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19 May 2026

Sarah Gillies
Chief Executive
Electricity Authority
Email - sarah.gillies@ea.govt.nz

Re: Submission on Distributed Generation Pricing Principles, request to discuss

Dear Sarah,

Today Lodestone filed its submission on the EA's consultation on Distributed Generation Pricing Principles (DGPP).

As you know from our previous correspondence, the allocation methodology for transmission and network costs is a critical regulatory setting that will either encourage or discourage wide-scale distributed solar and battery storage. We have five operating solar sites, six consented sites, and several others in consenting and planning processes; and all of this investment is materially affected by the outcomes of these discussions.

Our response provided is consistent with our previous views and reiterates the following:

1) Distributed generation has a clear benefit to any region it locates in - as it will reduce nodal pricing and release existing capacity for future load growth;

2) With batteries added, the combination will provide a distributed source of fossil fuel free, peak power; which is a desired part of an efficient grid; and

3) Since distributed generation must pay for 100% of their incremental connection costs, and all of the incremental maintenance costs of those assets, there is no need to allocated any more cost from the historic or future network; (as there is an inherent net benefit to consumers simply because the generation has been added).

The purpose of this letter is to let you know that we are concerned that the industry processes are potentially going to overlook these arguments, and this gives rise for obvious concern.

If it helps bring this to the forefront, I would certainly be willing to present to your Board, as we do fear that our message gets lost in the translation. We are also designing our campaign to bring virtual rooftop offers to the mass market, which they might like to hear about. (Noting that the transmission pricing methodology and ability to put a solar in each community are linked and work together for the good of consumers.)

Let me know if a presentation on those two issues is of interest and I will make myself available at your earliest convenience. I have **attached** our submission to this letter for quick reference.

Thank you very much for your time on this. I look forward to discussing this with you further.

Regards,

[redacted]

Gary Holden
Managing Director

Format for submissions

Reforming distributed generation pricing to promote efficient investment.

Please email your submission to **distribution.pricing@ea.govt.nz** by 5pm, Friday 15 May 2026

Name	**Lodestone Energy Ltd**
Organisation	Lodestone Energy Ltd

Questions	**Comments**
Q1. Do you agree with the background and context summary above? Why? Is there additional background, evidence, or context relevant to the proposals in this paper?	We agree with much of the factual background but consider that the context summary omits a fundamental consideration that should underpin the entire reform. Overall, we firmly believe that it should be openly acknowledged that distributed generation adds a clear local benefit to consumers— through reduced nodal prices at the connection node, reduced transmission losses, and deferred need for transmission investment. This benefit is not adequately reflected in the EA's framing, which focuses primarily on the costs DG creates and the need to recover those costs more accurately. The correct starting point for any pricing reform should be that DG is a net positive for consumers, not a cost to be managed. From that starting point, Lodestone's position is that DG should either be: 1) Exempt from network cost allocations beyond covering the incremental cost to connect and the maintenance of those assets, or, 2) If network cost allocations are desired, they should be determined by considering the positive effect distributed generation has on reduced transmission investment and should include the NPV of future nodal pricing reductions at the connection node. It is very clear that any costs related to allocation of transmission or network costs previously covered by the load side will be unpredictable and likely hurt the ability to build new generation. This conclusion is derived from our direct experience. Lodestone has added five solar farms to distribution networks across New Zealand, we have first-hand

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	experience of how current DG pricing rules fail to reflect either the costs DG creates or the genuine benefits it delivers to the system and to consumers. In summary, we believe that pricing rules that are opaque, unpredictable, or that fail to recognise the locational and system benefits of DG will deter investment, increase line losses and result in a more expensive electricity grid for consumers.
Q2. Do you agree there are workability challenges with defining incremental costs under the current DGPPs? Why, why not? Are there any additional challenges not discussed above?	Yes, but the workability challenge is not in defining what the genuine incremental costs of adding a DG are – those are straight forward and Lodestone accepts that DG should cover them as part of building the DG. The workability challenge lies in the current DGPPs failing to prevent costs that are clearly not incremental from being allocated to DG connections as if they were. When the clear local benefit to consumers from reduced nodal pricing is taken into account, the only legitimate incremental costs og a DG connection are the capital cost of the connection assets themselves and the ongoing maintenance of those assets. Beyond that, there should be no further cost allocation to DG. However, in practice, the current DGPPs allow EDBs to attribute costs to DG connections that bear no relationship to the incremental impact of the connection on the network. We have two case studies that illustrate how this has occurred. First, at our Kaitaia site, connection fees escalated 37% year-on-year as a result of a line upgrade near our Grid Exit Point. The EDB justified this increase as a pass-through of costs allocated under the Transmission Pricing Methodology (TPM). However, the rationale for why that specific TPM allocation constituted an incremental cost of our DG connection — rather than a shared network cost recoverable from consumers — was never clearly articulated. The current DGPPs do not provide sufficient guidance on when and how EDB pass-throughs of transmission charges can legitimately be attributed to individual DG connections as incremental costs. The result is that DG developers face cost increases that are opaque, uncontestable, and unrelated to the actual impact of their plant on the network. Second, the current rules allow lines companies to levy ongoing maintenance charges on DG connections expressed as an arbitrary percentage of asset value — for example, 3% per annum — without any requirement to demonstrate that this reflects the actual incremental cost of maintaining assets attributable to that DG connection. This is precisely the kind of 'black box' allocation the DGPPs were

