistent across distributors. These changes improved application processes focused on medium and large-scale DG, such as solar and wind farms, and infrastructure such as electric vehicle charging stations and industrial plant.

To date, the second stage of the project has focused on making export limits[4] more efficient for DG of all sizes, including household solar.[5] We expect more efficient export limits to not only increase returns to households and other consumers who have invested in DG, but also support lower electricity costs for all New Zealanders in the long run. This is because more DG supplying local networks reduces the need to use higher cost generation, and (when exporting during a demand peak) may defer the need for expensive network infrastructure upgrades.

This paper continues stage two of the Network connections project by discussing the regulatory issues that need to be considered if plug-in generation is to be integrated into the Code. The paper also proposes five Code changes to clarify the original policy intent of the recent export limit rule changes and to improve application processes for small-scale DG.

Considering issues for plug-in generation

Plug-in solar is becoming increasingly common internationally, and some New Zealand consumers are keen to access this technology. We use the term 'plug-in generation' rather than 'plug-in solar' throughout this paper to allow for similar technologies that may emerge in the future. Plug-in generation could give consumers who cannot install permanently-fixed DG – because of cost, property ownership, or other practical constraints – more options for self-generation.

Regulation of plug-in generation falls within the remit of multiple regulators, and we are engaging closely with these agencies to ensure a coordinated approach, if needed.

A WorkSafe New Zealand (WorkSafe) prohibition notice currently prevents the use of these products in New Zealand. Although that notice is currently under review, we do not assume any particular review outcome in this paper.

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[1] An issues paper outlines matters the Authority is interested in seeking feedback on to inform potential future proposals for policy or Code changes. A consultation paper contains already formed policy or Code change proposals for feedback.

[2] In short, 'distributed generation' is generation connected to a distribution network. For a detailed definition, refer to Part 1 of the Code Preliminary provisions: https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-6-connection-of-distributed-generation/.

[3] The Authority's 'Network connections project'. See: https://www.ea.govt.nz/projects/all/network-connections/.

[4] The rate at which distributed generators can export (inject) electricity into networks at any one time.

[5] See our previous work on maximising benefits from local electricity generation: https://www.ea.govt.nz/projects/all/network-connections/consultation/maximising-benefits-from-local-electricity-generation/.

If the regulatory settings were changed to enable the sale and use of plug-in generation in New Zealand, then the Code would apply to plug-in generation once it is connected to a distribution network. The Code includes requirements that would relate to approvals from distributors, compliance with technical standards, and export arrangements.

There are clear benefits from plug-in generation for consumers who would otherwise be locked out of other types of DG, like rooftop solar, such as reduced electricity bills. Removing barriers to the use of additional low-cost generation could also support system-wide benefits, including reduced overall energy and network costs – lowering the cost of electricity supply for all consumers.

For these reasons, we think it is appropriate to consider how the Code applies to plug-in generation and what changes may be needed if WorkSafe's review permits it.

We are seeking feedback on whether:

- plug-in generation might impact network power quality, and what could be done to mitigate any risks
- a register of plug-in generation devices is needed and how to inform consumers about their obligations
- users of plug-in generation will have sufficient information to make informed decisions about exporting electricity, understand the implications of doing so, and how export arrangements could work in practice.

Feedback on this paper will help inform any future policy work or Code changes to enable plug-in generation in New Zealand.

Consultation on Code change proposals for more efficient connection of distributed generation

Proposals to improve export limits

Since May 2026, distributors have been required to follow new rules that support more efficient DG export limits. Since then, we have become aware of three issues we consider warrant clarification to ensure the intended benefits flow to consumers. We propose addressing these through three Code changes as follows:

Proposal 1: Expand the 10kW default export limit to include the Part 1 DG application process.[6] This would ensure applicants using the Code's Part 1 process, whose DG does not meet the requirements to use the streamlined Part 1A process for small-scale DG, will still get the financial benefit of being able to export at 10kW. This is providing their installation control point[7] is not shown to be subject to congestion by a network study.

Proposal 2: Prevent distributors limiting their approved inverter list to only smart communicating inverters,[8] or requiring only dynamic or flexible export limits (and therefore by implication, smart communicating inverters), under their connection and operation standards. This would protect consumer choice to retain a static export limit[9] at this stage, rather than being required to accept communicating inverters in anticipation of flexible/dynamic limits[10] in the future.

[6] DG applications for small-scale DG up to 10kW that do not meet distributors' connection and operation standards must use the Part 1 application process rather than the lower-cost, quicker, and simpler Part 1A process.

[7] Point where a consumer or generator connects to the network.

[8] Smart communicating inverters are those that can receive and respond to signals from remote systems (eg, to dynamically control export limits).

[9] Fixed export 'caps' not dependent on network conditions.

[10] Export limits that adjust periodically or in 'real-time' (dynamic export limits) to network conditions or change exports during pre-programmed times when constraints are expected (flexible export limits).

Proposal 3: Allowing distributors to include a buffer of 10% extra DG penetration, when performing a network study to assess the hosting capacity of an installation control point or group of installation control points, to determine if a DG export limit lower than 10kW should apply. This would reduce how often distributors need to reassess network hosting capacity.

Proposals to improve application processes for small-scale distributed generation

Similarly, we have become aware of two further issues regarding small-scale DG application processes we consider warrant amendment. Our proposals aim to provide clarity to industry participants and ensure benefits to consumers are realised. The two Code change proposals are:

Proposal 4: Clarifying that DG applicants must have access to both Part 1A and Part 1 application processes. This would ensure that distributors must offer DG applicants both the streamlined Part 1A process as well as the more involved Part 1 process, as appropriate.

Proposal 5: Clarifying that distributors cannot request timeframe extensions for Part 1A applications, but that the timeframe 'clock' stops when the distributor is waiting for additional information from an applicant to complete an application. This would ensure notifications from distributors for Part 1A DG applications do not go beyond the 10 business-day Code requirement, and the distributor is not penalised for an applicant taking time to remedy an incomplete application.

Flexible and dynamic export limits

Some distributors are exploring using dynamic or flexible export limits or have trials underway. We acknowledge flexible and dynamic export limits (and dynamic operating envelopes) are useful for ensuring the most efficient use of network capacity and may defer the need for investment in new infrastructure.

Proposals 1 and 2, above, still allow distributors to offer dynamic and flexible limits, but the consumer retains the option of a minimum 10kW static limit – unless a network study shows a lower limit is necessary.

We are currently working on a future issues and consultation paper to discuss the best way to enable dynamic and flexible export limits. We want to ensure the most efficient implementation of this solution without 'locking-in' specific technology or operating systems, unless there is clear justification for doing so. We also want to ensure any changes are within scope of the Code, while considering distributor interests and protecting consumer interests.

Therefore, we are currently proposing Code changes to prevent distributors mandating specific solutions, until we can engage with the industry to consider whether a standardised solution across all distributors is a better approach.

Consultation on Code change proposals

We expect the Code change proposals we are consulting on in this paper, would result in more efficient DG connections processes and provide a range of benefits to DG owners, distributors, and all New Zealanders in the long run.

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1 Purpose

1.1 This combined issues and consultation paper seeks your views on:

(a) issues about plug-in generation and the role of the Electricity Industry Participation Code 2010 (Code)

(b) five Code change clarifications for more efficient connection of distributed generation (DG).

The role of the Code regarding plug-in generation

1.2 The availability and use of plug-in generation is an emerging area. While plug-in generation is not currently permitted in New Zealand due to a WorkSafe New Zealand (WorkSafe) prohibition notice, Electricity Regulations (Prohibited Electrical Fittings – Inverters) Notice 2012,[11] this is under review.

1.3 The Authority seeks views on the regulatory issues that should be considered in determining whether, and if so, how, plug-in generation should be integrated into the Code, subject to the broader regulatory framework permitting its use.

Code changes for more efficient connection of distributed generation

1.4 Under the Authority's Network connections project, established in 2024, the Authority has introduced changes to Part 6[12] of the Code *Connection of distributed generation* to address barriers so networks can operate efficiently, competitively and reliably. Stage one of the project included establishing application processes for connecting medium and large-scale DG. Stage two involved recent changes to support more efficient export limits for DG.

1.5 The Authority now proposes five further Code change proposals to address emerging issues regarding connection of small-scale DG. The proposed changes aim to clarify and support the original policy intent behind the new rules that aimed to make export limits more efficient and improve some processes for Part 1 and Part 1A applications for DG.

The Authority must consult before making Code changes

1.6 Under the Electricity Industry Act 2010 (the Act), the Authority must consult before making any changes to the Code and include a regulatory statement. The Act also requires the regulatory statement to include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment and alternative means of achieving the objectives of the proposed amendment.

1.7 A regulatory statement relating to the proposed amendments for Code changes for more efficient connection of DG is provided at section 6 on page 39.

[11] See Electricity Regulations (Prohibited Electrical Fittings - Inverters) Notice 2012 | New Zealand Gazette.

[12] See https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-6-connection-of-distributed-generation/.

2 How to make a submission

2.1 The Authority's preference is to receive submissions in Word documents in the formats shown in Appendix C for submissions on plug-in generation and Appendix D for submissions on the DG-related Code improvements.

2.2 Submissions should be emailed to connection.feedback@ea.govt.nz with 'Consultation – plug-in generation and DG Code improvements' in the subject line by 5pm, Tuesday 6 October 2026.

2.3 The Authority will confirm receipt of all submissions.

2.4 If you cannot send your submission electronically, please email info@ea.govt.nz or call 04 460 8860 to discuss alternative arrangements.

2.5 We will publish all submissions. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published and explain why

(b) provide a version of your submission that we can publish (if we agree not to publish your full submission).

2.6 All submissions, including any parts the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Act.

3 Issues the Authority would like to address

The Authority is considering how the Code could respond to plug-in generation

3.1 If plug-in generation is allowed in New Zealand (ie, if the prohibition notice is amended or revoked), consumers will be able to connect generation directly into their premises without needing a professional installer.

3.2 Without any change, plug-in generation is captured by the Code's definition of DG when it is connected to a consumer installation. This means that existing Code requirements relating to DG would apply when a consumer connects a plug-in generation system into their premises.

3.3 Their potential use in New Zealand therefore raises several questions for how the Code should apply to plug-in generation. Section 4 of this paper (at page 12) seeks feedback on the appropriateness of the Code's existing regulatory framework for plug-in generation.

The Authority is continuing to improve the efficiency of connecting and operating small-scale distributed generation

3.4 This paper continues the Authority's work on the Network connections project, a multi-stage work programme to improve the efficiency of network connections. Table 1 summarises the project to date. The proposals in this paper form part of Stage 2 of the project.

Table 1: Summary of the Network connections project to date

Stage	Scope	Status	Effective dates
Stage 1	• Update connection application processes for medium and large DG • Add medium and large load connection application processes	Complete	• 1 December 2026 – updated medium and large DG application processes • 1 June 2027 – new medium and large load application processes
Stage 2	• Revise DG export limits • Improve low voltage inverter standards	Complete	• 11 May 2026
Stage 2 (this paper)	• Consider how plug-in generation fits with the Code • Code clarifications for more efficient connection of small-scale DG	Currently consulting	• To be determined
Future Stage 2 work	• Consider flexible and dynamic export limits and 'smart' inverter requirements • Review small-scale DG application processes • Review DG processing fees • Introduce medium and large load application processing fees	Scoping	• To be determined

3.5 The Network connections project is being rolled out in stages so the Authority can:

(a) focus on the connection issues that are most important to stakeholders

(b) have flexibility to respond to industry developments (eg, plug-in generation) as they arise

(c) manage resources effectively.

3.6 This paper is a combination issues and consultation paper:

(a) We seek industry feedback where we need more information on the potential issues presented by more plug-in generation, before considering Code changes.

(b) The paper also includes proposals, with associated Code drafting, for industry feedback, for the Code changes relating to DG connections.

3.7 The issues, questions and proposals in this paper mostly relate to Part 6 of the Code. Part 6 sets out the rules to connect and operate DG on networks, and to connect medium and large load applicants.

3.8 The independent Network services technical group[13] has assisted the Authority with identifying the issues raised in the plug-in generation-related section of this paper. The Authority will also seek the group's views on our analysis of submissions we receive on plug-in generation.

3.9 The Authority has also engaged with the Ministry of Business, Innovation and Employment (MBIE), WorkSafe and the Energy Efficiency & Conservation Authority (EECA) regarding plug-in generation when developing this paper. These agencies have jurisdictions that overlap with some of the issues raised and, in some instances, a multi-agency response is expected to provide the most efficient response.[14]

3.10 The Authority has work underway to make connection pricing methodologies more efficient and improve visibility of capacity and constraints on high-voltage parts of networks. These projects work in conjunction with the Network connections project to improve the efficiency of connecting to distribution networks.[15]

The Authority is proposing five Code clarifications for more efficient connection of small-scale distributed generation

3.11 The Authority proposes to make five Code change clarifications concerning export limits-related and DG application-related Code provisions. In May 2026, the Authority introduced Code changes requiring more efficient DG export limits,[16] as part of Stage 2 of the Network connections project. Following implementation of these changes, it has become apparent that some clarification is needed to the Code drafting to ensure it fully supports the policy intentions (proposals 1, 2 and 3 below).

3.12 The Authority also considers changes are necessary to the Code's Part 1 and Part 1A application processes for connecting small-scale DG to networks to support greater benefits to connection applicants. The proposed Code changes (proposals 4 and 5) to address these issues are also set out below.

[13] The Authority's 'Network Services Technical Group', see: https://www.ea.govt.nz/about-us/our-people/our-advisory-and-technical-groups/network-services-technical-group/.

