

6 October 2026

Electricity Authority
PO Box 10041
Wellington 6143
By email to: connection.feedback@ea.govt.nz

Dear Electricity Authority team,

Consultation Paper— *Exploring plug-in generation and Code improvements for export limits and connection processes*

Electricity Networks Aotearoa (ENA) welcomes the opportunity to make a submission to the Electricity Authority (the Authority) on its consultation and issues paper on *Exploring plug-in generation and Code improvements for export limits and connection processes*.

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

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

ENA supports a simple and proportionate framework for plug-in generation that enables consumers to access these devices without unnecessary cost or administrative burden, while protecting the safety, power quality and reliability of distribution networks. Nationally consistent technical requirements, with product compliance assured before or at the point of sale, should be complemented by a straightforward national notification and registration process. The framework should recognise both the limited impact of individual devices and their potentially material cumulative effects, including where multiple devices or other generation are connected at the same premises. Requirements should remain practical for consumers and be reviewed as uptake grows.

ENA broadly supports the procedural clarifications for small-scale distributed generation connections, but has significant concerns about Proposal 2 and the balance it strikes between current and future customers. Preserving high static export limits for those connecting now risks allocating finite network hosting capacity to first movers, leaving later customers with lower static limits, more constrained dynamic arrangements, or additional network reinforcement costs. Requiring new installations to have communications capability is distinct from requiring customers to accept active dynamic control: it preserves options for managing capacity more efficiently and equitably as uptake increases. ENA therefore seeks an accelerated, nationally coordinated pathway to flex-ready connections, aligned with EECA's work and informed by Australian experience, rather than restrictions that could impede that transition. The Authority should explicitly assess these longer-term and distributional effects so that improved access today does not unnecessarily restrict opportunities for future consumers.

In addition to ENA's responses to the consultation questions, SA Power Networks (SAPN – the EDB for South Australia, serving 860,000 homes and businesses) has written to ENA with their views on some of the key elements of the Authority's proposal. ENA wholly endorses SAPN's views, and their letter is included with this submission. We urge the Authority to give significant weight to SAPN's comments, as they have widely acknowledged experience and expertise in accommodating significant penetration of residential solar on their network. New Zealand is at a much earlier stage of small-scale solar adoption, and we have an opportunity to learn the lessons from those who have gone before us – we would be wise to heed their advice.

If you have any questions about ENA's submission please contact Richard Le Gros, Policy and Innovation Manager (richard@electricity.org.nz).

Yours sincerely



Richard Le Gros
Policy and Innovation Manager

Appendix A: ENA Members

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

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

Appendix B: ENA Consultation Response – Part 1

Questions on issues regarding plug-in generation

Questions	Comments
Q1. Do you have any views on our characterisation of plug-in generation?	ENA agrees with the Authority's characterisation of plug-in generation. However, the regulatory framework should recognise both the small impact of an individual device and the potentially material effect of large numbers of devices operating together on low-voltage networks. The assessment should therefore consider aggregate impacts at an ICP, feeder and network level, rather than treating each plug-in device in isolation. ENA also considers it important to distinguish between the device's generation capacity and its maximum potential export to the network, as the latter is most relevant to network impacts.
Q2. What network performance requirements should apply to plug-in inverters in New Zealand, and why?	Plug-in inverters should be subject to a nationally consistent minimum set of network-performance requirements, proportionate to their size but sufficient to protect network safety, power quality and reliable operation. At a minimum, ENA considers this should include anti-islanding and appropriate voltage and frequency disconnection behaviour. The technical requirements should draw on AS/NZS 4777 principles, including power quality, volt-var/voltage response, controlled reconnection, harmonics and electromagnetic compatibility. The most effective means to assure compliance with these network performance requirements will be to require them at the product level through mandatory minimum product standards. To the greatest extent possible, these should rely upon existing international electrotechnical product standards. The Authority should work with the relevant agencies to establish a suitable plug-in standard, either by adapting the relevant AS/NZS 4777 requirements or developing an equivalent standard that preserves those protections.
Q3. What do you think of the Authority excluding plug-in generation standards from the Code?	ENA is open to detailed product and network-performance standards being prescribed outside the Code, for example through the Electricity (Safety) Regulations. However, the Code should expressly define plug-in generation and confirm its treatment as distributed generation. Our key concerns are that: • network performance requirements are met by these products • those network performance requirements are nationally consistent • compliance of the products is assured/demonstrated before or at point of sale, rather than post-purchase by the individual consumer Subject to that express Code basis, these technical requirements could be addressed through other regulatory instruments. The Code should also provide a clear basis for registration, inspection, enforcement and, where necessary, disconnection of non-compliant devices.