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	meant to prevent. A blanket percentage charge applied uniformly bears no necessary relationship to the incremental maintenance burden a specific DG connection creates, and provides no basis for the DG developer to assess, verify, or contest the charge. In both cases, the absence of clear, transparent, and verifiable incremental cost methodology is a material barrier to DG investment. Costs that are unmanageable and uncontractable increase debt service costs, reduce available leverage, and in some cases can render an otherwise viable project unfinanceable. Overall, Lodestone recommends that in the future pricing methodology, distributed generation should be recognised as adding a clear local benefit to consumers and, since they paid for the cost of connection, be exempt from TPM allocations or, alternatively, the local benefits be quantified and allocated to the determination of the charges assigned distributed generators.
Q3. Do you agree the current DGPPs cause costs and benefits to be under-allocated to injection connections, which can cause the issues listed above? Why?	Yes, in part. While we do not consider that costs are systematically under allocated to injection connections, we do agree that the benefits of DG can be materially under-estimated under the current DGPPs. The methodology fails to recognise the significant reduction in nodal prices — and the associated deferral of network upgrades — that DG delivers, particularly at high-priced constrained nodes such as Kaitaia. This asymmetry is fundamentally unfair and leads to investment outcomes that are suboptimal for consumers. Correcting it is central to unlocking the full potential of distributed solar and battery storage in New Zealand.
Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?	Yes, regulation of injection pricing methodologies remains appropriate. Distribution networks are natural monopolies and without regulatory oversight, lines companies have both the incentive and the ability to set DG pricing in ways that favour their own interests over those of consumers or competing generators. We believe that regulation must be anchored in transparent, stable, and predictable principles. It should also be openly acknowledged that distributed generation adds a clear local benefit to consumers and should either be exempt from TPM allocations or, alternatively, the local benefits be quantified and allocated to the determination of the charges assigned distributed generators. In terms of (load) customer facing pricing methodologies it is Lodestone's strong preference that time-of-use (TOU)

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	consumption charges as the primary mechanism — rather than complex, case-by-case rebate or allocation formulae — as fixed, published TOU rates provide the investment signal stability that DG developers require for project finance, and are readily verifiable by regulators.
Q5. Do you consider that consumers should remain residual payers? Why? Are there any additional economic concepts that should be considered in our reform of the DGPPs?	Yes. Once incremental connection costs are paid for by DG, consumers should be the residual payers for network costs. Transmission and distribution infrastructure are regulated natural monopolies and should be driven to encourage local generation as a means to lower overall nodal prices and reduce the long term demand for transmission. Consumers bear the obligation to pay for these assets and only a regulated monopoly can contractually recover the costs – (a distributed generator cannot compel consumers to pay for a share of regulated asset costs in the way a regulated network owner can.) In summary, DG participants should only pay for the incremental costs they directly create at their connection point. Beyond that, the grid should be viewed as a shared benefit asset from which all consumers derive value — particularly as solar farms emerge in communities across New Zealand, lowering nodal prices and reducing backbone transmission losses.
Q6. Do you consider that reframing the incremental cost rule to a requirement that charges 'must reflect a reasonable estimate of' rather than 'must not exceed' incremental costs is appropriate? Why?	Yes. Reframing the incremental cost rule from 'must not exceed' to 'must reflect a reasonable estimate of' is a positive step. The current 'ceiling' framing has created ambiguity and inconsistency in how lines companies set charges. A requirement to reflect a reasonable estimate creates a stronger obligation toward cost-reflective pricing, which is what DG developers need to make sound investment decisions. It also creates a clearer basis for regulatory monitoring and enforcement.
Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?	Yes. Clearer language and framing in the DGPPs will reduce the scope for inconsistent application by lines companies. Transparency and predictability are essential for project finance — uncertainty in future cost obligations is itself a barrier to investment, even before any charges are actually incurred. Knowing the cost to a new generator is limited to the incremental costs upfront and the maintenance of the assets that are paid for, is essential for investment in DG.
Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?	No. Lodestone does not consider that a non-prescriptive approach to capacity pricing for injection is appropriate, because we do not believe there is a sound basis for

