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Cross-submission on *Reforming network pricing for distributed generation to promote efficient investment*

Introduction

Network Tasman Limited (Network Tasman) thanks the Electricity Authority Te Mana Hiko (the Authority) for the opportunity to make this cross-submission on the April 2026 consultation paper Reforming network pricing for distributed generation to promote efficient investment.

Network Tasman's overarching view is that the current incremental cost rule does not produce an efficient or equitable allocation of costs across the users of distribution networks and that the Authority's proposed changes do not materially alter this conclusion. Notwithstanding that view, Network Tasman broadly endorses the Authority's proposed amendments as an improvement on the status quo.

However, regulation cannot rest on views and broad endorsements alone. Robust regulation requires analysis that objectively demonstrates the proposed intervention will, on the balance of evidence, deliver improved competition in, reliable supply by, or the efficient operation of the electricity industry for the long-term benefit of consumers. The Authority's analysis does not do this. Network Tasman's support for the direction of the proposals does not relieve the Authority of its obligation to satisfy itself, on adequate evidence, that the proposed Code amendments will deliver its statutory objectives. This cross-submission develops Network Tasman's concern that the Authority has not met that standard.

This cross-submission addresses one issue that is sufficiently important to warrant specific discussion: the adequacy of the analytical foundation for the proposed Code amendments.

1. The analytical inadequacy is acknowledged across distributor submissions

Several submissions raised questions about the:

- robustness of the Authority's analysis;
- the evidential basis used by the Authority; and
- whether the conclusions that underpin the proposed Code amendments are adequate to support the regulatory intervention proposed.

Some of these submissions are discussed below. For example,

ENA's submission at section 4.2 states:

> *The ENA supports the application of cost benefit analysis to assess the requirement for change. While the analysis included in the consultation does not adequately identify the benefits, the ENA does not support additional analysis being undertaken as the cost of the analysis would likely exceed the benefit.*

ENA further states that it believes “identified and unidentified shortcomings in the [consumer impact assessment] analysis makes it misleading” and identifies three specific shortcomings: that the analysis does not consider the long-term impact of inefficient investment from inefficient injection pricing signals; does not adequately identify or quantify cumulative and programmatic costs or network benefits; and does not adequately consider expected growth in distributed generation.

Powerco submitted that the Authority’s analysis is insufficient for anyone to conclude that the benefits outweigh the costs.

> *The information provided does not enable Powerco, or the Authority, to reach a conclusion that benefits outweigh costs. Comparing forecast EDB capex with business support costs is hardly a cost benefit analysis. It would be more rigorous to attempt to quantify the inefficiency of the current DGPPs and discount the costs of relieving them.*

Marlborough Lines and Mainpower, also expressing strong support for reform, observe at section 7 of their joint submission:

> *In our view, ensuring that robust data and analysis underpin regulatory interventions is critical to achieving proportionate and effective outcomes. A more explicit cycle of problem definition, evidence gathering, optioneering, intervention, and ex-post evaluation would support continuous improvement in regulatory design.*

Network Tasman agrees with all three submitters that the analysis undertaken by the Authority in the consultation paper is inadequate and cannot be relied upon to support the Authority's conclusions and proposed Code changes.

Network Tasman agrees that the standard the Authority should be meeting is the evidence-led cycle Marlborough Lines and Mainpower describe. Without robust evidence-led analysis underpinning the Authority's decision-making processes, it is unable to make objective decisions that maximise the long-term benefits to consumers.

Network Tasman also supports Marlborough Lines and Mainpower's proposal that every Code amendment should be subject to mandatory ex-post analysis.

This cross-submission expands on the issues raised by the submitters above and sets out where, in Network Tasman's view, the Authority's analysis lacks a robust analytical and/or evidential basis and therefore does not support a conclusion that the benefits of the proposed changes outweigh the costs.

The remainder of this cross-submission develops Network Tasman's position in three parts. Section 2 sets out why the Authority has not established that regulatory intervention is justified — that is, why the Authority's case for reform fails at the threshold question. Section 3 sets out why, even on the limited quantitative analysis the Authority has provided, the proposed reform is unlikely to deliver the consumer benefit the Authority claims. Section 4 sets out supporting analytical shortcomings in the Consumer Impact Analysis.

2. The Authority has not established that regulatory intervention is justified

2.1 An efficiency claim requires counterfactual analysis the Authority has not undertaken

A regulatory intervention that claims to improve efficiency is a claim about the future state of the world. It compares the world that will exist with the intervention against the world that would have existed without it — the counterfactual. Efficiency benefits arise where the intervention causes decision-makers to behave differently than they would otherwise have done, and where the resulting decisions produce better (more efficient) outcomes than would have occurred if the status quo remains. Efficiency benefits do not arise from the intervention itself; they arise from the behavioural changes the intervention produces. If there is no behavioural change, there is no efficiency benefit. In fact, there is an efficiency cost.

It follows that an efficiency claim requires three things: an estimate of the counterfactual (the behaviour that would have occurred without the intervention); an estimate of the behaviour the intervention will produce; and an assessment of whether the difference between those two states of the world constitutes an improvement. The estimates should be quantitative where appropriate data is available, or qualitative where it does not.

The Authority has not undertaken this analysis. The consultation paper states that the proposed amendments *"would improve efficiency"*, *"promote competitive pressure"*, *"lead to better utilisation of distribution networks"*, and support *"timely expansion of energy production using the lowest cost mix of projects"*. None of these claims is supported by an estimate of the counterfactual behaviour, an estimate of the behaviour the proposal will produce, or an assessment of the difference between the two. The Authority's case for reform is built on assertion rather than analysis.

