Orion

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Electricity Authority
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Submitted via email to policyconsult@ea.govt.nz

Consultation Paper – Evolving multiple retailing and switching

Introduction

1. Orion welcomes the opportunity to submit on the consultation paper 'Evolving multiple retailing and switching'.[1]
2. Orion owns and operates the electricity distribution infrastructure in central Canterbury, including Ōtautahi Christchurch city and Selwyn District. Our network is both rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia River in the south; from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 231,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business (EDB).

Executive summary

3. Orion supports the concept of multiple trading relationships ("MTR") as part of the electricity sector's future evolution, when implemented at the right time, with proper justification, and at appropriate cost. However, Orion does not support the Electricity Authority's ("Authority") current MTR code proposal as presented due to significant concerns about the current implementation approach. The current proposal appears premature, poorly justified, and likely to impose disproportionate costs on those consumers who are unable to participate in an MTR, while delivering uncertain benefits.
4. Orion submits that MTR represents a fundamental change to the underpinnings of the electricity system, and how all participants interact. This is not a simple regulatory enhancement, but a complete restructuring of market arrangements that will require substantial investment and operational changes across the sector. Orion has identified estimated implementation costs ranging from $2.79m – $3.89m.[2]

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[1] Evolving multiple retailing and switching

[2] This includes changes to our Registry and Billing tools, internal resources, updates to Pricing Methodology, and personnel costs to support the changes.

5. Orion submits that the Authority has not provided a quantified cost-benefit analysis for this proposal. This contrasts with similar international proposals, and regulatory good practice. Similar proposals in Australia, in both 2015 and 2024, were subject to comprehensive economic analysis, which found negative benefits for consumers in most scenarios. Without quantified economic analysis, the economic case for this proposal remains unclear.

6. Orion submits that the Authority's approach raises questions about alignment with its Consultation Charter Principles.[3] The Authority has not demonstrated a "*clear case for regulation*" (Principle 1), has provided only a superficial evaluation of costs and benefits that acknowledges costs "*cannot be quantified at this point*" while offering only vague, unquantified benefits (Principle 2).[4] The Authority has not shown preference for market solutions over regulatory intervention (Principle 5) and has dismissed the less prescriptive Option 2 without adequate justification contrary to its stated preference for non-prescriptive options (Principle 7).

7. It is challenging to see how the Authority's proposal meets its statutory objective to "*protect the interests of domestic and small business consumers in relation to their supply of electricity*."[5] The proposal imposes system-wide costs across all ICPs to enable a sophisticated market mechanism that will primarily benefit a small number of highly engaged prosumers with distributed energy resources. This approach risks harming the interests of domestic and small business consumers without distributed generation, who will bear the costs of MTR implementation through higher network and system costs, while being unable to access any benefits.

8. The accelerated timeline for MTR implementation is particularly concerning given the preliminary results from the on-going Wellington Multiple Trading Trial.[6] Despite claiming to want to "*use the lessons from the trial*," the Authority is proposing permanent Code changes only 1 year into a 5-year trial period.[7] The trial's 6-monthly reports reveal operational issues and complex implementation requirements. Most tellingly, the trial struggled to recruit participants (achieving only 174 of a targeted 200), potentially contradicting the Authority's assumptions about consumer demand for MTR, and demonstrating the challenge of achieving meaningful uptake even among motivated consumers.

9. Orion submits that the Authority's approach to implementing MTR appears influenced more by technological enthusiasm and influence from prosumers, rather than clear overall consumer sentiment or demonstrated system benefits. Consumer NZ's submission on the decentralisation green paper highlights that "*many* [consumers] *have become disengaged from the energy industry and as such are unlikely to readily invest time or capital in distributed energy technologies*." This proposal drives costs to optimise for approximately ~77,000 customers while imposing costs across the entire consumer base.[8]

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[3] https://www.ea.govt.nz/documents/482/Consultation_Charter_2024.pdf.
[4] Evolving multiple retailing and switching, paragraph 8.15.
[5] Electricity Industry Act 2010, clause 15(2).
[6] https://www.araake.co.nz/project/kainga-ora-mtt.
[7] Evolving multiple retailing and switching, paragraph 2.40.
[8] As of 31 May 2025, there are 76,819 ICPs with installed DG across all ICP types. See https://www.emi.ea.govt.nz/ for further details.

10. The Authority's proposal creates legal challenges. While clause 11.13C(b) requires distributors to apportion charges between consumption and generation traders, the Authority has provided no mechanism for distributors to levy or enforce payment from generation traders. Generation traders could simply refuse to pay, leaving distributors with no recourse beyond Code breach proceedings that do not create payment obligations.
11. Our specific responses to the questions posed by the Authority are set out in Appendix A.