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	capacity charges beyond the recovery of incremental connection costs and the maintenance of those assets. Once a DG developer has paid the incremental capital cost of connection and is covering the ongoing maintenance of the assets it has funded, it has fully compensated the network for the capacity it uses. There is no residual capacity cost to allocate. Granting EDBs discretion to levy additional capacity charges risks creating exactly the kind of opaque, uncontestable cost that this consultation is designed to address. To the extent the Authority is seeking a pricing signal that encourages DG to inject at times that benefit the network, Lodestone's preferred framework would anchor pricing to a time-of-use structure — with clearly differentiated Peak charges — rather than complex bespoke rebate mechanisms. Fixed published TOU rates (ideally two time periods, peak and other, or possible three) provide a more predictable and verifiable pricing signal than case-by-case rebate calculations, and are more compatible with existing billing systems. This will maximise DG and batteries and provide a benefit to all consumers.
Q9. Do you consider that the proposed extension of the pioneer scheme for load connections would help address position-in-queue issues for injection connections? Why?	Yes. Extending the pioneer scheme to cover injection connections would directly address one of Lodestone's most significant practical concerns. At our Waiotahe site, we faced inequitable connection costs as the lead project, effectively being required to fund the speculative connection costs of subsequent projects in advance under the Funded Asset Component mechanism. This 'first-mover disadvantage' can render an otherwise viable project uneconomic solely because a subsequent project does not proceed. The risk of non-reimbursement should not sit with the first mover; it should sit with the network operator or Transpower.
Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?	Yes. Pioneer schemes should also cover network injection capacity, not just connection assets. The first generator to trigger a network capacity investment should not bear the full cost of infrastructure that will benefit subsequent generators and consumers over time. Requiring subsequent connectors to share and reimburse capacity costs — with the network operator carrying the risk of non-reimbursement — is both fair and economically efficient. Reimbursement periods must be reasonable; periods of up to ten years, as

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	currently experienced under the FAC mechanism, are untenable for project finance.
Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?	Strongly supported. Non-discriminatory pricing requirements are essential, particularly given the Government's signalled intention to raise the cap on lines company-owned generation from 50MW to 250MW. Lines companies must not be permitted to give their own generation cheaper or more favourable pricing than competing DG. Without robust non-discrimination rules, lines companies have both the incentive and the structural ability to use pricing to entrench their own generation and exclude competing investment, to the long-term detriment of consumers.
Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?	Lodestone supports the proposed application provisions in principle. However, we believe these provisions should be underpinned by an overarching recognition that distributed generation adds a clear local benefit to consumers — including the positive effect on nodal energy costs at the connection node — and should either be exempt from network cost allocations beyond its incremental connection costs, or those allocations should be determined with reference to the quantified local benefits DG delivers. For clarity, this should include the positive effect distributed generation has on nodal energy costs at the connection node. With that principle in mind, we comment on each of the three specific provisions as follows. On opting out, we caution that opt-out provisions should not create a mechanism for lines companies to avoid cost-reflective pricing for their own generation. Any opt-out must be subject to the non-discrimination requirements proposed in Q11, and the Authority should require disclosure of the reasons for any opt-out to ensure it is not being used to confer a competitive advantage. On retrospectivity, existing DG projects require certainty. Retrospective changes to charges that alter the economics of consented or financed projects would be deeply damaging and should be avoided. Where new pricing rules result in increased charges, these should apply only to new connections or at the next scheduled pricing reset for existing connections, with adequate notice. On secondary networks, consistent treatment across primary and secondary networks is important to avoid