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?	Yes. ENA agrees that expecting consumers purchasing and ‘installing’ a small plug-in device themselves to be aware of, let alone comply with, the existing Part 6 process is entirely unrealistic. It also undermines one of the key attractive features of these devices – that no professional intermediary is required for their use. To impose any significant administrative or compliance burden on consumer purchasers of these devices would go some way towards undermining their appeal in the first place.
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?	ENA supports a simplified, mandatory national notification/registration process at connection, ideally beforehand (perhaps at point-of-sale), while recognising the practical challenges of keeping that information current. Even if initial compliance with notification requirements were reasonably high, plug-in generation devices are inherently portable and can easily be moved between properties. A second-hand market is also likely to develop, where compliance with notification requirements may be significantly lower. For any notification regime to remain accurate over time, consumers would also need to advise when a device is moved, sold, disposed of, or no longer in use. ENA considers sustained compliance with these ongoing notification requirements is likely to be difficult to achieve. These challenges should shape the design of the regime rather than rule out registration. A simple re-registration and updating process should aim to maintain a reasonably representative record without assuming complete accuracy or imposing disproportionate obligations on consumers.
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?	ENA favours a simple national notification/registration arrangement, rather than a process that generally requires individual EDB approval. EDB approval would not generally be necessary where: - the device complies with the applicable national technical standard - aggregate plug-in capacity/export at the ICP remains below the prescribed threshold - the installation does not interact with existing DG in a way that could breach an approved export limit. This approach would preserve network visibility without creating a connection process disproportionate to the risks involved.
Q7. What information should be required if a registration or application for a plug-in generation unit is to be implemented?	Registration requirements/processes should be kept as simple as possible – both to aid compliance and to recognise the relatively low impact of a single plug-in device. ENA considers the following information would be useful: - ICP/address - device/inverter make and model or product identifier - number of plug-in units installed at the ICP - whether battery storage is incorporated - whether other permanently installed DG is already present. If a suitable product specification register is maintained by the Authority or the sector, this should be sufficient information to determine the capabilities of any particular device purchased by a consumer. As a general principle, information requirements should be confined to information with a clearly identified network, market or regulatory purpose.

