29 July 2025

Electricity Authority
PO Box 10041
Wellington 6143

By email to: policyconsult@ea.govt.nz

Dear Electricity Authority team,

Submission to the Electricity Authority (Authority) on the *Evolving multiple retailing and switching consultation paper*

We thank the Authority for the opportunity make a submission on the Authority's recent consultation paper on *Evolving multiple retailing and switching*.

ENA is the industry membership body that represents the 29 electricity distribution businesses (EDBs) that take power from the national grid and deliver it to homes and businesses (our members are listed in Appendix A).

EDBs employ over 7,800 people, deliver energy to more than two million homes and businesses, and have spent or invested $6.2 billion in network assets over the last five years. ENA harnesses members' collective expertise to promote safe, reliable, and affordable power for our members' customers.

Executive Summary

ENA supports well-targeted, proportionate interventions that promote greater competition and deliver benefits for electricity consumers. However, we are concerned that the multiple trading relationship (MTR) proposals in this paper — like other recent decisions and publications from the Authority — appear mainly focused on the interests of a small number of highly engaged and politically active consumers.

This is concerning at a time when many households are facing energy hardship and affordability challenges, and the sector is already stretched responding to a torrent of regulatory and policy reforms — all while working to deliver for customers and shareholders.

Introducing an unquantified and unjustified intervention like this risks diverting regulatory and sector effort away from areas where it is most urgently needed. It is a misallocation of time and resources that will do little, if anything, to support the consumers who need it most.

Multiple trading relationships

ENA does not support the MTR elements of this proposal, and we urge the Authority to think carefully about how to better direct its resources (and by extension, the resources of the wider electricity sector) to deliver tangible and quantifiable benefits for the overwhelming majority of electricity consumers, who in the words of Consumer NZ[1], are having: "…*an industry* [and Electricity Authority]-*assumed future being projected onto* [them]*, many of whom neither asked for it, desire it, nor have the means to participate."*

We note that the Authority references in its consultation paper Kāinga Ora Multiple Trading Trial being undertaken by WE* and Ara Ake. That trial is still underway and we suggest that it would be prudent to allow it to run its course, and any learnings become known, before progressing MTR proposals further.

Authority coordination

ENA observes that this consultation paper is another example of the Authority not coordinating its proposals internally. The MTR proposal fails to take into account Task Force initiatives 2a, 2b and 2c. Even with this paper published before the Task Force decisions, there should at least have been reference to these decisions.

The 2a decision requires EDBs to pay rebates to consumers exporting solar. And yet this MTR consultation, and its proposed Code amendments, fails to recognise that such a requirement would also require EDBs to have a relationship with a generation trader.

We understand that the Authority is moving at pace, but this is resulting in the sector having to review poorly formed consultations and draft Code. These efforts and costs are ultimately borne by consumers.

Switching

ENA is supportive of the proposals in the paper covering trader, MEP and distributor switching. We have identified a few specific suggestions within our responses to the consultation questions in Appendix B, but otherwise believe the switching proposals are reasonable to improve switching processes.

We understand that the time stamping of distributor switching proposed in this consultation is not designed to result in real-time switching at this stage.[2] However, we note that the Authority is recently quoted as suggesting that real-time switching is an intended outcome longer term.[3] We wish to take this opportunity to highlight that real-time switching is not practical for most EDBs at the moment due to the lack of granular data it receives. Most EDBs do not receive data broken down into sufficient time packets in such a way to accurately calculate a real-time switch. If the Authority wishes to proceed with real-time switching in due course, it should first address the issue of EDB access to data.

Format of our response

ENA has engaged Chapman Tripp to provide expert advice on the MTR and distributor switching elements of the Authority's related Code amendment proposal[4]. We provide this advice in full in

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[1] https://www.ea.govt.nz/documents/7710/Consumer_NZ_-_Decentralisation_green_paper_submission_URT1P37.pdf

[2] Please refer to further clarification regarding this in response to question 28 in Appendix B and paragraphs 40-48 of Appendix C

[3] Energy News - Standardise data access to unlock consumer deals - EA, 17 July 2025, accessed 21 July 2025

[4] https://www.ea.govt.nz/documents/7387/Appendix_A_-_Proposed_amendments.pdf

Appendix C of this submission, but have included some key points in our responses to the consultation questions in Appendix B.

