29 July 2025

Retail and Consumer Team
Electricity Authority
By email: policyconsult@ea.govt.nz

Tēnā koutou,

Evolving multiple retailing and switching

Powerco welcomes the opportunity to contribute to the Electricity Authority (**Authority**)'s consultation on proposed changes to the Code and the registry to improve the efficiency and effectiveness of customer, MEP and distributor switching processes, and support multiple trading relationships (**MTR**).

Full MTR is complex, costly and untested. We are not aware of any example, anywhere in the world of full "behind the meter" MTR, indeed the AEMC has explicitly decided that its costs were greater than its benefits[1]. Neither has anyone in the world implemented intraday switching, for the same reason. The Authority's Option 1 is effectively "above the meter" and does not accommodate intraday switching so would limit the risk of costs blowing out for the limited benefits of splitting export from import at an ICP. Option 1 could not easily be extended to support full MTR for resources behind the meter or intraday switching, and costs and complexity that would come with such changes. Rather than deciding on a standalone rule change now which is unlikely to achieve the policy objective, it would be better to use the Authority's Power Innovation Pathway to run trials under code exemptions to establish the actual costs and benefits of different MTR variants.

"Behind the meter" MTR is very expensive to implement

- The Code and the industry processes and systems that implement it assume a 1-1 link between retailer and distributor at an ICP
- Breaking this link is expensive – as soon as there is more than one trader operating behind the meter at an ICP then it's necessary for every distributor and every incumbent retailer to change contracts, processes and IT systems to assign roles, responsibilities, costs, revenues and liabilities between them if the safety and reliability of the installation and the financial integrity of settlement are to be preserved.

Option 1 is "above the meter" MTR

- The "generation trader" proposed in option 1 simply settles the residual electricity that the consumer doesn't use from behind the meter generation so if it preserves all legacy retailer obligations at the ICP on the 'responsible trader' then this minimises the cost impact of the change on industry participants
- Because in option 1, the generation trader isn't responsible for all the electricity generated behind the meter, it isn't extensible to a form of MTR where different traders

[1] *Final Rule Determination - National Electricity Amendment (Multiple Trading Relationships) Rule 2016*, Australian Energy Market Commission. 25/2/16. On 15/8/24, the AEMC made a much narrower rule to allow optional trading of flexible CER for large consumers.

	exist for individual appliances, batteries and generation assets behind the meter as envisaged in options 2, 3 and 4 • Although the costs of option 1 are lower than the others, its benefits are correspondingly small.
Most "behind the meter" MTR benefits can be realised without changing central settlement	• Full "behind the meter" MTR envisages different retailers for all and any appliance, storage and generation asset but in 2016 the AEMC suggested that improved retail competition and off-market arrangements would deliver the same benefits without MTR[2] • The AEMC's 2024 determination[3] limits MTR to <u>flexibility</u> resources but it should not be necessary to change central reconciliation and settlement (which is for energy) to achieve this: Powerco already has off-market flexibility agreements with behind-the-meter flexibility providers • The Authority's Power Innovation Pathway is a great mechanism by which different MTR variants can be tested to understand the actual costs and benefits of each under code exemptions as the basis for developing efficient and effective code amendments.
Switching processes need to be efficient	• The Authority's proposed changes to switching are less uncertain, as they are developed from industry experience, but it is difficult to support them fully without understanding all the costs and benefits of implementing the proposals • Proposals for intraday switching, will require changes to all participant systems, not just the central registry so understanding implications and costs is particularly important.

We unpack our thinking on this in sections 1 –4 below and link these thoughts to the Authority's consultation questions in section 5.

We are always keen to meet with the Authority to discuss and develop the ideas in our submissions. In the meantime, if you have any questions or would like to talk further on the points we have raised, please contact Emma Wilson ([redacted]

Nāku noa, nā,

[redacted]

Emma Wilson
Head of Policy, Regulation and Markets
POWERCO

[2] *Final Rule Determination - National Electricity Amendment (Multiple Trading Relationships) Rule 2016*, Australian Energy Market Commission.
[3] *National Energy Retail Amendment (Unlocking CER benefits through flexible trading) Rule 2024*, Australian Energy Market Commission, 15/8/24

1. Different versions of MTR have hugely different costs and target different benefits

The Authority proposes 5 "different types of MTR"[4]. The AEMC has considered at least 2[5] as has the UK[6]. They all have different drivers, aim for different benefits and operate in different ways with hugely different costs.

The Authority's proposed amendments target 5 objectives:

- *Promote consumer choice by enabling consumers to contract with different providers at an ICP.*
- *Enhance competition and innovation by allowing multiple providers to serve different aspects of a consumer's electricity usage, improving price and service quality.*
- *Improve efficiency and consumer participation in the electricity industry through increased integration of distributed energy resources such as solar panels, batteries and demand response technologies.*
- *Ensure there is the lowest impact possible for participants and consumers that do not want to participate in a multiple trading arrangement.*
- *Ensure future flexibility and scalability through amendments which establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve*[7]

The Authority's option 1 only enables the first and fourth of these objectives.

AEMO's 2016 proposal to the AEMC would have enabled all 5 of the Authority's objectives through a mechanism more like the Authority's Option 4. The AEMC rejected this because

- *Implementing the proposed framework may deliver some cost savings to a small number of customers who seek to set up very specific MTR arrangements. However, it is unlikely to deliver cost savings to most customers seeking to engage with multiple retailers. It is therefore unlikely to materially reduce costs for customers generally, and so unlikely to drive demand for new energy service providers or stimulate service innovation and competition in the retail electricity market.*
- *Implementation of the proposed framework would require retailers and distributors to modify a number of IT systems and operational processes. These changes are significant, and the implementation costs would be passed on to all customers through increased electricity prices. As a result, while only a small subset of customers may receive a direct benefit from the changes, all other electricity customers would likely face increased retail electricity prices.*
- *It is likely that consumer protection mechanisms would need to be reviewed and significantly amended if the proposed framework was implemented. For instance, disconnection and life support equipment registration*

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[4] *Evolving multiple retailing and switching - Consultation paper*, Electricity Authority, June 2025. pp. 15-16

[5] AEMC op. cit.

[6] *Future energy retail markets: stakeholder views on multiple electricity supplier models in the UK*, Watson et al., University College London, June 2022.