The remainder of Section 2 develops the specific respects in which the Authority's analysis does not meet the threshold of what its efficiency claim requires.

2.2 The four problems the Authority identifies are not sized

The Authority identifies four problems with the existing DGPPs:

- **Under-allocation** — the DGPPs do not clearly support full allocation of incremental costs to injection, leading to consumer subsidisation.
- **Over-allocation** — the DGPPs do not clearly recognise benefits delivered by injection, leading to under-payment to generators in some cases.
- **Position-in-queue** — the DGPPs allocate costs in ways that produce first-mover disadvantage and stall investment.
- **Congestion management** — the DGPPs do not clearly support the use of price signals to manage injection congestion.

Each problem is described in theoretical terms — by reference to structural features of the existing rules that could, in principle, produce inefficient outcomes. The Authority seeks to measure the magnitude of the under-allocation in Appendix A. However, Appendix A measures only a narrow slice of near-term cost reallocation under the proposed reform, as noted in the ENA's submission. It does not measure the size of the underlying problem to determine whether it is material. It does not consider:

- How many uneconomic generation sites proceed under the current framework;
- How many uneconomic generation sites would not proceed under the proposed changes; or
- What the costs to consumers of these two outcomes are.

These are fundamental questions that must be answered if the Authority is to robustly determine the effects of its proposed Code amendment.

At best, the Authority's analysis is an estimate of the transfer the reform would produce, not the inefficiency the reform is intended to correct.

The aggregate cost to consumers from over-allocation is not estimated. The number of stalled or abandoned investments due to position-in-queue dynamics is not counted. The scale of congestion-driven curtailment or export limits is not measured. The Authority has asserted that these problems exist, but it has not demonstrated that they do, let alone that they are material.

The Authority is proposing mandatory Code amendments of substantial scope based on a theoretical case for reform that has not been tested against data that is readily available to the Authority.

This is the first respect in which the Authority has not followed the regulatory cycle Marlborough Lines and Mainpower describe: problem definition has not been completed.

2.3 The Authority has not established that the reform will alter investment behaviour

Even if the four problems exist at meaningful scale, the case for reform requires more. The reform is justified by reference to its effect on investment behaviour — that it will alter the locational, sizing and timing decisions of distributed generation investors, and that the resulting decisions will be more efficient than those produced under the status quo.

This is a behavioural claim. It depends on a chain of propositions:

- future distributed generation investment decisions are sensitive to connection and lines charges;
- current pricing fails to convey the right signal because charges are set too low (or too high) relative to incremental cost;
- the proposed reform will produce charges that are materially different from current charges;
- the difference will be large enough to materially alter investment decisions; and
- the altered decisions will be more efficient than the decisions investors would otherwise have made.

The Authority's analysis supports none of these links – it does not consider whether these links exist. There is no analysis of investment behaviour in the paper. There is no comparison of distributed generation uptake patterns across networks with different pricing approaches. There is no evidence linking observed investment decisions to the pricing rules. The

Authority does not assess what the marginal investor actually responds to, or whether the incremental costs proposed in the consultation paper will feature prominently in investment feasibility assessments relative to other cost and revenue drivers.

The Authority has identified a theoretical inefficiency, constructed what it considers to be a plausible story about its consequences, and proposed a remedy — without establishing that the inefficiency has actually produced the harmful investment behaviour it claims to be correcting, or that the proposed changes will materially change that behaviour. The entire chain from *problem exists* to *problem distorts investment* to *reform corrects this* is asserted rather than demonstrated.

The Authority's own figures suggest the chain breaks down on its own terms. Section 3 below shows that the magnitude of the reallocation produced by the reform is likely to be below the sensitivity range at which distributed generation investment decisions are made.

2.4 The Authority has not assessed per-connection impact, which is the analysis its efficiency claim requires

The Authority's central efficiency claim is set out at paragraph B.10 of the regulatory statement:

> *We expect the proposed amendments would improve efficiency by: (a) ensuring injection connections cover their full incremental cost (net of incremental benefits) so they are not subsidised. This would reduce the risk of uneconomic investments that shift costs to consumers, and of distributors being unwilling to host production.*

As noted earlier, the Authority has not sought to measure whether the risk of uneconomic investment is material. This claim also depends on the proposal altering the behaviour of injection connections relative to the status quo. Whether behaviour will be altered depends on the magnitude of the reallocation each future injection connection actually faces – cost reallocation cannot influence investment decisions of existing DG connections as the investment has already been made.

A reallocation that is small relative to the overall cost of DG investment is unlikely to deter investments that would have occurred under the status quo. If changing the distributed generation pricing principles to ensure injection connections cover their full incremental costs does not generate a material behavioural change in investment behaviour, Network Tasman submits that the risk of uneconomic investment, under the current principles, was nil in practice.

The per-connection impact is therefore the central analytical question for the efficiency claim. The Authority has not assessed it. At paragraph A.38(b) the Authority states:

> *we have not assessed impact per injection connection because we expect allocations would be likely to vary significantly between larger and smaller connections (or by factors such as line length).*

This is a concession that the Authority has not undertaken the analysis its own efficiency claim requires. The Authority cannot know whether the proposed amendments will alter investment behaviour without an estimate of the change to incremental cost that injection connections will face. Variation across connections is a reason to do a sensitivity analysis, or to model a range of representative cases — it is not a reason to forgo the analysis entirely.