If you have any questions about ENA's submission please contact Richard Le Gros, Policy and Innovation Manager ( ) or Gemma Pascall, Regulatory Manager ( ).

Yours sincerely

Richard Le Gros	Gemma Pascall
Policy and Innovation Manager	Regulatory Manager

Appendix A: ENA Members

Electricity Networks Aotearoa makes this submission along with the support of its members, listed below:

- Alpine Energy
- Aurora Energy
- Buller Electricity
- Centralines
- Counties Energy
- Electra
- EA Networks
- Firstlight Network
- Horizon Networks
- Mainpower
- Marlborough Lines
- Nelson Electricity
- Network Tasman
- Network Waitaki
- Northpower
- Orion New Zealand
- Powerco
- PowerNet (which manages The Power Company, Electricity Invercargill, OtagoNet and Lakeland Network)
- Scanpower
- Top Energy
- The Lines Company
- Unison Networks
- Vector
- Waipa Networks
- WEL Networks
- Wellington Electricity
- Westpower

Appendix B: Responses to specific consultation questions

<table>
<tr><th>Questions</th><th>ENA Comments</th></tr>
<tr><td colspan="2">Questions on the Authority’s vision</td></tr>
<tr><td>Q1. (Paragraph 2.20) Do you agree with the Authority’s vision for consumer mobility? If not, what would you change and why?</td><td>ENA does not agree with all elements of the Authority’s vision for consumer mobility. We do not agree that multiple trading relationships (MTR) as proposed in the paper is a key element of consumer mobility. It may be desirable for some consumers, and may offer benefits to those consumers, but that does not mean it should be pursued at any cost, and we do not think it is ‘key’ to consumer mobility.

We also disagree with the statement in para 2.11(b) that MTR will aid in “…reducing distributor costs…” in any material way and could in fact drive increased costs for distributors in administration. We also do not agree that MTR will lead to “…increased regional resilience” nor would it, as stated at para 2.12, “…enable local communities to maintain supply during disruptions…” While MTR may drive an increased uptake in distributed generation at the residential level, the role that this can play in providing electricity back into the network during supply disruptions is necessarily limited for technical and safety reasons. It therefore can only provide a resilience benefit to the owner of the distributed generation, and that is true whether or not this proposal goes ahead.

ENA does agree that an efficient, effective and reliable switching process is a key component of consumer mobility. To the extent that the proposals in this paper deliver that outcome, we agree that those proposals serve the Authority’s vision.

ENA is unsure what is meant by “…the scale of consumer will grow as will the complexity.” (para 2.4). If this means that the quantum of consumers’ consumption of electricity will grow, then we agree.

We have observed that many of the Authority’s recent consultations have focused on effects to support the ‘active’ consumer. If the Authority has conducted consumer research to suggest that consumers want to be ‘active’ and that outlines some of the ways that consumers want to be ‘active’, it would be very useful to the sector if these results were published and shared more widely.

If such research hasn’t been undertaken, on what basis is the Authority assuming consumers want to be ‘active’?</td></tr>
</table>

Questions	ENA Comments
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?	ENA reiterates that we do not support the MTR proposals described in the paper. However, ENA agrees that, in the design of stage 1 changes for MTR, it is sensible to preserve as much optionality for potential future stages as possible – with the caveat that this should not be done at the expense of unreasonable additional complexity in implementing this more immediate proposal.
Questions on Multiple trading	
Q3. (3.26) Do you agree with the proposed solution? If not, what would you change and why?	ENA does not agree with the proposed MTR 'solution' presented in the paper, and we urge the Authority not to progress with this intervention at this time.
Q4.(3.26) Do you agree with the benefits anticipated from the proposed solution? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	ENA agrees with the benefits of the proposed solution as identified in the paper. However, we note that these benefits will only be available to a miniscule proportion of all electricity consumers. Using the date in the EA's EMI data tool, there are ~73,489 ICPs with solar installed as at 30 June 2025. There are ~2,338,646 ICPs, so this suggests the benefits from this proposal will be available to ~3.1% of electricity consumers. Not only is this a trivial fraction of the overall electricity consumer base, these consumers will most likely be relatively affluent as well.
Q5. (3.26) Do you anticipate the proposed solution 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?	ENA has received a small sample of projected costs from some of its larger EDB members. While these may not be directly comparable, they suggest implementation costs in the (very approximate) range of \$3-\$5.5 million for each of those EDBs, with a timeline on the order of 3 years.
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 ENA comment
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 ENA comment
Q3. (3.26) Do you agree with the proposed solution? If not, what would you change and why?	ENA does not agree with the proposed MTR 'solution' presented in the paper, and we urge the Authority not to progress with this intervention at this time.
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 ENA comment
Q9. (4.55(q)) Do you agree with the proposal to align timeframes to a maximum of two business days for NT	No ENA comment