[77] *Evolving multiple retailing and switching - Consultation paper*, Electricity Authority, June 2025. p. 62

processes would need to clarify the roles and responsibilities for parties active at the same connection point to ensure that customers with life support equipment are not inadvertently disconnected[8].

Consumer NZ's recent submission to the Authority's Green Paper on decentralisation similarly cautioned

> *Our perspective is shaped by what we hear from consumers: many of whom feel disengaged from the electricity system, mistrustful of providers, and apathetic to emerging opportunities … We are concerned the Green Paper overstates the readiness and willingness of the general population to actively participate in a decentralised energy future … there is a real danger that decentralisation without safeguards will deepen existing inequalities …*
>
> *Consumer NZ is not opposed to decentralisation, but we are concerned about an industry assumed future being projected onto consumers, many of whom neither asked for it, desire it, nor have the means to participate. The industry must meet consumers where they are, not where they want them to be. The transition to a more decentralised electricity system should be driven by robust evidence, consumer need, and inclusive design - not just technological enthusiasm.*
>
> *We urge the Electricity Authority to take a cautious, consumer-centred, evidence-based approach. That means starting with the realities of consumers' lives not just the possibilities of emergent technologies*[9].

It is not possible to support the Authority's proposed Code Amendments without quantified evidence of costs and benefits. Given the AEMC and Consumer NZ's concerns about such proposals resulting in harm to consumers, the Authority should use the Power Innovation Pathway to test alternative MTR models under code exemptions to gather quantified evidence of costs and benefits. This will allow the industry to identify the consumer need and *establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve* which costs less than the benefits it aims to enable.

Option 1 is "above the meter MTR" and could preserve the 1-1 relationship between EDBs, retailers and consumers.

Given the poor consumer outcomes from an expensive implementation of MTR for which there is limited market demand, we commend the Authority for identifying option 1 which is simpler than the other options presented and would be less expensive to implement across the industry.

Importantly, however, option 1 will only be cheaper to implement than the other options if it doesn't change the 1-1 contractual relationship between distributors, retailers and consumers. This would mean the "generation trader" wouldn't be responsible for the generation behind the ICP if they're just buying the net surplus exported from the ICP.

Our view of the option 1 operation is illustrated in Figure 1.

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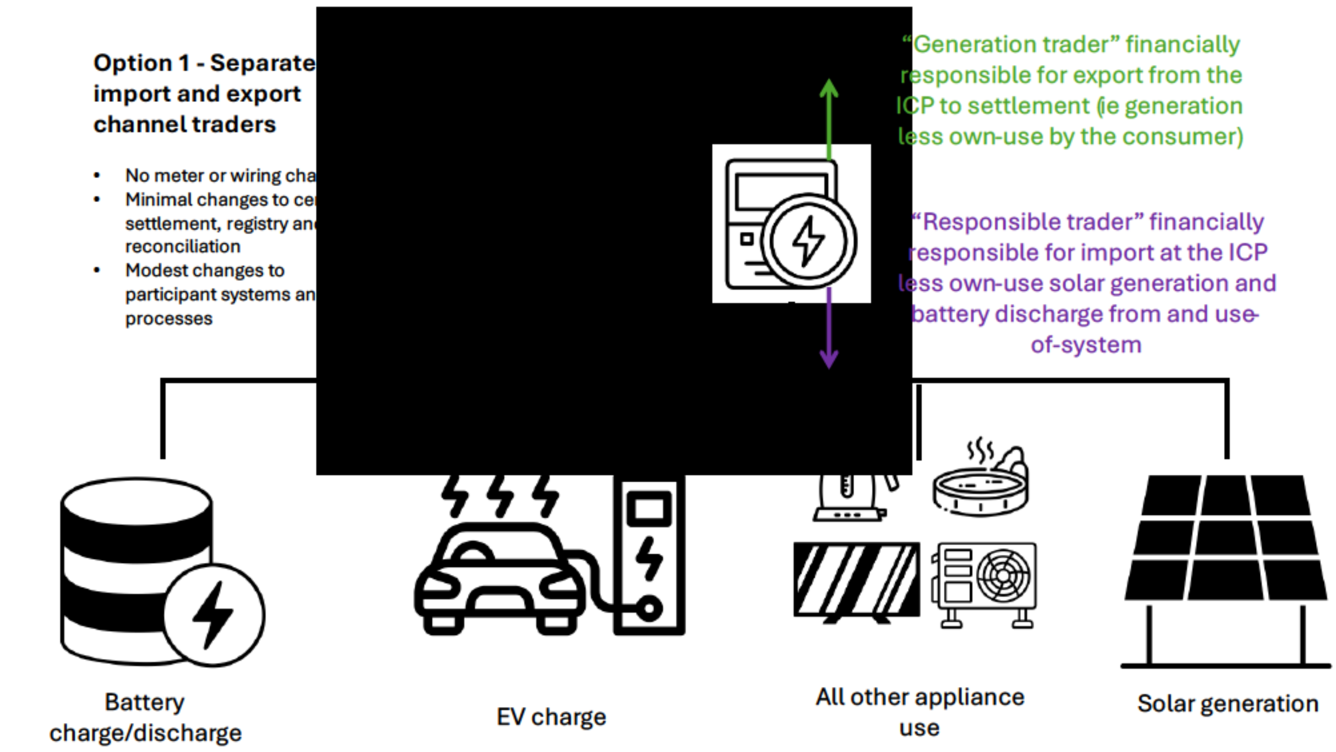
[8] *Final Rule Determination - National Electricity Amendment (Multiple Trading Relationships) Rule 2016*, Australian Energy Market Commission. pp. ii-iii

[9] *Submission on Green Paper: working together to ensure our electricity system meets the future needs of all New Zealanders*, ConsumerNZ, 25/6/25

Figure 1 Option 1 features



Even if the generation trader had the ability to control the charge and discharge of a battery behind the meter, they would not be responsible for the entire export from the battery and/or generation behind the meter because the consumer uses some or all of that electricity. The generation trader would equally not be financially responsible for the electricity used to charge a battery – with the responsible trader responsible for all import at the ICP regardless of what it is used for behind the meter.

For a consumer with no battery or generation behind the meter this is identical to the status quo. Practically it means that neither the incumbent retailer nor the distribution business need to make major changes to processes, systems or commercial arrangements as the effect of the battery storage and generation behind the meter is to increase or reduce the amount of electricity the incumbent retailer is liable for as "responsible trader".