From the information the Authority has published, it is not difficult to undertake an analysis of the impact based on a range of possible allocation measures. In this cross-submission, Network Tasman considers the effects of two possible allocation methodologies: a simple per-ICP allocation and an allocation on a per-kW basis. Other methodologies could be used and may well be more appropriate than those used here.

The purpose of this analysis is not to be precise about how the costs will be allocated. Rather, the purpose is to indicate the likely magnitude of the reallocation and consider whether these costs are likely to be material relative to the other costs of investing in DG. Network Tasman does this in Section 3 and determines the incremental effect of the cost reallocation to be $15/year if allocated on an ICP basis or $0.52/kW if allocated based on generation capacity.

Network Tasman considers it unlikely that these numbers are sufficiently material to alter investment behaviour in DG from what would otherwise occur under the current framework. This is because they are unlikely to be material when considered against the magnitude and volatility of the costs of capital, finance, resource consents and equipment required for DG investment.

The Authority cannot rely on the efficiency claim at paragraph B.10 unless it can establish that the cost reallocation will alter investment behaviour. The Authority has not done the analysis, has expressly declined to do it, and the analysis that can be done on the data published by the Authority does not support the claim.

2.5 The efficiency claims at B.10 do not establish efficiency benefits

A reallocation of costs from one group of network users to another is a wealth transfer. It is not, of itself, an efficiency benefit. A wealth transfer on its own can change who is better or worse off, but not how much total economic value exists. Efficiency benefits arise where decision-makers change their behaviour in response to changed incentives. In this case, behaviour changes could occur by DG investors locating, sizing, or timing investments differently than they would have done under the status quo. If behaviour does not change, no efficiency benefit arises; only the wealth transfer remains.

The Authority frames the assessment undertaken in the regulatory statement at paragraph B.7: *"Impacts will include some reallocation of costs between parties, but our focus is on aggregate economic impact."*

However, the actual discussion of the efficiency benefits contained in the regulatory statement primarily focuses on a range of matters, none of which are related to aggregate economic impact.

The uneconomic investment claim at B.10(a) relies on wealth transfers, not efficiency gains. The Authority's analysis at paragraph B.10(a) of the regulatory statement describes the proposed amendments as improving efficiency by:

> *ensuring injection connections cover their full incremental cost (net of incremental benefits) so they are not subsidised. This would reduce the risk of uneconomic investments that shift costs to consumers, and of distributors being unwilling to host production.*

Two effects are bundled in this passage. The first — *"ensuring injection connections cover their full incremental cost … so they are not subsidised"* — is the wealth transfer itself. It moves cost recovery from offtake consumers to injection connections. By itself, it is allocatively neutral and produces no efficiency benefit. The second — *"reduce the risk of uneconomic investments"* — is the behavioural claim, and is the claim discussion in earlier sections of this cross-submission address. *"Shift[ing] costs to consumers"* is again the wealth transfer, not an efficiency loss.

The Authority's analysis is solely focused on cost reallocations and offers no discussion on aggregate economic impact. The Authority's stated focus on aggregate economic impact, properly applied, requires excluding the wealth-transfer component from the efficiency assessment, not including it.

The consequence for the regulatory statement is twofold. First, the only genuine efficiency channel — behavioural change — is not established on the Authority's evidence. Second, the Authority's efficiency narrative is sustained by the wealth-transfer effect, which is not an efficiency benefit at all. Once the misclassification is removed, the B.10(a) claim does not carry the analytical weight the Authority places on it.

The position-in-queue claim at B.10(b) does not establish an efficiency benefit. B.10(b) describes the proposed amendments as *"mitigating position-in-queue dynamics (last-straw and first-mover disadvantage) that can disrupt or stall investment"*. Network Tasman does not accept that the proposed amendments necessarily mitigate last-straw pricing. Even taking the Authority's claim at face value, mitigation of last-straw pricing does not on its own establish an efficiency benefit. Last-straw pricing stalls investment at the point an upgrade is triggered, by signalling the full upgrade cost to the next applicant. Removing the last-straw mechanism distributes the same upgrade cost across a broader population of injection connections, increasing the incremental cost faced by every injection connection on the affected network. This may stall other investment that would otherwise have proceeded.

The analysis required to demonstrate an efficiency benefit is more nuanced than the Authority allows. Whether the net effect is more or less investment depends on (i) how much investment is inefficiently stalled by last-straw pricing, and (ii) how much investment would be inefficiently stalled by the higher incremental cost faced under capacity-consumption pricing. The Authority has not estimated either quantity. More fundamentally, stalled investment is not, on its own, evidence of inefficiency.

The question should not be whether a specific framework disrupts or stalls investment, but whether the investment it disrupts or stalls is efficient. The Authority does not consider this and assumes the status quo is inefficient and the proposed changes are more efficient.

Similarly, first-mover disadvantage is theoretical and not based on actual evidence of a problem. Network Tasman submits that removing first-mover disadvantage is highly unlikely to result in more efficient or competitive outcomes. First-movers have no certainty that there will be subsequent movers that will benefit from the first-mover's investments. As such, it is highly unlikely that a first-mover would proceed with an otherwise uneconomic investment on the basis that it would become economic if a second mover connected. Network Tasman submits that first-movers would likely view any reimbursement they receive from subsequent movers as a windfall gain rather than a necessary income stream that is required to ensure the project is economic. The introduction of a pioneer scheme is therefore unlikely to result in investment behaviour change.

However, on an efficiency basis, the introduction is likely to reduce efficiency as the cost of administering the pioneer scheme is levied on consumers, via higher lines charges, without any offsetting improvements in investment behaviour.