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	regulatory arbitrage. If pricing rules differ between primary and secondary networks, there is a risk that lines companies or generators structure connections to exploit the more favourable regime, which would undermine the efficiency objectives of the reform.
Q13. Do you agree with the proposed commencement provisions above? Why?	Yes, subject to ensuring sufficient transition time for existing projects to plan and adapt.
Q14. Do you have any suggestions for how we can most effectively support successful implementation?	Lodestone recommends implementation guidance focus on three areas. First, mandate TOU-based distribution pricing for all consumers, with clearly differentiated Day/Night, and Peak charges, removing fixed charges except for metering. TOU rates should be set with reference to actual network cost drivers and published transparently so they can be monitored and verified. Second, require retailers to provide symmetrical prices for exported and consumed energy in equivalent time periods — exported peak energy should receive the same value as the cost of peak consumption. Third, require lines companies to publish connection cost recovery methodologies (and maintenance cost methodologies) in a standardised format to allow meaningful comparison and regulatory oversight. These measures provide more stable and predictable investment signals than complex rebate mechanisms, are more compatible with existing billing systems, and are more readily verifiable by the Authority.
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	Lodestone supports robust monitoring and reporting requirements. We recommend the Authority require lines companies to report annually on: the charges levied on DG connections by category (connection costs and operating costs); the rebates or credits paid to DG generators; and any changes to pricing methodologies with explanatory justification. Charge reconciliation requirements should be standardised and accessible so DG developers can verify the basis for charges without costly disputes. Greater transparency would reduce barriers to DG investment.
Q16. Do you agree it is appropriate to give distributors relatively wide	No.

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discretion as to how they implement capacity charges for injection connections? Why?	We believe that once incremental capital is paid for, and maintenance of the assets are covered, there should be no need for additional capacity charges. It is possible to construct a capacity charge in lieu of paying some incremental assets costs. We would not object to replacing capital with an annual cost that is reflective of the cost of capital. To the extent charges are shared between more than one generator, there should be transparent guidelines.
Q17. Do you agree that for larger connections a more bespoke approach that accounts for dependability and mitigates risks such as over-injection or inefficient payments is more appropriate than the prescriptive broad-based approach used for residential and small business consumers? What do you consider such an approach should look like?	No. The rules can be the same for all generators. However, we acknowledge that all projects will affect the grid differently. To that end, the bespoke nature would be covered in determining the incremental capital costs and the maintenance of the assets.
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	We believe that once incremental capital is paid for, and maintenance of the assets are covered, there should be no need for additional capacity charges. It is possible to construct a capacity charge in lieu of paying incremental assets costs. We would not object to replacing capital with an annual cost that is reflective of the cost of capital.
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	Yes. The biggest concern we have is cost being added that is not related to the incremental connection costs of connection or the maintenance of the new assets. It is very clear that all other costs related to allocation of costs previously covered by the load side will be unpredictable and likely hurt the ability to build new generation. Inconsistency is clearly undesirable, but we are accepting that incremental connection costs may vary, case to case. We strongly recommend all future transmission connection costs are actual connection costs and the maintenance of those assets only.

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	Overall, it should be openly acknowledged that distributed generation adds a clear local benefit to consumers and should either be exempt from network cost allocations or, alternatively, the local benefits be quantified and allocated to the determination of the charges assigned to distributed generators. For clarity, this should include the positive effect distributed generation has on nodal energy costs at the connection node. This should apply whether the DG is connected at Transpower level or embedded within a network. Currently the treatment of transmission connection charges for grid-connected generation creates a real and material investment distortion that actively encourages generators to embed in the distribution network rather than connect directly to Transpower's grid. The mechanism of the distortion is as follows: a generator connecting to an existing Transpower GXP not only incurs the incremental costs of its own connection assets, but is then also required to pay an ongoing share of the costs of other existing assets that make up that GXP — allocated in proportion to its injection relative to other parties already connected at that GXP, whether those parties are generators or load. By contrast, a generator that embeds in the distribution network and connects to the EDB rather than directly to Transpower incurs only the incremental costs of its EDB connection. This asymmetry means that the transmission connection charge framework, as currently designed, creates a structural bias toward embedded generation — not because embedded generation is necessarily more efficient or better located, but simply because it avoids the non-incremental GXP cost sharing obligation. This is a distortion that should be addressed at the transmission level.
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	Lodestone's recommendation is that the solution to this distortion should not be sought at the distribution network level — for example, by allowing EDBs to pass through connection charges to embedded generation. Such an approach would simply replicate the distortion within the distribution network rather than removing it, and would further complicate the incremental cost framework that the DGPPs are designed to uphold. Instead, Lodestone recommends that the Authority, in conjunction with Transpower, undertake a review of Connection Charge policy under the Transmission Pricing Methodology so that it also adheres to incremental pricing principles. Under such a reformed approach, a generator connecting to a Transpower GXP would pay only the

