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Evolving Multiple Retailing and Switching Consultation Paper

1. This is Vector's ("our", "we") response to the Electricity Authority's (the Authority) consultation paper on Evolving Multiple Retailing and Switching dated 3 June 2025. This submission is not confidential and can be published on the Authority's website.

2. Vector wholeheartedly supports innovation and consumer choice. However, we have significant concerns with the current proposal to implement multiple trading relationships ("MTR"). These concerns must be addressed before the Authority proceeds any further with the MTR proposal. Broadly our concerns fall into two categories:

   a. The inequity issues the proposal raises, exacerbated by the limited consumer benefit it is likely to deliver and the lack of clear economic justification for the proposal; and

   b. The significant legal and commercial issues the proposal raises that have not been adequately covered in the consultation paper.

We expand on these two issues in the remainder of this cover letter. Our responses to a selection of the specific questions posed follow in an appendix.

Limited consumer benefits, equity risks and a lack of clear economic justification

3. We have concerns that the Authority's proposal risks creating a two-tier electricity system where benefits accrue to a minority of consumers, while costs are socialised across all consumers. The proposal suggests extensive market redesign for a very small subset of highly engaged prosumers (circa 77000 ICPs with distributed generation[1]), whilst imposing significant costs across the entire consumer base of 2.3 million ICPs. It risks exacerbating energy equity issues, because most consumers - particularly those experiencing energy hardship - will lack the means to (ever) participate in MTR.

[1] See https://www.emi.ea.govt.nz/ for further details of DG installations at 30 June 2025.

4. Consumer NZ's recent submission on the Authority's green paper on decentralisation reinforces this concern. It states[2]:

   "many [consumers] have become disengaged from the energy industry and as such are unlikely to readily invest time or capital in distributed energy technologies" and that *"equity must be a central concern. Wealthier households can shield themselves from rising costs by investing in distributed energy resources, with those left, bearing a greater share of infrastructure costs and higher energy costs".*

   Consumer NZ warned that *"an industry [and Electricity-Authority]-assumed future [is] being projected onto consumers, many of whom neither asked for it, desire it, nor have the means to participate."*

5. Vector also has serious concerns about the timing and costs of this MTR proposal, especially given the lack of evidence that the proposal will deliver clear benefit to a majority of consumers and the lack of demonstrable consumer desire for MTR. We believe that the current proposal fails to acknowledge the significant financial implications of this proposal for consumers and underestimates the scale of investment or cost required to implement the MTR proposal. Extensive changes will be required, at a minimum to participants' billing[3], pricing, and connection systems as well as to the Electricity Registry in addition to changes to multiple operational processes. Future-stage MTR changes would require **even more extensive** changes to our systems.

6. Vector estimates the total implementation effort for stage one of the MTR proposal to be between $3.85 million and $5.5 million[4], with over 12 distinct workstreams and resource types needed including architecture, business analysis, data engineering and change management. The scope spans system, process and regulatory domains, requiring coordinated delivery across multiple teams. Any future stage MTR proposals, such as those noted in the consultation paper would incur significantly greater costs and be significantly more complex to implement. Additionally, the timeframe to implement, especially when one considers the various other changes the Authority is proposing in other workstreams[5], is likely to be closer to 3 years. The overall costs are, in our view, financially prohibitive, particularly given that costs will be borne by consumers who are unlikely to ever benefit from the proposal.

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[2] https://www.ea.govt.nz/documents/7710/Consumer_NZ__Decentralisation_green_paper_submission_URT1P37.pdf pg 2.

[3] From a billing system perspective alone changes to our billing system (Gentrack) to enable the first stage of MTR changes would be extensive and would include such things as (a) ICPs needing to be maintained – created and updated, as well as enabling bulk updates (b) changes to interfaces to and from Siebel to create and update ICPs (c) Electricity Registry interface changes to/from Registry to Vector systems (d) Price Book changes and (e) Billing changes.