Network Tasman submits that it would be more equitable for the initial 'pioneer' to be compensated should other parties later connect to the assets it has funded, but notes that equity is not one of the Authority's statutory objectives.

The congestion management claim at B.10(c) depends on the ELAM/BELAM framework. B.10(c) describes the proposed amendments as *"enabling price-based congestion management … potentially allowing more injection connections to share the same capacity"*.

The paper presents congestion pricing via lines charges as a tool for promoting efficient use of existing injection capacity and deferring the need for network upgrades. It implicitly assumes that congestion pricing works through influencing actual physical flows — that a price signal during congested periods causes existing connections to inject less, which in turn defers the need for an upgrade and/or allows more people to connect DG to the network.

The paper does not, however, address (or consider) how available network injection capacity is assessed for the purpose of determining whether new connections can be accommodated and how much they can inject into the network. There is no reference in the paper to the Export Limit Assessment Methodology (ELAM) or Batch Export Limit Assessment Methodology (BELAM). This is a significant omission because the characteristics of these assessments will fundamentally determine whether price-based congestion management will achieve the outcomes asserted.

If available injection capacity is assessed under ELAM/BELAM on the basis of total network hosting capacity less the sum of each existing connection's *maximum permitted injection* — rather than actual or probabilistic injection flows — then congestion pricing via lines charges will not free up assessed capacity for new applicants. The assessed network hosting capacity will not change, even if existing connections are injecting well below their permitted maximum in response to a price signal.

A related issue arises on the demand side: a rational DG applicant will apply for the maximum permitted injection they could plausibly need, because the cost of constraining that maximum at the application stage is permanent (a subsequent application must be submitted to increase this parameter in the future), whereas the decision of how much to actually inject on any given day is not. Congestion charges that apply to actual injection do not alter this logic — they affect operational decisions post-connection, not the capacity headroom sought at application.

The effectiveness of congestion pricing as a genuine capacity management tool is therefore dependent on the structure of the ELAM and BELAM, and on whether applicants respond to congestion price signals when making connection-sizing decisions. The consultation paper does not consider these issues.

The offtake-freeing claim at B.10(d) is a framing change, not a behavioural one. B.10(d) describes the proposed amendments as *"expanding scope to reward and incentivise injection* *that frees up offtake capacity"*. The substantive ability for distributors to recognise such benefits already exists under the current incremental cost framework. Network Tasman considers these changes are better characterised as clarification and better framing of existing obligations and capabilities, rather than as new capabilities that would significantly change behaviour. The claim may have presentational value but is not a quantifiable behavioural change to weigh against the costs of the proposal.

2.6 The other claimed benefits in the regulatory statement do not establish an incremental case for reform

The regulatory statement identifies a set of competition benefits across paragraphs B.8 and B.9.

The competition benefits at B.8 are not incremental. B.8(a) describes the proposed amendments as *"continuing to mitigate the risk of distributors allocating residual costs to producers"*. The existing DGPPs already mitigate this risk through the incremental cost rule. *Continuing to* mitigate it is preservation of the status quo, not a change for which the proposal can claim credit in a cost-benefit assessment.

The "lower prices" claim at B.9 is ambiguous and unanalysed. Paragraph B.9 asserts the proposed amendments would *"benefit consumers by keeping prices lower than they would otherwise be"*. The paper does not specify whether "prices" means distribution charges, retail electricity prices, or some other aggregate. The distinction is material. If incremental costs are reallocated from offtake to injection, distribution charges to load consumers may fall. But if the reform alters DG investment decisions in a way that reduces the supply of generation, wholesale prices may rise — with the net effect on consumers' total electricity bills potentially negative. Without analysis of the net effect across these channels, the Authority cannot establish that prices to consumers in aggregate will be lower.

Once the non-incremental components of B.8 are set aside, the ambiguity of B.9 is recognised, the wealth-transfer element of B.10(a) is reclassified, the assumption that stalled investment is necessarily inefficient is removed from B.10(b), and the unsubstantiated capacity-management and reframing claims at B.10(c) and B.10(d) are set aside, the Authority has no quantified or qualitative efficiency benefit left to weigh against the compliance costs the proposal imposes. The conclusion at B.16 that *"only a small improvement in supply efficiency is needed to offset an increase in administrative costs"* assumes the existence of an efficiency improvement the Authority has not established.

2.7 The proportionality argument relies on a benchmark that is not fit for purpose

A central feature of the Authority's assessment of the balance of costs and benefits is its reliance on a BCG forecast of approximately $42 billion of required investment in generation and network infrastructure across the 2020s. The Authority uses this figure alongside a $350 million 2025 business-support-expenditure figure to argue that administrative costs are small relative to total industry expenditure and that even a small efficiency improvement would generate benefits sufficient to outweigh them. As noted earlier, the Authority has asserted there will be efficiency benefits, but has not established this to be the case. Notwithstanding this, the BCG figure is entirely unfit for the purpose it has been used in five respects.

First, the figure is a third-party forecast prepared in a different context for different purposes. The BCG forecast expressly assumes an electrification pathway more ambitious than that proposed by the Climate Change Commission; the Authority has not validated that the electrification pathway assumed by BCG is consistent with New Zealand's actual and forecast electrification pathway. If it is not, the figure overstates the in-scope investment and the potential efficiencies that might be available from it.