[14] For example, both the Code and the Electrical (Safety) Regulations 2010 reference the same installation standard for DG systems (AS/NZS 4777.1).

[15] For example, see https://www.ea.govt.nz/projects/all/distributed-generation-pricing-principles-reform/ and https://www.ea.govt.nz/projects/all/transitioning-to-a-more-digital-electricity-system/consultation/improving-information-on-high-voltage-network-capacity/.

[16] See the Authority's work to maximise benefits from local electricity generation: https://www.ea.govt.nz/projects/all/network-connections/consultation/maximising-benefits-from-local-electricity-generation/.

1. Expanding the 10kW default export limit to cover the Part 1 application process

3.13 This proposed change would ensure the 10kW export limit for small-scale DG connections also applies to applications under the Part 1 Code process, rather than being limited only to the Part 1A process.

2. Prevent distributors from limiting their approved inverter list to smart communicating inverters or mandating flexible/dynamic export limits

3.14 This proposed change would ensure that distributors cannot only list smart communicating inverters on their approved inverter lists, or mandate communicating smart inverters or flexible or dynamic export limits through their 'connection and operation standards' (COPS). They would also need to list approved inverters that cannot communicate with remote systems.

3.15 This would prevent distributors effectively mandating communicating inverters to force flexible/dynamic export limits. We consider this would protect customer choice, and that this is particularly necessary given benefits from flexible/dynamic export limits are not yet widely available to consumers to allow them to make informed decisions. Distributors do not yet generally have the technical systems or capability to support implementing flexible/dynamic export limits, with only some piloting or initial set up processes/planning currently established or underway.

3. Allowing distributors a buffer of 10% extra DG penetration when assessing export limits lower than 10kW

3.16 This proposed change would allow distributors to add an extra 10% DG penetration to existing DG, when undertaking assessments to set lower export limits than the 10kW default under the Part 1A and Part 1 application processes. This would reduce the need for distributors to undertake more frequent network capacity reassessments after new DG applications are approved.

4. Clarifying that DG applicants must have access to both Part 1A and Part 1 application processes

3.17 This proposed change explicitly clarifies that distributors must allow DG applicants to use either the Part 1A or Part 1 application processes, as appropriate. This is particularly so applicants have the benefit of the streamlined Part 1A process.

5. Clarifying that distributors cannot make timeframe extensions for Part 1A applications

3.18 This proposed change clarifies that distributors must not extend the timeframe of Part 1A applications but allows distributors to stop the timeframe 'clock' when they send an application back to the applicant if it is incomplete. This includes clarifying that non-payment of a relevant fee is considered an incomplete application. This recognises the Code drafting intention to notify Part 1A application outcomes within 10 business days and that the application is deemed as approved if the distributor does not notify approval within 10 business days.

3.19 These five Code change proposals are outlined in more detail in section 5 from page 28.

4 Issues regarding how the Code could respond to plug-in generation

4.1 In this section, we seek feedback on the appropriateness of the Code's existing regulatory framework for plug-in generation (in case such plug-in generation becomes legal in this country).

What is plug-in generation

4.2 Plug-in generation generally refers to a packaged solar photovoltaic (PV) system that can be purchased and installed without professional assistance and is connected to a building's electrical installation through a standard electrical socket.

4.3 A plug-in generation package will generally consist of one or more solar panels, low voltage-connection cables, and an inverter[17] that converts the direct current (DC) electricity generated by the solar panels into alternating current (AC) used in the home. The inverter is connected to a household's electricity supply via a standard 3-pin socket/plug. The panels may be installed on a structure, such as a balcony, carport, garage roof, or placed on the ground. Plug-in generation may or may not include batteries.[18]

4.4 This paper refers to 'plug-in generation' throughout, rather than 'plug-in solar'. This recognises that plug-in generation technologies may evolve beyond plug-in solar. Irrespective of the generation source, the issues discussed in this paper remain the same.

The Code applies to plug-in generation used in a distribution network-connected premises

4.5 Plug-in generation, particularly smaller systems, is typically designed for self-consumption, but may export electricity to a network during periods when generation is higher than household demand. For example, for a typical New Zealand house:

(a) hot water load is intermittent but can be 2-3kW when the electrical element is actively heating water in the cylinder[19]

(b) refrigeration load is also intermittent and can be around 300W[20] when the compressor is active

(c) constant baseload demand is around 100W, eg, for televisions, other electronics.

4.6 Therefore, if a plug-in generation system of, for example 800W, is generating at full capacity during the middle of a sunny day, then its generation could exceed household demand when discretionary loads (eg, dishwasher) and intermittent loads (eg, hot water heating and refrigeration) are inactive.[21] This is much less likely to occur if a household is using a heat pump to cool in summer.

4.7 The Code does not apply where the plug-in generation system cannot export to a network (ie, it is electrically isolated from the network). This is the same way the Code treats isolated generation (eg, a standby diesel generator with mains changeover control).

[17] Most DG generates direct current (DC) electricity. An inverter is a component of a DG installation that converts DC to alternating current (AC), the type of electricity generated and used by the electricity system.

[18] Many of the international product standards and guides currently do not cover the addition of batteries to plug-in generation. This is an area that requires more investigation.

[19] Some dwellings may have gas water heating, so no electrical demand for hot water.

[20] This load would be higher for a larger fridge/freezer.

[21] In practice, many plug-in generation panels are unlikely to be best aligned for the sun, and some may be shaded. Actual generation is therefore likely to be lower than the nameplate rating of the panels. Also, some households may have large baseload demand (eg, spa pool pumps) and never generate to exceed household demand.

4.8 Given the expense of electrically isolating plug-in generation compared to its capital cost, and the way it is purchased and installed (ie, without the involvement of a professional installer), we think plug-in generation would rarely be isolated when fitted in New Zealand.

4.9 The Code does apply where the plug-in generation **is not** electrically isolated from the network, regardless of whether it actually exports electricity into the network. The Code defines DG as generating plant that is connected, or that a distributed generator proposes to connect, to a distribution network or to a consumer installation that is connected to a distribution network.[22]

4.10 Plug-in generation falls within this definition because it is generating plant connected, via a plug, to the consumer installation that is connected to the distribution network. Accordingly, it is capable of exporting if its generation exceeds self-consumption. Given this potential to export electricity, the Authority is interested in understanding the potential impacts it would have on the electricity system.

The Authority aims to reduce barriers to consumer choice

4.11 The Authority is interested in understanding the potential implications of more plug-in generation use, and how the Code could support consumers to access the technology in a way that supports the Authority's statutory objectives.[23]

4.12 The broader regulatory framework, including potential development of a safety standard and changes to the Electricity (Safety) Regulations 2010, will likely set the boundaries for manufacturing, importing, purchasing and installing plug-in generation, particularly in relation to safety concerns. A high-level summary of the regulations that are relevant to DG is provided in Appendix B.

4.13 The Authority's remit is limited to the extent to which plug-in generation falls within the Code where it is connected to the network. Accordingly, this paper focuses on export-capable plug-in generation and does not address risks associated with electrically isolated systems.

4.14 Plug-in generation will require appropriate standards and amendments to regulations to allow its safe uptake in New Zealand. The Authority is working with MBIE, WorkSafe, EECA and Standards New Zealand to develop standards, guides and other measures (eg, consumer education) to support the uptake of plug-in generation. We are also considering how best to put these requirements into place.

Plug-in generation could make self-generation an option to more consumers

4.15 With little to no installation cost, plug-in generation can provide a lower-cost pathway to self-generation than permanently-fixed DG systems, which require permanent hard-wiring. The lower upfront cost of plug-in generation can make self-generation more accessible to a wider range of consumers.

4.16 Given their portability, plug-in generation systems may appeal to renters, or homeowners who are unable or uncertain about investing in permanently-fixed DG. They may also be suitable to consumers whose dwellings are not compatible with conventional rooftop solar, for example, apartment residents.

[22] See Part 1 of the Code for definitions: https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-1-preliminary-provisions/.

[23] See the Authority's statutory objectives: https://www.ea.govt.nz/about-us/.

4.17 By lowering these barriers to self-generation, increased uptake of self-generation can deliver system-wide benefits. These benefits include reduced investment needed in network infrastructure, especially where generation is paired with storage that can be optimised in response to distributor peak rebates, improved network resilience through fewer and shorter network interruptions, and lower wholesale electricity prices, particularly during dry-year conditions and periods of low wind generation.

Q1. Do you have any views on our characterisation of plug-in generation?

The Code's distributed generation rules may not be suitable for plug-in generation

4.18 The Code was developed before the emergence of plug-in generation and as a result, Code provisions that apply to DG may not align with the way these technologies are installed and operated. A high-level summary of the Code provisions that are relevant to DG is provided in Appendix B.

4.19 The compliance pathway for permanently-fixed DG may not be practicable for plug-in generation. Unlike for permanently-fixed DG, there is typically no installer or electrical inspector to provide advice to the consumer, or act on their behalf when submitting the required application to the distributor. Nor is it necessary for the consumer to engage with their retailer at the time of installation, unless they are seeking payment for exported electricity.

4.20 This raises questions about the practical effectiveness and enforceability of any compliance requirements. Many consumers may be unaware that their system could export electricity to the network, and, consequently, have little reason to engage with retailers, distributors, or Code processes.

4.21 As well, the Code requires low-voltage DG to comply with the New Zealand/Australian installation and performance standards. These standards do not consider plug-in generation, which raises the question of what performance requirements should apply to this technology. These requirements should be proportionate to the risks of plug-in generation, otherwise they could unnecessarily limit the benefits of plug-in generation to consumers.

4.22 There are also questions regarding how electricity exported from plug-in generation is to be measured, compensated, and treated in reconciliation. At this stage, electricity exported from plug-in generation is likely to be incidental and minimal, given these systems are predominantly intended for self-consumption. However, we expect the technology to evolve, and more plug-in export could occur over time. Additionally, a consumer could use more than one plug-in generation system, increasing their likelihood of exporting electricity.[24]

4.23 Plug-in generation is not prohibited under the current Code, but it would be difficult for plug-in generation to meet current Code requirements. The following sections consider whether, and to what extent, the Code should apply to plug-in generation.

[24] Standards developed in New Zealand could limit the use of multiple plug-in generation systems, but the standards may be difficult to enforce in practice.

Technical standards are required to ensure plug-in generation is safe and supports secure and resilient network operations

4.24 Part 6 of the Code sets performance standards for all low-voltage inverters to support a secure, safe and resilient network electricity supply. The relevant standards are contained in the AS/NZS 4777 series *Grid connection of energy systems via inverters.*

Plug-in generation is not considered by the inverter *installation* standard cited in regulations

4.25 Part 6 of the Code (and the ESRs) reference the 'inverter installation standard' (AS/NZS 4777.1:2024 *Grid connection of energy systems via inverters, Part 1: Installation requirements*).[25]

4.26 Incorrect installation of DG and inverters can create electrical safety risks and adversely affect the integrity of the installation. The inverter installation standard contains a range of requirements intended to ensure the safe and reliable installation of inverter-connected generation systems.

4.27 The Code requires the inverter installation standard for the streamlined DG application process only (Part 1A).[26] This requires a distributor to approve or decline an application within 10 business days, otherwise it is deemed to comply with the Code. This limits the time for a distributor to fully consider an application. Requiring DG to meet the installation standard provides the distributor with added assurance the installation is safe.

4.28 However, the inverter installation standard does not apply to plug-in generation, as generation connected via a standard three-pin plug and socket is not addressed.[27] Given this, the Authority is working with MBIE, WorkSafe, EECA and Standards New Zealand on an alternative installation standard for plug-in generation.

4.29 This new installation standard is intended to make plug-in generation safe. It will consider features specific to plug-in generation, such as controls to ensure people are protected from plug prongs that may be electrically live.[28] It will also consider wider protections from electrocution and for household appliances, and any features unique to New Zealand dwellings.

4.30 Government agencies are actively working on this standard. To accelerate this process, we are reviewing the suitability of international safety standards for New Zealand use (eg, the German standard[29] released in December 2025, and the United Kingdom standard[30] released in July 2026).[31] We are also considering what else is needed to ensure plug-in

[25] See https://www.standards.govt.nz/shop/ASNZS-4777-12024. The Code requires generation to meet this standard if it uses the streamlined Part 1A application process for small-scale DG (See clause 1D of Part 6: https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-6-connection-of-distributed-generation/).

[26] See clause 1D(1)(a) of the Part 1A application process: https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-6-connection-of-distributed-generation/schedule-61-process-for-obtaining-approval/part-1a-applications-for-distributed-generation-of-10-kw-or-less-in-total-in-specified-circumstances/.

[27] Section 3.2.1 requires connection by fixed installation wiring, or by a connector/coupling arrangement using flexible cord, to a dedicated circuit on a switchboard. Where a connector or coupling is used, it shall be in accordance with Clause 3.2.3. Section 3.2.3 explicitly prohibits the use of 3-pin plugs and sockets. The standard also refers to inverters being directly connected to a mains switchboard, which is highly unlikely to occur with plug-in generation.

[28] For example, German plug-in generation must have both an electronic (supply cut-out) and mechanical means (retractable shroud) to isolate plug prongs. German plugs also have recessed sockets. New Zealand sockets differ from those used in Germany.

[29] DIN VDE V 0126-95:2025-12 *Plug-in solar devices for grid-parallel operation* https://www.vde-verlag.de/p/normen/din-vde-v-0126-95-vde-v-0126-95-2025-12/0100923-DE-PR.

[30] *Plug-in Solar Device Interim Product Specification* https://assets.publishing.service.gov.uk/media/6a60a03c47af652afa0c89f5/plug-in-solar-final-_interim-product-specification.pdf.