Key themes from our submission

The Authority has not sufficiently defined the problem requiring regulatory intervention

12. While the Authority identifies some technical issues with current arrangements (paragraphs 3.10 – 3.12), the consultation reads as though MTR implementation has been predetermined as the solution rather than being justified by demonstrated consumer need or market failure. The Authority states that "*Multiple trading has been identified by many participants (and potential participants) as the next step in the industry evolution*" (paragraph 2.39) but provides no evidence of consumer demand for MTR, or analysis of problems with current market arrangements that would justify regulatory intervention.
13. The Authority has not demonstrated that a lack of MTR is preventing highly engaged prosumers, or consumers more generally, from connecting their distributed energy resources or benefiting from their investments. Existing price-mode offerings, time-of-use tariffs and buy-back arrangements already enable consumers to optimise value from their distributed energy resources.[9] The Authority has not shown that these current market mechanisms are inadequate or that MTR would deliver superior outcomes that justify the significant implementation costs or complexity.
14. As mentioned in point 8, the Wellington Multiple Trading Trial provides evidence that MTR implementation faces significant practical challenges. If the benefits of MTR were compelling and implementation straightforward, the Authority would be showcasing successful trial results to support system-wide rollout. Instead, the Authority is rushing through Code changes mid-trial while the trial reports document operational problems and implementation complexity that raise questions about mass market viability.
15. Australia considered a similar MTR proposal in 2015-2016.[10] Energy Networks Australia noted that there was a "*lack of clear evidence to justify any current demand from customers to support the urgent implementation of multiple trading relationships. Unless broad evidence of significant unmet demand is provided, the disruption and increased cost imposts across all customers should not be undertaken.*"[11] While not progressed then, a similar proposal was implemented in 2024 with comprehensive cost-benefit analysis showing negative benefits except in optimistic scenarios. See our comments in points 25-27 for further detail.

System architecture requires fundamental re-build not incremental fixes

16. The Authority cannot continue to add complexity to an Electricity Registry ("Registry") implemented in 1999, that still relies on text file transfers between participants.

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[9] The Authority has not adequately considered that market-based solutions already exist to achieve the stated competition objectives for distributed generation. For example, see Harrisons Solar partnering with Mercury to offer enhanced buy-back rates of 18 cents per unit for customers installing solar systems, and Ecotricity offering both flat rate peak/off-peak buy back rates or based on wholesale prices.

[10] https://www.aemc.gov.au/rule-changes/multiple-trading-relationships

[11] ENA - Submission on AEMC consultation paper, page 10

17. The Authority's recent regulatory changes demonstrate issues with its approach to updating market infrastructure. Rather than developing a strategic roadmap for Registry modernisation, the Authority has pursued fragmented updates (Omnibus 3, Network Connections, Consumer Care Obligations, and now MTR) that require overlapping system changes without coordinated implementation.

18. This piecemeal approach imposes cumulative costs on participants while failing to address the inadequacy of a Registry system designed in 1999 for today's sector needs. The Authority's recent EIEP4A and Consumer Care Obligations decision papers acknowledged challenges raised by both retailers and distributors on the suitability of the existing EIEP file transfer system, the accuracy of data sent between participants, and requesting a longer implementation timeline for any changes impacting the Registry.

19. As Ron Beatty acknowledged in 2018, "*the industry has never stepped back and asked whether this is the best switching process for the future*" and that "*the industry could be a very different animal*" requiring systems that can "*cater for customers receiving services from more than one player*." We note that Ron stated that any such "*change* [to enable the above capabilities] *would take at least three and a half years and probably five. A cost-benefit analysis would also be required to ensure it was worth undertaking*."[12] We question why the Authority has allowed for only an 18-month implementation period for MTR.

20. Rather than implementing MTR through further Registry modifications, Orion submits that the Authority should first prioritise a complete Registry replacement designed for the digital future.[13]

Consumer equity concerns require careful consideration

21. The Authority's proposals benefit a small segment of highly engaged consumers with distributed energy resources while imposing costs across the entire consumer base. This exacerbates existing inequalities between those who can afford to invest and those who cannot. International research reinforces these concerns. UK analysis found that "*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 born across the entire customer base. This would risk exacerbating existing inequalities between those who can and cannot afford to engage*."[14]

22. 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 additional complexity these market arrangements would bring*."[15]

23. Consumer NZ's submission on the Authority's decentralisation green paper highlights that "*equity must be a central concern*." Consumer NZ comments 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*."[16]

Economic justification is not robust

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[12] Electricity Authority eyes future of market registry.

[13] As described by the Authority recently in Our future is digital.

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

[15] Ibid.

[16] Consumer NZ's submission on the decentralisation green paper.

24. Orion has identified estimated implementation costs ranging from \$2.79m – \$3.89m.[17] We have not estimated ongoing operational costs.