Second, the figure is not scoped to the DGPPs. The DGPPs regulate how distributors set charges for injection connections on distribution networks. They are highly unlikely to have a material bearing on Transpower's pricing or investment decisions; transmission capex will proceed based on Transpower's revenue determinations, the Transmission Pricing Methodology, and system security requirements. Large-scale generation connecting to the transmission grid is similarly outside the DGPPs' scope and unlikely to be materially affected by the incremental changes to the DGPP's proposed by the Authority. Including the costs of transmission and grid-connected generation expenditure within the scope of the analysis dramatically overstates the potential efficiencies. The Authority does not make a case for why the proposed amendments could materially affect investment in transmission or grid-connected generation, which together account for approximately half the $42 billion figure.

Third, even within the distribution sector, only a fraction of total capex is influenced by injection pricing. The significant majority relates to load growth, maintenance, resilience and reliability, none of which is materially altered by how injection connections are priced.

Fourth, the proportionality comparison is misleadingly framed. The Authority's argument at paragraph B.15 sets the scale of administrative costs (illustrated by 2025 business support expenditure of less than $350 million) that relate to a single-year against the scale of in-scope investment (illustrated by the BCG forecast of $42 billion across the 2020s) which span an entire decade. The two figures are not remotely comparable.

Fifth, and most fundamentally, the figure is conceptually irrelevant. Under the current DGPPs, incremental expenditure triggered by a new generation connection is paid for directly by that generator and does not conceptually enter the residual cost pool. This changes slightly under the Authority's proposal, but when considered against $2.7 of expenditure by EDB's in RY25, the reallocation of $1.3m of costs is not particularly material in this context. Any welfare effects that may be created by the proposed reforms operate through a considerably narrower channel than the $42 billion figure implies. These being the size of any consumer subsidy and the sensitivity of generator investment, location and timing decisions to changes in the magnitude of that subsidy. Both of those are uncertain, unmeasured and, in Network Tasman's view, likely to be small.

This section discusses why the Authority's regulatory statement does not establish that the proposed Code amendments are justified. The analysis identifies multiple analytical gaps in the Authority's case — including the absence of counterfactual analysis, the failure to size the problems the proposal is intended to correct, the absence of any per-connection impact assessment, the misclassification of wealth transfer as efficiency benefit, and a proportionality argument that rests on a benchmark not fit for purpose. These discussion points build on the issues raised by Powerco, ENA, and Marlborough Lines and Mainpower.

3. The Authority's own analysis cannot support the conclusion that the reform will produce a net consumer benefit

3.1 The investment signal is well below the sensitivity range that determines project decisions

The Authority's case for reform requires the reallocation to produce a change in investment behaviour. Section 2.3 established that this is a behavioural claim the Authority has not tested. This section submits that the Authority's own numbers do not support it.

Following the Authority's correction to Table A.1, the Authority's revised estimate of the additional costs that would be reallocated to DG is $1.3 million. These costs have been identified as programmatic costs that should be reallocated to all DG connections. There are approximately 88,000 DG connections in New Zealand.

Allocating the $1.3 million on a uniform per-ICP basis would result in an additional approximately $15 per year in costs for each DG connection. When considering that DG investments typically exceed $10,000[1], a $15 per year increase in costs is highly unlikely to

[1] EECA, *Solar costs and savings,* https://www.eeca.govt.nz/for-homes/solar-for-homes/solar-costs-and-savings/, accessed 3 June 2026.

materially alter investment behaviour. Network Tasman notes that a $10,000 investment cost represents the lower end of the cost of installing DG. If this change is unlikely to alter investment behaviour of the smallest DG installations, it will have no effect on investment in larger 'grid-scale' generators.

An alternative allocation could be made on a per-kW basis across all installed DG capacity. The Authority's Electricity Market Information (EMI) portal states there is currently 2,526 MW of DG connected in New Zealand. Allocating $1.3m on a kW basis produces an annual charge of approximately $0.52/kW. EECA states that a 3–5 kW solar PV system typically costs between $8,500 and $11,500.[2] Using the middle of the range, a 4kW system costing $10,000, would experience a $2/year increase in lines charges. A cost change of this magnitude is highly unlikely to alter actual investment decisions given the magnitude of this cost when considered in the context of the overall investment cost.

Network Tasman notes that the Authority's analysis does not allocate these costs across all DG connections. Rather the modelling allocates these costs across DG with generation capacity of 10 kW or higher. The Authority notes that this is because it assumes all small connections are offtake connections and therefore already pay these costs. This approach misinterprets the dynamics of how the Authority's proposals would be applied in practice.

The published model estimates the reduction per offtake ICP at $0.59. This reduction applies to all offtake ICPs — including those that also have DG installed — and aggregates to $1.3 million. The $1.3 million is the amount the Authority proposes to reallocate to injection. Allocated across all 88,000 DG ICPs, the per-connection injection allocation is approximately $15.

It is analytically incorrect to assume that the net effects for ICPs with both offtake and injection are neutral. Connections that have both load and generation would have two countervailing effects. The load component of their lines charges would reduce by $0.59/year and the generation component of their lines charge would increase by $15. The net effect being an increase in lines charges of $14.41.

Notwithstanding this, it is not clear why the Authority used a 10kW threshold to distinguish between DG ICPs that have both offtake and injection from those that have injection only. The Registry requires distributors to populate an Installation Type for all ICPs connected to their network. The options for installation type are: L — for load, G — for generation and B

[2] Ibid.

— for both. This information, which is regulated by the Authority, would have provided considerably more accurate information for the Authority’s analysis.

3.2 The signal will diminish further as distributed generation grows

The pool of costs being reallocated does not scale proportionately with the number of injection connections. Many of these costs are relatively fixed in the short to medium term: a network monitoring system or a vegetation management programme does not double in cost simply because the number of injection connections doubles.