[31] For example, these standards also include requirements for weather protection, safe installation and warning labels.

generation is safe (eg, consumer education). Agencies will engage with industry experts and undertake public consultation before making decisions.

Plug-in generation is not considered by the inverter *performance* standard cited in the Code

4.31 The Code requires all low voltage DG to comply with the 'inverter performance standard' from 11 September 2026 (AS/NZS 4777.2:2020 A2 *Grid connection of energy systems via inverters, Part 2: Inverter requirements)*.[32] This standard is also mandatory for DG in Australia.

4.32 The inverter performance standard is different to the inverter installation standard discussed previously. It considers the interaction of the generation system with the distribution network (impacts 'after the meter', such as on power quality) rather than installation impacts in the home (impacts 'before the meter', such as risk of local electrocution).

4.33 The inverter performance standard is cited in the Code and the ESRs. It set a range of technical requirements that include, for example:

(a) Anti-islanding – ensures the inverter stops exporting electricity during an outage

(b) Disconnection settings – disconnects the inverter when the network exceeds safe operating parameters

(c) Sustained operation – ensures export continues during momentary fluctuations outside standard operating parameters, increasing security of supply

(d) Power quality modes – helps to support the management of power quality on networks (eg, voltage fluctuations)

(e) Ramp rates – sets limits on how quickly export ramps up and slows down, supporting network management.

In combination, these requirements are comprehensive and help to manage the impact of exported electricity on the network, while not constraining export[33] when issues are not present.

4.34 However, the inverter performance standard does not apply to plug-in generation. Section 2.3.1 of the standard requires inverters to be used and installed only as fixed equipment. Plug-in generation, that can be transferred from property to property and is connected and disconnected via a standard plug and socket, is therefore outside the scope of the standard.

4.35 The Authority wants the performance requirements of plug-in inverters to be commensurate with the risk posed to networks. Many international jurisdictions set plug-in limits of 800W maximum export, and a similar limit may or may not be applied in New Zealand. Regardless, plug-in generation is generally much smaller than permanently-fixed DG, with less or little export, so potentially has less impact on network operations. This raises the question of what level of performance should apply for plug-in inverters in New Zealand.

4.36 Although each individual plug-in system may have a lower network impact than permanently-fixed DG, we may ultimately see many plug-in systems in this country – there are now over a million plug-in systems installed in Germany alone. Also, plug-in generation is not typically installed with battery storage, so the timing of export will largely be uncontrolled. Therefore, any network performance requirements for plug-in inverters should consider the impact of plug-in generation over time and in aggregate.

[32] Requirement effective from 11 September 2026, inserted into Code on 11 May 2026 by clause 7 of the Electricity Industry Participation Code (Export Limits) Amendment 2026.

[33] This also includes controls on the rate that batteries can charge eg, reducing the charging rate when voltage on the network is low.

4.37 The Authority seeks feedback on what aspects of network performance should be required for New Zealand plug-in inverters. At a minimum, it is critical inverters have anti-islanding controls, which are included in international standards. Anti-islanding detects a loss of electricity supply on the network and automatically stops export, which protects people working on the network to restore supply. We seek industry feedback on what additional technical requirements may be needed (eg, voltage response modes, sustained operation, harmonics controls).

4.38 The information provided by submitters will help the Authority and other government agencies to develop appropriate performance requirements for plug-in generation. This includes the suitability of international standards for New Zealand use.[34] Agencies will engage with industry experts and undertake public consultation on proposed performance requirements before these are finalised.

4.39 A range of government agencies set rules and regulations in this area. Alongside standards development, agencies will work together on additional measures to support the safe installation of plug-in generation (eg, consumer education). We will also consider how best to implement the performance requirements for plug-in generation in New Zealand, given it is likely to be bought and installed by consumers with little knowledge of technical requirements.

4.40 Given standards are needed to help ensure plug-in generation is safe but are not currently available, the Authority is considering two Code options:

(a) exclude plug-in generation standards from the Code

(b) cite the New Zealand plug-in standards in the Code when available.

4.41 Option A is currently the Authority's preferred option as:

(a) The ESRs will set requirements for plug-in generation, including technical standards, so arguably Code citation is not required.

(b) The Authority does not envisage plug-in owners actively engaging with the Code unless they want to be paid for export, so standards cited in the Code may largely be ineffective.

Q2. What network performance requirements should apply to plug-in inverters in New Zealand, and why?

Q3. What do you think of the Authority excluding plug-in generation standards from the Code?

Distributors can set their own technical standards under the Code

4.42 The Code empowers distributors to set their own standards for DG. Distribution networks can have different properties, distributors know their networks best and, as technical experts, they can set technical standards to best support the operation of their networks. They do this through their COPS.[35]

[34] For example, see the German standard VDE-AR-N 4105 (VDE-AR-N 4105) Application Rule:2026-03 *Connection and operation of generation plants to the low-voltage grid* (TAR EZA NS) https://www.vde-verlag.de/p/normen/vde-ar-n-4105-vde-ar-n-4105-anwendungsregel-2026-03/0100940-DE-PR. Released in March 2026. It sets comprehensive, mandatory requirements for plug-in generation up to 800W, including disconnecting from the network within milliseconds when network parameters (eg, voltage, frequency) fall outside permissible limits. This is the updated version of a standard that informed development of New Zealand's inverter performance standard. It is available in German only.

[35] See the definition of 'connection and operation standards' in Part 1 of the Code *Preliminary provisions* (https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-1-preliminary-provisions/).

4.43 At present, there are no COPS that relate specifically to plug-in generation. However, if the prohibition notice is lifted, distributors could decide to implement COPS for plug-in generation that set additional requirements to the Code. However, we think this is unlikely given the level of risk posed by this technology and the associated cost for distributors to develop and monitor compliance.

Approval and registry arrangements may not be appropriate for plug-in generation

Part 6 requires distributor approval to connect distributed generation

4.44 Distributed generators must apply to a distributor under Part 6 of the Code[36] if they want to connect DG to a distribution network. The Part 6 application process provides distributors with visibility of DG connections, enabling distributors to assess network impacts and ensure the connection complies with applicable technical requirements.

4.45 Small-scale DG is typically installed through a professional intermediary. In most cases, the intermediary or installer completes the Part 6 application on behalf of their customer.

There are challenges applying Part 6 approval to plug-in generation

4.46 Without any changes to the current Code arrangements, a Part 6 application to the relevant distributor would be required by a plug-in generation consumer before connecting their device to the distribution network.

4.47 However, there are questions about whether this obligation is fit for purpose for plug-in generation, and whether any benefits of applying the Part 6 application process to plug-in generation would outweigh the practical challenges of compliance.

4.48 Arguably, the current Part 6 application processes may not be well suited to plug-in generation because it could:

(a) be too comprehensive and costly for plug-in generation, which will typically export lower volumes of electricity to networks

(b) require information from the consumer beyond what is useful to distributors

(c) be perceived as a barrier by consumers and reduce uptake

(d) be difficult to administer and enforce given plug-in generation is likely to be purchased and installed directly by consumers, without industry intermediaries that are typically involved in the Part 6 process.

4.49 That said, there may be value for certain parties, particularly distributors, in capturing information about the placement of plug-in generation systems for sufficient visibility to manage the network efficiently. While the absence of industry intermediaries with existing Part 6 requirements may make compliance more challenging, consumer information measures could help address this challenge.

4.50 Other jurisdictions have adopted simplified registration regimes for plug-in generation, rather than requiring the usual formal application processes that apply to permanently-fixed DG. For example, in Germany, the federal energy market regulator facilitates a 'Master Market Data Register'[37] where a person or small business is required to register a plug-in generation to connect and operate the device.

[36] Part 6 clause 6.4 refers to Schedule 6.1, clause 1B: *Distributed generator must apply*.

[37] See https://www.marktstammdatenregister.de/MaStR/Assistent/RegistrierungSolarArt (Master Market Data Register).A summary of the process of registering a plug-in product is here: https://sunsharetek.com/blogs/government-policies/germany-s-simplified-balcony-solar-system-registration-process-explained.

4.51 The Authority is considering whether an alternative approach to the current Part 6 application requirements may be appropriate for plug-in generation. One option could be a simplified registration process, like that adopted in Germany which does not require approval from a distributor.

4.52 Such an approach would support visibility of plug-in generation while not imposing major obligations on consumers, which could deter uptake. As in Germany, technical standards may still apply to ensure plug-in generation supports network operations (eg, voltage management).

4.53 We seek views on whether the benefits of registering plug-in generation would outweigh the associated costs, and if so, how a simplified approach should operate, or whether a more comprehensive approach would be preferable.

Q4. Do you agree that in the absence of a professional intermediary, it will be challenging to obtain a Part 6-type application from a plug-in generation consumer? Why, why not?

Q5. For a consumer to connect plug-in generation to their premises, should some form of Part 6-type application process be required? Why, why not?

Q6. If a form of Part 6-type application process should be implemented for plug-in generation, do you see that as a notification/registration, or an application that requires distributor approval? Why?

Q7. What information should be required if a registration or application for a plug-in generation unit is to be implemented?

Distributors record distributed generation information in the Electricity Registry

4.54 When DG is installed at an installation control point (ICP), Part 11 of the Code requires distributors to enter details of the installation in the Electricity registry (registry).[38] This information is taken from Part 6 applications.[39]

4.55 This registry is a national database of every electricity connection in New Zealand. It helps retailers, metering equipment providers (MEPs) and distributors share information, so they can:

(a) switch customers between retailers

(b) manage reconciliation and invoicing

(c) keep electricity connection information accurate and up to date.

4.56 The registry supports government monitoring, reporting and investigations. The data in the registry populates the Authority's publicly available electricity databases,[40] used by the electricity sector and other parties such as researchers and the media. Flexibility providers can also use registry data to develop and offer new business products.

4.57 Information in the registry includes details about the DG's maximum export power, the number of generating units and for each generating unit, the number of individual items comprising the generating unit connected to the ICP.

[38] See: https://www.ea.govt.nz/industry/retail/electricity-registry/.

[39] See Schedule 11.1, clause 7(1)(o): Electricity Industry Participation Code 2010 | Part 11 - Registry information management.

[40] For example, see https://www.emi.ea.govt.nz/Retail/Reports/GUEHMT.

Distributed generation Electricity registry requirements may be disproportionate for plug-in generation

4.58 Without changes to the Code, distributors' Part 11 obligations would apply where plug-in generation is connected at an ICP. However, this obligation may not be well suited for plug-in generation.

4.59 There are three related issues with applying the Part 11 requirement to plug-in generation. First, the information to be entered into the registry relies on information collected through the Part 6 process, which may not be well suited to plug-in generation, as discussed in paragraph 4.48.

4.60 Secondly, a notification or registration regime may only capture some plug-in systems, given owners are unlikely to engage with the Code unless they want to be paid for export. This is arguably an insufficient reason to not record information, particularly as other government agencies may have an interest in monitoring plug-in generation.

4.61 Thirdly, the level of DG information currently required for the registry may be excessive for plug-in generation. Individual plug-in generation systems have limited export capacity so there may be less need to record detailed information about each installation. However, if plug-in generation achieves significant uptake over time, particularly when combined with small-scale batteries, the aggregated effect could be material for network operations, system planning and future flexibility markets.

4.62 The Authority seeks views on whether plug-in generation details should be entered into the registry. If it is excluded, then the benefits of the registry noted earlier in paragraphs 4.55 and 4.56 are reduced. If recording plug-in generation in the registry were to be required, we also seek views on what level of information should be included in the registry. If a simple notification system is implemented, with basic system information recorded, then this may be sufficient for registry purposes.[41]

4.63 Given the portability of plug-in generation, keeping registry information current may be challenging. While a registration scheme could include requirements for updating records when a device is moved to a different address, compliance may be low in practice. As result, registry information could become quickly outdated, reducing its usefulness.

Q8. Would participants benefit from a registry that captures information about plug-in generation? Why, why not?

Q9. Should the existing registry be used? Why, why not?

Q10. Should entering information about plug-in generation be a requirement only after export has been identified at an ICP? Why, why not?

Q11. Would the type of information able to be collected at point of sale be sufficient to meet industry needs? Why, why not?

There may be alternative approaches to establish plug-in generation visibility

4.64 The Authority considers there is merit in considering whether alternative mechanisms ie, mechanisms that do not assume some variation of a Part 6 application, could achieve an appropriate level of visibility of plug-in generation more effectively.

4.65 One approach could be to leverage existing obligations on MEPs under Part 10 Metering. Under Part 10, MEPs must notify retailers if they become aware of an event that affects the

[41] For example, total generation output of the modules (panels) and maximum export rate of the inverter. A standard could require this information to be clearly labelled on the product.

integrity or operation of a metering installation. This includes when reverse electricity flow associated with unauthorised DG is identified.[42]

4.66 This could be a retrospective way to identify potential plug-in installations. Upon notification, the retailer could be required to make the consumer aware of any Code obligations, update the registry, and potentially direct the consumer to their distributor (or notify the distributor themselves).

4.67 We seek views on this approach, including whether there should be clear obligations on parties to notify others, whether there are other pathways to identify plug-in generation connected to the network, and what should be done if plug-in users decide not to engage with retailers and distributors. As consumers do not typically have a relationship with their distributor, we seek feedback on whether retailers may be best placed to engage directly with plug-in generators.

4.68 The portability of plug-in generation may also support an argument for placing notification and registry obligations on retailers, rather than distributors. Consumers typically inform their retailer when they move premises. Retailers could use these interactions to determine whether a plug-in generation device is also being relocated and, if necessary, update the registry accordingly.