Questions	ENA Comments
and AN notifications, and to reduce timeframes for the CS file?	
Q10. (4.55(q)) Do you agree with the proposed solutions? If not, what would you change and why?	No ENA comment
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 ENA 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 ENA comment
Questions on MEP switching	
Q13. (5.34) Are there any other files that should be added to this list?	No ENA comment
Q14. (5.38) Do you agree with the proposed solutions? If not, what would you change and why?	No ENA comment
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 ENA 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 ENA comment
Questions on distributor switching	
Q17. (6.13) Do you agree with the proposed solution? If not, what would you change and why?	ENA broadly agrees with the proposed solution subject to the Code amendments identified in response to question 28 and detailed further in Appendix C, as well as a couple of other observations below. **Intra-day timestamp**

Questions	ENA Comments
	We note that the Authority does not believe there are 'genuine alternatives' to the requirement that EDBs record intra-day status changes as part of the proposed solution. On the basis that the proposed Code amendment maintains that all distributor switches occur at midnight, we are not sure that the intra-day timestamp is required and therefore the status quo would be a 'genuine alternative'. That said, we understand that the Authority is requiring an intra-day timestamp to "lay the groundwork for real-time switching".[5] Please refer to the body of our submissions for further practical considerations for real-time switching. **Role of the Authority in the switch process** The Authority retains the right to intervene at 'any time during the switch process'. An EA intervention at the last minute would create time and processes challenges for all parties, including the consumer. We recommend that the Authority's intervention is time-limited in the same way as other parties. Since a trader's deemed consent is set at 5 days pre-switch, we recommend that the Authority's intervention is limited to 2-3 days pre-switch.
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?	ENA agrees with the benefits anticipated from the proposed solutions. Our members have not had time to quantify the anticipated costs or benefits. We recommend earlier consultation with affected parties in future to obtain more clarity on cost-benefit assessments prior to proposing changes and Code amendments.
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?	Refer to response to Q18.
Questions on implementation	
Q20. (7.4) Would you prefer a single implementation or a staged implementation? Please give reasons for your preference	ENA does not support the Authority proposals around MTR, however if the Authority decides to go ahead with both proposals in this consultation, we support a staged implementation as described in the paper.
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 switching timeframes appear reasonable for EDBs. We do however note the volume of changes being imposed on EDBs simultaneously and that EDBs are pushing their limits and capacity at this time.

[5] Energy News - Standardise data access to unlock consumer deals - EA, 17 July 2025, accessed 21 July 2025

Questions	ENA Comments
Questions on the regulatory statement	
Q22. (8.6) Do you agree with the objectives of the proposed MTR amendments? If not, why not?	Yes. ENA agrees with the objectives of the proposed amendments to implement MTR as described in section 8.6 of the consultation – however we don't believe that the proposed amendment will achieve these objectives. Additionally, based on our legal advice (refer Appendix C), we consider that there are significant gaps in the proposed MTR amendment which make it unsatisfactory and unsound in its own right, and certainly make it an unsuitable 'foundation' for the other objectives the Authority expresses here.
Q23 (8.11) Do you agree with the objectives of the proposed amendments to the switching process? If not, why not?	Yes. ENA agrees with the objectives of the proposed amendments to the switching process. Please refer to other responses in this submission in relation to our views on MTR though and whether it is necessary to lay a foundation for MTR (objective 8.11).
Q24 (8.17(q)) Do you agree the benefits of the proposed amendment outweigh its costs?	For the MTR proposals - No. And we are not sure how the Authority can make such an assumption without having done a cost-benefit assessment. For the switching components – for EDBs, yes, we think the benefits for switching parties will most likely outweigh the costs for EDBs.
Q25. (8.21) Do have any comments on the preferred and alternative options discussed in the 2019 Issues paper?	ENA does not support the Authority proposals around MTR. However, if the Authority decides to go ahead with this proposal, option 1 is preferrable.
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.	For MTR proposals – no, we do not agree that the proposed amendments are preferable. In particular, we think the Authority's conclusions at 8.22(a) and (c) are incorrect. For 8.22(a), we do not believe the MTR proposal meets the objectives outlined in the paper, as per our response to question 22. For 8.22(c), we are extremely sceptical that, for the specific MTR amendment proposed here, "…medium to long-benefits for participants, customers and stakeholders are expected to outweigh the upfront implementation costs." We see a very uncertain degree of benefit arising for a miniscule proportion of the overall electricity consumer base, certainly in the short term, and we do not agree that this will increase in a material way over the medium term at least. For switching proposals – yes, we agree the proposed amendments are preferable, with the small amendments recommended in this submission.
Q27. (8.25) Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	For MTR proposals – no. We do not think the proposed amendment complies with section 32(1) of the Act. The MTR proposal has the potential to benefit only 3.1% of current

