

Ref:26047



06 October 2026

Electricity Authority | Te Mana Hiko

By email to: connection.feedback@ea.govt.nz



Tēnā koutou,

SUBMISSION ON PLUG-IN GENERATION AND PROPOSED DISTRIBUTED GENERATION CODE AMENDMENTS

Unison Networks Limited (Unison) and Centralines Limited (Centralines) are consumer-owned electricity distribution businesses serving communities in Hawke's Bay, Taupō, Rotorua, and Central Hawke's Bay. We welcome the opportunity to comment on the Electricity Authority's issues paper on plug-in generation and consultation Part 6 code amendments.

As consumer-owned entities, we operate in the best interests of the communities we serve. Guided by our vision, and values, we strive to deliver economic benefits to both our customers and community shareholders, while championing a sustainable energy future. We are committed to maintaining the right balance between keeping electricity affordable and making strategic investments that secure the long-term reliability and resilience of our network. In all aspects of our operations, we place strong emphasis on meeting industry compliance requirements, ensuring we uphold all relevant standards. This approach not only supports New Zealand's transition to new energy solutions but also enables our communities to access cleaner, smarter, and more flexible energy options, now and for generations to come.

Executive Summary

This submission addresses two related consultation streams. Appendix C responds to the Authority's issues paper on plug-in generation and focuses on the design of an enduring framework for emerging customer generation technologies. Appendix D responds to the proposed distributed generation Code amendments and focuses on implementation, drafting and regulatory design considerations.

We support regulatory settings that enable greater customer participation and distributed energy resources while maintaining safety, reliability and the efficient use of shared network capacity. Across both consultations, regulation should remain proportionate, technology-neutral and evidence-based, while preserving flexibility to accommodate evolving technologies, customer participation models and system requirements. Technical requirements should be supported primarily through standards and objective performance requirements, with the Code providing the necessary regulatory framework and enforcement mechanisms.

In our view, the framework should be guided by four principles: establish technical standards before widespread deployment, prioritise visibility over approval, address hosting-capacity and equity issues explicitly, and preserve flexibility for future customer energy resources.

Technical standards should be established before widespread deployment

Technical standards should form the foundation of any plug-in generation framework. Establishing appropriate safety, performance and interoperability requirements before material uptake occurs will minimise future compliance costs and avoid the need for retrospective intervention.

Where practicable, the framework should align with the principles of AS/NZS 4777 and include minimum requirements covering anti-islanding, voltage and frequency response, power quality, controlled reconnection and interoperability. Establishing these requirements early will support both network resilience and future market development.

Visibility is more important than approval

The primary regulatory objective should be visibility of connected generation rather than approval processes that may create unnecessary barriers to participation.

We support a simple national registration framework in preference to a conventional distributor approval process. Visibility of connected generation and aggregate export capability at an ICP will become increasingly important for network planning, hosting-capacity assessments, compliance monitoring and future flexibility services. A registration-based approach is more likely to achieve these objectives while remaining proportionate to the risks associated with plug-in generation.

Hosting capacity and fairness require explicit policy consideration

The paper considers the interaction between plug-in generation and finite hosting capacity.

While individual plug-in generation units are likely to have limited network impact, aggregate uptake has the potential to consume capacity that would otherwise be available to other consumers or future distributed generation investments. As customer participation increases, access to network capacity will become an increasingly important policy issue.

We encourage the Authority to provide clearer policy direction on how access to shared network capacity should be allocated and managed over time. In our view, this is fundamentally a policy question and should be addressed through a nationally consistent framework rather than distributor-specific approaches.

The framework should remain adaptable

Plug-in generation should be viewed as part of a broader transition towards customer energy resources rather than as a standalone technology issue.

Future frameworks may need to accommodate greater interoperability, controllability, flexible export arrangements, battery integration and other emerging customer technologies. Regulatory settings should therefore avoid creating barriers to future solutions or locking participants into particular technologies before long-term system requirements are understood.

The framework adopted today should support current use cases while remaining capable of evolving as technology, customer expectations and system needs change.

