Evolving multiple retailing and switching

Consultation paper

3 June 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

Greater mobility puts consumers at centre of our energy future

The electricity sector is constantly evolving and innovating to meet consumers' needs. The Authority is working to ensure that every consumer is empowered to take full advantage of a dynamic and competitive energy market – we call this 'consumer mobility'.

This means households and businesses who are active participants, equipped with data and innovative tools to seamlessly compare and switch plans and providers, choose multiple providers for different services, and sell surplus power back to the grid, all with a few taps on a smart device.

This future will enable consumers to optimise costs, benefit from new technologies, and have more flexibility to choose the services that provide the best value for their needs – whether directly or through new providers and automated services.

Enabling multiple trading relationships are key to a consumer led future

To realise this future, consumers will require multiple trading relationships. This means having different retailers for different services in their homes and businesses.

This paper sets out proposals for the first stage of multiple trading arrangements – focussing on enabling consumers to buy and sell from different retailers for electricity consumption and generation.

Enabling consumers to choose different retailers for consumption and generation that offer the best value for these services will drive lower costs, improved services, and more reliable supply.

This in turn will encourage retailers to compete for and better reward consumers, including those with distributed generation like solar panels, battery storage and electric vehicles.

These changes will also encourage innovators to develop new products and services, leading to increased choice for consumers and more options for distributed generation.

There are wider system benefits from greater consumer use of distributed generation, including reducing reliance on the national grid and improving regional and local resilience.

The proposed changes are also designed to ensure there is minimal impact on consumers who do not wish to participate in a multiple trading arrangements – the aim is to provide consumers with the option to do so, either directly or having a service provider do so on their behalf.

To enable these changes, we need to update the Electricity Industry Participation Code 2010 (Code) and market systems.

This paper proposes the first stage of multiple trading relationships

These proposals put in place the foundation for further changes to multiple trading relationships that will expand and enhance the benefits for consumers.

Taking a staged approach enables consumers to benefit now from more choice, while creating a pathway for complex solutions to be implemented gradually, as demand increases, and technology evolves.

Signalling the future of multiple trading relationships now also provides a direction of travel to innovators for them to develop new providers and services for consumers.

Future stages could include:

- centralised energy sharing of surplus generation between properties, such as family members, iwi properties or donating to those in energy hardship
- more than one retailer for each metered load, such as hot water, space heating, or other separately metered loads
- additional retailers for designated appliances, such as electric vehicle (EV) chargers, batteries, air conditioning or heat pumps
- different retailers for different times of the day or different days of the week, such as a weekend retailer or an overnight retailer.

Industry processes for a consumer switching power companies need updating

Consumers will also require the ability to effectively and efficiently swich between providers to take advantage of these new opportunities. In addition to amending the Code to allow for contracts with more than one provider, this paper proposes improvements to processes for switching providers.

The Electricity Authority wants to make each step of the switching process easy for consumers in New Zealand, encouraging them to compare and switch power companies. We need to update the Code to improve the process of switching power companies for New Zealanders to make it more efficient, effective, and to maximise the benefits from multiple trading relationships.

In recent years, the back-end switching processes haven't kept up with the widespread use of smart meters and have caused inefficiencies for industry participants and poor experiences for some consumers, including delayed switches and incorrect bills. Reducing inefficiencies in the switching process should lower costs for participants and ultimately for customers.

The switching proposals outlined in this consultation are expected to provide significant benefits, including:

- more accurate metering records
- more accurate customer invoicing
- greater transparency and efficiency in the switching processes
- enhanced ability for participants to meet their obligations under the Code
- opportunities for participants to simplify systems leading to cost savings which can be directed towards innovation and cost relief for consumers
- reducing barriers to entry for new participants, leading to increased competition.

Distributor and metering equipment provider switching processes can also be improved

In addition to the process for switching a customer’s retailer, there are two other participant types that have responsibility for aspects of the electrical connection to the property. These are the distributor, that has responsibility for the connection of the property to the network, and the metering equipment provider (MEP), that has responsibility for the metering equipment installed at the property.

The Code and the registry also contain the requirements and processes to enable distributor and MEP switches. To maximise the benefit to consumers, we are also proposing changes to improve the efficiency and effectiveness of these processes.