Questions	ENA Comments
	consumers, whilst increasing costs for the other 96.9%. This appears to be contrary to the Authority's objective to protect the interests of domestic and small business consumers. For switching proposals – yes. We think the proposed amendment complies with section 32(1) of the Act.
Question on Code drafting	
Q28. (Appendix A) Do you have any comments on the drafting of the proposed amendment?	Please refer to Appendix C for a more comprehensive review of the Code drafting and our recommendations for amendments. These are focused around the following key areas: MTR (refer Appendix C, paragraphs 1-39) - Overall confusion and material omissions that expose EDBs to risk - Omissions in practical considerations with regards to the commercial arrangements between the EDB and generation trader - Impacts from Task Force initiatives 2a, 2b and 2c are not factored into Code drafting - Omissions in practical considerations with regards to the commercial arrangements between the consumption and generation traders Switching (refer Appendix C, paragraphs 40-48) - Time stamping and impact on actual switch time - Prospective identification of network extensions

Appendix C: Legal review of requirements

Refer next page.

Memorandum

Date: 17 July 2025

To: Electricity Networks Aotearoa

From: Simon Peart / Laura Green / Kendyl Oakey
Direct: [redacted]
Mobile: [redacted]
Email: [redacted]
Ref: 100565446/3468-2789-6379.1

By Email

PROPOSED CODE AMENDMENTS – EVOLVING MULTIPLE RETAILING AND SWITCHING

1 On 3 June 2025, the Electricity Authority (**EA**) published its "Evolving multiple retailing and switching – Consultation paper" (**Consultation Paper**) and proposed amendments to the Code. The proposed amendments aim to facilitate multiple trading relationships (**MTR**) and seek to improve the metered equipment provider, trader, and distributor switching process.[1]

2 This note responds to questions from Electricity Networks Aotearoa (**ENA**) relating to Part 1 (MTR) and Chapter 6 (proposed changes to distributor switching arrangements) of the Consultation Paper.

3 Our advice principally focuses on the treatment of generation traders under the Consultation Paper and the proposed Code amendments, as we have identified this as a key risk area for EDBs. In the Consultation Paper, the EA's intentions are unclear in relation to:

3.1 how the electricity distribution business (**EDB**) will deal with the generation trader at the installation control point (**ICP**). For example, how the EDB will manage risks associated with the generation trader's management of equipment connected to the network;

3.2 in what ways the consumption trader will be obliged to liaise with the generation trader (and, for example, what happens if disputes arise); and

3.3 whether and how the generation trader will be charged for their use of the network.

[1] Electricity Authority "Evolving multiple retailing and switching – Consultation Paper" (3 June 2025), 8.1.

4 In the proposed Code drafting, none of the above appears to be fully provided for, despite indications in the Consultation Paper that these arrangements are covered by the Code.

5 We anticipate the above concerns could give rise to revenue recovery risks and operational challenges for EDBs. Further, other related documents including the Default Distributor Agreement (**DDA**) will be affected by the proposed changes.

6 In addition to the risks relating to generation traders, this note covers issues that we have identified in reviewing the Consultation Paper and proposed Code drafting.

Does the Code drafting meet the EA's intent, as per the consultation paper?

7 The proposed Code amendments largely focus on those mechanical changes required to give effect to the EA's proposal to register traders at the metering channel level, rather than at the ICP level, in order to allow for separate generation and consumption traders at a single ICP.