Key Messages from our Appendix C Responses

Our detailed responses can be summarised as follows:

- Plug-in generation should be recognised within the Code and broader regulatory framework, with detailed technical requirements addressed primarily through standards and product specifications rather than prescriptive Code provisions
- Technical and network performance standards should be established before widespread deployment to avoid future retrofit costs and compliance challenges.
- A registration-based framework is preferable to an approval-based framework, with the primary objective being visibility of connected generation and aggregate capacity.
- Export limits and hosting-capacity assessments should apply at the ICP level and consider the cumulative impact of connected generation.
- Retailers are likely to provide the most effective and scalable customer interface for registration, consumer education and ongoing communication.
- Metering, reconciliation and compliance arrangements should remain proportionate initially, with future review triggered by evidence of material operational or market impacts.
- The Authority should provide clearer policy direction on hosting-capacity allocation, access to shared network resources and the treatment of future customer energy resources.
- The framework should preserve future flexibility and avoid unnecessarily constraining emerging technologies, interoperability standards or future flexibility services.

Appendix D – Distributed Generation Code Amendments

Appendix D relates to the Authority's proposed Code amendments for distributed generation connection and export arrangements. We broadly support the Authority's objective of improving consistency, transparency and efficiency while maintaining safe and reliable network operation.

Many of the proposed amendments are sensible improvements. However, several would benefit from refinement to ensure they remain evidence-based, technology-neutral and practical to implement.

Our responses are guided by three principles:

Customer access should be balanced with prudent network management

Connection pathways should be clear and accessible, but export limits must continue to reflect network capability and hosting capacity and the equitable allocation of shared network resources. Default export thresholds should not become automatic export rights.

Regulatory settings should preserve future flexibility

The Code should support customer choice while remaining adaptable as export management, communications standards, flexibility services and customer energy resources evolve. Static export limits should be regarded as a transitional network-management mechanism rather than the long-term end state. The framework should preserve customer choice while enabling a progressive transition toward dynamic exports and operating envelopes.

Obligations should be clear, objective and administratively workable

Obligations should be supported by objective criteria, clear drafting and practical implementation arrangements that enable consistent application across distributors and minimise unnecessary compliance costs.

Key Messages from our Appendix D Responses

Our detailed responses can be summarised as follows:

- We support applying the 10-kW default export threshold consistently across application pathways, provided lower limits remain available where justified by network evidence.
- We support customer choice but consider inverter approval requirements should be based on objective technical criteria rather than prescribed product categories.
- Hosting-capacity assessments should be transparent, evidence-based and consistently applied.
- The regulatory framework should support a progressive transition from static export limits toward dynamic export management and operating envelopes, supported by nationally consistent approaches to interoperability, communications, governance and customer protections.
- Future generation forecasts should inform network planning but should not unnecessarily ration current hosting capacity through increasingly conservative static export settings.
- The proposed amendments should not pre-empt future policy decisions regarding hosting-capacity allocation, access to shared network capacity, or the integration of emerging customer energy resources.
- New inverter-connected distributed energy resources should preserve the technical option to support dynamic export arrangements in future, without requiring customer to select or participate in dynamic service.
- Eligible applicants should have access to both Part 1 and Part 1A pathways.
- Application-processing requirements should clearly distinguish distributor performance from applicant-caused delays.
- We support the intent of the proposed amendments, but several provisions would benefit from further drafting refinement to improve certainty, consistency and practical implementation.

Comments on the Drafting of the Proposed Amendments (Q41)

We generally support the intent of the proposed amendments. However, several provisions would benefit from refinement to improve regulatory certainty, support efficient network management and ensure the Code remains adaptable as distributed energy resources evolve.

Our concern is not the overall policy direction, but whether the drafting creates clear, durable and operationally workable obligations.