Industry technical group has assisted

The Switch and Data Formats Group (SDFG) is a group of industry and consumer technical subject matter experts. SDFG members provide input as independent advisors, and in the interests of the industry as a whole.

The SDFG has supported the Authority to validate previously identified issues and options and identify any new issues and options. The SDFG has been involved at all stages of the development of this consultation paper, including providing advice on the 2019 Switch Process Review paper, which this consultation relies heavily on. The proposed solutions in this paper reflect input and guidance from this group, and the Authority thanks the SFDG for this assistance.

These proposals are part of range of project to enhance consumer mobility

The Authority has a range of related projects underway as part of its boarder consumer mobility programme to improve choice and affordability for consumers. These projects include:

- Supporting the Ministry of Business, Innovation and Employment (MBIE) to develop a potential ‘consumer data right’ (CDR) for the electricity sector. The CDR will enable consumers access to their own electricity consumption data and information about retailers’ products in a standardised and secure way, including through authorised third parties.
- Procuring a new and enhanced Authority-funded comparison and switching service to make it easier for consumers to find the best deal for their circumstances.
- Gathering information on barriers to, and opportunities for greater digitalisation across the electricity system to improve transparency and efficiency in the industry.

Have your say

The Electricity Authority invites feedback on the proposed changes and encourages stakeholders to participate in the consultation process to ensure the solutions meet the industry's needs and promote innovation and efficiency. See section 1 - What you need to know to make a submission, on page 7.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult on the Authority's proposal to make 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.

1.2. We are proposing these changes to address barriers to industry evolution and improve industry efficiency and innovation. This aligns with the promoting competition and efficiency limbs of our main statutory objective.

1.3. The amendments would benefit customers by reducing the issues that can result in a poor customer experience and reducing inefficiencies in participants' systems and processes. This will reduce cost pressures on participants and should result in lower overall costs for customers.

1.4. Section 39(1)(c) of the Act requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statement is set out in section 8 of this paper.

This paper is structured in three parts

1.5. The paper is divided into three parts:

(a) Part 1 contains the proposal to enable multiple traders

(b) Part 2 contains the proposals to change the switching processes

(c) Part 3 contains the implementation options and regulatory statement.

How to make a submission

1.6. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to policyconsult@ea.govt.nz with "Consultation Paper—Evolving multiple retailing and switching" in the subject line.

1.7. If you cannot send your submission electronically, please contact the Authority (info@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.8. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.9. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.10. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it and there are no countervailing public interest factors that would require it to be released. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.11. Please deliver your submission by 5pm on Tuesday 29 July 2025

1.12. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority info@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

A note on terminology

1.13. The process of customer switching is actioned by industry participants after a customer chooses a new retailer and is usually invisible to consumers. This process is mechanical, and industry focussed. By necessity this paper is written using technical terms and is targeted at industry participants that will be implementing the changes.

1.14. Appendix C contains a glossary of terms, abbreviations and acronyms used in this paper.

2. Issues the Authority would like to address

Greater mobility can empower consumers today and in the future

2.1. The electricity sector is constantly evolving through innovation and new technology, and consumer mobility is key to ensuring consumers can fully realise the benefits of these changes.

2.2. Mobility empowers consumers to compare plans, switch providers, adopt new technologies and trade or share energy. It means access to better information, smart-tools, and automated services.

2.3. It also means that consumers can make choices based on price, service, or other factors personal to them. This includes moving with ease between plans or providers, including different providers for different services within their property, for different times of the day and week.

2.4. As the electricity sector evolves to offer consumers more dynamic and diverse products and services, the scale of consumer will grow as will the complexity. Consumers will need support to cut through this complexity.

2.5. This means building the foundations for a future with multiple service providers now through a flexible and scalable framework that allows for the incorporation of future changes.

Enabling multiple trading relationships and improving switch processes underpins consumer mobility

2.6. To enable consumer mobility, consumers require the ability to have different retailers for different services in their homes and businesses. This arrangement is known as multiple trading relationships (MTR).

2.7. This paper contains proposals for stage 1 of enabling MTR. These changes will allow separate retailers for consumption and generation at a property.

2.8. This paper also includes proposed changes to improve consumers ability to effectively and efficiently switch providers and improve related back-end switching processes.