For this to be true, the generation trader would need to work through the responsible trader[10]. As Chapman Tripp note in their advice to the ENA

> *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.*[11]

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[10] *The draft Code Amendment uses the term "responsible trader" although the consultation paper uses the term "consumption trader" interchangeably*

[11] *Letter to Electricity* Networks Aotearoa Proposed Code Amendments – Evolving Multiple Retailing and Switching, Chapman Tripp, July 2025. Para 32. Letter attached to ENA submission.

Even if the Authority regulated obligations and access rights, option 1 will still require changes to legal, contractual and DDA arrangements to ensure that EDBs and responsible traders are able to manage risks to network service quality and recovery of efficient costs. These would be less complex than those described in section 2, below, but tens or hundreds of thousands of dollars for each EDB and incumbent retailer.

1.1 Option 1 has limited benefits

The corollary of option 1's simplicity is that it achieves the Authority's objective of *the lowest impact possible for participants and consumers that do not want to participate in a multiple trading arrangement* while *enabling consumers to contract with different providers at an ICP* but only in the limited sense of separating settlement responsibility for the net export from an ICP.

Option 1 does not meet the Authority's other 3 objectives:

Authority MTR objective	Relevance of option 1
Enhance competition and innovation by allowing multiple providers to serve different aspects of a consumer's electricity usage, improving price and service quality.	Option 1 explicitly excludes separately metered sub-ICP injection and offtake – it is limited to the total import and export at the ICP. The only difference from the status quo is that someone other than the incumbent retailer settles the net export from the ICP which may affect incentives for a landlord to invest in solar or storage behind the meter, or add to a generation portfolio for a retailer who does not supply this consumer but it doesn't affect <u>that</u> consumer's usage.
Improve efficiency and consumer participation in the electricity industry through increased integration of distributed energy resources such as solar panels, batteries and demand response technologies.	Because Option 1 explicitly excludes separately metered sub-ICP injection and offtake, it doesn't change how CER are integrated with the power system. The status quo has incentives for retailers to optimise the integration of CER to improve the competitiveness of their import and export prices. This is why the AEMC didn't approve the 2016 MTR proposal – they felt that these benefits would come from improved retail competition.
Ensure future flexibility and scalability through amendments which establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve	Because Option 1 doesn't take the complexity, risk and costs of separate responsibility for individual devices and appliances below the ICP, it is not cheaply or easily scalable to accommodate full "behind the meter" MTR – see section 2 below.

The two scenarios where option 1 might enable different competitive responses from the status quo are:

- Making a landlord slightly more likely to invest in solar generation behind the meter as they could capture the value of any surplus generation that their tenant doesn't use
- To add to a generation portfolio for a retailer who does not supply the consumer.

Neither of these benefits are likely to be material:

- A landlord's incentive to install solar for the benefit of their tenants will be to make the tenancy more attractive. The extra few dollars a week that might be available from generation that the tenants don't use are unlikely to make a big difference to whether the landlord spends upwards of $8,000 on solar for their tenants' benefit
- It's hard to see why the retailer who buys the export at the ICP wouldn't also be selling electricity to the same consumer but even if this was a plausible use case, the quality and value of the export in a portfolio would be limited. The residual solar export after own-use would be small and unpredictable quantities during the day when the spot price is low.

Importantly it is very unlikely that a generation trader would get access to battery export through option 1: batteries allow consumers to maximise the amount of electricity that they use which they generate themselves and to avoid peak prices. Retailers already offer incentives to customers to maximise the value of their batteries, much as they have by directly controlling hot water heating[12]. This doesn't require MTR, it just requires effective retail competition.

The Authority has suggested that registry costs for option 1 would be $700,000. There would also be legal and process change costs for both the Authority and all industry participants in complying with, testing and implementing the change. The total cost of option 1 is likely to be many million dollars across the 29 EDBs and 30 incumbent retailers across the industry, which would be cost imposed on all consumers, not just those participating. It is unlikely that the benefits from these two use cases would exceed this cost.

It would be better to use the Power Innovation Pathway to test alternative MTR models under code exemptions to gather quantified evidence of costs and benefits. This will allow the industry to identify the consumer need and *establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve* which costs less than the benefits it aims to enable.

2. "Behind the meter" MTR breaks the 1-1 link between consumer, EDB and retailer is expensive

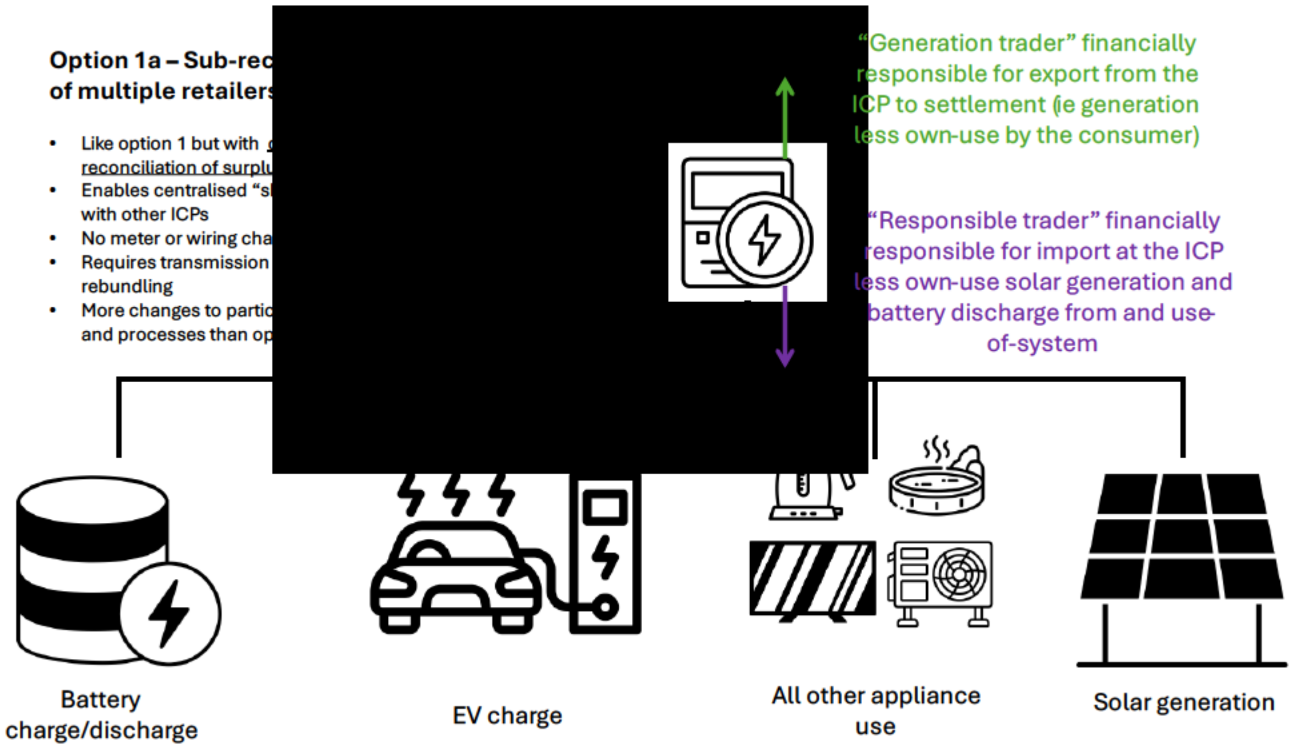
Because Option 1 doesn't change anything behind the meter, it doesn't really "lay a foundation for future stages of MTR". Full MTR envisages breaking the 1-1 relationship between retailer, EDB and consumer by allowing separate retailers for individual appliances and various intermediate steps to each appliance and generation/storage resource being separately metered and reconciled for central energy market settlement.