Q8. Would participants benefit from a registry that captures information about plug-in generation? Why, why not?	Yes. A national installation register should aim to provide a reasonably representative picture of connected plug-in generation. Complete accuracy is unlikely, but that should not prevent collection of useful information, supported by simple updating processes. EDBs would benefit from visibility of plug-in generation, particularly as uptake increases, as it is most likely the aggregate effect, rather than that of any individual device, that would generate network impacts.
Q9. Should the existing registry be used? Why, why not?	Yes. ENA sees no reason why the existing Electricity Registry could not be modified to be used for this purpose.
Q10. Should entering information about plug-in generation be a requirement only after export has been identified at an ICP? Why, why not?	ENA considers that, in practice, this approach would be difficult to enforce. It could also place unreasonable burdens on industry participants to identify and enforce this behaviour on consumers, potentially long after the actual plug-in generation purchase has occurred. Point-of-sale information should support a simple national registration process linked to connection, ideally completed beforehand, with re-registration when the device moves. Registration should not depend on detecting export.
Q11. Would the type of information able to be collected at point of sale be sufficient to meet industry needs? Why, why not?	Possibly, although it is unlikely that a consumer would have their ICP readily to hand when making their purchase of a plug-in generation unit. If it were possible for product retailers to assist the consumer in identifying their ICP (perhaps via the Authority website), then perhaps that is not an insurmountable barrier. However, point-of-sale registration alone would not reliably capture subsequent relocations or second-hand sales. It should therefore be complemented by the simple re-registration and updating process described in our response to Q5.
Q12. Should the MEPs reverse power indicator be leveraged in identifying potential plug-in generation export? Why, why not?	Information from MEPs' reverse-power indicators could be used as a secondary assurance or exception mechanism, but not as the principal means of identifying potential plug-in generation exports. Detection in this way would only occur after installation of the device, and only if the device actually exports some electricity, which may not occur for some time (if at all). Devices that only offset household load may never trigger reverse flow, but can still affect local capacity, voltage and power quality. In addition to the comments above, ENA understands that there may be some older, non-smart meters in use that may 'run backwards' in the case of export from the installation – effectively creating a net metering situation. ENA is not an expert in metering and so suggests that the Authority consult with metering experts to understand if this is possible, and to what degree, and consider whether steps could be taken to mitigate this risk.
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?	ENA considers that there is merit in requiring electricity retailers to be the primary customer interface for registration/notification of plug-in generation. Consumers' relationship with the electricity system and market is primarily via their electricity retailer, and it could be unhelpful and confusing to introduce a new party (e.g. the Authority) as the registrar for these devices.
Q14. Do you have any other suggestions on how consumers could be informed of Code requirements for plug-in generation?	ENA suggests that the most relevant time to provide this sort of information to consumers is at point of sale – packed in with the device, provided by the product retailer, or both. Information supplied might include: • that the device may export electricity • that registration or notification requirements may apply • that there may be a limit on total plug-in generation at an ICP • that special arrangements apply if other DG is already installed

	that additional metering or retailer arrangements may be necessary if the consumer wishes to receive payment for exports.
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?	Yes, payment to consumers for exported generation from these devices should require some form of Part 6-like application (and potentially approval) process. A consumer interested in receiving payment for their generation from a plug-in device is presumably intending to export regularly. In addition, they are the most likely to also be interested in purchasing multiple plug-in devices, to maximise export potential. In that case it is reasonable to seek an application and potentially approval, as this scenario is the one in which network impacts from these devices are most likely to arise.
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?	Consumers should be advised at the point of sale that their device may export electricity to the network and should be advised to contact their electricity retailer if they are interested in receiving payment for this export.
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?	Consumers should be advised at the point of sale that their device may export electricity to the network.
Q18. What issues do you see with more UFE in the reconciliation system as a result of more export from plug-in generation?	Over time, if such devices are widely adopted, UFE volumes could increase such that they start to become a material issue. The Authority should consider whether it has, or could put in place, mechanism to measure or estimate the extent to which this is occurring, and develop plans to accommodate these effects as well as it can.
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?	Yes, ENA considers this is a pragmatic initial approach for small amounts of incidental export where consumers do not seek payment. In addition, requiring completion of a 'formal gifting document' is likely to be disproportionate to the actual volume of electricity gifted. The Authority should, however, keep these arrangements under review, and as the uptake of plug-in generation increases, changes may be required. Some pre-determined thresholds/triggers for when this approach might be reconsidered could be usefully established now.
Q20. If gifting documentation were to be required by a plug-in generation consumer, how could this be facilitated?	ENA does not support the introduction of formal gifting process. However, if this is required it should be kept as simple and straightforward as possible. Some simple indication or flag at the point of sale should be sufficient to capture the consumer's intent here.
Q21. Are there other genuine issues identified by the reverse power indicator?	No comment
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?	Possibly, but ENA would not support removing this requirement without first understanding the other functions the reverse-power indicator performs. If widespread uptake increases routine reverse-power events, the underlying event data should still be retained. The Authority should explore cross-referencing it against registry information and changing the escalation pathway for registered plug-in devices, rather than suppressing the events.
Q23. Is there a way for a MEP to filter out plug-in generation related reverse power indicators?	The Authority should assess whether reverse-power events can be cross-referenced against registry information to support proportionate escalation for registered plug-in devices. The underlying records should remain available. Monitoring should also consider power-quality effects, rather than treating reverse flow as the only issue.