2.9. Together these changes will:

   (a) enable customers to choose more than one retailer at their property so they can choose the products and services that offer the best value for them; and

   (b) improve customer experience when choosing a new retailer by improving the underlying switching processes so that errors are reduced and switches are processed quickly.

2.10. The proposed changes in this paper will provide additional benefits, such as

   (a) evolving switching processes that are fit for purpose for the current and future electricity market,

   (b) lowering compliance effort for current and potential participants; and

   (c) increasing transparency and accuracy of information about the network, metering records and switch processes.

2.11. We consider that proposed stage 1 changes for MTR will provide real benefits for consumers now by:

(a) allowing retailers and innovators to offer consumers new products and services, ultimately benefiting consumers through improved service offerings and lower prices; and

(b) encouraging investment in distributed generation which provides benefits to consumers both directly (through generation revenue) and indirectly by reducing distributor costs and through increased regional resilience.

2.12. Distributed generation also improves regional resiliency by reducing reliance on the national grid. It enables local communities to maintain supply during disruptions and supports fast recovery after events like storms or earthquakes and enhances grid stability by balancing supply and demand closer to where electricity is used. By increasing the diversity of energy sources, these changes can create a more sustainable, affordable, and consumer focussed electricity system.

2.13. The proposals are also designed to benefits consumers by minimising disruption and additional costs.

2.14. For example, the 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).

2.15. The proposed Code amendments also define the roles and responsibilities of each trader at a property, including accountability for key functions such as load control, disconnections and billing. This will also help to minimise disruption and confusion for consumers.

2.16. The proposed stage 1 approach lays the foundation to enable more complex solutions to be implemented gradually, as demand increases, and technology evolves. It does this by allowing different traders to be assigned to the meter channels within each installation control point (ICP) record in the registry.[1]

A summary of next steps for multiple trading

2.17. If stage 1 multiple trading is approved after submissions have been considered, the Authority will consider the next stages of multiple trading. We are particularly interested in feedback from potential innovators and other parties that would consider offering products and services under an expanded multiple trading regime.

2.18. Future stages will need changes to the reconciliation processes to ensure all traders at an ICP are accountable for their share of the electricity consumed or generated. Under

[1] An ICP is the unique connection point where electricity is supplied to a home or business. Currently, a trader is assigned to the ICP in the registry and the Code only provides for one trader for each ICP.

the proposed stage 1, no change will be required to the current wholesale market reconciliation process, as it already manages consumption and generation separately.

2.19. Future stages will also give the Authority an opportunity to consider how the market administration of the consumption retailers is managed, including the evolution of the current market operations service providers.

2.20. The future stages of the multiple trading regime is set out in more detail at paragraph 3.6 of this paper. In summary, it involves progressively more complex solutions that enable greater customer choice and flexibility, for example sharing solar generation with other family members at different ICPs, designated traders for specific appliances like electric vehicles or batteries, or even separate traders for each time period.

Q1.	Do you agree that multiple trading relationships and improved switching are key components of consumer mobility? If not, what would you change and why?
Q2	Do you have any comments regarding future stages of multiple trading, whether the proposal provides optionality for the potential future stages, and the options the Authority should consider?

What outcomes are we seeking

2.21. We are proposing changes to MTR and improvements to the switch processes to:

(a) enable customers to choose more than one retailer at their property so they can choose the products and services that offer the best value for them

(b) improve customer experience when choosing a new retailer by improving the underlying switching processes so that errors are reduced and switches are processed quickly.

2.22. The proposed changes will provide added benefits, such as

(a) evolving switching processes that are fit for purpose for the current and future electricity market.

(b) lowering compliance effort for current and potential participants; and

(c) increasing transparency and accuracy of information about the network, metering records and switch processes.

The existing arrangements

Retailer switching and trading relationships

2.23. When a customer decides to change retailers, from their perspective the process to do so is reasonably seamless. However, behind the scenes there is considerable processing work needed by key participants to action the customer's decision.

2.24. The registry records which trader, distributor, and MEP has responsibility for, respectively, wholesale market electricity purchases, providing network services, and providing metering at the ICP.

2.25. The switching process is the combination of participant systems, the registry, and manual processes that ensure these responsibilities are correctly recorded, and the record changes at the point in time the responsibility changes.