4.69 The Authority is also interested in whether there are alternative ways to collect information about plug-in generation that are less dependent on consumers being the party responsible. For example, plug-in generation consumers could be required to register their product at the point of purchase. Although such an approach falls outside the scope of the Code, this may be achievable through other regulatory mechanisms (eg, EECA's product regulations). The Authority seeks feedback on the available options available to promote product notification and how effective these may be in New Zealand.

4.70 Another possible approach is requiring a Part 6-type application but only if the consumer wants to be paid for exported electricity (facilitating payment for exported electricity is discussed in the next section). This approach would have the benefit of excluding many smaller plug-in devices, reducing the burden on plug-in owners, and focusing regulatory requirements where there is a clear need.

Q12. Should the MEPs reverse power indicator be leveraged in identifying potential plug-in generation export? Why, why not?

Q13. Do you agree there is merit in considering whether retailers should be the primary customer interface for plug-in generation registration/notification? Why, why not?

Q14. Do you have any other suggestions on how consumers could be informed of Code requirements for plug-in generation?

Small export volumes from plug-in generation may not justify measurement

4.71 For permanently-fixed DG, many consumers choose to enter arrangements with a retailer to sell their surplus generation. To receive accurate payment for electricity export, the generator must have the appropriate metering arrangements, including a meter that measures electricity flows in both directions at the consumer's ICP.[43]

[42] See Schedule 10.6, clause 8(5A)(d). The Authority is aware some MEPs are configuring their meters for export when installed and where DG is not present. In this instance, the MEP may be unaware that plug-in generation is present.

[43] Often referred to as import/export metering.

4.72 Accurate metering arrangements also support other industry processes, such as reconciliation (the process of how electricity flowing in the power system is accurately allocated to buyers and sellers for invoicing).

4.73 At least in the short term, plug-in generation is primarily designed for self-consumption and should result in relatively low export volumes. Where a consumer's existing meter cannot measure export, the consumer would need to consider the cost of enabling import/export metering against the benefit of receiving payment for electricity export, particularly if a meter replacement or site visit is required.[44]

4.74 This means that, at least in the short term, a proportion of electricity exported from plug-in generation would likely be unmeasurable. This raises questions about how Code provisions and processes that rely on measured electricity in the system should apply to plug-in generation. Although exports from any individual plug-in generation system are likely to be small and incidental, the aggregate volume of unmeasured exports across many plug-in systems could be material to these processes, particularly over time.

4.75 Consumer awareness and engagement on the matter of export and possible payment is likely to vary. Some consumers may be unaware that their plug-in generation can export electricity to the network, while others may actively monitor their generation and exported electricity through apps or monitoring tools. Without a clear Code approach, or Authority guidance, there is a risk plug-in generation consumers receive inconsistent information about whether payment for electricity export may be available to them.

How to inform consumers of their options for plug-in generation where it exports

4.76 If a plug-in generation consumer were to look to be paid for their exported electricity, they would first need to notify their electricity retailer of their system. Their retailer can advise their customer on whether steps are needed to enable import/export metering (installation or reconfiguration), or whether their existing meter can measure bidirectional electricity flows. Several possible decision points may then arise regarding how the consumer's export is measured and compensated. The consumer could either:

(a) consider export volumes too small to justify the cost of an import/export meter

(b) recognise they have import/export metering enabled but choose not to seek payment for plug-in generation export

(c) arrange for import/export metering (or confirm it is already enabled) and seek payment for plug-in generation export.

4.77 Scenarios (a) and (b) would not be problematic, as the consumer has made an informed decision (although, we later discuss whether such consumers should be required to complete 'gifting' documentation). Scenario (c) would also be unlikely to present a significant issue. However, given that plug-in generation is an emerging area, we question if retailers would currently be able to provide consistent guidance to consumers. For example, would retailers advise plug-in generation consumers to complete a Part 6 application to their distributor, before offering a buy-back rate?

4.78 Other consumers will not be aware of the potential for their system to export. This raises a question of whether, or how, consumers should be proactively informed about the potential for export and the options available to them for receiving payment, including regarding whether new metering would be needed.

[44] Some meters can be remotely configured to measure and record electricity export.

4.79 We seek views on whether specific information should be provided to consumers with plug-in generation, and how it could be communicated, to ensure consumers can make informed decisions where there is potential for excess electricity generated by plug-in consumers to be exported to the network.

4.80 We seek views on how metering and payment arrangements could operate in a way that supports plug-in generation uptake. We are interested in views on what measures could be pursued to inform plug-in generation consumers of any export. We also seek views on how consumers could be informed about export metering, including whether, and what, education measures may be appropriate.

4.81 Some of the potential approaches outlined earlier in paragraphs 4.64 to 4.70 could also be extended to address this issue. For example, the existing requirement for MEPs to inform the relevant retailer of potential unauthorised generation at an ICP via a reverse power indicator, could be extended here. The retailer receiving the notification could be required to inform their customer for this ICP of any requirements and options available to them for receiving payment for their electricity export.

4.82 Paragraph 4.70 noted that compensation for plug-in generation export could be predicated on a distributor approval process, like that under Part 6 of the Code. Earlier, we identified this approach as a possible incentive for a consumer to complete the process of providing information regarding their plug-in generation to a distributor. Here, we seek views on this potential approach to ensure that any payment for plug-in generation export has appropriate assurances in place that the associated equipment has met any required technical standards.

Q15. Should an ability for plug-in generation consumers to receive payment for export be predicated by some form of Part 6 application and approval process? Why, why not?

Q16. What measures could be implemented to inform consumers of electricity export at their ICP that is potentially associated with plug-in generation, and what information should this include?

Q17. Should consumers be proactively informed of the potential for plug-in generation to export toa network. If so, which party is best placed to undertake this education role?

More unmeasured export may impact some Code provisions

4.83 The reconciliation model used in New Zealand's electricity market relies on all significant volumes of electricity being accurately measured and reconciled. If generation is not reconciled, it creates a cross-subsidy elsewhere in the system.[45] In this section, we seek views on whether unreconciled export from plug-in generation is likely to create problems.

4.84 Part 10 of the Code sets out, among other requirements, several requirements for DG metering to support electricity reconciliation processes.[46] Under Part 10, MEPs must ensure metering installations measure and record exported electricity.[47] Compliance with this requirement is usually triggered by a retailer's request for appropriate metering when a customer wants to be paid for export.

4.85 Part 15 of the Code contains provisions for the retailer to submit the metering data for reconciliation. This starts the process for the retailer to be paid for generated electricity and then pay the distributed generator.

[45] A potential cross-subsidy between traders. In low volumes, any policy to address the potential for this cross-subsidy would be unlikely to produce a net benefit to consumers.

[46] See Part 10 of the Code: https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-10-metering/.

[47] See Part 10, Clause 10.13A *Metering installation must record imported electricity separately from exported electricity.*

4.86 Part 15 also contains provisions for a generator to opt out of the wholesale market, including import/export metering, by gifting any generated electricity to the market.[48] Currently, if a generator chooses to gift their exported electricity to the wholesale market, then the associated volumes are recognised in the reconciliation process. This requires the generator to complete the necessary documentation.

4.87 Consumers that do not want to receive payment for any electricity exported from their plug-in generation, in theory, could act on the Part 15 gifting provisions. However, there would be little incentive on a plug-in generation consumer to complete the associated administrative requirements to formally gift their exported electricity.

4.88 Either gifting or not formally gifting but rather opting to not receive payment, may be preferred by some owners of plug-in generation given the low volume of exported electricity. It also avoids the cost and/or inconvenience for some of installing an import/export meter (or having their current meter reconfigured for export). Conversely, some consumers may expect to have the opportunity to receive payment where they export electricity.

4.89 However, in the absence of the formal gifting process, export appears as 'unaccounted for electricity' (UFE).[49] If the number of plug-in generation systems increases significantly over time in New Zealand, then its associated export could grow to be a significant part of overall UFE if not included in the reconciliation process. Excessive UFE caused by more plug-in generation could mask consumption metering or data handling errors.

4.90 We seek views on whether this would be a problem. For example, would excessive UFE trigger quality assurance checks by the reconciliation manager that are difficult to resolve, or skew distributor loss calculations during regular reviews.

4.91 We anticipate that exports associated with plug-in generation will be incidental and minimal (at least in the short term), and therefore unlikely to materially affect the reconciliation model. As batteries become more economic, it is likely that exported electricity from plug-in generation would be reduced even further as systems may come with batteries as standard or optional add-on.

4.92 Our initial view is that plug-in generation export can, at least initially, be treated as UFE for reconciliation processes. However, this position may evolve, and long-term implications should be considered now, particularly if plug-in generation uptake becomes widespread.

Q18. What issues do you see with more UFE in the reconciliation system as a result of more export from plug-in generation?

Q19. Do you agree with our view that plug-in generation export with no measurement enabled can be treated as UFE in reconciliation processes, with no need for formal gifting documentation? Would your view change as plug-in generation increases?

Q20. If gifting documentation were to be required by a plug-in generation consumer, how could this be facilitated?

[48] See clause 15.13 and clause 10.13(4) of the Code.

[49] For example, electricity line losses.

Plug-in generation may trigger Part 10 requirements on metering equipment providers

Event log notifications

4.93 Currently the Code requires the MEP to notify the retailer of events identified through the meter's event log. One common event is the 'reverse power indicator'. There can be several reasons for a reverse power indicator, one of which is unauthorised generation (although the reverse power indicator can also indicate metering issues or installation faults).

4.94 Enabling plug-in generation could lead to an increase in reverse power indicator events where generation is exported onto the network and is not known to the MEP. There is a potential issue of notifications for genuine reverse power indicator events being overwhelmed by the volume of reverse power indicators due to plug-in generation, leading to indicators being ignored by the MEP or retailer. We are unsure of the potential scale of this issue, or how other issues identified by this flag should remain able to be identified and remedied.

4.95 We seek views on whether there should there still be a requirement for the MEP to notify the retailer if they identify generation (for example through a 'reverse power' event notification). If there were to be no requirement, we are interested in whether there are genuine issues that may be missed.

Q21. Are there other genuine issues identified by the reverse power indicator?

Q22. Should the requirement on the MEP to notify the retailer via a reverse power indicator be reconsidered, if more plug-in generation is used? Why, why not?

Q23. Is there a way for a MEP to filter out plug-in generation related reverse power indicators?

Requirement to measure and record exported electricity

4.96 Part 10 requires MEPs to ensure exported electricity is measured and recorded, except where clause 15.13 *gifting documentation* applies. As already discussed, many plug-in generation consumers will be unlikely or unwilling to incur the cost of installing an import/export meter when their systems are intended primarily for self-consumption and may not be willing to engage with the process to formally gift their exported electricity.

4.97 Unless clause 15.13 has been completed by the consumer, the Part 10 requirement applies, and would leave the relevant MEP at risk of not complying with their Part 10 obligation.

4.98 This obligation could be addressed by requiring plug-in generation consumers to complete gifting documentation where they do not have, or do not intend to install, import/export metering (which has practical challenges earlier discussed in paragraph 4.87). An amendment to Part 10 to exclude plug-in generation from this clause could also be pursued.

4.99 We seek views on whether Part 10 metering requirements for measuring and recording exported electricity should apply where the electricity export is associated with plug-in generation.

Q24. Should Part 10 include an exclusion for requiring import/export metering for plug-in generation? Why, why not?

Other scenarios may need clarification in the Code

Plug-in generation connected alongside permanently-fixed distributed generation

4.100 The Authority has recently made changes to export limits for permanently-fixed DG.[50] Although plug-in generation is likely to export small volumes of electricity, it may lead to a property exceeding its agreed export limit when combined with permanently-fixed DG.

4.101 This could give rise to other issues such as voltage rise, hosting capacity constraints for other network users, invalidated protection assumptions, and conflicts with other export agreements.[51]

4.102 The Authority seeks feedback on whether this is a significant risk and, if so, how this risk should be addressed. A benefit for plug-in consumers with permanently-fixed DG is they will already have an import/export meter installed, so can be paid for plug-in generation without the cost to upgrade their meter.

Multiple plug-in units connected at an installation control point

4.103 Some consumers may decide to connect multiple plug-in systems at an ICP.

4.104 Recognising larger DG has a greater impact on networks, some jurisdictions limit plug-in generation systems to 800W maximum export.[52]

4.105 A simple notification scheme, possibly with penalties for consumers with plug-in generators who do not register the location of their systems, may be sufficient to discourage multiple plug-in generation systems at the same address, if this is considered to be a problem. However, this approach would be ineffective if plug-in consumers do not engage with a notification process.

Q25. Should Part 6 clarify requirements for a plug-in generation system being connected alongside approved permanently-fixed DG?

Q26. Should the Code clarify limits on the amount of plug-in generation capacity that can be connected at an ICP (noting any standards developed may define limits)?

Next steps for plug-in generation

4.106 Any future Code changes that would support plug-in generation should be proportionate, technology-neutral, interoperable with future consumer energy resources, represent a ‘least-regrets’ approach, and avoid creating real or perceived barriers to plug-in generation uptake, while managing any current or future risk.

4.107 We also note that any regulatory approach adopted should be sufficiently future-proof. If plug-in generation is not addressed within the Code at this stage, it may be more difficult to impose requirements after consumers have already invested in these products.

[50] The amount of electricity a distributed generator can inject into a distribution network at any time.

[51] To some extent, the inverter performance functions for permanently-fixed inverters (set out in AS/NZS 4777.2:2020) can mitigate these risks.

[52] For example, Germany allows the direct current (DC) nameplate capacity of the modules (panels) to exceed 800W on the premise as some generation will be self-consumed and not exported to the network.