25. The Authority has provided no quantified costs, benefits, or uptake projections for MTR. This contrasts sharply with Australia's approach, where comprehensive cost-benefit analyses in both 2015 and 2024 found that similar proposals would result in negative benefits for consumers except in best case, optimistic uptake scenarios.[18]

26. Australia's 2015 analysis found that DNSP (EDB) implementation costs alone would range from \$10.5 million (mean) to \$18.2 million (maximum) per network, with ongoing costs of \$2.7 million (mean) to \$7.5 million (maximum) per year. The net present value analysis showed negative economic benefits under most plausible scenarios, with benefits only materialising under assumptions of high uptake rates that were considered unrealistic at that time.[19]

27. Australia's CBA on the voluntary 2024 proposal found that even under best-case scenarios, the breakeven analysis only shows a positive business case when both small and large customers have net positive CBA outcomes, which requires an additional 184k devices per year (totalling 3.5m over 20 years) to be enrolled in CER flexibility services to break even. A similar level of uptake in New Zealand's context is unrealistic given the significantly smaller scale and less mature DER market that would need to support MTR costs.[20]

28. As mentioned in points 8 and 14, the Wellington Multiple Trading Trial reinforces concerns about the economic viability of MTR. The trial has experienced significant variance from projections, with revenue estimates revised downward.[21] This raises questions about the Authority's qualitative benefit assumptions and uptake for a system-wide mandatory implementation, reinforcing our argument that the Authority has not provided adequate economic justification for MTR.

29. Orion notes that between 2018 – 2021, the UK considered a modification that would have enabled multi-party supply. This was withdrawn, as the cost-benefit analysis concluded that "*the costs… outweighed the benefits at that moment in time*."[22]

Administrative and operational complexity requires further analysis

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[17] This includes changes to our Registry Manager and Billing tools, internal resources, updates to Pricing Methodology, and personnel costs to support the changes.

[18] See Jacobs SKM Benefits and Costs of Multiple Trading Arrangements and Embedded Networks Table 2, page 6; Energeia - Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Cost Benefit Analysis pages 8-9, 32-35.

[19] See Jacobs SKM Benefits and Costs of Multiple Trading Arrangements and Embedded Networks Table 1, page 3.

[20] See Energeia - Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Cost Benefit Analysis , pages 42-43 for further details.

[21] As noted in the most recent 6-monthly trial report, estimated total revenue for the year has reduced from \$150,000-200,000 annually to \$70,000-110,000. This was primarily influenced by weather conditions, spot price volatility, and achieving only 174 participants against a target of 200. While these factors may explain the variance, they highlight the inherent uncertainty in forecasting MTR benefits and the sensitivity of returns to external market conditions and participation rates.

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

30. The Authority's proposal creates gaps in contractual arrangements between distributors and generation traders. Under current arrangements, only load retailers are obliged to enter into a Default Distributor Agreement ("DDA") with distributors, which provides essential protections and obligations for network operations, system security, payment, and liability allocation. Generation traders would have no such contractual relationship with distributors, creating unacceptable operational and commercial risks.
31. Without a DDA between distributors and generation traders, distributors would have no mechanism to levy charges on generation traders or enforce payment for network services. This creates a risk that distributors are obliged to apportion charges between consumption and generation traders but have no way to enforce payment from generation traders, potentially leading to revenue shortfalls. The Code drafting appears to address these matters only partially through clause 11.13C(b), but without a DDA between the distributor and generation trader, there is no mechanism for the distributor to levy charges on the generation trader at all, nor any way to compel generation traders to pay for network services. The Authority has also not outlined the impact on Code obligations for ICP management and records.
32. Critical operational matters currently managed through DDAs would remain unresolved for generation traders, including: supply of distribution services to specified service levels, payment for distribution services, planning and communication of service interruptions (noting that Part 12A only requires communication to retailers party to a DDA), load shedding obligations, load management protocols for system security, prudential obligations and security posting, access to premises and damage to distributor equipment, network connection standards compliance, power quality acknowledgments, connections/disconnections procedures, breaches and dispute resolution, liability and indemnity arrangements, and customer agreement alignment. For example, distributors currently enforce network connection standards via retailers, but generation traders will not be similarly obliged to comply or ensure consumer compliance.
33. The proposed Code amendments in clause 11.13B only partially address the relationship between consumption and generation traders, requiring generation traders to work through consumption traders for network changes and disconnections. Clause 11.13B(5) makes it a Code breach for consumption traders not to action generation trader requests within 2 business days, but this creates a complex dependency relationship without proper contractual framework, dispute resolution mechanisms, or clear obligations enforcement (outside of a Code breach). It is difficult to imagine consumption traders willingly taking responsibility for coordinating with generation traders, or generation traders being comfortable working within a framework where their network access rights are entirely derived from consumption traders.