8 The proposed amendments create a new defined term – the "responsible trader" – which is the consumption trader at an ICP with multiple traders. As we understand it, the EA's intent is that the consumption trader should primarily be responsible for the relationship between the distributor and traders at that ICP (for example, if the generation trader requires a temporary disconnection to undertake works they must make that request via the consumption trader). However, the EA's intent for the relationship between the EDB and the generation trader, and separately the relationship between the consumption trader and the generation trader:

8.1 is difficult to reconcile in terms of the various statements made in the consultation paper; and

8.2 is not provided for in full by the proposed Code drafting.

9 Those omissions are material because: (i) they expose distributors to risks they would otherwise manage through the DDA, and (ii) it is unclear what commercial relationship the EA intends distributors will have with generation traders and how this will be effected.

10 In our view these omissions need to be addressed *before* the proposed amendments enter into force. It would not be sufficient to address these at a later date.

11 In relation to switching, there are also a small number of areas in which the implementation of the EA's intent could be improved.

MTR: relationship between EDB and generation trader

12 Under the status quo it is the DDA that allocates risks, responsibilities and liabilities between distributors and retailers trading at ICPs:

12.1 retailers trading at an ICP are obliged to enter into a DDA with the relevant distributor, which provides for: (i) the distributor to provide distribution services to the retailer, and (ii) the retailer pays the distributor for the provision of those services;

12.2 the DDA provides for the distributor to take certain steps necessary to manage the network, including ensuring system security, and allocates risk and liability between the parties;

12.3 the DDA also obliges the retailer to ensure that *its* customers (end-consumers) comply with the distributor's network connection standards; and

12.4 to the extent the customer installation includes generation or storage and that is actively managed or traded in the market, it is the retailer that does this.

13 Where generation is installed on a customer installation, behind the ICP, and that is actively managed or traded in the market, it is the retailer trading at the ICP that is responsible for those services. Charges to the retailer do not differentiate between generation and consumption (except to the extent volumetric charges are affected by the consumer generating their own electricity). Network-connected generation (distributed generation) is also provided for under Part 6 of the Code, which creates a separate framework for generation connected to distribution networks or to customer installations connected to distribution networks. Under Part 6, generators are only charged for the incremental costs of their connection to the network. Part 6 applies when a customer seeks to connect generation and feed into the network, but does not necessarily apply to a generation trader.

14 The existence of a DDA, or equivalent contractual mechanism or regulated terms, is important to: (i) ensure that distributors have the rights necessary to operate the network in accordance with good electricity industry practice, (ii) manage risks to network operations and system security, (iii) ensure that distribution services are provided to appropriate service levels, and (iv) ensure that distributors can charge traders for their use of the network (and take appropriate steps in events of default).

15 Many of those matters are equally relevant to a generation trader trading at an ICP. However, only *retailers* are obliged by the Code to enter into a DDA with a distributor. A generation trader is not so obliged by the current Code arrangements. It is, at best, unclear whether a generation trader behind the ICP would be subject to the requirements of Part 6. Moreover, even if a distributor sought to enter into a contract with a generation trader, that trader could refuse and the distributor would be unable to disconnect the ICP because of its obligations owed to the consumption trader.

16 As an example of how risks could arise for EDBs is practice, we understand some EDBs impose additional metering requirements to those in the Code in certain circumstances, including enhanced half-hourly metering for certain generation installations. EDBs impose these requirements to meet their operational needs. If the EDB does not have a contractual relationship with the generation trader, it will have no ability to impose and enforce those requirements, and it is difficult to

imagine the consumption trader willingly taking responsibility for these matters (as discussed further at paragraphs 31 to 39 below).

17 The consultation paper suggests the EA has deliberately sought to exclude any direct relationship between the EDB and the generation trader. Paragraph 3.12(e) of the Consultation Paper provides:

> [M]ost connections have only one point of connection and metering installation, which introduces complexity for participants and market systems such as…. Introducing more than one relationship between the distributor and multiple traders at a property, which would lead to a requirement for multiple distribution agreements, communication with multiple traders about physical works affecting the point of connection, and the risk of overcollection of line service charges increasing the customer's cost.

18 Paragraph 3.12(e) implies distributors will have no contractual relationship with the generation trader at the ICP. Elsewhere, however, the consultation paper appears to imply that distributors will charge generation traders for services or will apportion their charges between the generation trader and consumption trader.