[4] This includes changes to our Registry Manager and billing tools, updates to Pricing Methodology, data related costs, internal resources and personnel costs to support the changes.

[5] See our response to consultation question 5 on other Authority projects.

7. Or does the Authority consider that under the Distributed Generation Pricing Principles, distributors may charge an elevated, cost-reflective charge reflecting the back-end system upgrade costs noted here, to be an incremental cost that can be ring-fenced to generation consumers who choose to have a different trader for their generation as either a fixed charge or injection charge? After all, but-for the multiple trader system changes, this cost would not be incurred so it would reflect the actual cost of providing services to this specific consumer group. Of course, the challenge is how we apportion costs fairly to today's users whilst still ensuring that future users / beneficiaries pay a fair share, when the cost of the upgrade is borne now or up front but future uptake is uncertain at best. Would EDBs spread the cost of the upgrade over a 10 – 30-year period and would any consumers who elect to take up MTR then pay a higher price until the cost of the upgrade is recouped? What if no consumers move to the MTR price category because of the higher price? How then do EDBs recoup the investment cost – via cross-subsidisation from all consumers?

8. The lack of a quantified cost-benefit analysis is also concerning. Given the significant implementation costs, the inequity issues it will create and the marginal benefits to consumers, robust economic analysis must accompany and justify this proposal. Similar proposals in Australia, in both 2015 and 2024 were subject to comprehensive economic analysis. It found negative benefits for consumers in most scenarios and that MTR only became economically viable under highly optimistic uptake scenarios – requiring 3.5 million devices over 20 years[6]. A similar level of uptake in New Zealand is highly unlikely and unrealistic, given the significantly smaller scale and less mature DER market we have in New Zealand to support MTR costs. This divergence from (and lack of adherence to) international precedents and best practice is deeply concerning.

9. Likewise, UK analysis of MTR concluded that the costs outweighed benefits in most scenarios, leading to the withdrawal or non-progression of similar proposals. UK research found that MTR would likely exacerbate existing inequalities, benefiting only highly engaged consumers while costs are borne by all, stating:

   "Although it is likely that only a small portion of highly engaged consumers would engage with the offerings enabled by multiple suppliers, these costs would likely be borne across the entire customer base. This would risk exacerbating existing inequalities between those who can and cannot afford to engage." The same research found that *"long contracts, third party involvement, and multiple bills reduced stated likelihood of engagement,"* demonstrating that *"whilst consumers would like the benefits delivered by multiple suppliers, there is reluctance to accept the additional complexity these market arrangements would bring."*[7]

10. Further, the Authority has not provided any evidence that existing market mechanisms (e.g. time of use tariffs, buy-back arrangements and existing price-mode offerings) do not adequately enable consumers to optimise value from their distributed energy resources. The

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[6] Energeia - Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Cost Benefit Analysis , pages 42-43

[7] Watson, N.E., et al, Future energy retail markets: stakeholder views on multiple electricity supplier models in the UK (2022)

Authority has not shown that these current market mechanisms are inadequate or that MTR would deliver superior outcomes that justify the significant implementation costs and complexity of MTR.

11. The proposal potentially caters to a niche group of tech-savvy prosumers while neglecting the broader population, who are either uninterested or financially incapable of participating. It ignores the potential financial burdens on consumers, especially those already facing energy hardship, and the Authority risks not adhering to its statutory responsibility to *"protect the interests of domestic and small business consumers in relation to their supply of electricity"*, by insisting upon this MTR proposal now.

12. We do not support or understand the Authority's inconsistency in wanting to *"use the lessons from the [Wellington Multiple Trading] trial"*[8] (as stated at paragraph 2.40 of the paper) and then proposing to implement permanent Code changes now, when the Wellington trial is only a year into its 4-year term. The Wellington trial's 6-monthly report reveals operational issues and complexity with MTR implementation requirements. This throws into question how viable system-wide rollout actually is. From the outset, the Wellington trial struggled to recruit participants (achieving only 174 of a targeted 200 consumers), suggesting the challenge of achieving meaningful uptake is greater than the Authority might think, even with the most motivated consumers.