As distributed generation continues to grow — which the consultation paper itself anticipates and is partly designed to accommodate — these costs will be spread across an ever-larger number of connections, and the per-connection reallocation amount will fall accordingly. The investment signal, already negligible at current connection volumes, will become progressively smaller in proportionate terms as the sector grows.

3.3 The compliance costs of the reform fall on consumers

Earlier sections submit that the proposed reform is, on the Authority's own evidence, a wealth transfer with no demonstrated efficiency benefit. That conclusion is compounded by the compliance costs the reform imposes:

- **EDB compliance costs.** Distributors must develop and publish methodologies for the modified incremental cost rule, the expanded scope (programmatic, cumulative, capacity), the “incremental to” principle, the pioneer scheme extension, the connection charge reconciliation methodology, the non-discriminatory pricing requirement, and the various commencement-timing distinctions. Each methodology requires cross-functional development, board approval, regulatory disclosure, and ongoing maintenance.
- **Authority compliance costs.** The Authority must monitor, guide, and (in due course) enforce a regulatory regime whose substantive content is largely delegated to distributor discretion.
- **Pricing disruption.** Existing connections face changed pricing arrangements after long-standing reliance on the existing DGPPs. New applicants face uncertainty about how the methodologies will apply to their projects.
- **Regulatory uncertainty.** The reform will, on the Authority's own framing, require further Code amendments to address capacity pricing design, congestion pricing methodology, and revenue recycling. The framework is not stable on commencement.

These compliance costs are real. The Authority has not quantified them, but they are non-trivial. A wealth transfer with no demonstrated efficiency benefit and substantial compliance costs is, in net terms, a *negative* effect on consumer welfare. It is the opposite of what the Authority's main objective requires.

Marlborough Lines and Mainpower observe in their submission that regulatory compliance costs are ultimately borne directly by local consumers. The cost of regulatory error in this domain therefore falls disproportionately on the very consumers the Authority's main objective is designed to protect.

3.4 The Authority has corrected the central analytical figure but has not engaged with what the correction means

Soon after publishing the consultation paper in early April, the Authority identified errors in the impact analysis discussed in the paper and issued an updated consultation paper on 21 April. The original paper identified cost allocations totalling $4.4 million in aggregate and $2.95 per offtake ICP that would be shifted from load connections to injection connections. The updated impact analysis (and the modelling published by the Authority) identified cost allocations of $1.34 million in aggregate and $0.585 per offtake ICP.

Category	Total reallocation	Per offtake ICP
Vegetation management	$143,820	$0.063
Routine maintenance	$283,832	$0.124
Service interruptions	$199,979	$0.088
Total distribution	**$627,631**	**$0.275**
Benefit-based charges	$709,198	$0.310
Total transmission (BBC only)	**$709,198**	**$0.310**
Total reallocation	**$1,336,830**	**$0.585**

The original Table A.1 of the consultation paper, by contrast, reported:

Category	Per offtake ICP
Total distribution	$0.27
Connection charge (transmission)	$2.37
Benefit-based charge	$0.31
Total	**$2.95**

The entire discrepancy was attributable to a $2.37 per offtake ICP transmission connection charge component.

Two points follow from the correction.

First, the Authority's acknowledgement of the correction is not commensurate with its significance. The Authority acknowledges this correction in two places: in section 1 of the updated paper and at the beginning of Appendix A.

In section 1, the Authority states:

> *This consultation paper was updated on 21 April 2026 to correct figures in tables A.1 and A.2 in Appendix A and to reflect the extended deadline to provide feedback. The corrections do not impact the proposals as discussed throughout this paper.*

In Appendix A, the Authority states:

> *The updated tables are intended to illustrate the Authority's thinking and proposals as expressed throughout this paper and we are satisfied that they now do so. The proposals themselves do not depend on the tables or analysis presented here, which are included to provide context for interested parties.*

The Authority does not characterise the correction as material, does not explain its origin, and does not engage with what it means for the rest of the analysis. A correction of this magnitude, packaged in brief explanations with a deadline extension as if it were a simple administrative matter, does not meet the standard of regulatory transparency that correction of a central analytical figure requires.

Second, the Authority's claim that "the proposals themselves do not depend on the tables or analysis presented" is implausible on its own terms. The updated paper retains the conclusion that the $1.3 million reallocation will deliver the efficiency benefits described in paragraph B.10. An efficiency benefit requires a behavioural response — investment decisions made differently than they would have been without the reallocation. For both the original paper and the updated paper to be correct, the Authority must hold simultaneously that:

- a reallocation of $1.3 million is sufficient to trigger the behavioural change that produces the claimed efficiency benefit; and
- a significant reduction in magnitude of the costs being reallocated ($3.1 million, the difference between the original $4.4 million figure and the corrected $1.3 million figure) has no effect on investment behaviour.

These propositions are not readily reconcilable. The $3.1 million reduction is approximately 2.4 times the size of the residual $1.3 million reallocation. If the reallocation is the mechanism through which the proposed amendments influence investment decisions, it is implausible that a reduction of this scale — representing around 70% of the originally modelled costs — would have no behavioural impact, while the remaining $1.3 million is sufficient to alter behaviour.

Put a different way, had the initial modelling estimated cost reallocations of $1.3m and that figure had been revised up to $4.4m. It is plausible that this change would result in not behavioural change if both figures are small relative to the other costs of investing in DG. However, if the $1.3m cost allocation is considered to be sufficiently material that it would alter investment decisions, it is not plausible that a 70% increase in this figure would have no further influence on investment behaviour.