19 Paragraph 2.14 of the Consultation Paper provides:

> [T]he proposals require MEPs and distributors to structure charges based on the services provided, rather than the number of traders associated with the property, avoiding inefficient or duplicative charging practices. Only the incremental costs of additional services can be charged (ensuring there is no cross-subsidisation from other consumers).

20 Paragraph 2.14 appears to anticipate that distributors will apportion charges between the consumption and generation traders.

21 Paragraph 3.14(c)(vii) of the Consultation Paper states:

> [W]here the point of connection and metering installation at an MTR property is used for both consumption and generation… prevent the distributor from charging twice for the same service, but allow flexibility to introduce pricing that reflects the actual costs for the generation service… the total cost to the consumer for a multiple trader ICP should not exceed what it would be if the property had a single trader (but can include incremental costs of servicing two retailers).

22 Again, this suggests distributors will (or could) charge the generation trader for the provision of a "generation service". That implies both a commercial and contractual relationship between the distributor and the generation trader, which is not provided for in the Code currently or in the proposed amendments.

23 Further, applying the Part 6 rules, the EDB cannot currently charge more than the incremental costs of the "generation service", which may be zero because the connection infrastructure already exists. That default position should be reconsidered given that, over time, as more generation traders join the network, an increasing proportion of network utilisation will be by generation traders but the costs of the network will be met solely by consumption traders. Furthermore, while

the incremental cost of any generation trader may be negligible or nothing, the proportion of total network costs attributable to generation traders as a whole may be significant.

24 The Code drafting appear to address these matters only partially, through the inclusion of the following:

> The distributor must set charges so that not trader is double charged for the same service, any trader specific charges only reflect actual costs and are consistent with single-trader ICPs, and total charges for multiple charges do not exceed those for a single trader, except for reasonable extra costs of managing multiple traders (clause 11.13C(b)(i)-(iii)), and
>
> The metering equipment provider must ensure no trader is double charged for the same service, any trader specific charges only reflect actual costs and are consistent with single trader ICP's and total charges do not exceed those for a single trader except for reasonable extra costs of managing multiple traders (clause 11.13D(1)(a)-(c)).

25 However, the Code drafting does not fully implement the EA's intent. As above, without a DDA between the distributor and the generation trader, there is currently 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. This exposes distributors to the risk that they are obliged to levy some proportion of their charges on generation traders but have no way to enforce payment.

26 The omission of amendments to provide for a contractual relationship between distributors and generation traders:

26.1 gives rise to risks to network operations and system security; and

26.2 revenue recovery risks for distributors.

27 Set out below is a non-exhaustive selection of matters provided for in the DDA that would need to be addressed in circumstances where there are separate consumption and generation traders trading at an ICP:

Issue / DDA clause	Comment
Supply of distribution services to specified service levels (cl 2)	Distributors have no obligation to supply distribution services to generation traders despite their use of the network. Service levels are not enforceable against distributors.
Payment for distribution services (cl 2)	Generation traders have no obligation to pay for their use of the network.
Planning and communication of service interruptions (cl 4)	Proposed clause 11.13C obliges distributors to notify all traders at the ICP of any unplanned service interruption "as required under Part 12A". But Part 12A only requires service interruptions to be communicated to retailers that are party to a DDA. Clause 11.13C also does not appear to extend to planned service interruptions.
Load shedding (cl 4)	The proposed Code amendment is not clear what obligations the distributor owes to the generation trader, if any, in