Q24. Should Part 10 include an exclusion for requiring import/export metering for plug-in generation? Why, why not?	ENA supports an exception for small plug-in generation where the consumer does not seek payment for export, provided the scale of unmeasured export remains immaterial. Mandating a meter replacement or reconfiguration simply because a very small device may occasionally export would impose costs disproportionate to the benefit. Where consumers seek payment, appropriate import/export metering should continue to be required.
Q25. Should Part 6 clarify requirements for a plug-in generation system being connected alongside approved permanently-fixed DG?	Yes. It is important that plug-in generation does not provide a mechanism for an ICP with existing DG to exceed an agreed export limit or circumvent conditions applying to the existing installation. Part 6 should make clear how the aggregate generation and export capability at the ICP is treated, including interaction with any existing static, flexible or dynamic export limit.
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)?	Yes, although the Code could potentially reference some other more detailed national technical standard or guidance. It is important that any threshold or limit that is established applies to the ICP (PoC) as a whole, and not to individual devices connected at that ICP.
Q27. What sources of information could the Authority use to monitor uptake of plug-in generation and/or any issues that may arise?	The Authority should seek to use whatever relevant data sources it can access to monitor uptake, use and issues arising from plug-in generation. These could include: • The registry • Point-of-sale or product registration information • Information from retailers and MEPs, including on reverse power flows • Complaints and safety incident information (e.g. via UDL and Energy Safety respectively) • Consumer surveys • Product importer/retailer information and engagement
Q28. Do you agree with our overall characterisation of the challenges of plug-in generation? Why, why not?	ENA largely agrees with the Authority's characterisation of the challenges of accommodating plug-in generation into the existing regulatory regime, especially the Code. The existing Part 6 framework in the Code is clearly inadequate and unsuited to dealing with these devices in its current form, and it is not desirable, practical, or proportionate to impose all those requirements on this class of device. The framework should also address how finite hosting capacity is shared between existing and later customers, including plug-in users. The Authority should make the relevant entitlements and fairness principles explicit, rather than leaving distributors to resolve them case by case.
Q29. Which of the challenges outlined in this paper present the most pressing issue for the Authority to address?	From an EDB perspective, the priority issues are most likely: 1. Establishing, mandating and enforcing national technical and network performance requirements on these devices 2. Establishing a simple national notification/registration process linked to connection and relocation, supported by point-of-sale information 3. Determining aggregate limits at ICP level, for both ICPs with multiple plug-in units connected and ICPs with some combination of permanently installed DG and plug-in generation. 4. Clarifying the principles for fair allocation of finite hosting capacity between existing and later customers. 5. Ensuring the arrangements put in place now are as future-proof as they can be, while anticipating the need to amend these arrangements as uptake of plug-in generation occurs and new or more acute issues arise.

Appendix C: ENA Consultation Response – Part 2

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.	Provided the network technical requirements for inverters are still met, it seems reasonable that Part 1 applications should also be able to access the 10kW default export limit – notwithstanding any decisions about whether the 10kW default export limit remains the appropriate setting in general.
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.	ENA does not support the proposal as currently framed. We agree with the Authority that requiring a customer to participate in a flexible or dynamic export arrangement is a different question from requiring new inverters to have communications capability. ENA does not consider that preserving consumer choice over the former requires the Code to prohibit distributors from requiring the latter. Requiring an inverter to be communications-capable does not mean that the distributor must actively control that inverter or impose a flexible or dynamic export limit from the time it is connected. Rather, communications capability can provide relatively low-cost future-proofing, allowing the installation to participate in more sophisticated export arrangements if and when network conditions require them. This is particularly relevant given the expected life of inverter equipment and the Authority's own expectation that communicating inverters, interoperability and flexible/dynamic export arrangements will become increasingly important. The consultation itself acknowledges these benefits and proposes further policy work on them within the next nine months. Communications readiness should be defined by the capability of the installation as a whole: secure remote monitoring and control through an open, recognised or otherwise interoperable interface. This could be provided by the device, an on-site gateway, or a manufacturer or third-party cloud platform. This capability should enable an appropriately authorised party to implement dynamic export limits. These readiness requirements should apply to new inverter-connected solar and battery installations. ENA also considers that the proposal gives insufficient consideration to equity between present and future small-scale distributed generation customers. A static export limit effectively allocates a portion of finite network hosting capacity to a customer for an extended period. Where early applicants receive relatively high static limits, the remaining hosting capacity available to later applicants progressively reduces. Later customers may therefore face lower static export limits, or flexible/dynamic limits that are more constrained than would have been necessary if available capacity had instead been shared dynamically across a larger group of customers. There is consequently a trade-off in the Authority's proposal. Protecting the ability of customers connecting today to obtain a firm static export limit may provide those customers with greater certainty and control, but can do so at the expense of customers seeking to connect in future. Conversely, requiring new installations to be capable of participating in dynamic arrangements can preserve a greater ability to allocate available hosting capacity efficiently and equitably as penetration increases. ENA considers this intertemporal equity issue should be explicitly recognised and assessed in the Authority's cost-benefit analysis. Restricting active management options may also increase the network reinforcement needed to accommodate later connections, with associated costs for