Conversely, if a change of this magnitude does not affect investment responses, this calls into question whether the scale of the reallocation is, in fact, the operative mechanism at all. In that case, the efficiency claim advanced at paragraph B.10 is unsupported, as no alternative mechanism has been identified by which the proposal would give rise to a behavioural change.

The Authority's position would be coherent if it had explained that a threshold effect operates (the behavioural response is triggered above some signal magnitude, and both $4.4 million and $1.3 million exceed it), or that some non-quantitative feature of the reform produces the behavioural response. The Authority does neither. The updated paper retains the original analysis without revision and asserts, without explanation, that the correction does not affect the conclusions. That assertion is not analytically sustainable.

3.5 The Authority's analysis is internally inconsistent on the population to which the reform applies

The proposed amendments and the impact analysis adopt fundamentally different positions on the population of injection connections that would be subject to the reform.

The substantive proposal at paragraph 4.44(a) provides that the updated injection pricing principles would apply to *"lines charges for any connection, regardless of when it was built"* and would enable *"ongoing incremental costs to be allocated across all connections"*. The reform reaches the full population of distributed generation connections — including the sub-10 kW residential and small-commercial DG population that, on the EMI website, makes up the significant majority of distributed generation in New Zealand (more than 80,000, or 92% of DG ICPs).

The impact analysis at paragraph A.38(b), however, states that *"the analysis assumes around $1.3 million is allocated across around 5,000 injection connections"*. That figure corresponds to the DG-greater-than-10 kW population the analysis defines at A.32. It excludes the sub-10 kW DG population on the rationale that those connections *"already pay these costs"* through their offtake charges.

The two positions cannot be reconciled. They imply fundamentally different per-connection allocations (using the corrected $1.3 million aggregate):

- on the A.38 population (6,700 ICPs at 30 April 2026), the average per-connection allocation is approximately $200 per year;
- on the 4.44 population (88,000 DG ICPs at 30 April 2026), the average per-connection allocation is approximately $15 per year.

These figures are an order of magnitude apart. The Authority states that it allocates costs to DG-only connections (those larger than 10kW) because it assumes all small connections are offtake connections and therefore already pay these costs. Network Tasman discusses issues with this assumption in section 3.1.

The Authority's decision to allocate costs to a small subset of all DG connections significantly overstates the effect of its proposals.

4. Supporting analytical defects

4.1 Factual errors and data integrity in the Consumer Impact Analysis

The published Consumer Impact Analysis contains three discrete errors of fact or issues with data accuracy. None has been addressed in the Authority's 21 April 2026 update to the consultation paper, which addressed only the Table A.1 transmission connection charge discrepancy.

Incorrect distributed generation data for Network Tasman. The Authority's published model sources data on distributed generation connections appears to come from the EMI website as at 31 July 2025. For Network Tasman, the value used in the Authority's model for the number of distributed generation connections greater than 10 kW is five. However, the correct figure, as recorded on the EMI website for the same date, is 235. The Authority appears to have inadvertently changed the figure at some point in its modelling process.

Stale data underpinning the analysis. The EMI data extract embedded in the published model is dated 9 September 2025, with a data cut-off of 31 July 2025. The consultation paper was published in April 2026 — more than six months after the data was extracted and more than eight months after the data cut-off. For Network Tasman, distributed generation greater than 10 kW grew from 235 ICPs at 31 July 2025 to 325 ICPs at 30 April 2026 — a 38% increase between the cut-off and the most recent available data. Network Tasman acknowledges that the Authority must use a static dataset for its analysis and is not criticising the decision to use data to 31 July 2025. However, the current rate of DG growth, and the material difference outdated data can have on analytical conclusions, means that reliance on static data in periods of significant change risks materially over- or under-estimating the effects of the Authority's proposals.

Nelson Electricity is incorrectly identified as a distributor. Nelson Electricity did not exist as a distributor at the date of publication. Network Tasman and Nelson Electricity amalgamated with effect from 31 March 2026. On completion of the amalgamation, Nelson Electricity's assets and liabilities vested in Network Tasman and Nelson Electricity ceased to exist as a distributor.

4.2 The Authority should examine the incentives for GXP-adjacent embedding

Meridian Energy's submission notes that it *"owns several large generation assets at 33kV near GXPs, with minimal downstream network use but full distributor pricing control"*, and recommends that the Authority *"consider preparing guidance and requiring a level of transparency on how incremental costs are applied in these cases, including clear expectations for GXP-adjacent assets and legacy distributed generation"*.

Network Tasman makes two observations.

First, the bespoke approach Meridian proposes — guidance and transparency requirements tailored to a specific class of assets — is not how distribution pricing is typically developed. Load pricing is set using aggregated cost structures across broad categories of users; it is neither practical nor efficient for distribution prices to routinely be developed on an asset-by-asset basis, and the costs of attempting to do so would be likely to outweigh the benefits. The principles applied to load consumers should be the principles applied to injection connections.

Second, Meridian assumes that its generation uses only the section of distribution network located between its generator and the upstream GXP. This is not how electricity distribution networks operate.

Third, and more substantively, the characteristic Meridian identifies — large generation assets at 33 kV near GXPs with "minimal" downstream network use — is itself a product of the current DGPP framework. The current incremental cost rules create significant incentives for generators to connect on the EDB side of a GXP wherever it is technically feasible to do so. In Network Tasman's experience, a generator connecting to a distribution network at 33 kV avoids a large proportion of the transmission charges that apply to transmission connected generators and faces distributor pricing arrangements that can only allocate incremental costs to the generator. A generator connecting directly to the transmission grid faces Transpower's full charging arrangements. The financial differential is, in many cases, substantial.