Drafting issue	Risk	Suggested improvement
Approved inverter list requirements	The requirement to maintain a “reasonable range” of communicating and non-communicating inverters introduces subjective concepts and effectively regulates product availability rather than connection outcomes.	Replace subjective terms with objective approval criteria focused on technical performance, compliance and network outcomes.
Restrictions on communicating inverters and flexible exports	The drafting may unintentionally constrain future network management, interoperability and flexibility services by limiting when communications capability can be required. It may also result in new inverter-connected resources being technically incapable of transitioning to dynamic export arrangements in future.	Preserve customer choice while allowing communications requirements were supported by future Authority policy decisions, dynamic connection-readiness requirements, customer election of a dynamic service, or demonstrated operational need. Clarify that requiring technical capability does not, by itself, require a customer to participate in a dynamic service.
10% distributed generation allowance	The proposed allowance lacks a clearly defined methodology and risks becoming an arbitrary planning assumption rather than an evidence-based hosting-capacity assessment. It may also withhold capacity from current customers for future generation that may not eventuate.	Provide a clear methodology and supporting guidance, or adopt an approach linked to network-specific characteristics and evidence of likely uptake. Any interim allowance should be time-limited, rebuttable and reviewed as dynamic export capability develops.
Requirement to offer a static export option	A static export option may not always be feasible where network constraints can only be managed through active export controls. Conversely, communications capability should not automatically require participation in a dynamic service.	Allow an exception were supported by a network study and clearly justified. Preserve a genuine static option where technically feasible, while allowing lower static limits to reflect the greater capacity made available through dynamic management.
Part 1 and Part 1A pathway availability	The drafting could be interpreted as requiring both pathways to be available even where an application is clearly ineligible for Part 1A.	Clarify that distributors must make the Part 1A process available where Part 1A eligibility requirements are met.
Application completeness and fees	The amendments do not clearly define when an application is complete or how fee-related deficiencies should be treated.	Link completeness requirements directly to Code-specified information requirements and published fees.
Part 1A clock-stop mechanism	The drafting does not clearly define when assessment timeframes stop and recommence, creating compliance, reporting and dispute risks.	Clearly define the triggers for stopping and restarting the assessment clock and set expectations regarding further information requests.

The common theme across these issues is the need for drafting that is objective, outcomes-focused and capable of evolving alongside changing technologies and network requirements.

While we support the overall direction of the proposed amendments, further refinement would improve regulatory certainty, reduce implementation complexity and better support the long-term development of distributed generation and flexibility services.

Conclusion

Both consultations reflect the continuing evolution of New Zealand's distributed energy landscape. We support regulatory settings that enable greater customer participation while maintaining network safety, reliability, power quality and equitable access to shared network capacity.

Across both consultations, we encourage the Authority to adopt an evidence-based, proportionate and future-focused approach that supports innovation while preserving flexibility for future technologies, services and customer energy resources.

Looking beyond the current amendments, we consider the Authority should work with industry to establish a nationally consistent framework for dynamic connection readiness. Over time, new inverter-connected distributed energy resources should be capable of supporting flexible export arrangements through standardised communications, interoperability and customer consent frameworks. Such an approach would preserve future optionality, support efficient use of network capacity and minimise inequitable outcomes between existing and future distributed generation connections.

Static export arrangements should remain available to customers where technically feasible but should be regarded as part of the transition rather than the enduring model for network-capacity management. Requiring dynamic connection readiness would not force customers to select a dynamic service. It would preserve their ability to do so in future and avoid locking new distributed energy resources out of emerging flexibility arrangements.

The Authority should therefore progress nationally consistent requirements for interoperability, communications, governance, accountability, customer protections and commercial arrangements alongside the transition to dynamic exports and operating envelopes.

We look forward to continuing to engage with the Authority as this work progresses and would welcome the opportunity to discuss any aspect of this submission.

Ngā mihi nui,

GREG MORGAN / TARRYN BUTCHER

INTERIM GROUP GM CUSTOMER, COMMERCIAL AND REGULATORY / REGULATORY MANAGER

[REDACTED]

Appendix C - Submission form (Plug-in generation)

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

Name	Tomas Kocar
Organisation	Unison Networks and Centralines

Questions on issues regarding plug-in generation

Questions	Comments
Q1. Do you have any views on our characterisation of plug-in generation?	Broadly agree. Two qualifications: the framing is too export-focused, when local capacity, voltage and power quality matter whether the device exports; and plug-in generation is not uncontrolled, because it contains an inverter whose functionality can be specified.
Q2. What network performance requirements should apply to plug-in inverters in New Zealand, and why?	AS/NZS 4777.2 should be the starting point wherever practicable. Because AS/NZS 4777 does not permit three-pin plug connection, amend it to add a plug-in section or create an equivalent standard, preserving its principles as mandatory requirements.
Q3. What do you think of the Authority excluding plug-in generation standards from the Code?	Do not exclude plug-in generation from the Code. Detailed product standards can sit outside it, but the Code must define plug-in generation as distributed generation. Recognition alone is too weak; enforcement requires a Code basis.
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?	Agree, with a qualification. The barrier is proportionality and behavior rather than capability: an over-complex process produces non-compliance or suppresses the innovation. Put the compliance burden on the product but require notification.
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?	Yes, but as notification or registration rather than approval. Approval would be prohibitive for a consumer product of this size.
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?	Registration. A certified product, within a defined capacity limit, registered nationally, means connection is permissible
Q7. What information should be required if a registration or application for a plug-in generation unit is to be implemented?	A minimum dataset only. Use "electricity account holder" rather than "customer", and "connection" rather than "installation". Capture equipment owner separately, and whether distributed generation already exists at the ICP.
Q8. Would participants benefit from a registry that captures information about plug-in generation? Why, why not?	Yes, for network planning, hosting-capacity studies, peak investigations, enforcement and uptake monitoring. The caveat is maintenance: the register must