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	incremental costs of its own connection — consistent with how EDB connection charges are intended to work under the DGPPs — rather than being required to absorb a proportional share of pre-existing GXP asset costs that it did not cause and from which its incremental benefit may be limited. The current policy can result in a windfall transfer of annual connection charges from load to generation. Lodestone experienced this firsthand at Waiotahe, where the proportional cost-sharing mechanism has reallocated significant asset recovery and O&M costs for historical GXP and spur line assets to our project rather than just the actual incremental costs of assets related to our connection. Aligning TPM Connection Charge policy with incremental cost principles would remove the distortion at its source and create a level playing field between grid-connected and embedded generation.
Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	Yes. The restriction on recognising transmission benefits in DG pricing should be reconsidered as part of this reform. Nodal pricing already serves as the primary mechanism for allocating locational benefits between generators and consumers. However, where DG demonstrably reduces the need for future transmission upgrades or reduces peak loading on constrained lines, this benefit should be capable of recognition in distribution pricing. Failing to recognise genuine benefits while allocating costs is neither fair nor economically efficient, and it systematically understates the value of DG to the system.
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	Lodestone urges the Authority to pursue predictability and verifiability as the overarching design principles for DG pricing reform. Our experience across five operational solar farms and six consented projects has taught us that complexity and opacity are themselves barriers — to investment, to project finance, and to effective regulatory oversight. Our preferred framework is a mandated TOU-based distribution pricing structure for all consumers, with variable charges across Day/Night and Peak periods, combined with a retailer obligation to provide symmetrical export and import prices. Fixed, published TOU rates provide the investment signal stability that DG developers require for project finance and that regulators need to monitor compliance effectively. We acknowledge that TOU pricing delivers its strongest benefits for participants who are able to respond to price signals, and that rate-setting must be carefully calibrated by EDBs to genuinely reflect network cost drivers — arbitrary rate

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	differentials would undermine the framework's integrity. Subject to those conditions, this approach works within existing regulatory separations, is implementable within current billing systems, eliminates the need for complex case-by-case rebate mechanisms, and provides correct investment signals to both demand-side and supply-side participants. Connection charges — covering the incremental capital and ongoing costs of a DG participant's specific connection — provide a natural and appropriate constraint on DG investment without the need for additional unpredictable cost allocations.
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	Lodestone notes that the consumer impact analysis confirms what we observe in practice: the primary barrier to realising consumer benefits from DG is not the level of charges per se, but their unpredictability and opacity. We recommend the Authority consider the impact of financing costs in its analysis — unmanageable and uncontractable cost exposure increases the cost of project debt and reduces available leverage, ultimately raising the cost of delivered energy for consumers. A pricing framework that is simple and predictable will deliver greater consumer benefits than one that is theoretically more precise but practically uncertain.
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	Yes. Lodestone agrees with the objectives of the proposed amendment. Enabling more DG investment at efficient cost — in ways that reflect both the costs DG creates and the benefits it delivers — is fully consistent with the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	Yes. The benefits of the proposed amendments significantly outweigh the costs. Greater predictability and cost-reflectivity in DG pricing will unlock investment that is currently being deterred or delayed, delivering lower-cost renewable energy to consumers and reducing long-term transmission and distribution costs. Implementation costs for lines companies are modest relative to these system-wide benefits, particularly if a simple TOU-based framework is adopted.
Q26. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's	Yes. The proposed amendment is preferable to the status quo and to the alternative options considered. Lodestone's preference, as described in our responses above, would be for a framework anchored in mandated TOU distribution pricing and retailer symmetry obligations. We believe this would be more predictable, more verifiable, and ultimately

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statutory objective in section 15 of the Electricity Industry Act 2010.	more beneficial to consumers than a principles-based rebate approach, provided TOU rates are carefully calibrated to reflect actual network cost drivers and are subject to robust regulatory oversight. However, the proposed amendment is a significant improvement on current arrangements and Lodestone supports its adoption.
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	Yes. The proposed amendment appears consistent with section 32(1) of the Electricity Industry Act 2010, in that it is reasonably necessary to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	Yes, with qualifications. Lodestone agrees that cost-reflective injection pricing — where charges reflect a reasonable estimate of incremental costs and benefits are recognised where they genuinely exist — is consistent with the distribution pricing principles. We reiterate our view that the most predictable and verifiable expression of these high-level settings is a TOU-based framework, where the value of peak injection mirrors the cost of peak consumption, and connection charges cover only the specific incremental costs of each DG connection. For this to be effective, TOU rates must be calibrated to actual network cost drivers rather than set arbitrarily, and must be published transparently so that both DG developers and the Authority can assess whether they are cost-reflective.
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	Yes. Consolidating distribution pricing methodology requirements into Part 6B would improve clarity and reduce the risk of inconsistent application. Lodestone supports any structural improvements that make the regulatory framework easier to understand and apply, both for lines companies and for DG developers assessing the costs and risks of new projects.
Q30. Do you have any comments on the drafting of the proposed amendment?	No specific comments on the drafting of the proposed amendment at this stage. Lodestone reserves the right to provide more detailed comments on specific drafting once further detail is available.