34. The recent Energy Competition Task Force ("Task Force") decision papers 2A and 2BC demonstrate a concerning pattern of introducing confusion and complexity into the Code and DDAs through poorly considered override provisions. For example, these proposals include terms such as "*despite clauses 1 to 4 or anything contrary in a distributor agreement*..." and "*despite anything contrary in any agreement or the regulated terms*." As we described in our prior submission, these override clauses create legal uncertainty, undermine existing contractual arrangements, and force industry participants to navigate conflicting obligations between the Code and their commercial agreements.[23] The MTR proposal continues the Authority's problematic pattern of overriding established contractual frameworks without adequate consideration of practical impacts on industry participants, introducing further network and system risk through inadequately thought-through arrangements.

35. Overseas research found that unresolved administrative and operational arrangements create significant challenges for all parties. UK research found that multiple supplier arrangements create significant operational challenges, with analysis identifying "*impacts on competition, related to challenges brought about by the increased risk and uncertainty for primary suppliers and the differentiation of responsibilities of primary and secondary suppliers*."[24]

Task Force initiatives may compound MTR implementation challenges

36. As the Authority is no doubt aware, the Task Force has recently released decision papers on two initiatives: distributors paying rebates to consumers who supply electricity during network congestion (2A), mandatory time-of-use pricing plans (2B), and mandatory variable buy-back rates reflecting peak-time value (2C). These initiatives require EDBs to pay rebates to retailers for customers who inject during periods of peak demand. However, without proper contractual frameworks between distributors and generation traders, there is no mechanism to ensure generation traders receive these rebates from distributors, creating uncertainty about whether intended consumer benefits would materialise and potentially leading to disputes about payment responsibility and compliance between multiple parties.

Concluding remarks

37. Orion supports the ENA's submission in principle.

38. The Authority and the Energy Competition Task Force are simultaneously pursuing multiple initiatives aimed at the same objectives that MTR is intended to address. All these initiatives will directly impact how consumers interact with and benefit from their distributed energy resources. Given this overlap in objectives and the significant implementation burden that concurrent regulatory initiatives place on industry participants, the Authority should allow these existing measures to be implemented and evaluated before introducing the additional complexity and cost of MTR.

39. While we support MTR as a valuable future market mechanism, Orion submits that the Authority should not implement any MTR options at this time. Instead, the Authority should defer MTR and review the proposal again in 3-5 years when:

    a. New Zealand's DER market has matured sufficiently to justify the costs,

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[23] Orion submission - Task Force proposals 2A & 2BC, paragraphs 9a, 40 and Q16.

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

b. comprehensive cost-benefit analysis can be undertaken with realistic uptake projections,

c. the Electricity Registry has been replaced with a modern platform capable of supporting more advanced market mechanisms, and

d. clear evidence of consumer demand for MTR services has been demonstrated rather than assumed.

40. Alternatively, we suggest pausing work on amending and gazetting the Code amendment to instead run trials on the five MTR types through the Power Innovation Pathway. This would enable the sector to gather actual data on costs, benefits, and consumer demand via Code exemptions, providing the evidence-based foundation currently missing from this proposal.

41. This submission is not confidential and can be publicly disclosed.

42. If you have any questions or queries on aspects of this submission which you would like to discuss, please contact us on [redacted]

Yours sincerely,

[redacted]

Connor Reich
Regulatory Lead – Electricity Authority

Appendix A

Submitting organisation	**Orion New Zealand Limited ("Orion")**
Contact person	**Connor Reich**

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?	Orion supports multiple trading relationships as an important component of future consumer mobility as the electricity sector evolves. However, successful implementation requires the implementation to occur at the right time, in the right way, and at the right cost. We have significant concerns about the Authority's current approach to implementation, which appears premature and poorly justified. The Authority's vision in paragraph 2.20 describing progressively complex solutions including family energy sharing, appliance-specific retailers, and time-based trading appears speculative and disconnected from consumer demand.[25] The New Zealand market reality is that only 3.5% of residential ICPs, nationally, have distributed energy resources installed, and of those, only around 13% have batteries (representing only 0.5% of total residential connections). While uptake is likely to increase in the future, this proposal will enable prosumers to optimise their own costs, while imposing costs across the entire consumer base. As we have submitted previously, there appears to be a disconnect between the Authority's desired future, and New Zealand's consumer wants and needs.[26] Consumer NZ found that 45% of consumers have been with their current electricity provider for more than five years,[27] while EMI switching data shows that as of April 2025,

[25] As outlined by Consumer NZ in their submission on decentralisation.
[26] Orion submission - Our future is digital.
[27] Consumer NZ, Record savings available to people who switch power providers.