	consumers. That trade-off should be assessed alongside the impact on future customers' export opportunities. This does not mean that ENA considers every new SSDG customer should necessarily be subject to active dynamic control from the outset. A more proportionate distinction would be between requiring communications capability and requiring its use. ENA considers distributors should be able to require new inverter-connected installations to be communications-ready where this is a reasonable and prudent means of future-proofing their networks, while preserving customer choice about static or dynamic arrangements and requiring customer consent to a subsequent move from a static to a dynamic limit. The transition to dynamic exports and operating envelopes should be accelerated through nationally consistent rules on interoperability, communications and the application of constraints. In parallel, the Authority and the sector should develop the governance, accountability and commercial arrangements needed to support informed customer choice. ENA proposes a target of 1 July 2027 for Code backing for nationally standardised flex-readiness requirements for new DG connections. The pathway should include standardised flexible-connection contracts, uniform device requirements, post-installation connectivity, defined service levels, transparent reporting and consequences where service levels are not met. Requirements should be designed not to materially increase connecting consumers' costs. Being flex-ready should not, of itself, authorise curtailment. Under the proposed framework, exports should be curtailed only when and where the relevant ELAM/BELAM assessment establishes that this is necessary, within the agreed service and consent arrangements. For these reasons, ENA does not support the proposed prohibition on requiring communicating inverters. At minimum, the Authority should defer this prohibition until it and EECA have clarified their respective roles and agreed a consistent approach to inverter communications requirements. The same distinction between equipment capability and its subsequent use is relevant to EECA's smart EV charger work. The agencies should consider the parallel network-flexibility rationale and explain any different treatment of inverter-connected resources, taking account of ENA's earlier correspondence on communicating inverters.
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.	ENA supports allowing distributors to make a reasonable allowance for further DG uptake when undertaking network studies. The current restriction on taking future DG into account can result in unnecessarily frequent reassessment as successive DG applications are received. Allowing some headroom should reduce administrative effort and provide more durable assessments. ENA supports an interim allowance in principle, but does not consider that the proposed 10% has been adequately justified or shown to work across different network circumstances. The Authority should assess the size and basis of the allowance before fixing a national percentage. Any allowance should remain a transitional measure and be assessed against the risk of restricting current customers for