2.26. The switching process has served consumers and the industry well over the last two decades. For the vast majority of switches the process is invisible to the customer and from their perspective the change in retailer 'just happens'. However, behind the scenes the processes were designed to optimise a non-half hour, manual meter reading world. Over the last 10 years, the industry has evolved with the widespread use of 'smart meters', currently installed at around 93% of ICPs.

2.27. In addition to the switching process, the industry is also required to account and pay for electricity in the wholesale market. Responsibility as a trader for an ICP in the registry also means responsibility for the wholesale electricity purchases and sales for distributed generation. To ensure all electricity is accounted for and there is no double billing, the industry has required a one-to-one relationship between trader and ICP. This relationship has been enforced through industry processes, and system design and validation and prevents the industry processes being used for multiple traders at an ICP.

MEP switching

2.28. The Code places the obligation for ensuring there is metering at the ICP on the trader. Therefore, any change in the MEP needs to be initiated by the trader. This is done through a "nomination" process. If the MEP accepts the nomination, it can arrange to physically change the metering and update the metering records on the registry. This confirms the accepting MEP as the new MEP.

2.29. Sometimes the MEP cannot physically change the metering. This can be due to constraints on access to site, safety or other technical reasons. If the MEP does not decline the nomination, the nomination stays on record and for any enquirer (eg a prospective new retailer) it will appear as if there is a MEP switch (and meter change) in progress. Some traders and MEPs opt to delay the nomination until after the MEP has changed the metering, meaning a prospective new retailer may not be aware the MEP and meter change is in progress.

2.30. The record of the MEP in the registry is driven by the MEP's participant identifier. When MEPs sell or transfer metering to other MEPs, or MEPs with multiple participant identifiers want to consolidate under one identifier, they must follow the standard MEP switch process. This means asking the trader to nominate the new participant identifier and upload the metering information (which is the same as the current information). This also usually triggers the "meter change" process within the trader's billing system even though the meter has not been changed. This is a material administrative burden for traders.

Distributor switching

2.31. An ICP can change distributors for several reasons, including the establishment or dis-establishment of an embedded network or sale of a network.

2.32. The process for switching distributors is totally manual. It involves the gaining distributor obtaining written confirmation from the losing distributor and from the trader for each ICP. The gaining distributor creates the distributor switch request using the prescribed format (known as the DS-010 file) and the file is submitted to the Authority. If the switch is approved by the Authority, the Authority processes the file through the registry to action the switch. Except for the email communications from the gaining distributor, the process is invisible to all participants, especially prospective retailers, until after the file has been processed.

Issues with existing arrangements

2.33. Technology, systems, and retail business models in the industry have evolved considerably over the past 10 years. Along with this evolution in technology has come an increasing demand from consumers for more sophisticated services and products that integrate seamlessly with the modern lifestyle.

2.34. The current switching systems and processes for retailer and MEP switching were optimised for the non-half-hour metering and the manual meter reading model. With widespread adoption of smart meters and the increasing reliability of remote meter reading, these switching processes have become cumbersome and inefficient.

2.35. While MTR for services are currently possible, this requires the retailer to work with the current trader, adding a layer of complexity to the provision of the service and increased costs. To realise the full advantage of these services, with the lowest cost to customers, these retailers need to have direct wholesale market responsibility for their part of the service. This means permitting more than one retailer to be linked to the ICP. The MTR trial underway in Wellington required exemptions from the Code to enable the trial to work without this complexity.

2.36. The current process for distributor switching is manual. The switch process is initiated (usually) at least 40 days ahead of the switch event date to give traders time to agree to the switch and update their systems. Lack of advance notice of distributor switching can cause issues for gaining traders that switch ICPs during this time. There is no centralised record of losing distributor and trader consent, causing issues if there is a dispute, or for regular auditing of compliance with the Code requirements.

Why the Authority is addressing these issues now

2.37. In 2020, the Authority completed preliminary work, under separate projects, on the switching process project (Switching Process Review (SPR) project) and multiple trading project (Multiple Trading Relationships (MTR) project) which was renamed to Additional Consumer Choice of Electricity Services (ACCES) project. Both projects were paused in 2020 due to other priorities.

2.38. Outdated or absent switching processes continue to create inefficiencies for participants, ultimately driving higher costs for customers. By reviewing and updating processes and enabling technology such as the registry to align with current industry context, resultant cost savings can be directed towards innovation and cost relief for consumers.