13. The Authority states that *"multiple trading has been identified by many participants (and potential participants) as the next step in the industry evolution"* (at paragraph 2.39) but provides no evidence of consumer demand for MTR or any analysis of problems with existing market arrangements that MTR seeks to solve. The recruitment difficulties faced by the Wellington MTR trial suggest current demand for MTR is just not there. Whether this ostensive support is borne out in submissions will be watched closely.

14. Finally, the Authority's proposal suggests that distributors must avoid double-charging consumption and generation traders and should only recover incremental costs from generation traders. However, the incremental costs charged to generation traders may be negligible, because connection infrastructure already exists, as Part 6 of the Code requires. This default position should be reconsidered in our view, given that over time, as more generation traders join the network, an increasing proportion of network utilisation will be by generation traders, but the cost of that network capacity will be met solely by consumption traders. While the incremental costs of any individual generation trader may be negligible, the proportion of total network costs attributable to all generation traders may be significant. This risks creating long-term pricing inequities by shifting the burden of network costs disproportionately onto consumption traders. There will be further complications when EDBs begin implementing payments for injection. When the consumption and generation retailers are distinct, self-consumption of on-site generation becomes less attractive, and the

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[8] https://www.araake.co.nz/project/kainga-ora-mtt

coordination and assessment of load and generation management becomes more complex with more uncertain outcomes.

Commercial and legal risks

15. We also have significant concerns about the current MTR proposal from a legal and commercial perspective. The legal advice provided by Chapman Tripp to the Electricity Networks Aotearoa highlights some of these concerns. For electricity distribution businesses (EDBs) these fundamental legal gaps must be addressed before the MTR proposal progresses any further.

16. The significant legal issues include:

    a. A lack of a clear legal framework between generation traders and EDBs, as well as between consumption traders and generation traders. This gives rise to revenue recovery risks and operational challenges for EDBs because:

        i. It is unclear how risks associated with the generation trader's management of equipment connected to the network should be managed by EDBs
        ii. It is unclear what a consumption traders' obligations to liaise with the generation trader looks like (e.g. if a dispute arises)
        iii. It is unclear whether a generation trader behind the ICP would be subject to the requirements of Part 6 of the Code. A generation trader could refuse to enter into an approaching EDB's agreement, and yet the EDB would be unable to disconnect that ICP if it has obligations to the consumption trader at the ICP (as covered by the DDA).

17. Currently only retailers (or consumption traders) are required to enter into a DDA with distributors. It appears generation traders are:

    a. Not obliged to enter into a DDA with the EDB under the proposed MTR option
    b. Not subject to Part 6 of the Code unless <u>they</u> are connecting distributed generation
    c. Not required to pay for network or distribution services, post security or comply with network standards.

18. The MTR proposal implies that distributors may need to apportion charges between consumption and generation traders. However, there is no mechanism to enforce payment against generation traders given the lack of a contractual arrangement between generation trader and an EDB. Further, distributors may face shortfalls in revenue recovery if consumption traders refuse to pay for the services used by generation traders. At this time, it is also unclear whether there will be an agreement between the consumption trader and generation trader.

19. Without a contractual arrangement between the generation trader and EDB, such as the DDA or a DDA-like agreement, distributors will not be able to enforce metering requirements or

network connection standards on generation traders. Additionally, distributors will have no recourse if a generation trader breaches these standards or obligations, that only consumption traders will be subject to under the DDA.