	generation that may not eventuate. It should not delay the development of dynamic management of actual network constraints.
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?	A 10% allowance would reduce the frequency of network reassessment to some extent. However, ENA is not convinced that 10% will be sufficient in all circumstances. For example, where current DG penetration is relatively low but uptake is increasing rapidly, 10% of the existing connected and committed DG may represent only a very small amount of additional capacity and may therefore provide little actual relief from the need for repeated reassessment. The Authority should test alternative allowance designs. One member reports that a 20% buffer is more useful across a range of situations. Separately, that member suggests applying a 10% allowance to the total maximum export power of DG expected over the following year, rather than only the current base. These are options for assessment, not a single agreed replacement formula. The assessment should also compare reductions in modelling effort with the export opportunities forgone by current customers. The longer-term direction should be dynamic management of actual constraints, with forecasts informing network planning rather than becoming a standing basis for restricting current exports.
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.	ENA agrees that EDBs should be required to offer both Part 1 and Part 1A DG application processes.
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.	ENA agrees that the Code should be clear that EDBs cannot extend timeframes for Part 1A applications, but also clear that they cannot be penalised for the time taken by the applicant to remedy a deficient application.
Q36. Do you agree with the objectives of the proposed amendments? If not, why not?	ENA broadly agrees with the objectives associated with Proposals 1, 3, 4 and 5. ENA does not agree with objective 6.1(b) to the extent that it assumes preserving access to non-communicating inverters necessarily promotes the most efficient outcome for consumers.
Q37. Do you agree the benefits of the proposed amendments outweigh their costs?	ENA broadly considers that the benefits of Proposals 1, 4 and 5 are likely to outweigh their costs. For Proposal 3, ENA supports the objective of reducing repeated assessments but seeks further analysis of the allowance's size, calculation base and effects on current customers before endorsing the specific design. ENA is not satisfied that the Authority has demonstrated this for Proposal 2. The assessment gives much greater weight to the benefits available to consumers adopting SSDG now, via a non-communicating inverter and a static export limit, than to the benefits available to consumers who may wish to adopt SSDG at some point in the future. The consideration and treatment of this temporal inequity is incomplete, and the Authority should carry out further analysis to reassure itself, and the wider sector and stakeholders, that this approach is consistent with the long-term interests of consumers.
Q38. Do you have any feedback on the Authority's assessment of the costs and benefits and the balancing of these as set out	ENA considers the assessment of Proposal 2 should be expanded. In particular, it should directly consider:

in this paper, including any evidence of quantified costs and benefits?	• the long asset life of inverters installed today and the potential cost of creating a continuing installed base of devices that cannot readily participate in future dynamic arrangements • the potential network and system benefits forgone if communications capability is not incorporated at the point of installation • the distributional effect between earlier and later DG applicants as finite hosting capacity is consumed • the possibility that future customers face lower static export limits or more constrained flexible export arrangements as a consequence • the potential future cost of retrofitting or replacing devices where communications capability subsequently becomes desirable or necessary. • the potential additional network reinforcement and associated consumer costs if communications-enabled management of network constraints is unavailable or delayed. • the costs of delivering interoperable flex-readiness, post-installation connectivity, service-level reporting and standardised contracts, compared with the benefits of preserving future management options.
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.	ENA broadly agrees in relation to Proposals 1, 4 and 5. For Proposal 3, the alternative allowance designs and transition to dynamic management outlined in responses to Q32 and Q33 should be assessed before concluding that the proposed 10% design is preferable. For Proposal 2, ENA reiterates its previous response that the Authority should make a clear distinction in its considerations between the concept of requiring a device to have a certain capability at the time of installation, and any subsequent arrangements or offerings that might be made to the consumer that make use of those capabilities. The Authority should also assess an alternative connection offering that retains a static option without flex-readiness, alongside a flex-ready option with different export conditions. Any lower static limit for the non-flex-ready option would need an explicit policy basis and assessment of its interaction with the 10 kW default, network-study requirements and fairness objectives. It should not be assumed to follow automatically from the ability to require communications capability.
Q40. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act?	ENA does not have any concerns with Proposals 1, 3, 4 or 5 in relation to section 32(1). For Proposal 2, however, ENA considers the Authority should reconsider its assessment of how the proposal promotes the efficient operation of the electricity industry and the long-term interest of consumers.
Q41. Do you have any comments on the drafting of the proposed amendments?	No comment.

Richard Le Gros
Electricity Networks Aotearoa
Sent via email to richard@electricity.org.nz
02 October 2026

Dear Mr Le Gros,

Subject: Advice on the Electricity Authority's Consultation Paper – Code improvements for export limits and connection processes

SA Power Networks welcomes the opportunity to provide input on the Electricity Authority Te Mana Hiko's (the Authority) Consultation Paper on *Code improvements for export limits and connection processes*.

South Australia provides a useful reference point for these reforms. Nearly half of South Australian homes have rooftop solar, with more than 3 GW connected to our distribution network. Accommodating this level of distributed generation has required us to progressively evolve our approach to connection standards, export limits and network operation, including the introduction of dynamic export limits across South Australia.

Our experience is that export arrangements should be designed for the long-term interests of all customers, rather than allocating available network capacity primarily to those who connect first.