Figure 2 illustrates option 1a with the primary difference to option 1 being the central reconciliation of surplus generation which allows peer-peer sharing of exported power across all retailers with larger central system change costs. This is already possible off-market in New Zealand and has been demonstrated in the Franklin Energy Sharing Pilot[13].

[12] Powerco's 30,000 ICP retailer hot water trial is a great example of how retail competition has shared these benefits with consumers https://www.powerco.co.nz/news/media/residential-hot-water-control-trials

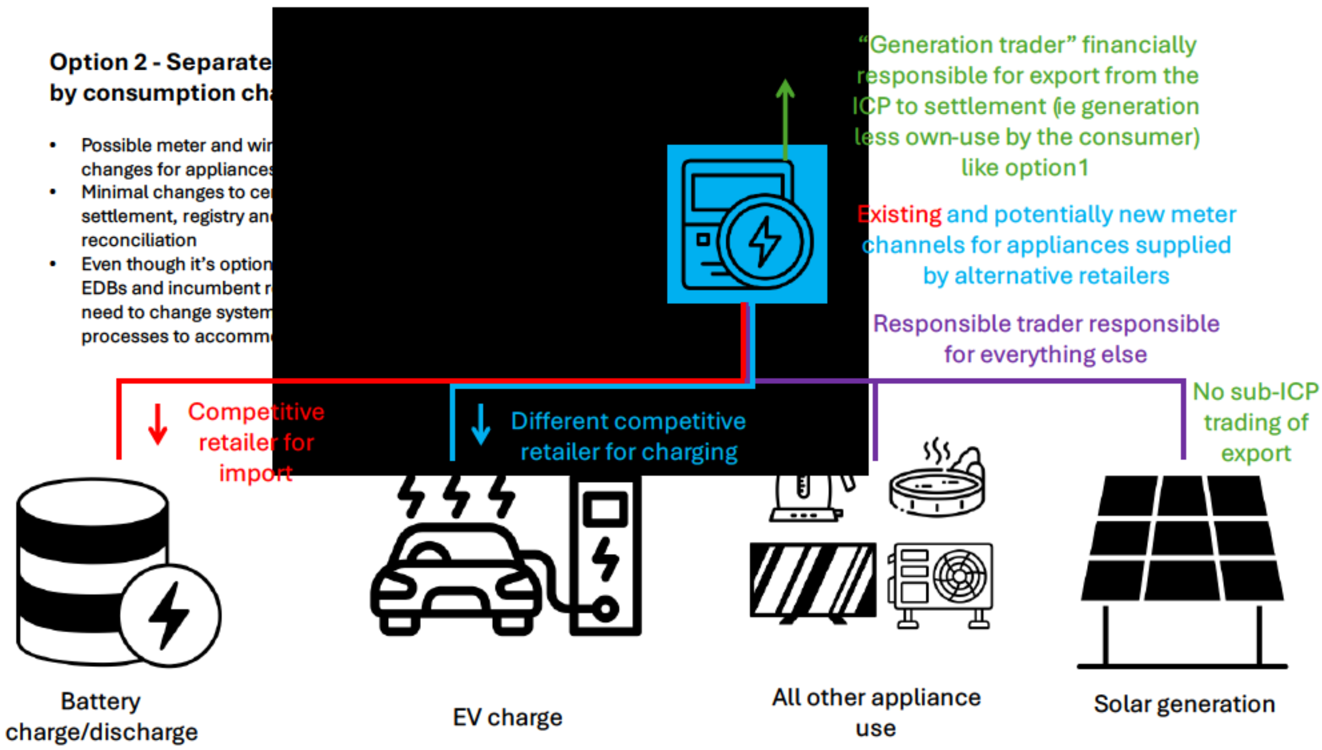
[13] https://countiesenergy.co.nz/media-centre/counties-energy-enables-community-energy-sharing-pilot-with-ara-ake-and-climate-connect-aotearoa/