	be nimble and support relocation, or it will not be relied on.
Q9. Should the existing registry be used? Why, why not?	Yes, preferably, but through a simplified plug-in data class rather than the full distributed generation dataset.
Q10. Should entering information about plug-in generation be a requirement only after export has been identified at an ICP? Why, why not?	No. Register at connection, and ideally beforehand. Export-triggered registration systematically misses devices that only displace household load but still occupy hosting capacity.
Q11. Would the type of information able to be collected at point of sale be sufficient to meet industry needs? Why, why not?	A useful component, but not sufficient alone, because it does not establish where the device is connected. Combine product registration with ICP and address confirmation and collect anonymised regional sales data.
Q12. Should the MEPs reverse power indicator be leveraged in identifying potential plug-in generation export? Why, why not?	Yes, as a secondary detection mechanism, cross-referenced against the register. The indicator identifies a behavior, not a product. The same logic should be applied to unregistered conventional distributed generation.
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?	Yes, with clearly defined roles across manufacturer, retailer, registry, distributor and metering equipment provider. The same question arises for other consumer energy resources.
Q14. Do you have any other suggestions on how consumers could be informed of Code requirements for plug-in generation?	Reframe this as obligations rather than Code requirements: what to do before connecting, while connected, if something goes wrong, and how payment and metering work. Guidance in the box, prominent labelling, education at registration.
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?	No. Payment should require compliance, registration, being within the capacity limit, two-way metering and a retailer plan supporting export, not full Part 6 approval.
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?	A combination of retailer communication, product information, registration confirmation, portal data and event notification. The key message is that export may occur without the consumer intending it.
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?	Yes. Primary responsibility with the manufacturer and seller, supported by retailers, before or at purchase. Distributors can provide supplementary information but are not the right primary channel.
Q18. What issues do you see with more UFE in the reconciliation system as a result of more export from plug-in generation?	Little impact initially. Unmetered exports are unidentified rather than lost, and its value is socialised across the consumer base. The issue is scale, not the economics of one device.
Q19. Do you agree with our view that plug-in generation export with no	Agree for the low-capacity class, with a gifting acknowledgement captured at registration. Our view

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?	would change with penetration, so review triggers should be set now.
Q20. If gifting documentation were to be required by a plug-in generation consumer, how could this be facilitated?	Digital and automatic, built into the registration flow, rather than a conventional generator form or Part 15 documentation.
Q21. Are there other genuine issues identified by the reverse power indicator?	Yes, including wiring and configuration problems, CT polarity, metering faults and connection errors. Retain the indicator and improve classification. Power quality is our larger concern.
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?	Yes, reconsider if uptake grows. Distinguish a registered, compliant device operating within its limit from an unexplained event at an ICP with no registered generation.
Q23. Is there a way for a MEP to filter out plug-in generation related reverse power indicators?	Potentially, through registry cross-references are held by the registry or retailer. Filtering should change the escalation pathway, not suppress the underlying event data.
Q24. Should Part 10 include an exclusion for requiring import/export metering for plug-in generation? Why, why not?	Yes, for the defined low-power class where no payment is sought. Where payment is sought, import and export metering is required. Where fixed distributed generation exists, metering is already in place.
Q25. Should Part 6 clarify requirements for a plug-in generation system being connected alongside approved permanently-fixed DG?	Yes, and the Code should be explicit. The approved export limit belongs to the ICP, not to each device. Exceeding it should trigger a revised distributed generation application, declared at registration.
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, expressed as aggregate export per ICP, with one qualifying device initially. The 800 W figure is adopted from overseas and should be tested explicitly against New Zealand conditions.
Q27. What sources of information could the Authority use to monitor uptake of plug-in generation and/or any issues that may arise?	A multi-source framework: registration, anonymised sales, metering equipment provider, retailer, distributor and product compliance data, plus continued international evidence. Power quality deserves particular attention.
Q28. Do you agree with our overall characterisation of the challenges of plug-in generation? Why, why not?	Broadly agree, with three refinements: proportionality at scale is the real challenge; local network effects are understated; and fairness and equity are missing from the paper altogether.
Q29. Which of the challenges outlined in this paper present the most pressing issue for the Authority to address?	In order: the network performance standard; visibility and aggregate capacity; then metering and reconciliation. Fairness and entitlement to hosting capacity should be resolved in parallel.