We support the Authority's objective of maximising customers' ability to export rooftop PV. However, we consider that a framework based predominantly on current network conditions will create inequities between early and later adopters and can make the eventual transition to dynamic exports materially more difficult.

Our key advice is that New Zealand should:

1. take a long-run view of network hosting capacity, including anticipated growth in distributed generation that preserves equitable access to network capacity for current and future customers;
2. use dynamic exports to maximise utilisation of capacity above an appropriate basic export level;
3. begin establishing dynamic export capability now, leveraging existing Australian standards, certification arrangements and industry capability where appropriate; and
4. recognise the broader value of establishing a secure and interoperable communications interface with distributed energy resources as an enduring system-operating capability.

The detailed comments below explain these recommendations, drawing on the relevant experience from South Australia. We welcome the opportunity to continue engaging with ENA and the Authority and to share further practical experience from the implementation and operation of dynamic export arrangements.

Yours sincerely,



Travis Kauschke
Strategy and Development Manager

Detailed comments

1. Network capacity should be considered over the long term and equitably distributed between current and future customers

We understand that recent Code amendments require Electricity Distribution Businesses (EDBs) to offer a default export limit of 10 kW for rooftop PV systems, with lower static or dynamic limits available where a network constraint is present. We also understand that current network studies are generally required to consider existing hosting capacity and submitted connection applications, rather than anticipated future constraints.

We support the objective of maximising rooftop PV exports. However, maximising exports today is not necessarily the same as maximising exports over the long term.

Network hosting capacity is finite. Where high static export limits are allocated while rooftop PV penetration is relatively low, that capacity becomes effectively committed to those early connections. As rooftop PV uptake increases, **later customers will receive lower export limits and/or experience greater curtailment because they must operate within the residual hosting capacity remaining after legacy static connections are accounted for.**

Importantly, this is not simply a temporary issue that can be corrected once network constraints emerge. **The export capacity allocated to legacy static connections cannot practically be recovered until those systems are replaced, upgraded or otherwise moved onto new connection arrangements.** Given the operating life of rooftop PV and inverter systems, decisions made today can therefore affect the allocation of network capacity for many years.

South Australia has experienced this directly and implemented learnings from this. Our export arrangements evolved from no export limits prior to 2015, to 10 kW per phase from 2015, 5 kW per phase from 2017, and progressively to dynamic exports from 2023. Dynamic exports up to 10 kW per phase became the default offer across South Australia in 2025.

This history means customers connected to the same part of the network can now operate under substantially different export arrangements depending largely on when they installed their system. Where network constraints arise, customers with legacy static arrangements retain their existing export rights, while newer customers receive lower limits or dynamic connections that must respond to the curtailment necessary to maintain network limits. New Zealand has an opportunity to avoid embedding this outcome while rooftop PV uptake remains relatively low.

SA Power Networks distinguishes between the physical hosting capacity of the network and the export entitlement offered to an individual customer. We define **intrinsic hosting capacity** as the aggregate level of coincident export that can be accommodated without breaching voltage requirements or network asset ratings.

Our hosting-capacity studies then considered what level of export could be made available if rooftop PV were ultimately adopted by all customers. For approximately 95% of our network, this analysis identified a minimum export level of 1.5 kW per customer, per phase. We refer to this as the **basic export level**. Alongside our default flexible export limit offer, we offer a static 1.5 kW limit based on this analysis.

The 1.5 kW value is specific to the South Australian network and is not suggested as an appropriate value for New Zealand. The relevant principle is that some portion of intrinsic hosting capacity should be preserved for future customers rather than being fully allocated to early adopters.

We recommend that the Authority enable EDBs to determine an appropriate basic export level having regard to intrinsic hosting capacity and expected long-run distributed generation uptake, rather than allocating network capacity solely according to current capacity.

2. Dynamic exports should maximise utilisation above the basic export level

A conservative static export limit alone would leave substantial network capacity unused for much of the year. Dynamic exports provide a way to reconcile customer equity with network utilisation. They allow customers to export at substantially higher levels when network capacity is available, while reducing exports only when necessary to maintain network limits.