Figure 2 Option 1a features



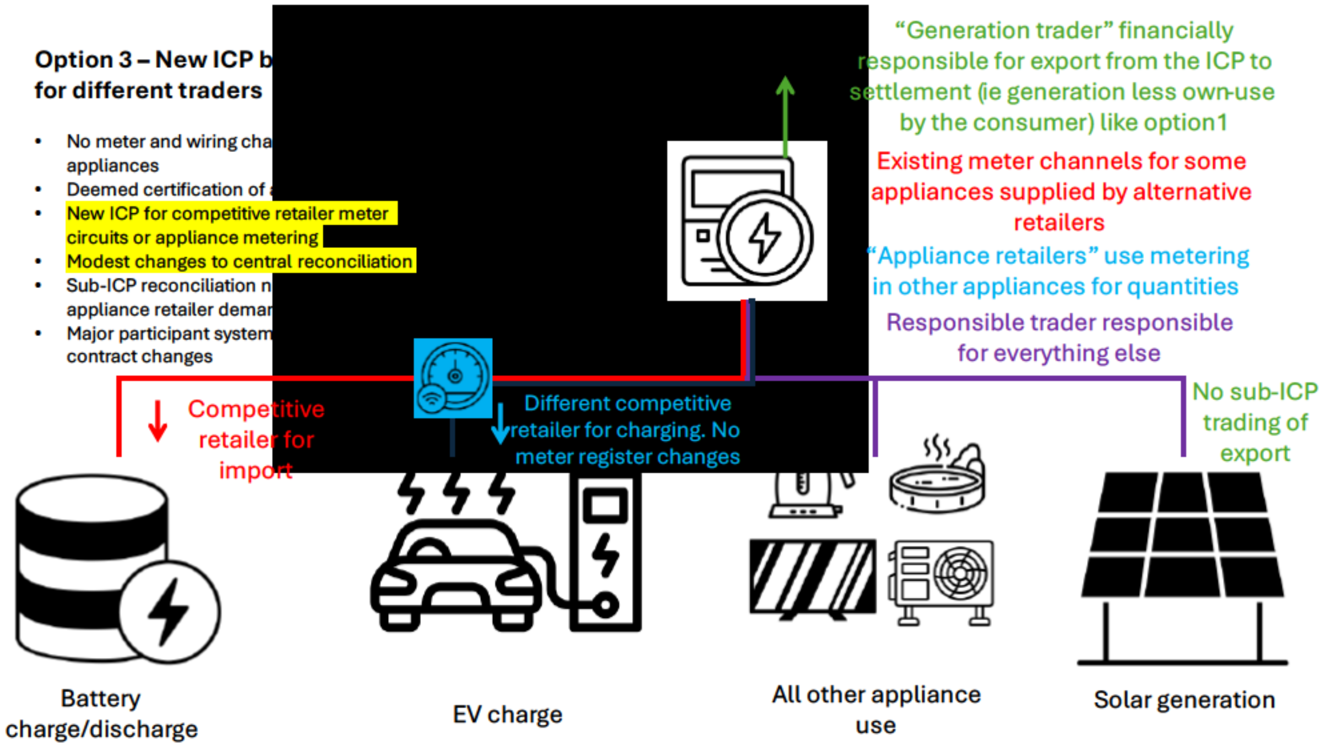
By limiting changes to meter channels, option 2 (Figure 3) avoids the need and cost for sub-ICP reconciliation but adds the cost of meter and wiring changes to each installation.

Figure 3 Option 2 features



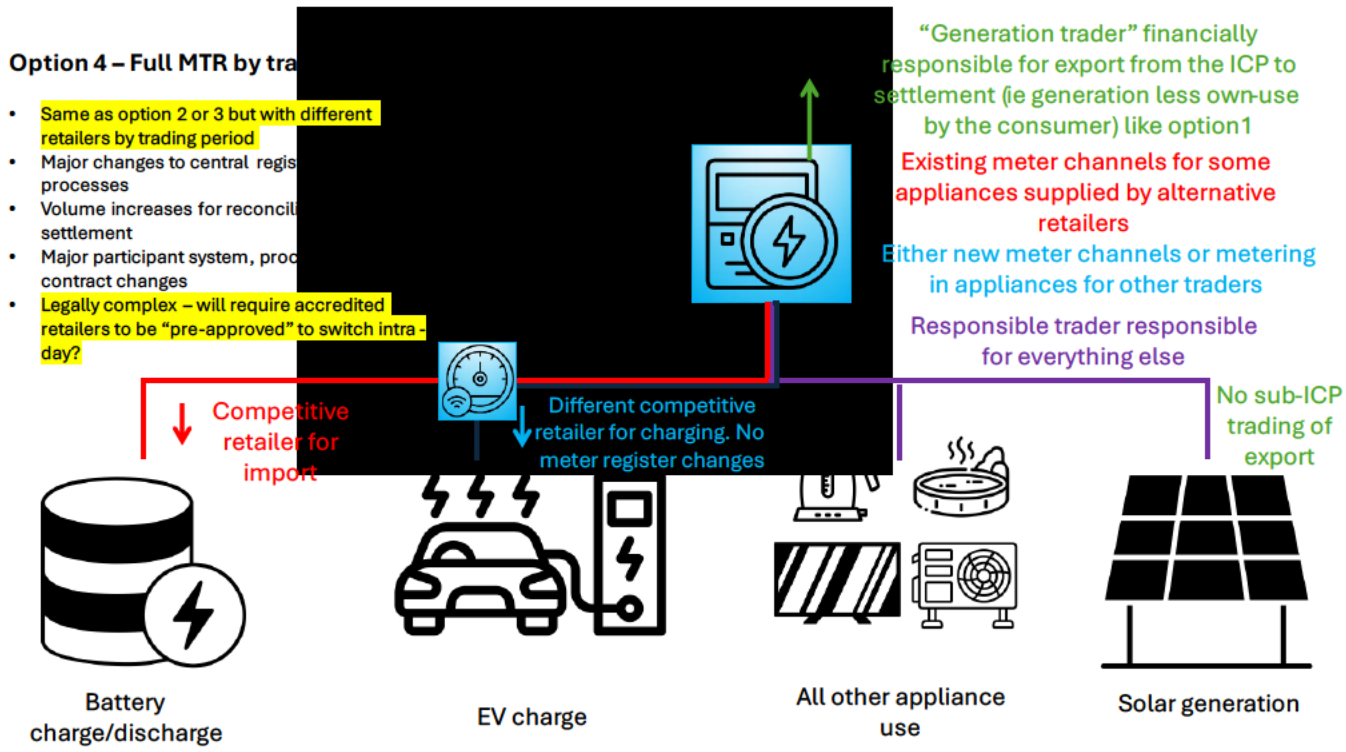
Option 3 (Figure 4) minimises central system change costs by assigning new ICPs to all appliances and channels supplied by different retailers and minimises the cost of physical wiring and meter changes by deeming in-appliance metering suitable for settlement but introduces “behind the meter” MTR and the need for sub-ICP reconciliation which is expensive.

Figure 4 Option 3 features



Option 4 (Figure 5) is the same as option 2 or 3 but with intraday switching which allows a very different retail model where individual appliances may have different retailers at different times of day. In addition to the costs of sub-ICP reconciliation from option 3, the scale of technology, process and legal changes to switch and registry processes and systems would be material and expensive.