20. Overall, the proposal and Code amendment creates significant risks for EDB that create:

    a. Legal and commercial risks – the lack of enforceable agreements with generation traders exposes EDBs potentially to:
        i. Unlimited liability without any indemnity
        ii. The inability to recover costs
        iii. Uncertainty in managing breaches or disputes.

    b. Operational challenges – distributors may face challenges to do with:
        i. Coordinating service interruptions and load management – which parties do they contact with and when?
        ii. Ensuring compliance with network standards
        iii. Managing connections and disconnections without direct control over generation traders.

    c. Rebate administration risks – when EDBs are required to pay rebates to consumers for peak time injection, via generation traders, there is no mechanism to ensure proper administration or pass through which raises the risk of disputes for non-compliance. The Authority admitted to ENA personnel in a recent meeting, that the EA had not considered the Rebate proposal when writing up this MTR paper.

21. In conclusion, given the consumer appetite and equity issues raised, the legal risks and operational uncertainties as well as the mammoth costs involved with this change, and the lack of clear economic justification for the MTR proposal at this time, Vector considers the proposal must not proceed until these issues are resolved.

22. We urge the Electricity Authority to review these critical issues and collaborate with industry stakeholders to develop better solutions that better meet consumer needs and safeguard the interests of all parties involved. An approach that considers consumer needs and equity issues, with robust cost-benefit analysis will ensure that the financial burden on consumers is justified and supports innovation and consumer mobility in better ways.

23. The remainder of our submissions respond to the consultation paper questions.

Yours sincerely

[redacted]

Monica Choy
Senior Regulatory & Pricing Partner

Appendix A

Questions	Comments
Questions on the Authority's vision	
Q1. (Paragraph 2.20) Do you agree with the Authority's vision for consumer mobility? If not, what would you change and why?	We acknowledge that MTR may have a role to play in supporting consumer mobility in the evolving electricity sector, provided implementation is timely, appropriate, and cost-effective. However, we remain concerned that the Authority's current approach is premature and lacks sufficient justification, as our response above elaborates on. Currently, approximately only 3.5% of New Zealand's residential ICPs have distributed generation, and only about 0.5% have batteries[9]. Although adoption may increase, this proposal allows prosumers to lower their costs to the detriment of all other consumers, particularly those unable to afford to take part e.g. those in energy hardship. Consumer NZ research suggests that there is a gap between the Authority's goals and the needs of New Zealand consumers, which the Authority must be cognisant of given its statutory objectives. The Authority must present clear evidence of consumer sentiment for the MTR proposal and conduct a comprehensive cost-benefit analysis prior to proceeding with the substantial market restructuring it is proposing here.
Q2. Do you have any comments regarding future stages of multiple trading, whether the proposal provides optionality for the potential future stages, and the options the Authority should consider?	The Authority's proposed future direction for MTR, encompassing energy sharing among family properties, appliance-specific retailers, and time-based retail models, is speculative at best. The Authority underestimates both consumer appetite for and willingness to grapple with this level of complexity, as international research shows, as well as the significant costs involved in implementing this proposal.

[9] See https://www.emi.ea.govt.nz/ for further details of DG installations.

	The Authority should wait for the Wellington MTR trial to finish in 2028 and review its results, as well as results from abroad, before considering any MTR implementation at this time. The rush to implement now is at odds, with the Authority's statement at 2.40 that it wishes to *"use the lessons from the [Wellington Multiple Trading] trial".* The Authority and Energy Competition Task Force are also pursuing initiatives that may conflict or be inconsistent with this MTR proposal. It would make more sense for the Authority implement and assess those other measures first. Taking a sequential and prioritised approach allows for the identification of existing market gaps and helps reduce the risks and costs associated with implementing multiple new solutions at once.
Questions on Multiple trading	
Q3. Do you agree with the proposed solutions? If not, what would you change and why?	We do not support the Authority's current MTR proposal. While we recognize that MTR *could* have a role to play in the future electricity sector, we consider implementation at this stage is far too premature in view of the concerns raised above and the lack of economic justification for the proposal. Both Options 1 and 2 would require EDBs to update multiple systems to support multiple traders at each ICP, regardless of whether that is necessary for every ICP. This would result in complex system changes for approximately 2.3 million ICPs to potentially serve up to 77,000 prosumers and at substantial costs. See our estimated costs above at paragraph 6 ranging from $3.85 million and $5.5 million. Option 3 increases an EDB's administrative workload by adding more ICPs, does not align with the Authority's long-term vision and is not practical to scale. Additionally, the Authority has not addressed key legal and operational questions arising from the