	only 5.48% of customers actively switched retailers in the previous 12 months.[28] Australian research reinforces these patterns, finding that 54% of households want only a “basic” relationship with the energy system focused on “a simple reliable electricity service at a good price,” [29] 37% don't know what type of retail tariff they're on, and 37% don’t even know what a retail tariff was.[30] Similarly, in the UK, as of 2019, more than 50% of consumers are still on a default tariff.[31] The Authority should demonstrate clear consumer sentiment and provide robust cost-benefit analysis before restructuring market arrangements.
Q2. (2.20) 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 future vision for MTR, including energy sharing between family properties, appliance-specific retailers, and time-based retailers, appears highly speculative and risks creating complexity. Simply Energy's submission noted that “*the benefits of a consumer being able to buy energy from one retailer and sell energy to another retailer are unlikely to be significant*” as “*the wholesale market is an open competitive market and it is unclear how one retailer could value the customer's energy significantly differently to another*.”[32] Before considering any future stages, the Authority should wait for the Wellington MTR trial to conclude in 2028 and evaluate its findings. Given that the Authority and Energy Competition Task Force are simultaneously pursuing multiple initiatives aimed at the same objectives as MTR, the Authority should allow these existing measures to be implemented and evaluated first.

[28] EMI switching data, 12-month rolling rate for Trader Switch as of 30 April 2025, https://emi.ea.govt.nz.

[29] Energy Consumers Australia, Consumer Energy Report Card, January 2025.

[30] Energy Consumers Australia, Consumer Energy Report Card, December 2024. While we note that 46% of consumers wanted an “active” relationship, allowing more choice, control, or flexibility over how they manage their electricity, the survey found that these were more likely to be households with solar and higher income.

[31] See Liberalized retail electricity markets: What we have learned after two decades of experience?, page 4.

[32] Simply Energy submission, page 2.

	This sequential approach would provide clearer evidence of remaining market gaps that might genuinely require MTR intervention, while avoiding the compounding risks and costs of implementing untested solutions simultaneously.
Questions on Multiple trading	
Q3. (3.26) Do you agree with the proposed solutions? If not, what would you change and why?	We do not support the Authority's current MTR code proposal as presented. While we acknowledge that MTR may play a part in the electricity sector's future evolution, we believe implementation is premature and poorly justified. We note that Australia has recently implemented a *voluntary* multiple-CER trading relationship for small and large customers.[33] As proposed, both Option 1 and Option 2 would require EDBs to overhaul systems to accommodate multiple traders at every ICP regardless of need, creating system overhead for approximately 2.3 million ICPs to serve potentially, at maximum, 77,000 prosumers.[34] This would introduce significant cost into the sector. Option 3 creates significant administrative burden for EDBs by requiring creation and management of additional ICPs and will not support the Authority's future vision. In all Options, the Authority has provided no analysis of critical operational questions that MTR will create, such as: • Can pre-pay meters support MTR? • What happens when a generation trader has unpaid bills, but the consumption trader is current, or vice versa? • What dispute resolution mechanisms exist between traders? • What happens if one trader becomes insolvent? • What happens if traders provide conflicting information to the same customer? • Who manages communication from the distributor to the trader during planned outages? Would both Traders be required to, which may potentially cause confusion to the consumer?

[33] https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading
[34] As of 31 May 2025, there are 76,819 ICPs with installed DG across all ICP types. See https://www.emi.ea.govt.nz/ for further details.

	- How are Consumer Care Obligations managed when a medically dependent consumer has multiple Traders? - How will Default Distributor Agreements (DDA) be managed with multiple traders at one property? - If the Authority proceeds with Option 3, what happens if a consumer moves house, and the new party forgets to update their generation ICP, or is unaware of the requirement to do so? - How will distributors enforce network connection standards when generation traders have no DDA obligations to ensure consumer compliance? - What prudential obligations and security arrangements will apply to generation traders who have no contractual relationship with distributors? - How will load management protocols for system security be enforced when generation traders are not subject to DDA obligations under clause 5? - What liability and indemnity arrangements will exist between distributors and generation traders in the absence of DDA protections? - How will distributors communicate planned and unplanned service interruptions to generation traders when Part 12A only requires communication to retailers party to a DDA? - What happens when generation equipment causes damage to distributor assets, but the generation trader has no DDA obligations regarding access to premises or equipment damage. These unresolved operational complexities will create significant administrative burden and operational challenges. Furthermore, while New Zealand has made significant progress in smart meter deployment, regional variations in metering infrastructure capabilities remain. MTR implementation requires consistent advanced metering functionality across all participating sites. The Authority should ensure that metering infrastructure requirements for MTR are clearly defined and universally available before introducing additional system complexity.