Figure 5 Option 4 features



The cost, risk and complexity of enabling behind-the-meter MTR and intraday switching over Option 1 is enormous. In its 2016 consideration of AEMO's full MTR proposal, the AEMC noted (terminology changed to NZ market participants):

> *A number of (EDB)s identified that their IT systems and operational processes are currently based around a one to one relationship between connection point, FRMP, NMI and metering installation. The proposed framework would break this relationship by introducing the concept of a separate settlement point, and allowing for each connection point to have multiple settlement points with multiple (retailer)s and (ICP)s. (EDB)s advised that allowing such an arrangement would require significant changes to IT systems and operational processes in addition to changes required to implement metering contestability. Due to the integrated nature of these systems, (EDB)s identified that breaking the link between connection point, (retailer), (ICP) and metering installation would require a number of systems to be simultaneously overhauled.*
>
> *While it can be difficult to estimate the cost of such significant system changes, the range of (EDB) IT systems and processes that would likely be affected by such a change include:*
>
> - *billing systems;*
> - *standing data systems;*
> - *meter data management systems;*
> - *meter management systems;*
> - *works management systems;*
> - *faults management systems;*
> - *geographic information systems;*

- *supervisory control and data acquisition systems which remotely monitor and control the distribution network assets, including zone substations and feeders;*
- *reporting (including operational, managerial and regulatory reporting); and*
- *IT integration systems which manage communications between IT systems and business process management.*

(EDB)s also stated that the proposed framework would require changes to the following operational processes:

- *processes supporting connections and disconnections;*
- *life support equipment registrations;*
- *the development of new tariff structures to reflect the presence of multiple FRMPs active at a premises, through a reopening of the tariff structure statement process;*
- *B2B and B2M processes;*
- *solar feed-in tariff management;*
- *reliability performance measurements (related to the service target performance incentive scheme); and*
- *processes for (ICP) creation and allocation, and the management of associated (ICP) standing data.*

(EDB)s stated that increasing the number of (retailer)s and (ICP)s active at a premises could create additional complexity, potentially resulting in increased risk of errors. To reduce the risk of these errors and to develop processes for resolution, some (EDB)s stated that they would need to undertake additional system testing, training, and exceptions management processes. The development of these processes would add to the costs faced by the industry and would ultimately be passed on to customers.

New operational processes would be needed to support the proposed framework. These could include a process to track the number of customer connections (rather than (ICP)s as is the current practice) and new systems to capture information on total demand at each connection point.

A number of estimates of the actual cost to adapt (EDB) systems and processes to enable the proposed framework were provided by (EDB)s. These ranged from ***$8 million and $20 million per (EDB) business[14]****.*

Australian DNSPs (EDBs) are bigger than New Zealand's and their IT systems and integration is more complex, so the cost of compliance per company in New Zealand might lower but it will be in the order of millions of dollars per company[15] to say nothing of the corresponding system change costs for incumbent retailers and meter data service providers.

With 29 EDBs and around 30 retailers, the direct industry implementation costs for full MTR in New Zealand could be in the order of tens of millions of dollars. The Authority's assessment of its option 4 is that it is *complex and cost likely to outweigh benefit* but this is true of <u>any</u> behind the meter implementation of MTR or intraday switch process.

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[14] *Final Rule Determination - National Electricity Amendment (Multiple Trading Relationships) Rule 2016*, Australian Energy Market Commission. pp. 40-41 (emphasis added)
[15] Orion quantified the costs for it as a single EDB to implement the Authority's network connections project stage one amendments at $1.7m for IT changes and a further $700k for organisational implementation
https://www.ea.govt.nz/documents/6412/Final_Redacted_-_Orion_cross_submission_-_Network_connections_project.pdf

3. Off market solutions and the Power Innovation Pathway will reveal efficient options for MTR

The AEMC's 2016 decision not to make a rule for behind-the-meter MTR identified that a lot of the benefits identified for the change could be achieved through off-market arrangements (again market participant names have been translated from Australian to New Zealand):

> *New energy services can also be delivered through private, off-market solutions offered by service providers who are not (retailer)s (therefore avoiding the need for two (retailer)s at a premises). Such arrangements could include an energy service provider partnering with a retailer to offer a customer a specific service … The benefits provided by such off market arrangements may be similar to those potentially provided by arrangements where the customer engages with multiple (retailer)s …*
>
> *The Commission considers that private, off-market arrangements are capable of delivering similar services and value to customers as those otherwise provided by engaging with multiple (retailer)s. Given these factors, the proposed framework is unlikely to materially enhance the ability of businesses to meet customer demand for new energy services.*

New Zealand already has several examples of off-market solutions meaningfully delivering many of the benefits attributed to centralised MTR:

- Trustpower introduced peer-to-peer energy sharing for its customers in 2017 through its Solarbuddies programme[16]
- Our Energy have offered a peer-to-peer energy sharing platform *Lemonade*[17] since 2018
- Several EDBs have tendered for flexibility services including both Aurora[18] and Powerco[19] contracting for flexibility from behind-the-meter battery energy storage systems orchestrated as a virtual power plant.

None of these projects are reconciled through central settlement – they are multilateral contracts between behind-the-meter flexibility service providers and flexibility buyers. This raises an important point: MTR is about changing central market settlement and reconciliation processes for energy because the efficiency of balancing the wholesale market includes consideration of network externalities across all injection to and offtake from the interconnected transmission system. This isn't true for flexibility which is about time-shifting energy demand and supply.

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[16] https://www.seanz.org.nz/trustpower_s_solar_buddies

[17] https://www.go-p2p.org/case_studies/kia-whitingia-to-be-shone-upon/ and https://www.go-p2p.org/wp-content/uploads/Word_Case-study_GO-P2P_Kia-Whitingia.pdf

[18] https://centralapp.nz/NewsStory/aurora-energy-solarzero-partner-up-for-upper-clutha/5ffbbcbddbd04f0028d36fd8

[19] https://www.powerco.co.nz/news/media/solarzero-to-supply-coromandel-network-support-to-powerco-using-virtual-power-plant-technology

3.1 Off market solutions for flexibility already exist in New Zealand

Although the AEMC rejected a rule for full behind-the-meter MTR in 2016, it recently made a rule *to enable three key arrangements:*

- *Large customers will be able to engage multiple energy service providers at their premises more easily- to manage and obtain more value from their CER.*
- *Energy service providers for small and large customers will be able to separate and manage 'flexible' CER from 'passive' loads in the energy market - leading to innovative products and services for consumers.*
- *Market participants will be able to use in-built measurement capability in technology such as electric vehicle (EV) chargers and smart streetlights - to enable the delivery of innovative and essential products and services at lower cost.*[20]

Unlike the 2016 proposal, the rule is optional and primarily focused on flexible (controllable) CER. Large users can select multiple traders, but they still need to be separately measured and submitted to settlement. This is not full behind-the-meter MTR as envisaged in 2016.