4.108 The Authority recognises that plug-in generation is one example of an emerging group of consumer energy resources (which is likely to include portable battery systems and vehicle-to-home/grid systems). Any proposals to amend the Code that are developed for plug-in generation by the Authority should, where practical, support future technologies such as portable battery systems, vehicle-to-home/grid systems and other consumer energy resources without requiring substantial redesign.

4.109 Under the status quo, where plug-in inverters are prohibited by the current WorkSafe prohibition notice, we do not consider that any amendments to the Code to create an explicit pathway for plug-in generation are necessary. Any such amendment may inadvertently be seen as undermining the prohibition.

4.110 We are working concurrently with other agencies to ensure we are prepared to ensure the Code appropriately addresses plug-in generation, if, or when, the broader regulatory framework allows the use of plug-in generation. We will also continue to liaise with other agencies and will consult with industry on any Code amendment proposals, the timing of which may be informed by other agencies' work.

4.111 We will continue to monitor developments relating to plug-in generation, including international progress on regulatory frameworks and standards development. These findings, along with submissions on this paper, will inform our view of the options to update the Code to enable safe and reliable integration of plug-in generation on distribution networks, as appropriate.

Q27. What sources of information could the Authority use to monitor uptake of plug-in generation and/or any issues that may arise?

Q28. Do you agree with our overall characterisation of the challenges of plug-in generation? Why, why not?

Q29. Which of the challenges outlined in this paper present the most pressing issue for the Authority to address?

5 Proposals for Code changes for more efficient small-scale distributed generation connections

5.1 In this section, we set out five proposed Code change clarifications concerning Code provisions related to export limits and DG applications.

Proposals to improve export limits

1. Expanding the 10kW default export limit to cover the Part 1 application process

5.2 Part 6 of the Code provides for two processes for small-scale DG applications at or below 10 kW: Part 1A and Part 1. Part 1A is a more streamlined process for DG applications that meet a range of criteria set out under clause 1D of Schedule 6.1. These include, among other things:

(a) DG with inverters that:

(i) comply with the installation standard AS/NZS 4777.1:2024[53] and performance standard AS/NZS 4777.2:2020[54]

(ii) have settings meeting the distributors' COPS for Part 1A applications

(b) will export electricity less than or equal to the maximum export power threshold set by the distributor in clause 6.3A(2).

5.3 The Part 1A process is designed to be a straightforward, fast, lower-cost DG application process for low-risk, small-scale DG that distributors do not need to consider in detail. Distributors must approve applications meeting Part 1A requirements within 10 business days, and the applicant can then connect.

5.4 The alternative Part 1 DG application process is available for small-scale DG that does not meet the requirements for the Part 1A process due to having:

(a) greater capacity than the distributor's maximum export power threshold, and/or

(b) different inverter specifications or settings than those specified for Part 1A applications in the distributors' COPS.

5.5 Part 1 applications require more scrutiny by the distributor due to their greater complexity, consequently taking more time and being more costly to process. Distributors must approve or decline Part 1 applications within 30 business days (clause 3, Part 1, Schedule 6.1), although extensions of up to 20 business days are possible by mutual agreement (clause 4, Part 1, Schedule 6.1). The Code then allows a further 30 business days for the parties to negotiate a connection contract (clause 6 Part 1, Schedule 6.1).

The 10kW default export limit should benefit all small-scale DG applicants

5.6 On 11 May 2026, a new Code requirement came into force under clause 6.3A providing a default 10kW export limit under the Code's streamlined Part 1A application process for DG at or below 10 kW. This default applies unless the distributor has conducted a network study determining that a lower export limit is needed.

5.7 However, this requirement did not extend to the standard Part 1 application process as the Authority believed most small-scale applications would be processed using the Part 1A process. There is no default export limit under Part 1, nor a need to undertake a network

[53] Grid connection of energy systems via inverters, Part 1: Installation requirements: https://www.standards.govt.nz/shop/ASNZS-4777-12024.

[54] Grid connection of energy systems via inverters, Part 2: Inverter requirements: https://www.standards.govt.nz/shop/ASNZS-4777-22020.

study to set an export limit lower than 10kW. This means for Part 1 applications, distributors can set conservative static[55] export limits without the need to justify these limits.

5.8 The Authority has become aware that there is potential for distributors to place requirements in their COPS that affect access to the Part 1A process and create an effective barrier to the default 10kW export limit. This is by diverting applicants into the Part 1 process, and its potentially more conservative default export limit. For example, the Authority has been made aware of distributors setting requirements for DG applicants to have a 'smart' (ie, network communicating) inverter and accept a flexible or dynamic limit under COPS requirements, in order to be eligible for the Part 1A process.

5.9 It was not the Authority's policy intention that DG applicants could be diverted to the Part 1 process and therefore be precluded from getting the benefit of the 10kW default export limit. The policy intention was for the default 10kW to be available to as many applicants as possible, to enable benefits to DG owners, and ultimately all New Zealand consumers and for lower limits to be applied in limited circumstances, where supported by a network study.

5.10 Further, the Authority does not want to prevent distributors from offering a flexible or dynamic export limit, but it was not our policy intention for this to be a mandated requirement. We consider this should be an option offered to consumers, particularly where that approach would support distributors to offer higher export limits than would otherwise have been available, benefitting consumers. There are also other reasons consumers may prefer static limits such as more predictability and control (see paragraph 5.31). We do not support lower limits being applied in a blanket approach across sections of networks unless justified (eg for power quality or reliable supply reasons).

5.11 This is made clear in the Code requirement that was introduced in May 2026 requiring that any export limit below the default 10kW for flexible or dynamic limits must only be in operation when the network is congested, and the limit itself must be justified by a network study. It is contrary to the Authority's policy intent behind this requirement for distributors to be able to apply a different approach between applications depending on whether they are considered under the Part 1 process or Part 1A process.

5.12 The Authority therefore proposes amending clause 6.3A of the Code so the 10kW default export limit and need for a network study to justify lower limits also applies to Part 1 applications. We note this would not require distributors to conduct extra network studies. This is because these will need to be conducted in any case to justify any lower limits on ICPs or groups of ICPs that may be associated with Part 1A applications. Part 1A applies to the same small-scale DG (up to 10kW) as Part 1 applications.

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.

2. Prevent distributors limiting their approved inverter list to smart communicating inverters, or mandating this through connection and operation standards

5.13 Clause 6.3(2)(f) of the Code requires distributors to provide a list of the makes and models of inverters they have approved for connection to their distribution network.

5.14 Cause 6.3B further provides that from 11 September 2026, a distributor must require a distributed generator that injects electricity at low voltage to use an inverter that is compliant

[55] Fixed electricity export 'caps' not dependent on network conditions.

with, and applies, the “Australia A” inverter settings specified in inverter performance standard AS/NZS477.2:2020 incorporating Amendments No. 1 and 2.

5.15 A distributor may also specify different inverter settings than these in its COPS, if it has conducted a network study showing different settings are necessary to maintain voltage or network safety.

5.16 Thus, the Code requires low-voltage DG applications to use inverters complying with the latest inverter performance standard but allows flexibility where necessary to alter inverter settings. The Authority currently considers this is sufficient to ensure inverters conform to best practice standards.

Risk that distributors could mandate smart inverters on networks before operationally justified

5.17 With growing interest in applying flexible or dynamic export limits, the Authority is concerned there is a risk that distributors may seek to use their approved inverter lists to effectively mandate ‘smart’ communicating inverters by default. Distributors could apply this approach by listing only communicating inverters in their approved lists. For distributors to be able implement flexible or dynamic export limits, DG needs to be controllable through the functionality that communicating inverters provide.

5.18 A smart inverter is an advanced type of electricity inverter, commonly used in solar energy systems. It not only converts direct current (DC) from sources like solar panels into alternating current (AC) for use in homes, cars or networks, but also actively manages and optimises how electricity flows.

5.19 In general, smart inverters can respond to changing conditions (such as voltage or frequency fluctuations), and provide support functions like voltage regulation, reactive power control and network stabilisation. However, in the context of this paper, the key feature defining smart inverters is that they can communicate with network servers or gateway systems used by flexibility service providers (eg, aggregators), usually via the internet. Crucially, they can receive and respond to signals to curtail exports during network congestion or allow higher exports during times of low constraint.

5.20 The Code defines COPS in Part 1 as requirements that relate to connecting DG to a network or a consumer installation connected to a distribution network. The Code does not have any other obligations or restrictions regarding the contents of the COPS beyond that they must reflect or be consistent with reasonable and prudent operating practice.[56]

5.21 Where it is consistent with reasonable and prudent operating practice a distributor could potentially use the COPS to require using a smart inverter or require a consumer to accept flexible/dynamic export limits, thus implicitly require a smart inverter. However, as noted in paragraph 5.10 above, our policy intention is that any flexible/dynamic export limits must be by customer choice, and the lower export limit during congested periods must be supported by a network study.

5.22 There are several reasons we take this position, including the following points (which are elaborated with more discussion below):

(a) There is no urgent need to mandate communicating inverters and flexible/dynamic export limits now – all networks are currently offering 10kW limits for small-scale DG, unless there are areas of network constraint, where export can be limited.

[56] Defined in the Code at clause 1.1 ‘Interpretation’. See: https://www.ea.govt.nz/code-and-compliance/the-code-electricity-industry-participation-code-2010/part-1-preliminary-provisions/.

(b) Aside from pilots and initial planning or set-up work, distributors do not yet widely have the technical requirements established (eg, servers configured to communicate with inverters) or capability to roll-out flexible/dynamic limits.

(c) There are various inverters available with different technical functionality in communication ability or certification, and it is not prudent to mandate particular functionality now, without considering the options

(d) There are wider policy issues to consider including appropriate communication protocols, how the Code should support flexible/dynamic export limits, device interoperability and implementation.

Communicating inverters enable flexible or dynamic limits

5.23 The Authority recognises that in future, communicating inverters are likely to be an important enabler of flexible/dynamic export limits, dynamic operating envelopes and flexibility services. However, the current Code framework also supports static export limits, which do not require communication capability between the inverter and the distributor.

5.24 Communication protocols, such as the Common Smart Inverter Profile – Australia (CSIP-AUS),[57] based on IEEE 2030.5,[58] are also needed to coordinate data flows between inverters and networks for flexible/dynamic export limits. Thus, distributors could, for example, conceivably limit their approved inverter list to CSIP-AUS certified inverters, therefore effectively mandating communicating inverters. However, the Authority notes there are other communication protocols, and there are competing technologies in the smart inverter market.

5.25 We consider such a step (limiting the approved inverter list in this way) would be premature. This is because it appears that it is not based on current operational need or capability to use communication protocols to avoid injecting electricity from DG that (according to the Code's definition of reasonable and prudent operating practice):

(a) exceeds the distribution network capacity at the point of injection; or

(b) results in a significant adverse effect on voltage levels; or

(c) results in a significant adverse effect on the quality and reliability of electricity conveyed to other users of the distribution network.

5.26 This is evident as distributors are not yet widely implementing flexible/dynamic limits yet are complying with the 10kW default export limit for small-scale DG. This suggests that networks currently have sufficient capacity to offer the default 10kW static limit generally and do not currently need to mandate flexible/dynamic limits. We note that there are safeguards in place – ie, the existing ability to reduce exports in constrained parts of networks.

5.27 Consequently, requiring all distributed generators to install communicating inverters at this stage may impose additional costs and lock in particular technologies, without providing corresponding customer benefits.

We propose to preserve consumer ability to use non-communicating inverters

5.28 Ability to communicate with networks (eg, to facilitate flexible/dynamic limits) is not a current Code requirement for inverters and is not required where distributors implement static export

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57 CSIP-AUS (Common Smart Inverter Profile – Australia) is a standardised communication framework that enables smart inverters to securely exchange information and respond to signals, designed for Australian electricity networks. It is based on the IEEE 2030.5 standard. See: https://www.csipaus.org/

58 Institute of Electrical and Electronics Engineers standard IEEE 2030.5. A communication standard defining how smart energy devices exchange information with utilities to support network management and distributed energy resources. See: https://standards.ieee.org/ieee/2030.5/5897/.

limits. The Authority understands many inverters available in New Zealand have communications by default, while only a proportion of these will currently have capabilities to meet the CSIP-AUS communication protocol.

5.29 We propose to (for the time being) preserve the ability of consumers to use a non-communicating inverter if available, where they elect to operate under a static export limit. We consider customers should not be required to purchase or enable communications functionality where it is not required to receive the service being offered.

5.30 We consider this reasonable. This is because while communications capability may be required for future flexibility services, many New Zealand distributors do not yet have the capability to implement flexible/dynamic export limits through establishing communication with inverters, either directly via their own systems or through flexibility aggregators. For example, most distributors do not yet have servers configured for this functionality. Further, we have not yet considered what regulatory requirements would need to be in place for flexible/dynamic export limits to ensure greatest consumer benefit.

5.31 We also note some distributed generators may prefer static limits, which can be provided by a non-communicating inverter, because they allow:

(a) Greater predictability and control: provide a fixed, reliable export level with no reliance on communications or external control, making system performance and revenue more certain.

(b) Better synergy with batteries: create consistent excess solar that can be stored and later used or sold, increasing battery value and arbitrage opportunities.

(c) Lower complexity and risk: are simpler, cheaper, and easier to comply with, avoiding the uncertainty, variability, and operational complexity of flexible/dynamic export limits.

5.32 The Authority acknowledges that customers seeking access to flexible/dynamic export limits, dynamic operating envelopes, or participation in flexibility services, when eventually widely available, may reasonably be required to install communicating inverters capable of receiving and responding to external signals. However, we consider this should be addressed through future policy work rather than through approved inverter lists or COPS requirements. This is because wider policy issues need to be considered first to ensure requirements are implemented that ensure most benefits for consumers.