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 provided no quantified benefits, making meaningful evaluation challenging. The claimed qualitative benefits appear speculative and ignore current consumer realities. Almost 1 in 10 of New Zealand households were declined by new retailers due to unpaid bills, and 360,000 consumers experienced difficulty paying their electricity bills in 2024.[35] This proposal optimises market design for approximately 77,000 potential prosumers while imposing costs across the entire consumer base, including those already struggling financially.[36] Simply Energy's submission observed that "*the benefits of MTR are limited, especially when compared to the expectations created by advocates of MTR*" and that "*energy costs make up only one component of the costs incurred by a retailer when servicing a customer.*"[37] We refer the Authority to details on Australia's cost-benefit analyses from 2015 and 2024, which found that similar proposals would result in a negative benefit for consumers, in all but the most optimistic of uptake scenarios.[38] Australia's 2024 Energeia Report on the voluntary MTR proposal found that even under best-case scenarios, the breakeven analysis only shows a positive business case when both small and large customers have net positive CBA outcomes, which requires an additional 184k devices per year (totalling 3.5m over 20 years) to be enrolled in CER flexibility services to break even.[39] A similar level of uptake in New Zealand's context is unrealistic given the significantly smaller scale and less mature DER market that would need to support MTR costs. We cannot identify clear operational effectiveness improvements from MTR. Rather, we expect increased complexity in dispute resolution, disconnection processes, and system administration. The absence of rigorous economic justification makes this proposal economically unjustifiable.

[35] https://www.consumer.org.nz/articles/why-is-the-electricity-market-failing-people

[36] As of 31 May 2025, there are 76,819 ICPs with installed DG across all ICP types. See https://www.emi.ea.govt.nz/ for further details.

[37] Simply Energy submission

[38] Jacobs SKM Benefits and Costs of Multiple Trading Arrangements and Embedded Networks; Energeia - Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Final Cost Benefit Analysis

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

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?	Orion has identified estimated implementation costs of the Authority's MTR proposal ranging from $2.79m – $3.89m. However, this must be viewed in the context of the unprecedented volume of concurrent regulatory changes EDBs are currently managing. Combined with Network Connection changes (Orion estimated first-year implementation costs exceeding $2.5m), and other regulatory initiatives, the cumulative costs are substantial and will likely require EDBs to reprioritise funding from core distribution line services and other ongoing or planned operational and process improvements that we are undertaking for the benefit of consumers.[40] While individual regulatory changes may potentially be below reopener thresholds, the aggregate impact forces EDBs to absorb costs that collectively represent a significant financial burden. As outlined in our prior submission, the Authority must request that the Commerce Commission re-open the default price-quality path using s54V of the Commerce Act.[41] Energy Networks Australia's submission describes the scale of system changes required to implement 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.*"[42]

[40] Orion cross-submission Network Connections, point 4.

[41] Ibid, point 6.

[42] ENA - Submission on AEMC consultation paper

	For the Authority's awareness, similar to our Australian counterparts, our internal systems are built on one-to-one relationships between ICPs and traders. MTR will require us to re-engineer our billing system, works management, faults management, GIS, SCADA, and reporting systems. These costs will ultimately be borne by all consumers, and the majority will receive no benefit from MTR. While the Authority may assume long-term benefits will eventually materialise, this approach creates inequity by imposing immediate costs on today's consumers – including many experiencing energy hardship – to subsidise infrastructure that will only benefit prosumers with distributed energy resources. MTR implementation will create significant operational and legal challenges around contractual relationships. Without DDAs between distributors and generation traders, we will have no mechanism to enforce critical obligations including: network connection standards compliance (currently enforced via retailers under DDA clause 13), prudential security requirements (DDA clause 10), load management protocols essential for system security (DDA clause 5), payment obligations for network services, liability and indemnity protections (DDA clauses 24-26), or access to premises and equipment damage responsibilities (DDA clauses 11-12). The proposed Code amendments in clause 11.13C only partially address charging arrangements but provide no enforcement mechanism without underlying DDA relationships. These implementation challenges will be compounded by the Authority's approach to updating the Electricity Registry. The recent Omnibus 3 implementation highlights issues that raise concerns about the Registry's ability to manage complex system changes. For example: • EDBs were given 12-months to update systems to meet new Code requirements, yet the Registry Functional Specification was not published until December, reducing actual implementation time to 9 months. • The Registry UAT was not available until March, providing only 4-5 months for industry testing of complex system changes, allowing for insufficient development planning for critical market infrastructure.