While households can offer flexible supply and demand separately from non-flexible supply and demand, they still can only have one trader – this is not MTR at all – it is a nudge to retail market competition.

As noted above, off-market solutions for flexibility already exist in New Zealand. Over the years Powerco has been experimenting with the use of flexibility to defer planned network investment:

- Our first step in this process was in 2018 when we called for expressions of interest in providing non-transmission network solutions as options for reinforcing electricity supply in the South Waikato. In this instance, the non-network alternatives were more expensive than the transmission solution
- In 2021 we ran a tendering process for network support to the Coromandel Region. SolarZero was awarded a contract to provide 1MW of network support during peak consumption times. We paid them to keep their batteries fully charged when a local network peak was forecast and to export stored electricity into the network when the peak occurred[21]
- In September 2023, we livened four controllable fast chargers for electric vehicles at Z's forecourt in Waiouru. These support the electricity network by intelligently responding (reducing load) to minimise impact during peak demand periods
- In December 2023, Z Energy livened a 500kW flexible Kwetta EV fast charging array at Ngātea, on a part of our network which has voltage constraints during peak periods
- In February 2025 we sought expressions of interest from flex service providers to provide demand reduction services during peak electricity load times in the Mt Maunganui area.

None of these projects have touched central settlement, registry or reconciliation processes because they're about flexibility rather than wholesale energy yet they are addressing the same wider pool of benefits that the Authority is targeting with MTR.

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[20] *Energy Retail Amendment (Unlocking CER benefits through flexible trading) Rule 2024*, Australian Energy Market Commission, 15/8/24. Page i

[21] We have suspended the contract with SolarZero as a result of their liquidation: SolarZero enters liquidation | RNZ

3.2 The Power Innovation Pathway is a way to determine costs and benefits of different MTR variants

The Authority offers 'enhanced regulatory support' via its Power Innovation Pathway including:

- *providing specific support to assist the applicant in understanding certain clauses or Parts of the Electricity Industry Participation Code 2010 relevant to the project*
- *supporting the scoping of a trial to ensure its outcomes inform regulatory activities*
- *acting as a pilot observer to connect trial findings and perspectives to relevant Electricity Authority work streams*
- *assisting in the identification of any Code barriers and providing information on the process for any exemption applications that may be required.*[22]

This mechanism could be easily applied to run industry trials of alternative MTR models – both on- and off-market, behind-the-meter and above-the-meter to gather evidence of the actual costs and benefits of each and assess market and consumer demand for different products and services that depend on changes to central market processes, and compare these to non-MTR solutions.

This will allow the industry to identify the consumer need and establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve which costs less than the benefits it aims to enable and address Consumer NZ's demand that

> *The transition to a more decentralised electricity system should be driven by robust evidence, consumer need, and inclusive design - not just technological enthusiasm*[23].

4. Deciding *which* changes to switching processes are efficient needs quantified cost-benefit analysis

The majority of the changes proposed for switching processes have been raised by industry participants and are closer to an omnibus code amendment to deal with known problems.

Like the MTR proposal, there are no costs or benefits quantified for the switching change proposal.

The requirement to allow intraday switching is not one that has been raised by industry participants – it anticipates a time when consumers switch retailers more than once a day. The Authority's assessment of its option 4 – full MTR by trading period - is that it is *complex and cost likely to outweigh benefit*. The difference between option 3 and 4 is the intraday switching not the behind the meter implementation of MTR.

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[22] https://www.ea.govt.nz/industry/power-innovation-pathway/enhanced-regulatory-programme/
[23] *Submission on Green Paper: working together to ensure our electricity system meets the future needs of all New Zealanders*, ConsumerNZ, 25/6/25

This change would be particularly expensive to implement – like behind-the-meter MTR, it would require extensive changes to the processes, systems for all EDBs and incumbent retailers to accommodate a capability for which there is no evidence of market demand or consumer need which would cost tens of millions of dollars to implement across the industry.

Consumer NZ's caution to the Authority is instructive here:

> *We urge the Electricity Authority to take a cautious, consumer-centred, evidence-based approach. That means starting with the realities of consumers' lives not just the possibilities of emergent technologies*[24].

It is critical that the Authority follow its own Code Amendment principles in the evolution of the switching process:

- *Principle 1 – Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so.*
- *Principle 2 – Costs and benefits are summarised: The Authority is required to include with any Code amendment proposal an evaluation of the costs and benefits of the proposed amendment. The Authority will also include a summary of this evaluation.*

The Authority will also apply the following additional principles where analysis demonstrates a clear benefit to a Code amendment proposal, but there is no clear best option in terms of a solution:

- *Principle 3 – Preference for small-scale 'trial and error' options: The Authority will prefer options that are initially small-scale, and flexible, scalable and relatively easily reversible with relatively low value transfers associated with doing so. The Authority will monitor the implemented option and reject, refine or expand that solution in accordance with the results from the monitoring.*
- *Principle 4 – Preference for greater competition: The Authority will prefer options that have larger pro-competition effects, because greater competition is likely to be positive for economic efficiency, reliability of supply and, ultimately, for the long-term benefit of consumers.*
- *Principle 5 – Preference for market solutions: The Authority will prefer options that directly address market failure so as to facilitate efficient market arrangements. The Authority will discount options that subdue or displace efficient market structures.*
- *Principle 6 – Preference for flexibility to allow innovation: The Authority will prefer options that provide industry participants with greater freedom and lower compliance costs, unless more restrictive options are justified such as where it may be more efficient to use a 'one size fits all' approach (for example, uniform standards).*
- *Principle 7 – Preference for non-prescriptive options: The Authority will prefer options that specify outcomes required of industry participants rather than prescribe what they must do and how they must do it, unless the benefits of prescription outweigh an outcomes-based approach.*[25]

Again the Power Innovation Pathway provides a mechanism by which the Authority could follow principle 3 - running small scale trials to see if there is market and consumer demand for intraday switching and if so collect costs and benefits to identify the most efficient way to do this under principle 1 and 2.