5.33 Preventing distributors from only listing smart communicating inverters on their approved list does not prevent distributors from offering flexible/dynamic export limits and, by implication, smart inverters, through their COPS. Rather, it clarifies that approved inverter lists cannot be used to mandate communicating inverters and that customers retain the option of accepting a static export limit using a compliant non-communicating inverter.

5.34 Distributors will still be able to specify the technical inverter performance requirements they need (eg, volt-var, volt-watt, 'ride-through' and Standards compliance) and communication ability to support flexible/dynamic limits if the consumer chooses that option, in their COPS.

5.35 Therefore, we propose amending clause 6.3 and 6.3A of the Code to address the above issues. This includes adding subclauses to make it clear that distributors may not limit their approved inverter lists to only communicating smart inverters and the COPS must not mandate use of communicating smart inverters or flexible/dynamic export limits.

We will undertake future policy work on regulating smart inverters

5.36 It is important to note that this proposal is not intended to determine whether communicating inverters should ultimately become mandatory in New Zealand. Rather, it aims to ensure approved inverter lists and COPS are not used as de facto mechanisms to require communications capability before the Authority has considered the broader policy questions associated with flexible/dynamic export limits, communications standards and interoperability.[59]

5.37 There is a wider policy question about whether communicating smart inverters should become mandatory and for what services. We acknowledge there are benefits from greater communications capability, interoperability, and support for future flexible/dynamic export arrangements. However, we think this should be considered alongside matters such as appropriate communication protocols (eg, CSIP-AUS/IEEE 2030.5, OpenADR[60]), flexible/dynamic exports, costs and consumer benefits, implementation pathways, and governance arrangements. The Authority intends undertaking this policy work later in 2026.

5.38 We also acknowledge calls from the distribution sector, notably Electricity Networks Aotearoa (ENA), that a mandate be introduced requiring all inverters used in New Zealand be 'smart' – ie able to communicate with remote systems. The ENA also proposes that that any mandate introduced should reflect the preference of the distribution sector that inverters conform to CSIP-AUS. We will address this proposal in our future policy work.

5.39 We expect the first paper on this policy work to be released for public comment within nine months.

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.

3. Allowing distributors a buffer of 10% extra DG penetration when assessing and setting DG export limits lower than 10kW

5.40 The Authority's recent export limits-related Code changes[61] gave distributors flexibility to set export limits lower than 10kW for Part 1A applications, where a network study justifies this. However, the study can only consider currently connected DG or applications being assessed; not future expected DG penetration (clause 6.3A(3)(b)).

5.41 We considered inclusion of potential future DG in the assessment may:

(a) require difficult, hypothetical estimates of future connection scenarios and timeframes

(b) lead to overly conservative limits as a safeguard for potential future applications that may never materialise

(c) by limiting higher exports, reduce the benefit that can be gained now.

[59] In this paper, interoperability is the ability of smart inverters, flexible/dynamic export limit controllers, and electricity network systems to communicate and operate together reliably, regardless of manufacturer or software platform. It is enabled by common communication standards, protocols, and data models that allow devices and systems to consistently exchange, interpret, and respond to export limit commands and operational data.

[60] OpenADR (Open Automated Demand Response) is a standardised communication protocol enabling distributors and utilities to send real-time signals to energy devices and systems to adjust electricity usage in response to network needs.

[61] See: https://www.ea.govt.nz/projects/all/network-connections/consultation/maximising-benefits-from-local-electricity-generation/.

5.42 We noted in our *Maximising benefits from local electricity generation (Export Limits)* decision paper (paragraph 5.37) that the standardised Export Limits Assessment Methodology (ELAM) could still allow for projected DG penetration as part of a distributor's future forecasting, but not to set export limits for current applications:

> "… *we expect projections of future DG growth could still be part of the ELAM. This will be to identify at what DG penetrations (trigger points) more stringent export limits may apply. That would be so distributors could then project/monitor numbers to estimate when an ELAM reassessment would likely be necessary to determine what those lower limits should be*."

5.43 However, we are aware that some distributors consider that not being able to incorporate a current buffer for future expected DG penetration means a need for distributors to do more frequent reassessments of available network capacity. In some cases, this may be after each DG application is approved, which could use considerable resources and delay application processing.

5.44 We also acknowledge a broader policy question about how network capacity should be allocated as DG penetration increases. We consider there would be value in considering how active congestion management, flexible/dynamic exports, dynamic operating envelopes, or capacity sharing approaches may evolve as DG penetration increases.

5.45 A key question is whether, and under what circumstances, distributors should be permitted to actively manage capacity for future uptake, while maintaining nationally consistent and transparent outcomes. However, any such change should be developed nationally and transparently, rather than through individual distributor assumptions about future uptake.

5.46 A challenge is that if distributors are permitted to preserve 'headroom' for future uptake, this starts to move beyond a simple connection assessment and towards a broader feeder-level capacity management framework. Questions arise around how reserved capacity is determined, how often network feeder[62] studies are updated, and whether capacity allocations are managed dynamically over time.

5.47 To avoid the need for numerous network studies as DG penetration marginally increases, a more practical approach may require periodic feeder-level assessments that establish available export capacity for both current and future customers. This points to future congestion management and export allocation frameworks, rather than simply changing the connection assessment methodology.

5.48 The Authority considers that an enduring solution is likely to involve more sophisticated export allocation and congestion management approaches, including flexible export limits and dynamic operating envelopes. However, these require further policy development and industry implementation and are issues to assess in our future policy work noted earlier. Accordingly, the Authority considers an interim approach is appropriate.

We propose an interim approach pending further policy work

5.49 In the interim, and based on engagement with industry, we propose amending clause 6.3A of the Code to allow distributors to 'build in' a buffer of an additional 10% DG penetration when calculating available DG hosting capacity. This allows for some future growth in penetration and aims to avoid the need for numerous network studies as DG penetration marginally increases. This means allowing distributors a further 10% increase over the current installed DG capacity when doing a network study that may lead to parts of networks qualifying for export limits below 10kW.

[62] The main distribution circuit that 'feeds' electricity from the substation out into the network.

5.50 For a simplified example of this approach, a low voltage section of line might have three consecutive ICPs with DG connected totalling 20kW maximum export power. When calculating the remaining capacity for the section of line, the capacity of existing DG connected can be increased by 10% to 22kW.

5.51 We consider this is a simple, transparent approach to address the immediate issue of distributors needing to undertake frequent reassessments of network capacity. We expect this efficiency gain for distributors to ultimately benefit consumers through lower electricity prices.

5.52 In practice, we expect distributors to only need to use the additional 10% buffer if they would otherwise need to conduct unreasonably frequent network assessments. This is not intended to address the broader policy question about how network capacity should be allocated as DG penetration increases. The Authority intends to progress that question in a separate consultation.

Q32. Do you agree the Code should be amended to allow distributors to 'build in' an extra 10% DG penetration when doing a network study that may lead to parts of networks qualifying for export limits below 10kW? Please explain your views.

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?

Small-scale DG application process-related proposals

4. Clarifying that DG applicants must have access to both Part 1A and Part 1 application processes

5.53 As noted previously, the Code provides for Part 1A and Part 1 application processes for DG applications. The Authority expects DG applicants to have access to either process as appropriate, particularly as Part 1A is quicker and cheaper for both distributed generators and distributors.

5.54 Wording in clause 1C of Schedule 6.1, 'How Parts apply to applications', makes it clear the Code intends that distributed generators have a choice regarding which application processes they are applying under. This clause provides that Part 1 applies to applications regarding DG with a nameplate capacity of 10 kW or less, unless the distributed generator has *elected* to apply under Part 1A.

5.55 Similarly, clause 1C provides that Part 1A applies to applications regarding DG with a nameplate capacity of 10 kW or less in total, if the distributed generator has *elected* to apply under Part 1A.

5.56 Clause 1D(1) of Schedule 6.1 further provides that a distributed generator may *elect* to apply to a distributor under Part 1A instead of Part 1 if the DG to which the application relates meets various requirements.

5.57 However, information the Authority gathered from distributors in a December 2025 information request under section 46 of the Electricity Industry Act 2010, indicates that not all distributors are explicitly offering applicants the Part 1A process pathway. This means applicants may not be benefiting from the streamlined application process, which is not the Authority's policy intention.

5.58 We understand some distributors may be offering ‘fast-track’ application processes without these being formally identified as Part 1A application processes. We consider this needs to be clarified to align with the intentions of the Code.

5.59 The Authority therefore proposes to remedy this by making it explicit in the Code that distributors must make both the Part 1A and Part 1 DG application processes available, as appropriate. This can be achieved by an addition to Code clause 1D of Schedule 6.1.

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.

5. Clarifying that distributors cannot make timeframe extensions for Part 1A applications

5.60 The Authority’s December 2025 information gathering request under Section 46 of the Act also indicated some distributors were taking extended time periods to process Part 1A DG applications.

5.61 Clause 9F(1)(2) of Schedule 6.1 of the Code provides that distributors must give notice of final approval for a Part 1A application no later than 10 business days after the application is submitted:

(a) if the distributor is satisfied the DG meets requirements specified under clause 1D; and

(b) the information provided by the distributed generator is complete and accurate.

5.62 Clause 9F(3) then provides that if the distributed generator does not receive notice within 10 business days, the distributor is deemed to have given notice of final approval.

5.63 Information we received covering the last six months of data gathered (1 May to 31 October 2025), shows distributors’ average time to notify decisions for Part 1A applications was approximately three business days – a satisfactory result. This excludes applications that took longer than 10 business days to process.

5.64 However, of the total number of Part 1A applications assessed (3955),[63] 561 (14%) took longer than 10 business days for decisions to be notified. A total of 120 of these applications took between 31 and 60 business days for notification and 83 applications took 61 business days or longer. Further, there were 38 applications identified where the time to merely notify that an application was complete and accurate was longer than 10 business days.

5.65 This is contrary to our policy intention, given the Part 1A process is designed to be a simplified, quick, one-stage application process, as noted in clause 9A(2) of Schedule 6.1 of the Code.

Distributors have advised of several reasons for delays to processing applications

5.66 In follow up responses to our information request, distributors noted the following reasons Part 1A application processing times are sometimes delayed beyond the 10 business-day target. We consider reasons (a) and (b) have some legitimacy.

(a) Incomplete or inaccurate application information. This is a significant cause of delays where more time is required to request, receive, and verify the necessary information before processing can continue.[64]

[63] Excludes 306 applications in our dataset that were quarantined and excluded from analysis.

[64] Around 80% of distributors contacted reported incomplete or inaccurate application information as a significant reason for processing delays.

(b) Delays in paying application fees. Many distributors do not consider an application complete until the required application fee has been paid. Some distributors have a provisional approval stage and require payment confirmation or supplementary documentation before an application is deemed complete and eligible for final approval.[65]

(c) Technical complexity of applications. More complex applications often require detailed technical assessments, including verification of installation records, network capacity checks, phase or fuse upgrades/downgrades, anti-islanding[66] requirements, or evaluation of associated network works. We note the criteria for a Part 1A application, and the requirements to identify congested areas and assess hosting capacity (from 1 December 2026) aim to ensure these issues are identified prior to an application being submitted.

(d) Number of applications. Applications can occur in waves, particularly when installers submit multiple applications simultaneously on behalf of customers. These surges can create temporary backlogs and increase processing times. We consider this requires extra resourcing or management and is not a legitimate reason for processing delay.

(e) Reporting limitations/inaccuracies. One distributor noted reporting issues can occur when applications are reopened to trigger customer satisfaction survey responses. Consequently, the system may record the reopening date rather than the original approval date, making the processing time appear longer than it was. We consider these reporting issues simply need to be addressed by fixing system functionality.

Processing delays should only occur for legitimate reasons under the Code

5.67 Under the Code, the legitimate reasons for distributors not to follow the requirement to give notice of final approval of applications within 10 business days relate to provisions under:

(a) Clause 9E of Schedule 6.1 ‘Non-compliance or incomplete information’. This relates to circumstances where the distributed generator has not provided the necessary or accurate information to enable the distributor to approve the application, or it does not meet the requirements to qualify for the streamlined Part 1A process.

(b) Clause 9C(2) of Schedule 6.1, where the distributor gave notice it wants to inspect the DG, but the distributed generator has not provided or arranged for the distributor to have reasonable access.

(c) Clause 2 of Schedule 6.5 where distributors can require payment of certain fees under Part 1A and non-payment would indicate non-compliance with the Code requirements.

5.68 We agree that non-payment of relevant fees should be able to be considered as an incomplete application.

5.69 We note that clause 9E(3) of Schedule 6.1 provides that if the distributed generator is advised of any deficiencies in the application, it must remedy these to the satisfaction of the distributor no later than 10 business days after being advised. Given distributors must advise of deficiencies within 10 business days (noting 10 business day deemed approval), few Part 1A applications dealing with deficiencies should take much longer than 20 days to process.

5.70 In the above cases of non-compliance or incomplete information, it is legitimate for distributors to halt the application process until these issues have been resolved. However,

[65] Around 45% of distributors contacted reported delays in paying application fees as a reason for processing delays.

[66] A safety feature in electrical power systems that automatically disconnects distributed generation from networks when network power supply is lost. Its purpose being to prevent the generation from continuing to energise a section of the network ("island"), which could endanger utility workers, damage equipment, or cause power quality and synchronisation problems when grid power returns.

the distributor should not be penalised for the time taken by the applicant to remedy the incomplete or inaccurate application. The distributor's processing time 'clock' should stop when the distributor advises the applicant of the deficient application, and restart when the applicant resubmits the complete and accurate application. The distributor should keep these dates in its records for the Authority's monitoring purposes.