2.39. Multiple trading has been identified by many participants (and potential participants) as the next step in the industry evolution, and the Code has become a barrier to this.

2.40. Currently, there is a MTR trial underway in Wellington that has separate traders for each energy flow within an ICP (consumption and distributed generation), using exemptions from the Code to enable the trial. We want to use the lessons from the trial to propose a permanent solution. This solution may progress to the other multiple trading paths in future stages, but the current project is only considering separate traders for each energy flow (MTR stage 1).

2.41. The multiple trading work has dependencies on the registry and enhanced switching processes. As these enhanced processes will be developed through the switch process review work, the Authority is now progressing both as a combined project – Evolving Multiple Retailing and Switching. Although this creates a larger project, it reduces the total work needed by participants and the registry.

Two separate project parts

2.42. There are two separate parts to the project. Each part has issues identified and options to resolve them. Within each part many of the issues identified are also inter-related. Many can be progressed independently; however, some issues are so inter-related that we consider that the matters addressed in each part need to be managed together.

2.43. The two separate parts are:

(a) Part 1 - MTR stage 1 (consumption and distributed generation)

(b) Part 2 - Retailer, MEP, and distributor switching

Part 1 - Multiple trading relationships

3. Proposed changes to enable multiple trading relationships

Benefits of these proposals

3.1. We are proposing changes that would allow consumers to buy electricity from two providers (one for their consumption and one for their generation) and make it easier to switch between providers to get the best deal.

3.2. The proposals result in improved customer experience and choice when choosing a new retailer.

3.3. The proposals are laying the foundation for future stages of MTR.

3.4. In delivering these benefits, we want to minimise change impacts and costs for participants while achieving the objectives.

What are multiple trading relationships

3.5. MTR means the ability for a customer to have contracts with more than one retailer for different services at their property. MTR can take different forms, such as separate traders for each energy flow (consumption and generation), each meter register, or designated appliances.

3.6. The following table describes the different types of MTR that could be implemented, each increasing in complexity, as more customer choice is enabled:

MTR type	Benefits	Issues / notes
1: Two traders – distributed generation and consumption	Simple solution Sets foundation for other MTR solutions Allows innovative retailing Allows third-party reconciled energy sharing (similar to 1A below, but not centralised)	This is the current project scope and proposal
1A: Separate retailers with full central energy sharing	Introduces a centralised sub-reconciliation for energy sharing. Can be used with 2 or more retailers or traders	Not a true MTR but provides for enhanced reconciliation to transfer credits. This is not currently proposed
2: Separate traders for each consumption meter channel	As above, but allows central reconciliation if separately metered	Slightly more complex than above Currently little demand

	(eg, hot water, storage heating, EV or battery charge circuits)	This is not currently proposed
3: Separate retailers for designated appliances	As above, but doesn't require re-wiring for separate meters Allows innovative trading for specific appliances such as EVs, batteries, aircon	Requires a "master retailer" and a participant to manage sub-reconciliation to ensure no gaps or double ups This is not currently proposed
4: Full MTR by trading period	For each of the types above, supports separate traders and retailers for each trading period	Complex and cost likely to outweigh benefit Unlikely to be much demand at this time This is not currently proposed

3.7. The Authority has granted Code exemptions to enable a trial in the Wellington region with separate traders for consumption and generation. The proposal will provide for separate traders for consumption and generation as an option for the industry in the Code. Future stages of the MTR project may explore other multiple trading paths, but the current focus is on separate traders for each energy flow (MTR stage 1).

3.8. Regardless of whether a customer has one or several traders, the trader switching processes will be used to switch traders.

Issues with current arrangements

3.9. Multiple trading is the next step in industry evolution, but the current Code and industry systems and processes are a barrier to this innovation.

3.10. In the registry, traders are currently linked at an ICP level, which prevents more than one trader from supplying services to a property.

3.11. Where a distributed generation installation has its own point of connection to the network (as may be more likely in large commercial installations), it will have a second separate ICP identifier and metering that is separate (physical and data entity) from the consumption ICP.