Network Tasman submits that the proposed amendments to the DGPPs will not materially alter this incentive.

This embedding incentive is not addressed in the consultation paper. The Authority's analysis does not estimate the magnitude of the incentive, does not consider whether the proposed amendments alter it, and does not assess whether the embedding behaviour that has resulted is in the long-term interests of consumers.

Network Tasman encourages the Authority to undertake a number of case studies of existing GXP-adjacent generation sites to estimate the magnitude of the incentive to connect on the distributor side rather than directly to the transmission grid. This work would assist the Authority in understanding the broader incentive landscape within which its DGPPs operate. It would also inform whether additional regulatory work is required to ensure there is competitive neutrality between the costs of connecting to distribution networks or the transmission network. Under the current (and proposed) arrangements, Network Tasman submits that the DGPPs provide significant incentives for generators to connect to distribution networks where practicable.

5. Recommendation: the Authority should develop a published framework for assessing regulatory interventions

The analytical defects identified in this cross-submission are not isolated to the present consultation. Marlborough Lines and Mainpower observe in their submission that they reflect a broader pattern in the Authority's recent regulatory programme. ENA's diagnosis that the analysis *“does not adequately identify the benefits”* and is *“misleading”* reflects the same concern. Network Tasman submits that the underlying issue is structural: the Authority does not publish a framework for assessing the costs and benefits of proposed regulatory interventions, and the analytical approach varies materially in rigour and content between consultations as a result.

Other regulators of comparable functions publish such frameworks. Ofgem, the UK economic regulator of energy networks, publishes Impact Assessment Guidance setting out how it appraises proposals. The guidance is structured around the ROAMEF cycle — Rationale, Objectives, Appraisal, Monitoring, Evaluation, Feedback — and closely tracks the evidence-led cycle Marlborough Lines and Mainpower describe in their submission. Ofgem has had a statutory duty to carry out an impact assessment for any proposal it considers “important”, or to publish a statement of its reasons for not doing so. An explicit screening process determines when an impact assessment is required. Specific provisions cover industry code modifications — directly analogous to the Code amendments the Authority makes under the Electricity Industry Act 2010.

Looking more broadly, the OECD Best Practice Principles for Regulatory Policy on Regulatory Impact Assessment set out comparable requirements across member countries.

These frameworks share several features that the Authority's current approach does not provide:

- **a published, standing methodology** — visible to submitters and the public, applied consistently across consultations, rather than a regulatory statement which is produced once per intervention and varies materially in content and rigour between consultations;
- **defined screening criteria** for when a full impact assessment is required and when a lighter approach is appropriate;
- **a required counterfactual** against which all proposed options are appraised;
- **required options analysis**, with each option appraised individually rather than as a preferred bundle;
- **structured treatment of impacts**; and
- **a required monitoring and evaluation plan** specifying, at the time of decision, how outcomes will be measured and when the intervention will be reviewed.

Network Tasman submits that the Authority develop and publish an impact assessment framework setting out at minimum:

- the criteria that determine when a full impact assessment is required;
- the components of a full impact assessment (problem definition, counterfactual definition, options analysis, costs and benefits, risks and uncertainties, distributional impacts, unintended consequences, and monitoring and evaluation plan);
- the analytical standards to be applied, including the treatment of transfer payments versus efficiency effects, and the treatment of uncertainty;
- the disclosure requirements, including publication of supporting models and data; and
- the process for monitoring and evaluating the outcomes of regulatory decisions and feeding the resulting evidence back into future interventions.

The Ofgem guidance provides a starting reference. Network Tasman would welcome the opportunity to engage with the Authority on the development of a framework appropriate to the New Zealand context.

6. Conclusion

A number of parties have submitted that the Authority's analysis is not adequate to support the proposed Code amendments. This cross-submission endorses these views and sets out in detail why Network Tasman agrees with these submission points.

The Authority's own correction of the central analytical figure in Table A.1, reducing the reported benefit by a factor of more than three, is the clearest evidence that the original analysis materially overstated the case for reform — and the Authority's assertion that this correction "does not impact the proposals" is not credible.

ENA's proposed response — that the case for change is "indisputable" on other grounds, and that additional analysis is not warranted — is not, in Network Tasman's view, available to the Authority as a matter of regulatory practice. Nor is it sustainable on the Authority's own evidence. The Authority has not undertaken the counterfactual analysis that an efficiency claim requires (section 2.1). The reallocation the analysis produces is too small to alter the investment decisions the reform claims to correct (sections 2.4 and 3.1). The central efficiency claim at paragraph B.10(a) conflates a wealth transfer with an efficiency benefit (section 2.5). The other claimed benefits in paragraphs B.8 to B.11 either preserve the status quo or assume conclusions the Authority has not established (section 2.6). The substantive proposal and the impact analysis adopt incompatible positions on the population to which the reform applies (section 3.5).

Network Tasman observes that the proposed amendments may nonetheless deliver an improvement in equity by reducing the cross-subsidy from load consumers to distributed generation investors, and Network Tasman supports the changes on that basis. But equity is not one of the matters the Authority is required to promote under section 15 of the Electricity Industry Act 2010. The Authority's main statutory objective is to promote competition, reliability and efficiency for the long-term benefit of consumers. The proposed amendments do not, on Network Tasman's analysis, deliver those benefits — and the regulatory statement does not, on its current evidence, establish that they will.