5.71 Other than for these legitimate reasons, there is no provision in the Code under the Part 1A application process for distributors to negotiate or take extensions for the time taken for notice of approval of applications (ie, 10 business days from application).

5.72 To clarify that distributors cannot extend timeframes for processing Part 1A applications other than the legitimate reasons noted above, and that the 'clock' stops when a deficient application is notified to the applicant, we propose amending clause 9E and adding a subclause to 9F in Schedule 6.1 making this point clear.

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 for the time taken by the applicant to remedy a deficient application? Please explain your views.

6 Regulatory statement

Objectives of the proposed amendments

6.1 The objectives of the proposed Code amendments are to ensure:

(a) distributed generators have access to the 10kW default DG export limit when applying under the Part 1 application process, unless there is justification a lower limit should apply

(b) distributed generators can continue to use non-communicating inverters, where appropriate, to allow greater opportunity to connect DG as suits their preferences

(c) distributors need not conduct unnecessarily frequent network assessments

(d) distributed generators can elect to apply to connect DG under either the Part 1A or Part 1 application processes

(e) the Part 1A application process remains streamlined and rapid, benefitting both applicants and distributors.

(f) requirements for more efficient DG export limits to provide the most benefit possible to DG investors, networks and consumers, in accordance with our objectives for the Maximising benefits from local electricity generation[67] Code amendment.

Q36. Do you agree with the objectives of the proposed amendments? If not, why not?

The proposed amendments

6.2 The proposed Code amendments involve amending clauses or adding subclauses as follows:

(a) 6.3(2)(f) to add an amendment clarifying that distributors may not limit their approved inverter lists to only communicating smart meters or require agreement to flexible or dynamic export limits under their COPS

(b) 6.3(4) to add a subclause stating that distributors may not include a requirement in their COPS for a distributed generator to install a communicating inverter or accept a flexible export limit or dynamic export limit

(c) 6.3A(2) to expand the 10kW default export limit to cover the Part 1 application process (rather than solely the Part 1A process)

(d) 6.3A(3)(b)(i)(ii) to add an amendment allowing distributors to add a buffer of 10% for extra DG penetration when undertaking network assessments, for Part 1 and Part 1A DG Code application processes

(e) 6.3A(3)(c)(iii) to add an amendment requiring distributors to offer the option of export limits that are not dynamic or flexible, under Part 1 and Part 1A

(f) 1D(3) of Schedule 6.1 to add a sub-clause clarifying that distributors must offer applicants the opportunity to apply under both the Part 1A and Part 1 processes as appropriate

(g) 9E(1)(d) of Schedule 6.1 to add an amendment to clarify that non-payment of any relevant fee is considered non-compliance or incomplete information under clause 9E.

[67] See: https://www.ea.govt.nz/projects/all/network-connections/consultation/maximising-benefits-from-local-electricity-generation/.

(h) 9F(2) and (4) of Schedule 6.1 to add a sub-clause providing that distributors must not extend the timeframe for Part 1A applications, but the timeframe 'clock' stops until the applicant has submitted a complete application.

6.3 The drafting of the proposed amendment is contained in Appendix A.

The Authority expects the proposed amendments' benefits to outweigh the costs

6.4 The Authority considers that taken as a whole, the five proposed DG connections-related Code changes would present clear benefits to existing and potential distributed generators and ultimately all New Zealand consumers. Our qualitative assessment indicates the benefits of the proposals outweigh the costs, which mainly comprise limited administrative costs to distributors.

6.5 The Authority completed a qualitative assessment of the costs and benefits of the proposal, as we considered the identified costs and benefits could not be accurately quantified. This is largely because the amendments clarify existing Code requirements and address implementation issues identified following recent reforms. They do not create substantial new regulatory obligations or investment requirements.

6.6 Further, many of the expected benefits (see Table 2 below) relate to improved regulatory certainty, consumer choice, consistency of application processes, preservation of future technology options, and more efficient administration of DG connections. These benefits are tangible and potentially significant, but are also not readily capable of reliable quantification, given variables including consumer DG uptake and distributor-specific systems and practices.

6.7 We expect the costs to be modest and predominantly administrative, but also variable across distributors for the above reasons. This makes quantitative estimates speculative. Given the above, we consider attempts to assign cost values would rely heavily on assumptions and could create a misleading impression of precision.

6.8 We consider the qualitative analysis provides a sufficient basis for stakeholders and the Authority to assess whether the proposals are likely to promote the efficient operation of the electricity industry for consumers' long-term benefit. However, should submitters provide quantified evidence of costs or benefits, we will consider this.

Benefits

6.9 The Code amendments are designed to clarify our policy intent regarding our recent DG export limits-related Code requirements and ensure more efficient connections-related DG processes. Table 2 below sets out the expected benefits associated with each Code amendment.

Table 2: benefits of miscellaneous distributed generation connections Code changes

Code change	Benefits
1. Expanding the 10kW default export limit to Part 1	• Ensures distributed generators applying under Part 1 have the benefit of a default 10kW export limit. • Matches the above DG export limits requirements for both Part 1 and 1A DG application processes, creating a more aligned, equitable small-scale DG application process. • Encourages distributed generators to install larger DG systems to both meet personal needs and export surplus electricity to support network supply at times of peak load.

	• Supports greater availability of lower-cost local solar generation, displacing higher-cost network supplied generation, increasing efficiency and lowering electricity prices • Ultimately increases reliable supply and lowers electricity costs to all consumers through greater availability of local, renewable electricity and less need for infrastructure upgrades to supply more network-level generation.
2. Require that distributors cannot limit their approved inverter list to communicating smart inverters or use their COPS to mandate flexible/dynamic export limits or communicating smart inverters	• Supports efficient operation of the electricity industry for consumers' long-term benefit by maintaining distributed generators' choice to install standard non-communicating inverters and accept static export limits, protecting consumer preferences and ensuring that access to DG is not limited. • Preserves the status quo until policy work can be done to consider options to regulate, if any change in approach is warranted. For example, this prevents being 'locked' into particular communication protocols and inverter functionality before considering relative benefits to consumers and networks, and the most effective regulatory structures to support implementation. • Avoids requiring distributed generators to incur additional costs associated with communications functionality before flexible export services are widely available.
3. Allow distributors a buffer of 10% for extra DG penetration when undertaking network assessments	• Should reduce the need for distributors to assess network DG hosting capacity so frequently, saving assessment-related and administrative resources. • Provides an interim nationally consistent means of incorporating future DG uptake when undertaking network studies.
4. Clarifying DG applicants must have access to both Part 1A and Part 1 processes	• Ensures DG applicants have access to the one-step streamlined Part 1A process, which is lower cost, quicker, and more straight forward. This also provides associated benefits for distributors as regards lower administrative costs. • Requires distributors to explicitly offer both Part 1 and Part 1A processes, meaning small-scale DG applicants have two appropriate pathways to connect depending on the nature of their DG systems. • Ensures consistency across distributors with Code application processes, enhancing system efficiency which benefits consumers.
5. Clarifying distributors cannot request timeframe extensions for Part 1A applications, but the timeframe 'clock' stops when the distributor is awaiting additional applicant information to complete an application	• Helps the streamlined Part 1A DG application process function as intended when originally implemented. The Part 1A process was designed to provide a straightforward, fast, one-step process saving both distributed generators and distributors time, cost, and staff resources. • Benefits distributors by preventing them from failing to comply with timeframes for reasons not reasonably within their control.

Costs

6.10 We consider costs relating to the five Code changes to fall on distributors but with a significant proportion being administrative and insignificant when compared to benefits to distributed generators, New Zealand consumers and distributors. Table 3 below sets out the expected costs associated with each Code amendment.

Table 3: Costs of miscellaneous distributed generation connections Code changes

Code change	Costs
1. Expanding the 10kW default export limit to Part 1	• Removes distributors' ability to use the Part 1 process to set 'blanket' conservative static export limits. This may increase network administration costs through need for more detailed consideration.
2. Require that distributors cannot limit their approved inverter list to communicating smart inverters or use their COPS to mandate flexible/dynamic export limits or communicating smart inverters	• A continuing proportion (likely low) of inverters will not be able to be controlled by distributors or aggregators, giving less scope for using DG for network management in the short-term. • May slow uptake of communications-enabled DG capability and flexible/dynamic export limits in the short term compared to a mandatory approach, causing some system efficiency loss.
3. Allow distributors a buffer of 10% for extra DG penetration when undertaking network assessments	• May reduce the DG export limit for current applicants, limiting benefits to consumers and networks from higher exports in the short term. • A standard 10% allowance may not accurately reflect future DG uptake on every feeder and therefore represents a pragmatic rather than optimised assumption.
4. Clarifying that DG applicants must have access to both Part 1A and Part 1 processes	• Where distributors have been assessing applications only under Part 1, they will need to establish processes for Part 1A applications, meaning changes to their connection and operation standards, publishing information and upskilling staff. This will incur limited cost.
5. Clarifying that distributors cannot request timeframe extensions for Part 1A applications, but the timeframe 'clock' stops when the distributor is awaiting additional applicant information to complete an application	• Distributors take less time to process Part 1A applications, potentially meaning a higher risk of applications being incorrectly refused or approved, and associated administrative costs. However, less time processing should mean reduced distributor costs overall and Part 1A is designed to be a streamlined 10 business day process by definition.

Q37. Do you agree the benefits of the proposed amendments outweigh their costs? Please explain your views.

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 Authority has considered alternative options to the proposals

An alternative means to address some objectives is Authority guidance

6.11 These Code changes are straightforward amendments to address targeted issues, including to better align the Code with our original policy intentions.

6.12 We acknowledge it would be possible to issue guidance to distributors to clarify or explain the Authority's original intentions. However, we consider it clearer for distributors and the public to make these amendments to the Code's wording, so they are mandated and required to be followed.

6.13 Guidance would also not be a viable option to address the proposed amendment to allow distributors to add a 10% buffer for extra DG penetration, as this is prohibited in the Code.

We prefer the proposed amendments to issuing guidance

6.14 Overall, the Authority does not consider that issuing guidance would have the impact necessary to change distributors' actions. Therefore, guidance, by itself, is not preferred.

6.15 In the case of clarifying that distributors may not extend the Part 1A process timeline, for example, the Code is already clear that the intention is for approvals, or otherwise, to be notified in 10 business days. This has not been sufficient to prevent cases of distributors taking extended time periods to process these applications.

6.16 We consider Code change is necessary to ensure that our policy objectives are achieved. This does not preclude us issuing industry guidance to support the proposed changes, where necessary.

Delaying allowing a 10% buffer for extra DG penetration

6.17 It would be possible to delay introducing the 10% allowance for extra DG penetration for export limits assessment, until after future policy work on congestion management and export allocation. However, this prevents an interim solution to the need for frequent network capacity reassessments. Consequently, we prefer the Code change option.

An alternative to a 10% DG buffer is reducing existing line capacity by 10%

6.18 We also considered an alternative approach to allowing a buffer of 10% for extra DG penetration when assessing and setting DG export limits lower than 10kW. This was to instead allow distributors to reduce the capacity of the section of line (total circuit capacity) by 10%, before calculating the remaining available capacity, thus also creating a buffer for assessing DG penetration.

6.19 However, we prefer the proposed approach of adding 10% to existing DG, given it relates to actual installed DG on the circuit. It thus reduces the need to recalculate constraints or reassess export limits, potentially after each DG approval. This approach is also more aligned with our understanding of previous industry practice.

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.

The proposed amendment complies with section 32(1) of the Act

6.20 The Authority considers the proposed amendments are consistent with section 32(1) of the Electricity Industry Act 2010 (Act). Table 4 below outlines our assessment of the proposed changes with the Authority's objectives as listed in section 32(1).

Table 4: Assessment of Code changes against section 32(1) of the Act

Code change	How the change supports s32(1) alignment
1. Expanding the 10kW default export limit to Part 1	• Reliable supply of electricity to consumers by allowing higher electricity exports to support networks at times of peak load.
2. Require that distributors cannot limit their approved inverter list to communicating smart inverters or use their COPS to mandate flexible/dynamic export limits or communicating smart inverters	• Efficient operation of the electricity industry by protecting distributed generator choice in preferred type of inverter and export limit, while retaining distributor ability to set technical requirements.

	• Efficient operation of the electricity industry by allowing consideration of the most beneficial communication protocols, inverter functionality and regulatory structures for highest efficiency, supporting most consumer benefit.
3. Allow distributors a buffer of 10% for extra DG penetration when undertaking network assessments	• Efficient operation of the electricity industry by reducing the need for distributors to frequently assess network DG hosting capacity. • Efficient operation of the electricity industry by supporting nationally consistent decision-making by providing a common approach to account for future DG uptake.
4. Clarifying that DG applicants must have access to both Part 1A and Part 1 processes	• Efficient operation of the electricity industry through ensuring distributors offer the streamlined, quick, lower cost Part 1A DG application process.
5. Clarifying that distributors cannot request timeframe extensions for Part 1A applications, but the timeframe 'clock' stops when the distributor is awaiting additional applicant information to complete an application	• Efficient operation of the electricity industry by clarifying that distributors may not take more time than necessary in processing Part 1A DG applications.

Q40. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act? Please explain your views.

The Authority has given regard to the Code amendment principles

6.21 The Authority is satisfied the proposed Code amendments are consistent with the Code amendment principles. In particular, the proposed Code amendments involve a clear case for regulation by addressing problems created by the existing Code requiring amendments. The costs and benefits of the amendments are also summarised.