3.12. However, most connections have only one point of connection and metering installation, which introduces complexity for participants and market systems such as:

(a) the risk of electricity getting lost or double counted in the system

(b) new requirements and responsibilities for reconciliation between generation and consumption ICPs or channels in later stages of MTR

(c) challenges for MEPs to manage when more than one trader may initiate changes to a metering installation

(d) issues could arise in separate meter installations, where traders have appointed different MEPs and the two ICP data entities are rejoined (i.e. customer chooses only one trader for both)

(e) 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

(f) introducing more than one relationship between the MEP and multiple traders at a property would lead to a requirement for communication with multiple traders about physical works affecting the meters, multiple metering agreements, and the risk of overcollection of meter lease charges increasing the customer's cost.

3.13. We have identified three options to enable MTR. The preferred option (option 1) is designed to provide for MTR and avoids the above complexities.

Preferred solution (Option 1) – Assign trader to the meter channel for all ICPs

3.14. Our preferred solution for addressing these issues is to allow different traders to be assigned to the meter channels. In summary this would involve amending the Code, and where relevant reconfiguring the registry to:

(a) use the channels within each ICP record in the registry to link different traders to each meter channel

(b) include a field in the gaining trader switch request file (NT file) to signal if a customer wants to enter a multiple trading arrangement, or deal with a single trader. The default selection on the NT file will be single trader, which means the same trader will be automatically assigned to all channels in the registry

(c) where the point of connection and metering installation at an MTR property is used for both consumption and generation:

(i) prevent distributed generation traders from initiating changes to a metering installation so that only consumption traders may initiate changes

(ii) prevent distributed generation traders from changing MEPs where the generation ICP channel is part of the same meter as the consumption ICP channel

(iii) prevent the distributed generation trader from initiating any work on the electrical installation point of supply, or requesting the distributor to do so

(iv) permit the distributed generation trader to initiate changes to the generation equipment and wiring, but 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

(v) prohibit the distributed generation trader from initiating disconnection or reconnection of the ICP, including remote disconnection through the MEP, or physical disconnection at the property. The generation trader would be able to initiate work on the generation equipment and wiring, but if the supply to the installation is to be disconnected this would need to be initiated through the consumption trader

(vi) require distributors to include all relevant traders when notifying of planned and unplanned outages

(vii) 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, especially if similar pricing is applied to an ICP with a single trader for both consumption and distributed generation - 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) - the Code and registry should not prevent the implementation of cost-reflective distribution pricing

(viii) prevent the MEP from charging twice for the same service, but allow flexibility to introduce pricing that reflects the actual costs for the generation metering, especially if similar pricing is applied to an ICP with a single trader for both consumption and distributed generation (but can include incremental costs of servicing two retailers) - 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 - the Code and registry should not prevent the implementation of cost-reflective metering pricing.

Additional detail of changes

3.15. The following sets out the detailed steps proposed for when an MTR is initiated, when a customer switches their consumption or generation to a new trader, and when the customer decides to exit MTR and combine their accounts with a single trader.

Initiate a multiple trading relationship

(a) The customer decides to select a separate trader for their generation (or consumption) and makes an arrangement with that second trader.

(b) As future proofing for other stages, the second trader would be required to indicate which register(s) it wants to be the trader for and sends an NT file of a new type (eg, initiate MTR switch) to the registry.

(c) The registry would notify the current trader, MEP and distributor, and wait for five business days for the current trader to reject the switch or for the customer to change their mind. A ‘MTR switch in progress’ flag would be placed on the relevant ICP channel. This delay would allow for the ‘cooling off period’ required by the Fair Trading Act 1986 to some sales methods.

(d) On day six the registry would automatically:

(i) link the generation meter channel(s) to the generation trader

(ii) link the consumption meter channel(s) to the generation trader

(iii) send a notification to the distributor, MEP, and both traders.

(e) After receiving the notification from the registry, all participants would update their systems.

(f) The MEP would send a generation switch event meter reading, and time of reading (if intraday switching) or midnight reading to the current and new traders.