In South Australia, dynamic connections currently operate between lower and upper bounds of 1.5 kW and 10 kW per phase, with limits updated every 15 minutes according to network conditions. We consider there is a particular risk if high static limits are widely allocated before dynamic arrangements are introduced. Later dynamic customers will effectively be required to operate within the residual capacity left by earlier static connections.

A high static offer can also reduce the attractiveness of a future dynamic offer if customers can receive a similar export level without accepting any possibility of curtailment.

We recommend that static and dynamic export arrangements be designed together, with the static level preserving equitable access and the dynamic offer providing a meaningful opportunity to export above that level when network conditions permit.

3. New Zealand can leverage the Australian pathway

Establishing dynamic export capability requires coordination across EDBs, equipment manufacturers, technology providers and installers. Australia has already undertaken much of this work.

Dynamic exports across Australia share a common technical foundation through the **Common Smart Inverter Protocol for Australia (CSIP-AUS)**. Supporting arrangements include AS 5385:2023 and TS 5573:2025, national testing and certification processes for CSIP-AUS clients and servers, and secure communications arrangements supported through the National Energy Public Key Infrastructure (NEPKI).

Importantly, these arrangements are the product of **several years of coordinated effort between Australian distributors and international inverter OEMs** to develop, test and implement a common approach capable of operating across different distribution networks and jurisdictions. This coordination has driven substantial industry readiness. **More than 95% of inverters sold in the Australian market today are CSIP-AUS certified**, meaning the technical capability required to participate in dynamic export arrangements is already embedded across the great majority of new equipment entering the market.

There is evidence that New Zealand can benefit directly from this work. SA Power Networks has worked with a New Zealand EDB to assess the readiness of its inverter fleet for CSIP-AUS and found that **~85% of inverters installed since September 2023 in its network area are already CSIP-AUS certified**.

This is important because New Zealand and Australia draw on many of the same international inverter manufacturers. Alignment with the Australian approach would therefore allow New Zealand to take advantage of capabilities already developed and supported by OEMs, rather than requiring

manufacturers to develop and maintain a separate technical implementation for a comparatively small market.

The Australian rollout has also supported the development of distributor technology solutions, certification processes, installer training and industry guidance. Each additional jurisdiction adopting a consistent approach reduces implementation barriers for the next and provides manufacturers and service providers with greater certainty to invest in supporting capability. Conversely, adopting materially different communications protocols, certification requirements or implementation approaches in New Zealand would risk duplicating several years of coordinated industry effort, increasing costs for OEMs and potentially slowing the availability of compatible products.

We recommend that New Zealand leverage the Australian technical and industry pathway wherever practical, including the existing CSIP-AUS ecosystem, while adapting implementation to New Zealand-specific regulatory, market and network requirements.

4. The communications interface is an enduring system-security capability

There is a broader benefit from introducing dynamic exports that extends beyond the allocation of network hosting capacity. Implementing dynamic exports requires a secure and interoperable communications pathway between EDBs and customer energy resources, together with the capability to identify resources, communicate operating limits and verify their response. Once this capability is established at scale, it becomes **reusable system-security infrastructure rather than a single-purpose dynamic export solution**.

The same communications foundation can support other capabilities as the penetration of distributed generation, batteries and electric vehicles grows. These may include emergency curtailment of distributed generation, management of resources during transmission outages or other system-security events, flexible import and load controls, coordination of batteries and EV charging, visibility of device status, and controlled restoration or ramping of distributed resources following an operational event.

Other technical requirements will continue to remain important alongside communications. For example, voltage and frequency ride-through should primarily be delivered through appropriate inverter performance standards so resources can respond autonomously and rapidly to power-system disturbances. A communications interface complements them by enabling visibility, coordination and active-power management before, during and after system events.

The specific system-security challenges that will emerge as New Zealand's distributed resources grow cannot all be known today. Establishing a common communications interface as part of dynamic exports creates an additional tool that EDBs and system operators can draw on as new operational risks and opportunities emerge, without needing to retrofit communications capability across a large legacy fleet.

We recommend that the Authority consider the establishment of dynamic export communications capability not only as a means of managing distribution hosting capacity, but as foundational infrastructure for the future operation of a power system with high levels of distributed energy resources.