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	Tarryn Butcher
Organisation	Unison and Centralines

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.	Unison supports applying the 10-kW default consistently to Part 1 and Part 1A applications. The Code should clarify that 10 kW is a default export threshold, not an automatic capacity entitlement, and distributors must retain the ability to apply a lower limit or other conditions objectively justified by a network study or application-specific technical requirements.
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.	Unison supports retaining a genuine static-export option but does not support the drafting as proposed. The requirement for a “reasonable range of readily available” non-communicating inverters creates uncertainty because product availability is outside distributors’ control. The Code should instead provide that a distributor cannot reject an otherwise compliant inverter solely because it lacks communication capability where a customer elects a static-export service. And to preserve future dynamic connection capability where objectively justified through their Connection and Operation Standards. To support efficient and equitable use of network capacity over time, the Code should preserve customer choice between: • a 5-kW static-export service without a communication capability requirement; and • a dynamic-export service, capable of supporting exports up to 10 kW, using communications-enabled functionality. This approach preserves customer choice while providing a clear incentive for customers to adopt flexibility-enabling technologies that support greater

	network utilisation and export capability. It also remains technology-neutral because eligibility is based on the capability of the service being provided rather than specific products, manufacturers or technologies. Over time, the regulatory framework should support a transition from static export limits toward dynamic exports and operating envelopes. Dynamic export arrangements can unlock additional network capacity, enable greater deployment of distributed energy resources, and manage constraints only when and where they arise. Achieving this outcome will require nationally consistent arrangements for communications, interoperability, governance, accountability, and appropriate commercial frameworks that support informed customer choice. The Code should also preserve optionality for future implementation of dynamic exports. New inverter-connected distributed energy resources should be capable of supporting secure remote monitoring and control through recognised interoperable communications arrangements. This capability would not require customers to participate in dynamic export services, nor prevent customers from continuing to operate under static export arrangements. Rather, it preserves the ability for customers to transition to dynamic export services in the future should they choose to do so. The capability may be delivered directly through the device, an on-site gateway, or an appropriately recognised and interoperable third-party communications solution. At a minimum, installations should be capable of supporting the control functions necessary to implement dynamic export limits if the customer later elects a dynamic service or dynamic management is otherwise permitted under an applicable regulatory and customer-consent framework. This approach does not force customers to choose a dynamic service. Customers would retain the ability to select and remain on a static-export arrangement. Its purpose is to avoid new connections being technically incapable of participating in dynamic arrangements in future, thereby preserving customer and network optionality.
Q32. Do you agree the Code should be amended to allow distributors to	Unison supports a prudent allowance for near-term DG uptake to reduce unnecessary reassessments of hosting

'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.	capacity. However, a fixed buffer of 10% of connected and pending export capacity is unlikely to reflect actual hosting capacity, forecast uptake, or local network conditions. The consultation paper suggests a 10% buffer would reduce the frequency of hosting-capacity assessments. This may be appropriate in parts of the network but is unlikely to achieve that objective on lightly loaded rural transformers serving a small number of customers, where a single additional DG connection can consume a significant share of remaining hosting capacity. In these circumstances, hosting capacity must still be reassessed regardless of any fixed buffer, limiting the effectiveness of the proposal. The Code should instead allow an evidence-based allowance under the ELAM, informed by assessed hosting capacity, local uptake trends, pending applications, network characteristics, and a defined review period. This would better align capacity allocations with actual network capability while providing flexibility to accommodate near-term growth. However, static export restrictions should be regarded as a transitional mechanism while the sector progresses toward dynamic management of network constraints. Applying an additional allowance for hypothetical future distributed generation may unnecessarily constrain current customers in anticipation of generation that may never eventuate. While future uptake assumptions are important for network planning, export management should increasingly be based on actual network conditions and dynamic management capabilities rather than increasingly conservative static limits. Forecast uptake should therefore inform network planning and investment decisions, while restrictions on current customers should be based on demonstrated network constraints and proportionate operational requirements.
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 may reduce reassessment in some circumstances but will not do so consistently. It may be immaterial where existing DG penetration is low and unrelated to the size of subsequent applications. Unison prefers an ELAM-governed, evidence-based allowance. If a numerical cap is retained, it should be a rebuttable maximum rather than the exclusive methodology. Any interim allowance should also be time-limited and reviewed as dynamic export capability develops. The purpose of an interim allowance should be to support prudent network management during the transition, not