[24] *Submission on Green Paper: working together to ensure our electricity system meets the future needs of all New Zealanders*, ConsumerNZ, 25/6/25

[25] *Consultation Charter*, Electricity Authority. 27 February 2024 4,2 and 4.3

5. Responses to the Authority's consultation questions

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?	No. We agree with Consumer NZ who, in their recent submission to the Authority on its Green Paper on decentralisation cautioned *Our perspective is shaped by what we hear from consumers: many of whom feel disengaged from the electricity system, mistrustful of providers, and apathetic to emerging opportunities …* *The transition to a more decentralised electricity system should be driven by robust evidence, consumer need, and inclusive design - not just technological enthusiasm.* *We urge the Electricity Authority to take a cautious, consumer-centred, evidence-based approach. That means starting with the realities of consumers' lives not just the possibilities of emergent technologies*[26].
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?	As discussed in sections 0, 2 and 3, Option 1 does not provide a low cost pathway to full MTR. It is not possible to support the Authority's proposed Code Amendments without quantified evidence of costs and benefits. Given the AEMC and Consumer NZ's concerns about such proposals resulting in harm to consumers, the Authority should use the Power Innovation Pathway to test alternative MTR models under code exemptions to gather quantified evidence of costs and benefits. This will allow the industry to identify the consumer need and *establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve* which costs less than the benefits it aims to enable.
Questions on Multiple trading	
Q3. (3.26) Do you agree with the proposed solutions? If not, what would you change and why?	No. See question 2
Q4. (3.26) Do you agree with the benefits anticipated from the proposed solutions? Are there other	No. See question 2

[26] *Submission on Green Paper: working together to ensure our electricity system meets the future needs of all New Zealanders*, ConsumerNZ, 25/6/25

Questions	Comments
benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	
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?	Yes. As discussed in section 0, there would also be legal and process change costs for both the Authority and all industry participants in complying with, testing and implementing Option 1. Even though option 1 is much simpler than the alternatives it will still introduce significant cost for all EDBs and incumbent retailers - hundreds of thousands if not millions of dollars per industry participant.
Q6. (3.47) Do you agree options 2 and 3 are not preferred? If not, why not and how would you overcome the disadvantages?	Yes , Section 3 explains how the Authority can use its Power Innovation Pathway to run industry trials of alternative MTR models – both on- and off-market, behind the meter and above the meter to gather evidence of the actual costs and benefits of each and assess market and consumer demand for different products and services that depend on changes to central market processes. This will allow the industry to identify the consumer need and establish a foundation that can accommodate future stages of MTR as technology and the industry continue to evolve which costs less than the benefits it aims to enable
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?	As discussed in section 0, Option 1 is less expensive than the other options but offers very little benefit. Section 2 explains how expensive other options would be. Our preferred option described in section 4 is to use the Power Innovation pathway to run industry trials first.
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?	Yes, remain mandatory.
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?	Yes
Q10. (4.55(q)) Do you agree with the proposed solutions? If not, what would you change and why?	Yes

Questions	Comments
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 - as discussed in section 4, intraday switching will be extremely expensive to implement for an unproven benefit.
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?	Yes. As discussed and evidenced in sections 2, 3 and 4, implementing intraday switching will be cost tens of millions of dollars across the industry to implement.
Questions on MEP switching	
Q13. (5.34) Are there any other files that should be added to this list?	NA
Q14. (5.38) Do you agree with the proposed solutions? If not, what would you change and why?	NA
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?	NA
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? Questions on distributor switching	NA
Q17. (6.13) Do you agree with the proposed solutions? If not, what would you change and why?	The Authority should make a formal definition of "network extension" to support the proposed Code requirements to report on it.

Questions	Comments
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?	NA
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?	NA
Questions on implementation	
Q20. (7.4) Would you prefer a single implementation or a staged implementation? Please give reasons for your preference	Staged, based on benefits and cost evidence in industry trials.
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 functional specification for any changes needs to be finalised at least 6 months before any code changes become effective to give participants long enough to implement them. Again, industry trials to develop these specifications would give participants advance notice of upcoming changes. Given the need to establish the costs and benefits of various versions of MTR and the opportunity to evolve rules over time, there is an opportunity to use industry trials in the short term to develop a regulatory roadmap for MTR over a 10 year period so that participants can architect future capability into their systems as they face routine replacement and refinement rather than meeting it reactively.
Questions on the regulatory statement	
Q22. (8.6) Do you agree with the objectives of the proposed MTR amendments? If not, why not?	No. See section 3.
Q23 (8.11) Do you agree with the objectives of the proposed amendments to the switching process? If not, why not?	As discussed in section 4, the requirement to allow intraday switching is not one that has been raised by industry participants – it anticipates a time when consumers switch retailers more than once a day. This change would be particularly expensive to implement – like behind-the-meter MTR, it would require extensive changes to the processes,

Questions	Comments
	systems for all EDBs and incumbent retailers to accommodate a capability for which there is no evidence of market demand or consumer need which would cost tens of millions of dollars to implement across the industry. Currently days are sliced into 48 time periods in the EIEP 1 file – reconciling this with intraday switches of trader would require extensive changes to participant data systems (retail and network billing, reconciliation and settlement) from being day-based to trading-period-based. The business and legal rules governing like this would need to be aligned correspondingly.
Q24 (8.17(q)) Do you agree the benefits of the proposed amendment outweigh its costs?	No. Neither industry implementation costs nor benefits are quantified, yet the costs of full MTR and intraday switching will be in the tens of millions of dollars across the industry. Benefits are unlikely to be anything like as big as discussed in sections 1 and 2.
Q25. (8.21) Do have any comments on the preferred and alternative options discussed in the 2019 Issues paper?	Yes. See section 2.
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.	Yes in the sense that it will be cheaper to implement but it will have very limited benefit as discussed in section 1.1 and it is very unlikely that the benefit will outweigh the costs of implementation.
Q27. (8.25) Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	No. See question 26.
Question on Code drafting	
Q28. (Appendix A) Do you have any comments on the drafting of the proposed amendment?	See Chapman Tripp's advice to the ENA (attached to the ENA submission).