	- Industry participants identified Code-required fields missing from the Registry that were missed during the Authority's development process, indicating inadequate quality assurance procedures. - Inconsistent terminology between the Code and Registry creates regulatory uncertainty about compliance requirements. This misalignment between legal obligations and operational systems forces industry participants to interpret regulatory intent rather than follow clear guidance, increasing compliance risk and implementation costs. - To-date, the Authority has not delivered promised industry guidance documentation, creating uncertainty about regulatory expectations and compliance requirements. EDB staff are currently managing or implementing an **unprecedented volume of regulatory change**: Omnibus 3, Network Connections, Consumer Care Obligations (EIEP4A), DDA updates, proposed updates to Distributed Generation Pricing Principles, distribution connection pricing, Task Force initiatives 2A and 2BC, and now MTR. These changes all impact the same specialist teams and systems **yet lack strategic coordination or realistic implementation timeframes**. The Authority should allow adequate time for proper implementation rather than rushing complex system changes. Each change drives costs and diverts resources from other internal strategic and BAU initiatives to improve our operations for our consumers. Rather than continuing to add incremental changes to an outdated Registry platform the Authority should prioritise a complete Registry replacement designed for the digital future.
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 disagree with the Authority's assessment and recommend deferral of MTR for 3-5 years rather than proceeding with any option at this time.

	The Authority has not provided adequate justification for immediate implementation when New Zealand's DER market remains immature compared to international examples. With only ~77,000 DER customers as of 31 May 2025, the market scale is insufficient to justify the system-wide costs and complexity that MTR would impose across all participants. The Authority's competition concern on Option 2 (paragraphs 3.32 – 3.35) lack supporting evidence. Retailers already take a strategic view of customer segments for various operational reasons without meaningfully reducing competition (at least to the extent that the Authority desires to intervene). It is unwise to treat MTR customers differently from any other specialised market segment.[43] Other examples include retailers that exclude customers who require a new connection, customers without smart meters, customers with shared unmetered loads, customers with export generation, or properties without specific meter types.[44] As Simply Energy noted: "*energy retail is a highly competitive market with new providers joining. If a customer is not satisfied with their current retailer's feed-in offer or EV charging rates then the customer can easily choose another retailer.*"[45] This competitive market reality is already evident in New Zealand, where retailers are partnering with solar installers to offer differentiated buy-back rates.[46] These market-driven solutions demonstrate that competition for generation services is already occurring without the need for complex regulatory intervention through MTR.

[43] Retailers routinely specialise in different customer segments based on operational capabilities, risk appetite, and business models, demonstrating that market segmentation does not reduce overall competition.

[44] For example, Electric Kiwi requires customers to establish connections through other retailers before switching (see: *I'm planning a new smart meter installation for my house, and I'm not an existing Electric Kiwi customer. Can I join Electric Kiwi?*); Flick Energy and Electric Kiwi do not accept customers without smart meters; Wise Pre-Pay does not accept customers with export generation; and some retailers cannot accommodate shared unmetered loads for new connections. These are merely illustrative examples to demonstrate that retailers routinely specialise in different customer segments, without reducing overall competition.

[45] Simply Energy submission

[46] For example, see Harrisons Solar partnering with Mercury to offer enhanced buy-back rates of 18 cents per unit for customers installing solar systems, and Ecotricity offering both flat rate peak/off-peak buy back rates or based on wholesale prices.

	The Authority's preference for the Option 1 approach that requires system-wide changes to enable MTR across all ICPs, regardless of actual overall market desire or ability to participate is concerning. This reflects a broader pattern where the Authority appears to be increasingly using regulatory mandates to force market outcomes rather than allowing competitive forces to respond to consumer demand. As an example, the Energy Competition Task Force recently stated, "*we do not consider that competition has led to fast enough uptake of initiatives that promote efficiency, which is the focus of our intervention*," seemingly revealing a belief that regulatory prescription can deliver better outcomes than competitive markets.[47] Multiple retailers have recently warned the Authority against this approach. 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.*"[48] Genesis noted that "*premature regulatory intervention risks stifling innovation and diverting retailer resources away from pricing strategies aligned to their comparative advantage.*"[49] 2Degrees warned that "*Any regulatory interference with commercial decisions and retail tariff pricing* [or availability] *could directly hamper a core part of our ability to compete and differentiate from our competitors.*"[50] Electric Kiwi cautioned that "*Retail competition – not regulation – should be the driver of innovation, provided there is a level playing field.*"[51] Flick Energy argued that "*Mandating retail offers will send a message that innovation will not be rewarded*" and that "*there is a risk as an innovator that by developing a new and attractive offer, the regulator will mandate other participants to offer the same thing, minimising competitive advantage.*"[52]

[47] Time-varying retail pricing for electricity consumption and supply, paragraph 4.23
[48] https://www.ea.govt.nz/documents/6930/R_ERANZ_2B2C_submission_2025.pdf
[49] https://www.ea.govt.nz/documents/6932/R_Genesis_2BC_submission_2025.pdf
[50] https://www.ea.govt.nz/documents/6928/R_2degrees_-_2BC_Submission_2025.pdf
[51] https://www.ea.govt.nz/documents/6988/R_Electric_Kiwi_2BC_Submission_2025.pdf
[52] https://www.ea.govt.nz/documents/6931/R_Flick_Electric_2BC_submission_2025.pdf