	to embed progressively more conservative static capacity allocation as the enduring approach.
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.	Unison supports making both pathways available. However, election of Part 1A must remain subject to the eligibility requirements in clause 1D. The Code should provide a simple transfer mechanism from Part 1A to Part 1 where eligibility is not met, including treatment of application dates, additional information and fees, to avoid duplicate applications.
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.	Unison supports a firm 10-business-day processing requirement and agrees extensions should not be available for distributor workload or resourcing reasons. The Code should precisely define when the clock starts, pauses and restarts, preserve elapsed processing time, and exclude only applicant-caused delays such as remedying identified deficiencies, paying properly due fees or providing inspection access. Ineligible applications should transfer to Part 1 rather than remain indefinitely within the Part 1A deficiency process
Q36. Do you agree with the objectives of the proposed amendments? If not, why not?	Unison broadly supports the objectives but recommends expressly recognising safe and reliable network operation, technology neutrality, interoperability and administrable obligations. These considerations are necessary to ensure the amendments promote long-term consumer benefit while preserving prudent network management. The objectives should also recognise the transition toward dynamic management of actual network constraints and the importance of preserving customer and network optionality as communications and interoperability arrangements mature.
Q37. Do you agree the benefits of the proposed amendments outweigh their costs?	The benefits are likely to outweigh the costs if the drafting issues identified by Unison are addressed. Clearer pathways and timeframes should reduce disputes and rework. However, uncertain inverter obligations, poorly calibrated headroom and constraints on future flexible-export capability could create material implementation and opportunity costs. Each amendment should therefore be assessed individually rather than relying solely on a package-level conclusion.
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 understates distributor implementation costs. Relevant costs include changes to COPS and controlled standards, forms, websites and application systems; workflow and compliance reporting changes; staff training; inverter-list administration; network studies; and potential future integration costs. The final assessment should recognise these costs without

	assuming they outweigh the benefits and should assess each amendment. The assessment should also consider the opportunity cost of unnecessarily withholding existing hosting capacity through a fixed future-DG allowance, alongside the potential longer-term benefits and implementation costs of dynamic export management.
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.	Binding Code amendments are preferable to guidance where regulatory certainty is required. However, Unison prefers objective inverter approval criteria rather than a product-range obligation; an ELAM-based headroom methodology rather than a fixed percentage; and communication requirements that preserve future flexible/dynamic export capability. Guidance and worked examples should supplement the Code amendments. The Code should also provide a clear pathway toward nationally consistent dynamic export arrangements, while preserving a genuine static option and informed customer choice.
Q40. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act?	The amendments can satisfy section 32(1), provided the final drafting is necessary, proportionate and appropriately balances efficiency, reliable supply and consumer interests. Uncertain obligations, inefficient capacity allocation or unnecessary restrictions on future network-management tools would weaken that assessment.
Q41. Do you have any comments on the drafting of the proposed amendments?	Clause 6.3(2)(f): replace "reasonable range of readily available" with objective, technology-neutral approval requirements. Clause 6.3(4): preserve justified communication requirements for elected flexible or dynamic services**, future dynamic connection readiness** and demonstrated network needs. Clause 6.3A(2): clarify that 10 kW is a default threshold, not a capacity right. Clause 6.3A(3)(b): replace the fixed 10% formula with an ELAM-based, evidence-driven allowance**, and provide for any interim allowance to be reviewed as dynamic export capability develops**. Clause 6.3A(3)(c)(iii): expressly require a static option and clarify when it may be below 10 kW**, while preserving the ability for customers to elect a dynamic service where available**. Clause 1D (3): add Part 1A eligibility and transfer provisions. Clause 9E(1)(d): distinguish application fees from inspection fees. Clause 9F: define clock start, pause and restart events, preserve elapsed days and exclude only applicant-caused delay; also correct the "The" drafting error.