	implementation of MTR under any of the proposed options. These include (amongst many others): • What dispute resolution mechanisms will govern interactions between traders? • Are pre-pay meters compatible with MTR? • How should situations be handled where a generation trader has outstanding bills, but the consumption trader's account is current, or vice versa? • What procedures are in place if one trader becomes insolvent? • How will conflicting information provided by traders to a single customer be managed? • Who will be responsible for distributor-to-trader communications during planned outages? • Requiring both traders to communicate could lead to consumer confusion – how is that to be handled? • How will Consumer Care Obligations to medically dependent consumers with multiple traders, be handled? • How will the DDA be managed when there are multiple traders serving one property? • Under Option 3, if a consumer relocates and the new occupant fails to update their generation ICP—or is unaware of this requirement—how is that to be managed? • How can distributors enforce network connection standards for generation traders who do not have DDA obligations? • What prudential and security arrangements will apply to generation traders lacking contractual relationships with distributors? • How will load management protocols for system security be enforced when generation traders are not subject to DDA obligations under clause 5? How is that fair to consumption traders? Is the Authority concerned with the un-level playing field? • What liability and indemnity provisions will define the relationship between distributors and generation traders in the absence of DDA protections? • Where generation equipment damages distributor assets and the generation trader lacks DDA

	obligations relating to equipment damage, what processes will apply? • Where an ICP serves both a consumption consumer (e.g., tenant) and a different generation consumer (e.g., landlord owning distributed generation), how will matters such as rebates and trust dividends be managed?
Q4.(3.26) Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	The Authority has not provided quantified benefits, which makes proper evaluation difficult. The stated qualitative benefits are based on projections and may not fully reflect present consumer conditions. The proposal optimises market design for about 77,000 potential prosumers but spreads costs to all consumers, including those facing financial hardship. We direct the Authority to Australia's 2015 and 2024 cost-benefit analysis, which showed that similar proposals generally do not benefit consumers except under the most optimistic uptake scenarios. Australia's 2024 Energeia Report on the voluntary MTR proposal indicates that, a positive business case is achieved only when both small and large customers have net positive CBA outcomes. This outcome would require an additional 184,000 devices per year (totalling 3.5 million over 20 years) to be enrolled in CER flexibility services to reach the breakeven point.[10] Achieving similar uptake in New Zealand is unlikely due to our smaller scale and less developed DER market to support MTR costs.
Q5. (3.26) Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	Vector has identified estimated implementation costs for this MTR proposal to be between $3.85 million and $5.5 million. However, this should be considered in the context of the significant volume of concurrent regulatory changes EDBs are currently having to grapple with. These include upcoming changes to the Network Connections processes, which have been estimated at $3.4 million approximately, and does not include estimated costs for changes to Connections pricing and other regulatory initiatives noted in the next

[10] Energeia - Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Cost Benefit Analysis , pages 42-43

paragraph. The overall costs are significant. These expenses will require EDBs to reallocate funding from distribution line services and other operational or process improvement initiatives that are currently in progress.

We note Energy Networks Australia's submission on the scale of system changes required for MTR:

"[EDB] Business systems and processes are designed with internal automatic validations based upon one-on-one relationships. To identify multiple transactions against a single customer connection would require significant system changes plus validation checks on all or most transactions to verify whether multiple traders are present."[11]

Our internal systems are designed around one-to-one relationships between ICPs and traders. Implementing MTR will require substantial re-engineering of billing, works management, faults management, GIS, SCADA, and reporting systems at a minimum. These costs will be passed to all consumers, most of whom will not benefit from MTR. The Authority's approach results in costs for current consumers, including those facing energy hardship, to subsidise infrastructure that will primarily benefits prosumers with distributed energy resources.