	Mercury emphasised that "*A competitive retail market plays an essential role in delivering better outcomes for consumers by driving innovation, expanding product choice, and encouraging efficient pricing*" and warned against "*reactive measures that risk compromising long-term outcomes.*"[53] These consistent insights from across the retail sector suggest that allowing the market to determine when MTR is required may be preferable to regulatory mandate. Option 3 is not preferable as it will create significant administrative burden for EDBs by requiring creation and management of additional ICPs and will not support the Authority's future vision. It will necessitate hiring new staff, potentially create registry compliance challenges, and impose manual administrative processes that undermine system efficiency. The Wellington MTR trial demonstrates these administrative burdens in practice - Wellington Electricity reported that "*significant manual work is required to keep the registry compliant*" when managing the dual ICP structure required under Option 3.[54] This manual overhead would be multiplied across thousands of potential MTR sites, creating unsustainable operational complexity for EDBs while delivering questionable consumer value.
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 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 prosumers while imposing disproportionate costs across all consumers regardless of whether they have the ability to access MTR. The Authority's preference for Option 1 appears driven by regulatory ideology rather than economic efficiency or evidence-based analysis.

[53] https://www.ea.govt.nz/documents/6807/R_Mercury_2A2B2C_submission_2025.pdf
[54] https://kaingaora.govt.nz/assets/About-us/202406-Wellington-MTR-Six-monthly-report-summary-version.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 is not designed to support modern data exchange requirements and cannot adequately support the data-rich, interconnected system envisioned for New Zealand's digital electricity future. The Registry still relies on text file transfers between participants and must be replaced with a modern data exchange platform that supports real-time, secure data sharing, and intelligent reporting. Rather than implementing incremental improvements to this legacy system, the Authority should prioritise a comprehensive Registry replacement.
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. The current Electricity Registry is not designed to support modern data exchange requirements and cannot adequately support the data-rich, interconnected system envisioned for New Zealand's digital electricity future. The Registry still relies on text file transfers between participants and must be replaced with a modern data exchange platform that supports real-time, secure data sharing, and intelligent reporting. Rather than implementing incremental improvements to this legacy system, the Authority should prioritise a comprehensive Registry replacement.
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 and efficiency? Can you quantify these benefits?	No comment.
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. The current Electricity Registry is not designed to support modern data exchange requirements and cannot adequately support the data-rich, interconnected system envisioned for New Zealand's digital electricity future. The Registry still relies on text file transfers between participants and must be replaced with a modern data exchange platform that supports real-time, secure data sharing, and intelligent reporting. Rather than implementing incremental improvements to this legacy system, the Authority should prioritise a comprehensive Registry replacement.

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	We do not support implementation of MTR at this time for the reasons outlined 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	No. The proposed 18-month timeframe is unrealistic given the system complexity involved and change burden already being navigated by sector participants. As noted in paragraph 15 of our submission, Ron Beatty acknowledged that enabling customers to receive services from multiple providers would "*take at least three and a half years and probably five*."[55] We question why the Authority considers that this implementation can be completed in half of the originally identified timeframe. The Authority's recent Omnibus 3 implementation demonstrates the risks of inappropriate timelines, as detailed 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 stated objectives are aspirational but lack evidence-based justification. As outlined previously, the Authority has not demonstrated strong consumer sentiment for MTR or established that current market structures prevent efficient outcomes.

[55] Electricity Authority eyes future of market registry.

	The objectives assume benefits that have not been quantified or proven.
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. As detailed in our submission, the Authority has provided no quantified cost-benefit analysis while international evidence from Australia and the UK shows negative benefits for consumers in most scenarios. The absence of rigorous economic justification makes this proposal economically unjustifiable.
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.	No. Our preferred option is to defer MTR for 3-5 years, rather than proceeding with any of the proposed options at this time. Alternatively, if the Authority is unwilling to defer implementation, we suggest pausing work on amending and gazetting the Code amendment to instead run trials on different MTR models through the Power Innovation Pathway. These approaches may better align with the Authority's statutory objectives by: • Ensuring efficient operation by avoiding system-wide costs for unquantified benefits, and allowing time for evidence-based justification through either market development or properly designed trials under Code exemptions. • Protecting domestic and small business consumers from bearing implementation costs for services they cannot currently access, avoiding wealth transfers from most consumers to prosumers. • Promoting competition by allowing market forces to develop generation service offerings (as evidenced by Harrison's Solar/Mercury partnership).

	• Promoting long-term consumer benefits by allowing existing market mechanisms and Task Force initiatives to deliver the same objectives MTR seeks to achieve, or by gathering actual evidence through Code exemption trials rather than imposing premature regulatory complexity.
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?	Please refer to ENA's submission for further details on issues regarding the drafting of the proposed amendment.