	relation to the distributor's rights to undertake load shedding under cl 4.
Load management (cl 5)	Clause 5 of the DDA provides for the distributor's management of load to take precedence for purposes of system security and requires traders to enter into a load management protocol. The generation trader is not subject to an equivalent obligation despite the fact they may be managing equipment that has implications for system security.
Payment obligations (cl 7, 8, 9)	The proposed Code amendment suggests that distributors will be required to apportion their charges between consumption and generation traders, but there is no obligation on generation traders to pay for their use of the network. If distributors continue to recover 100% of their regulated revenue requirement consumption traders, there is a risk consumption traders will refuse to pay, on the basis of the amended Code, and distributors will be left with a revenue shortfall. Conversely, the DDA includes various protections for traders relating to notification of prices, price changes, etc, none of which will apply in the case of a generation trader.
Prudential obligations (cl 10)	Generation traders are not required to post security.
Access to premises and damage to distributor's equipment (cl 11, 12)	All responsibilities relating to property access and interference with or damage to the distributor's equipment are responsibilities of the consumption trader solely. Conversely, the distributor has no recourse against the generation trader if it contributes to a breach of these obligations by the customer.
Connection of generation (cl 12.7, 12.8)	Clauses 12.7 and 12.8 contains specific obligations in relation to generation connected to a customer installation. Particularly, the trader is required to ensure there is a connection contract in place for the generation, or otherwise prohibit injection into the network. That obligation appears to conflict with the EA's concept of a generation trader in the proposed Code amendment.
Network connection standards (cl 13)	Distributors currently enforce their network connection standards via retailers. Generation traders will not be similarly obliged to comply, or ensure that consumers comply, with network connection standards. We would also expect consumption traders to object to an attempt by distributors to enforce network connection standards against them in circumstances where the breach is attributable to the generation trader.
Power quality (cl 14)	Retailers are obliged to require customers to acknowledge that voltage/frequency may fluctuate and damage equipment. Generation traders are not required to secure an equivalent acknowledgement.
Connections/disconnections (cl 17)	The DDA provides for processes as between the retailer and distributor to manage connections and disconnections. The proposed Code amendment provides that generation traders must liaise with the retailer in relation to these matters, but those provisions are incomplete having regard to the matters typically addressed in the DDA, and the generation trader has no recourse against the distributor. This creates a risk of disputes between generation traders and distributors without

	a contractual framework to properly manage those rights and responsibilities.
Breaches, dispute resolution and termination (cl 18, 19, 23)	It is not clear what obligations the EA anticipates the distributor will owe the generation trader in circumstances where there is a dispute between the distributor and the retailer that might result in termination of the DDA. For example, is the distributor required to continue providing services to an ICP at which a generation trader is present if the consumption trader has gone insolvent?
Liability & indemnity (cl 24, 25, 26)	The DDA contains extensive provisions allocating and limiting liability as between the retailer and distributor. No equivalent arrangements will exist between the distributor and the generation trader, which results in unacceptable uncertainty and risk for both parties.
Customer agreements (cl 29)	The DDA requires that customer agreements align with the obligations under the DDA. That obligation does not apply to generation traders, meaning they are free to enter into obligations that are inconsistent with the terms on which distribution services are provided, or to assume risks and liabilities inconsistent with the DDA that they then seek to pass through to the distributor.

Rebates

28 The EA and the Commerce Commission have recently jointly established the Energy Competition Task Force (**Task Force**) to investigate ways to improve the performance of the electricity market. We understand the Task Force is looking at different "packages" and consulting on them. The package two initiatives that are currently being considered are:[2]

28.1 **2A**: Distributors would be required to pay rebates to consumers who supply electricity during times of network congestion, with these rebates deducted from charges to retailers and ultimately passed on to consumers through buy-back pricing plans,

28.2 **2B**: Retailers would be required to offer time-of-use pricing plans, which would encourage consumers to use electricity outside of peak periods, and

28.3 **2C**: Large retailers would be required to offer variable buy-back rates that reflect the higher value of electricity supplied by consumers at peak times.

29 The above initiatives focus on ensuring that customers receive rebates, which may require EDBs to pay these rebates via generation traders, who then pass them on to consumers. We understand the EA has not considered the above initiatives as part of the Consultation Paper and proposed Code drafting.

30 If EDBs are required to pay rebates to consumers via generation traders, a mechanism would need to be put in place to ensure generation traders receive, administer, or pass on these payments. This could result in consumers not receiving

[2] https://www.ea.govt.nz/projects/all/energy-competition-task-force/

the intended rebates, or in disputes about responsibility for payment and compliance.

MTR: relationship between consumption trader and generation trader

31 From an operational perspective, the Consultation Paper aims to address the absence of a direct relationship between the distributor and generation trader by effectively requiring the generation trader to work through the consumption trader. For example, Paragraph 3.14(iv) of the Consultation Paper provides:

> …if the supply to the installation is to be disconnected, the distributed generation trader must notify the consumption trader and any request for metering or network changes must be initiated through the consumption trader.

32 In practice, the above implies the consumption trader becomes responsible for coordinating between the generation trader and the distributor. It is difficult to imagine the consumption trader willingly taking responsibility for these matters, or that a generation trader would be comfortable working within a framework where their rights to access the network are entirely derived from the consumption trader.

33 Further, the Consultation Paper does not suggest there will be a contractual relationship between the consumption trader and the generation trader. Given the relevant Code obligations are minimally stated, it is not clear how disputes between the generation trader and consumption trader will be managed.