The implementation of MTR is anticipated to introduce considerable operational and legal complexities. In the absence of DDAs between distributors and generation traders, there will be no effective mechanism to enforce several critical obligations, including compliance with network connection standards (currently managed under DDA clause 13), prudential security requirements (DDA clause 10), essential load management protocols for system security (DDA clause 5), payment commitments for network services, liability and indemnity protections (DDA clauses 24–26), as well as responsibilities related to premises

[11] https://www.aemc.gov.au/sites/default/files/content/f448f49d-200d-4623-996b-5f0783a4b65c/RuleChange-Submission-RRC0005-Energy-Networks-Australia-150911.pdf

	access and equipment damage (DDA clauses 11–12). While the proposed Code amendments in clause 11.13C address some aspects of charging arrangements, they do not establish an enforcement mechanism in the absence of a foundational agreement such as the DDA. Additionally, EDB staff are handling a large number of regulatory changes—including Omnibus 3, Network Connections, Consumer Care Obligations (EIEP4A), DDA updates, Distributed Generation Pricing Principles updates, distribution connection pricing, Task Force initiatives 2A/2BC, and MTR—all affecting the same teams and systems. These efforts lack coordinated planning and realistic timelines that may result in inconsistencies in implementation. The Authority should provide sufficient time for thorough implementation of each of these changes. Each change increases costs for businesses and diverts resources from other key operational improvements. Instead of making incremental updates to the outdated Registry platform, the Authority should consider prioritising a full replacement built of the Registry to cater for a future digital world.
Q6. (3.47) Do you agree options 2 and 3 are not preferred? If not, why not and how would you overcome the disadvantages?	No. We do not support the Authority's current MTR code proposal (any of the options) presented. We support the deferral of MTR implementation for at least 5 years, until such time as the Wellington trial concludes and further learnings from abroad can be considered. The Authority has not sufficiently justified the need for immediate implementation. New Zealand's DER market is still developing and includes only about 77,000 customers currently. The current market size does not warrant the system-wide costs and complexity of MTR at this time. The Authority's competition concerns with Option 2 (paragraphs 3.32 – 3.35) are also unfounded. New Zealand retailers are already working with solar installers to provide varied buy-back rates, showing that market competition for generation services exists

	without the need for complex MTR solutions at this time. The Authority's support for Option 1—which mandates Registry changes for <u>all</u> 2.3 million ICPs regardless of market demand—is concerning given that several retailers have cautioned the Authority against imposing regulations that limit pricing flexibility. As ERANZ submitted: *"ERANZ emphasises the competitive nature of the retail market, and the need for retailers to be free to design consumer plans that allow for innovation and ensure market competition."*[12] The Authority should let market forces, not regulations, decide on MTR adoption based on consistent feedback from the retail sector. Option 3 would place a heavy administrative load on EDBs by requiring additional ICPs, leading to increased staffing needs, compliance issues, and inefficient manual processes. The Wellington MTR trial highlighted these challenges, with Wellington Electricity noting the significant manual work needed for dual ICP management. Scaling this approach across many sites would increase complexity without clear consumer benefits.
Q7. (3.47) Do you agree that option 1 is the preferred option over options 2 and 3 and the reasons for preferring option 1? If not, why not?	No. We do not support Option 1 or the Authority's current MTR code proposal as presented. We recommend the Authority defer MTR implementation for 3-5 years to allow New Zealand's DER market to mature and for comprehensive cost-benefit analysis to be undertaken. Option 1 creates complexity for the entire sector to serve a small subset of consumers while imposing disproportionate costs across all consumers regardless of whether they use MTR. The Authority's preference for Option 1 appears driven by regulatory ideology rather than economic efficiency or evidence-based analysis.