Appendix A Proposed Code amendment

Part 6
Connection of distributed generation

…

6.3 Distributors must make information publicly available

…

(2) Each **distributor** must make publicly available, free of charge, from its office and Internet site,—

…

(f) a list of the makes and models of inverters that the **distributor** has approved for connection to its **distribution network**, which must include a reasonable range of readily available inverters which include both inverters that are non-communicating and unable to receive and respond to signals from remote systems and inverters that are communicating and can receive and respond to signals from remote systems; and

…

(4) The **connection and operation standards** referred to in subclause 2(b) —

(a) must not include any provisions that require or have the effect of requiring that a **distributed generator** install a communicating inverter or accept a **flexible export limit** or **dynamic export limit** on **maximum export power** unless a **flexible export limit** or **dynamic export limit** applies under clause 6.3A(3)(c) and a **distributed generator** chooses to accept the **flexible export limit** or **dynamic export limit**.

…

6.3A Limits on maximum export power and installed generation

…

(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 1 or 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—

…

(b) only takes into account the following –
(i) the total **maximum export power** of **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~~
(ii) an allowance of up to 10% of the amount determined under subparagraph (i); 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; and

(iii) the **distributor** offers **distributed generators** under Part 1 or Part 1A, or both, the option of a limit on the **maximum export power** threshold that is not a **dynamic export limit** or a **flexible export limit**.

...

Schedule 6.1 cl 6.4

Process for obtaining approval

…

1D When application may be made under Part 1A

…

(3) A **distributor** must offer a **distributed generator** the opportunity to elect to apply to the **distributor** under Part 1A or Part 1 and, if the **distributed generator** makes an application under Part 1A, the **distributor** must process the application in accordance with clauses 9A to 9H.

…

9E Non-compliance or incomplete information

(1) This clause applies if a **distributor** considers that an application made to it by a **distributed generator** under this Part of this Schedule has 1 or more of the following deficiencies:

(a) the **distributed generation** to which the application relates does not meet the requirements specified in clause 1D:

(b) the **distributed generation** to which the application relates is not as described in the information given under clause 9B(2):

(c) the **distributed generator** has not complied with clause 9B(2)~~.~~:

(d) the **distributed generator** has not paid any relevant fee specified by the **distributor** in accordance with clause 6.3(2)(e).

…

9F Notice of final approval

…

(2) Subject to subclause (4), ~~T~~the **distributor** must give the notice no later than 10 **business days** after the date on which the application was submitted and must not extend this timeframe.

…

(4) In determining the 10 **business** days period in subclause (2), the following is not counted:

(a) the time the **distributed generator** takes to remedy any deficiency listed in clause 9E(1) and advised by the **distributor** to the **distributed generator** under clause 9E(2); or

(b) the time the **distributed generator** takes to arrange reasonable access for an inspection or to pay the inspection fee under clause 9C(3)—

Q41. Do you have any comments on the drafting of the proposed amendments?

Appendix B Regulators relevant to distributed generation

B.1 This section presents a high-level summary of the existing regulatory landscape that applies to DG. DG is subject to a range of regulations, including consumer product, electrical safety, and electricity market regulation. As a result, responsibility for regulating different aspects of DG is shared across multiple agencies.

Electricity (Safety) Regulations 2010

B.2 MBIE and the Minister for Energy are responsible for the Electricity (Safety) Regulations 2010 (ESRs), while WorkSafe is the regulatory agency responsible for their enforcement and compliance. The ESRs provide pre-market controls for electrical fittings and appliances, including through the declared high risk articles regime, in addition to controls relating to electrical installation safety.

B.3 The ESRs include that electrical work that comprises the installation of, or adjustment of the settings of, a mains parallel generation system in an installation is prescribed as 'high-risk prescribed electrical work'. This means there are certain requirements for certification and compliance where DG is being installed at a premises.

B.4 Specifically for DG, the ESRs cite AS/NZS 4777.1 for installation requirements of a 'low voltage mains parallel generation system that is connected to the national grid', to support the safe and effective installation of inverters.

Energy Efficiency and Conservation Act 2000

B.5 EECA regulates the energy performance of a range of products through its Equipment Energy Efficiency (E3) Programme. This includes residential products (eg, heat pumps, hot water cylinders) and commercial and industrial products (eg, distribution transformers). Products must meet EECA's requirements to be legally sold in New Zealand.

B.6 The Energy Efficiency and Conservation Act 2010 is in the process of being amended, which proposes including the ability to set regulatory requirements for demand flexibility on products, services and systems (but not safety). The Bill to make these amendments is expected to be introduced to Parliament in late 2026 or 2027.

The Electricity Industry Participation Code (2010)

B.7 The Authority is tasked with regulating the electricity industry under the Act. The Act authorises the making of regulations and the Code. The Code sets out the rules for the electricity sector.

B.8 As a subset of DG, the Authority is interested in the potential impact of plug-in generation on the electricity system, where plug-in generation is connected to a distribution network. Requirements relating to DG are covered by several parts of the Code, as outlined below. Because plug-in generation falls within the broader category of DG, the applicability of these requirements to plug-in generation is considered later in this chapter.

Part 6 Connection of distributed generation

B.9 Part 6 of the Code sets the rules for connecting DG to a distribution network and, among other things, requires the connection to be approved by a distributor and consistent with the distributor's COPS.

B.10 Part 6 provides a range of benefits for connecting DG, which include, that Part 6:

(a) places obligations on distributors and distributed generators to ensure the install process occurs readily and risks are appropriately managed

(b) sets technical installation standards to ensure DG supports the secure and resilient operation of the network

(c) sets limits on the cost to process applications

(d) provides a disputes process if parties disagree on the specifics of an installation

(e) places obligations on parties to ensure the continued operation of DG is safe once installed.

B.11 One of the key benefits of the Part 6 regime is that it provides regulated processes that make DG connection applications and rules more consistent for consumers across New Zealand's 29 distribution networks. This is particularly beneficial for businesses wanting to connect to networks in multiple regions.

Part 10 Metering

B.12 Part 10 Metering contains provisions for the accuracy and certification of metering. This includes requirements that all electricity conveyed through a point of connection must be metered.

B.13 For DG, this means all systems must have an import/export meter installed to ensure export is measured and recorded. These requirements are on the metering equipment provider (MEP) and are triggered once the retailer requests import/export metering. The only exception to this requirement is if the exported electricity is 'gifted' to the market under the provisions of Part 15 Reconciliation.

Part 11 Registry information management

B.14 Part 11 Registry Information Management requires distributors to enter information about installed DG into the electricity registry. Having this information in the registry means distributors are supported to better plan and manage their networks and retailers are aware of the DG when offering products and services to their customers and prospective customers.

Part 15 Reconciliation

B.15 Reconciliation is the process of how electricity flowing in the power system is accurately allocated to buyers and sellers for invoicing.

B.16 Part 15 of the Code contains the provisions for the retailer to submit metering data for reconciliation. This starts the process for the retailer to be paid for electricity generated by the distributed generator and therefore pay the distributed generator for any electricity exported to a network.

B.17 Part 15 also contains a provision for the distributed generator to opt out of the wholesale market, including export metering, by gifting any surplus electricity they generate to the market.

Appendix C Submission form (Plug-in generation)

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

Name	
Organisation	

Questions on issues regarding plug-in generation

Questions	Comments
Q1. Do you have any views on our characterisation of plug-in generation?	
Q2. What network performance requirements should apply to plug-in inverters in New Zealand, and why?	
Q3. What do you think of the Authority excluding plug-in generation standards from the Code?	
Q4. Do you agree that in the absence of a professional intermediary, it will be challenging to obtain a Part 6-type application from a plug-in generation consumer? Why, why not?	
Q5. For a consumer to connect plug-in generation to their premises, should some form of Part 6-type application process be required? Why, why not?	
Q6. If a form of Part 6-type application process should be implemented for plug-in generation, do you see that is a notification/registration, or an application that requires distributor approval? Why?	
Q7. What information should be required if a registration or application for a plug-in generation unit is to be implemented?	
Q8. Would participants benefit from a registry that captures information about plug-in generation? Why, why not?	
Q9. Should the existing registry be used? Why, why not?	
Q10. Should entering information about plug-in generation be a requirement only after export has been identified at an ICP? Why, why not?	
Q11. Would the type of information able to be collected at point of sale be sufficient to meet industry needs? Why, why not?	
Q12. Should the MEPs reverse power indicator be leveraged in identifying potential plug-in generation export? Why, why not?	
Q13. Do you agree there is merit in considering whether retailers should be the primary customer interface for plug-in generation registration/notification? Why, why not?	

Q14. Do you have any other suggestions on how consumers could be informed of Code requirements for plug-in generation?	
Q15. Should an ability for plug-in generation consumers to receive payment for export be predicated by some form of Part 6 application and approval process? Why, why not?	
Q16. What measures could be implemented to inform consumers of electricity export at their ICP that is potentially associated with plug-in generation, and what information should this include?	
Q17. Should consumers be proactively informed of the potential for plug-in generation to export to a network. If so, which party is best placed to undertake this education role?	
Q18. What issues do you see with more UFE in the reconciliation system as a result of more export from plug-in generation?	
Q19. Do you agree with our view that plug-in generation export with no measurement enabled can be treated as UFE in reconciliation processes, with no need for formal gifting documentation? Would your view change as plug-in generation increases?	
Q20. If gifting documentation were to be required by a plug-in generation consumer, how could this be facilitated?	
Q21. Are there other genuine issues identified by the reverse power indicator?	
Q22. Should the requirement on the MEP to notify the retailer via a reverse power indicator be reconsidered, if more plug-in generation is used? Why, why not?	
Q23. Is there a way for a MEP to filter out plug-in generation related reverse power indicators?	
Q24. Should Part 10 include an exclusion for requiring import/export metering for plug-in generation? Why, why not?	
Q25. Should Part 6 clarify requirements for a plug-in generation system being connected alongside approved permanently-fixed DG?	
Q26. Should the Code clarify limits on the amount of plug-in generation capacity that can be connected at an ICP (noting any standards developed may define limits)?	
Q27. What sources of information could the Authority use to monitor uptake of plug-in generation and/or any issues that may arise?	
Q28. Do you agree with our overall characterisation of the challenges of plug-in generation? Why, why not?	
Q29. Which of the challenges outlined in this paper present the most pressing issue for the Authority to address?	

Appendix D Submission form (DG-related Code changes)

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

Name	
Organisation	

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.	
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.	
Q32. Do you agree the Code should be amended to allow distributors to 'build in' an extra 10% DG penetration when doing a network study, that may lead to parts of networks qualifying for export limits below 10kW? Please explain your views.	
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?	
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.	
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.	
Q36. Do you agree with the objectives of the proposed amendments? If not, why not?	
Q37. Do you agree the benefits of the proposed amendments outweigh their costs?	
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?	

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.	
Q40. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act?	
Q41. Do you have any comments on the drafting of the proposed amendments?	

Appendix E Glossary of abbreviations and terms

Term	Definition
Anti-islanding	A safety feature in electrical power systems that automatically disconnects distributed generation from networks when network power supply is lost.
AS/NZS 4777.1	Australian/New Zealand inverter installation standard.
AS/NZS 4777.2	Australian/New Zealand inverter performance standard.
Authority	Electricity Authority Te Mana Hiko.
Act	Electricity Industry Act 2010.
Code	Electricity Industry Participation Code 2010.
COPS	Connection and operation standards. Distributors policies and technical requirements for connecting distributed generation to a network
CSIP-AUS	Common Smart Inverter Profile – Australia. A standardised communication framework enabling inverters to exchange information and respond to signals, designed for Australian networks.
DG	Distributed generation. Electricity generated at an ICP for local use or injection into networks.
Discretionary load	Load that can be adjusted or turned on/off without impacting operations, eg, dishwasher.
Dynamic export limits	Electricity export limits that adjust continuously to 'real-time' network conditions.
Export limits	The maximum amounts of electricity a DG owner is permitted to supply (export) to the network at any given time
Flexible export limits	Export limits that adjust periodically based on predefined schedules or scenarios.
IEEE 2030.5	Institute of Electrical and Electronics Engineers standard IEEE 2030.5. A communication standard defining how smart energy devices exchange information with utilities to support network management and distributed energy resources.
ICP (Installation control point)	Point where a consumer or generator connects to a network.
Intermittent load	Load that operates occasionally or for short periods rather than continuously, eg, electric water heating.
Inverter	Device that converts DC electricity into AC for network use.
kW (Kilowatt)	Unit of real power equal to 1,000 watts.

Maximum export power threshold	Export limits as expressed in the Code.
Nameplate capacity	The maximum continuous output a generating plant or its inverter can produce under specific conditions, whichever is lower, measured in kilowatts (kW) or megawatts (MW). Defined in Part 1 of the Code.
OpenADR	Open Automated Demand Response. A standardised communication protocol for energy devices and systems.
Part 1A	Streamlined Code process for DG ≤10 kW that meet simple criteria.
Part 1	Comprehensive Code process for DG ≤10 kW not meeting Part 1A criteria.
Phase	The position of a point in an AC (alternating current) waveform relative to a reference point, usually measured in degrees. It describes the timing relationship between voltage or current waveforms.
Ride through	The ability of an inverter to continue operating or stay connected during short-term voltage or frequency disturbances instead of shutting down.
Static export limits	Fixed electricity export 'caps' not dependent on network conditions.
Volt-var	An inverter function that progressively absorbs reactive power from DG exports to the network when voltage is high (thereby enabling maximum export) or injects reactive power to the network when voltage is low, to keep voltage at desired levels.
Volt-watt	A function in an inverter that progressively reduces DG export to the network as voltage rises, to keep voltage within desired levels.