34 We understand the relationship between the consumption trader and the generation trader, and the corresponding obligations for them, are designed to be implemented through the Code. We understand the EA envisages that any failure of the consumption trader to assist the generation trader would be a breach of the Code (for example, if the generation trader needs to have the ICP disconnected temporarily and asks the consumption trader to ask the EDB, but the consumption trader does not do so).

35 Clause 11.13B(2)) of the proposed Code drafting goes only part way to establish a relationship between the consumption trader and the generation trader. It states:

> [W]here an ICP contains more than one meter channel, the responsible trader is the only participant that may-
>
> > (a) initiate changes to a metering installation including nominating a new metering equipment provider;
> > (b) initiate any work on the electrical installation point of supply;
> > (c) initiate electrical disconnection, or electrical connection of the ICP, including remote disconnection through the metering equipment provider or physical disconnection at the ICP.

36 Further to clause 11.13B(2) set out above, clause 11.13B(3) provides:

> The responsible trader may request a metering equipment provider, distributor or agent to undertake any actions under [clause 11.13B] subclause 2 on its behalf.

37 Clause 11.13B(4) provides:

> Where an ICP contains a generation meter channel, the generation trader may-
>
> (a) initiate changes to the generation equipment and wiring associated with the generation meter channel; and
>
> (b) where subclause (4)(a) applies, the generation trader must request the responsible trader to complete any required metering or network changes.

38 Clause 11.13B(5) also makes it a breach of the Code for the consumption trader not to action a request by a generation trader:

> A responsible trader that receives a request from a generation trader under subclause (4)(b) must request any required metering or network changes within 2 business days or receiving the request.

39 That said, the Code drafting does provide for this relationship in full. For example, it does not provide for dispute resolution between the consumption and generation traders. While the clause above restricts what a generation trader can do, by approaching this in a piecemeal way, the proposed Code drafting does not give effect in full to the EA's intention.

Switching

40 We have identified two places where the EA's intent does not appear to be reflected in the proposed Code drafting.

41 Paragraph 6.9(c) of the Consultation Paper states the EA is amending the Code to move to intra-day status changes for distributor switches, which would require distributor events to have a time stamp for the event in addition to the date stamp. New clause 12A in Schedule 11.1 provides that "when the status of an ICP is changed, the participant that changed the ICP status must notify the registry manager of the time of the status change".

42 Clause 12A then goes on to say that the status change takes effect:

42.1 from the start of the next day for a change to "Decommissioned" status; and

42.2 from the start of the trading period within which the change occurs for all other status changes.

43 However, new clause 7 of Schedule 11.2 provides that "the gaining distributor takes responsibility for the ICPs from 00:00 hours on the intended transfer date". We understand that, despite the requirement for a time stamp, and that the status change takes effect from the start of the relevant trading period, it is nonetheless intended that responsibility for ICPs switching between distributors would occur at 00:00 hours (i.e. that there are no part-days). The drafting could be clarified by specifying in clause 7 that "*notwithstanding clause 12A of Schedule 11.1,* the gaining distributor takes responsibility for the ICPs from 00:00 hours on the intended transfer date".

44 Separately, paragraph 6.7 of the Consultation Paper raises the issue that:

> No information is recorded in the registry about network extensions (i.e., electricity lines or an electrical installation owned by someone other than the local (parent) distributor but managed by the parent distributor as if they were part of their network), leading to confusion of roles and responsibilities for fault management, connection requests and consents required for the intended switch.

45 We understand the EA views identifying network extensions as only a prospective requirement, i.e., that the proposed amendments will not introduce an obligation for EDBs to identify all existing network extensions.

46 You have asked whether this is the case under the proposed Code drafting, or if the drafting requires distributors to identify existing network extensions.

47 Clause 7(1) of Schedule 11.1 requires distributors to provide ICP information to the registry manager. The proposed Code drafting introduces a requirement for the distributor to provide, for each ICP on its network:

> (d) the reconciliation type code assigned to the ICP, to indicate if the ICP is connected to a local network, embedded network, network extension, or is a special type of ICP for reconciliation purposes:

48 The drafting requires the distributor to provide a reconciliation code indicating if the ICP is connected to a network extension "for each ICP on the distributor's network". We read that as requiring distributors to identify existing network extensions. If that is not the intent, the drafting should be clarified.

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