[12] https://www.ea.govt.nz/documents/6930/R_ERANZ_2B2C_submission_2025.pdf

Questions on trader switching	
Q8. (4.55(q)) Should the provision of the average daily consumption remain mandatory, or should it be optional? If optional, please explain why?	No comment.
Q9. (4.55(q)) Do you agree with the proposal to align timeframes to a maximum of two business days for NT and AN notifications, and to reduce timeframes for the CS file?	No comment.
Q10. (4.55(q)) Do you agree with the proposed solutions? If not, what would you change and why?	No. The current Electricity Registry does not meet modern data exchange requirements and is not equipped to support the level of data connectivity required for New Zealand's digital electricity system. The Registry continues to use text file transfers between participants. To address these requirements, a new data exchange platform capable of real-time, secure data sharing and advanced reporting is needed. Instead of focusing on incremental enhancements to the legacy system, the Authority should consider prioritising a complete replacement of the Registry.
Q11. (4.55(q)) Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	No comment.
Q12. (4.55(q)) Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	No comment.
Questions on MEP switching	
Q13. (5.34) Are there any other files that should be added to this list?	No comment.
Q14. (5.38) Do you agree with the proposed solutions? If not, what would you change and why?	No. See our response to Q10.
Q15. (5.38) Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness	No comment.

and efficiency? Can you quantify these benefits?	
Q16. (5.38) Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	No comment.
Questions on distributor switching	
Q17. (6.13) Do you agree with the proposed solutions? If not, what would you change and why?	No. See our response to Q10.
Q18. (6.13) Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	No comment.
Q19. (6.13) Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	No comment.
Questions on implementation	
Q20. (7.4) Would you prefer a single implementation or a staged implementation? Please give reasons for your preference	At this time, we do not support the implementation of MTR for the reasons detailed in our submission.
Q21 (7.4) Do you agree with the suggested implementation timeframes? If not, please state your preferred timeframes and give reasons for your preference	The proposed 18-month timeframe is not feasible given the complexity of the systems proposed and ongoing changes affecting sector participants. We have indicated a timeframe of 3 years is more likely to be appropriate given the concurrent work the Authority is proposing under other workstreams as noted in our response to Q5.
Questions on the regulatory statement	
Q22. (8.6) Do you agree with the objectives of the proposed MTR amendments? If not, why not?	The objectives are ambitious but not supported by evidence. The Authority has not provided evidence of strong consumer support or sentiment towards MTR, nor has it demonstrated that the existing market structures do not achieve efficient outcomes. The MTR objectives assume unproven and unquantified benefits.

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Q23 (8.11) Do you agree with the objectives of the proposed amendments to the switching process? If not, why not?	No comment.
Q24 (8.17(q)) Do you agree the benefits of the proposed amendment outweigh its costs?	No. The Authority has not provided a quantified cost-benefit analysis, and international evidence from Australia and the UK indicates negative consumer outcomes in most cases. Without solid economic justification, this proposal is not viable.
Q25. (8.21) Do have any comments on the preferred and alternative options discussed in the 2019 Issues paper?	No comment.
Q26. (8.22(d)) 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 statutory objective in section 15 of the Electricity Industry Act 2010.	We do not support any of the options proposed for the reasons outlined above. Options 1 and 2 will impose significant costs that cannot be justified at this time and Option 3 is not a viable option for the future scenarios noted in the paper. We encourage the Authority to consider all issues raised. Until such time as these have been addressed and we have had the opportunity to take learnings from the Wellington MTR trial, and insights from abroad, we do not believe the MTR proposal should progress further. Ensuring efficient operation by avoiding system-wide costs for uncertain benefits and allowing time for evidence-based justification through either market development or properly designed trials under Code exemptions is the better way to go, in our view.
Q27. (8.25) Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	No comment.
Question on Code drafting	
Q28. (Appendix A) Do you have any comments on the drafting of the proposed amendment?	We submit in support of the ENA's proposed re-drafting, which has the benefit of legal input from Chapman Tripp.