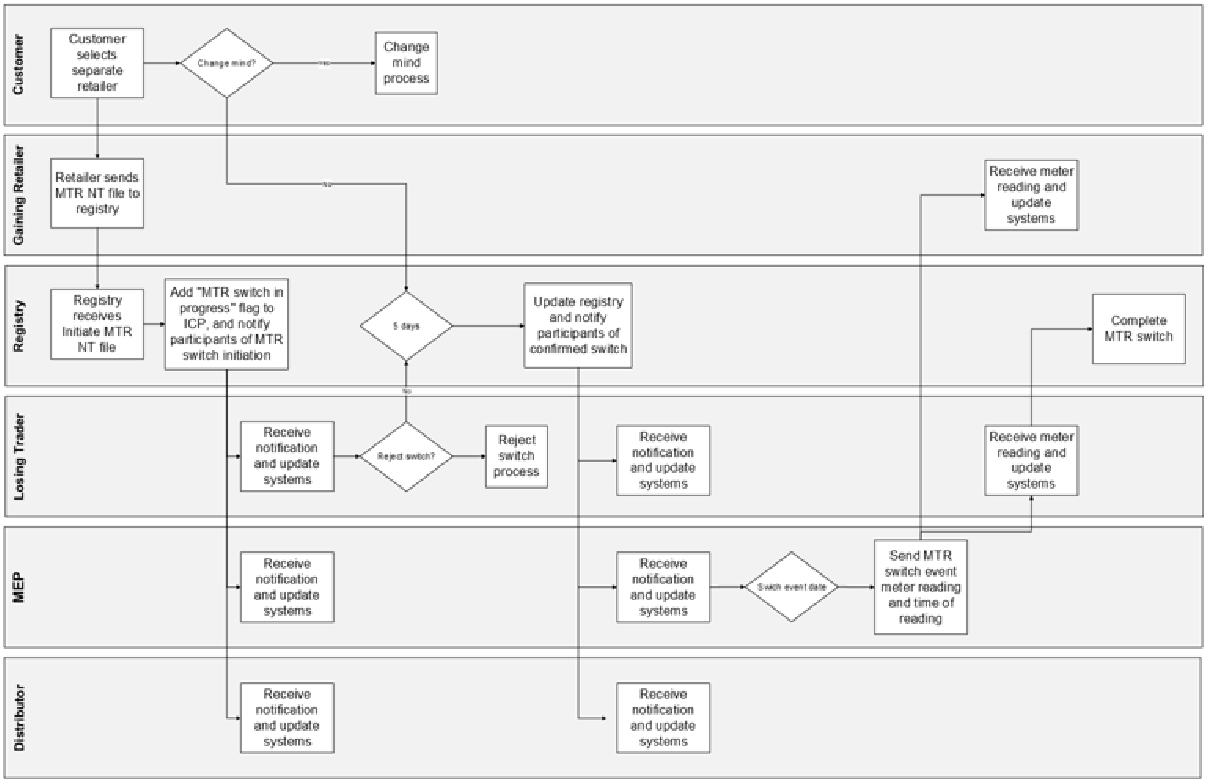
(g) The registry would automatically notify both traders.

(h) The registry would make the switch event date the date of the meter reading and completes the switch.

(i) Both traders operate the ICP as if it is a standard ICP.

Figures 2 and 3 below set out the process for a standard new MTR to be created and combined. It assumes that proposals made in the trader switching section of this paper are made. If the proposal does not proceed, the MTR process will be adjusted accordingly. We have not process mapped the alternative paths, for example where a smart meter reading is not available.

Figure 2: Initiating a multiple trading relationship



Customer switches the consumption or generation to a new trader

(j) The customer decides to select a new consumption or generation trader.

(k) Prior to accepting the customer, the new trader would be aware the ICP is an MTR ICP from the ICP setup in the registry.

(l) The trader would be required to ensure their systems can manage the MTR (including having a relationship with the other trader for physical work).

Customer decides to combine their accounts with a single trader

(m) The customer decides to combine accounts either with a new trader or one of their existing traders.

(n) The gaining trader would be aware the ICP is an MTR ICP from the ICP setup in the registry.

(o) The gaining trader would send a NT file of a new type (eg, COMBINE switch) to the registry. As future proofing for other stages, the trader should indicate which registers it wants to combine.

(p) The registry would notify the losing trader(s), MEP, and distributor and would wait five business days for the losing trader(s) to reject the switch or the customer to change their mind. In the meantime, a 'MTR combine in progress' flag would be placed on the ICP.

(q) On day six, the registry would automatically combine the ICP - the generation trader is removed, the ICP is returned to a single trader, and the generation trader information is archived and the details are available as if it was decommissioned.

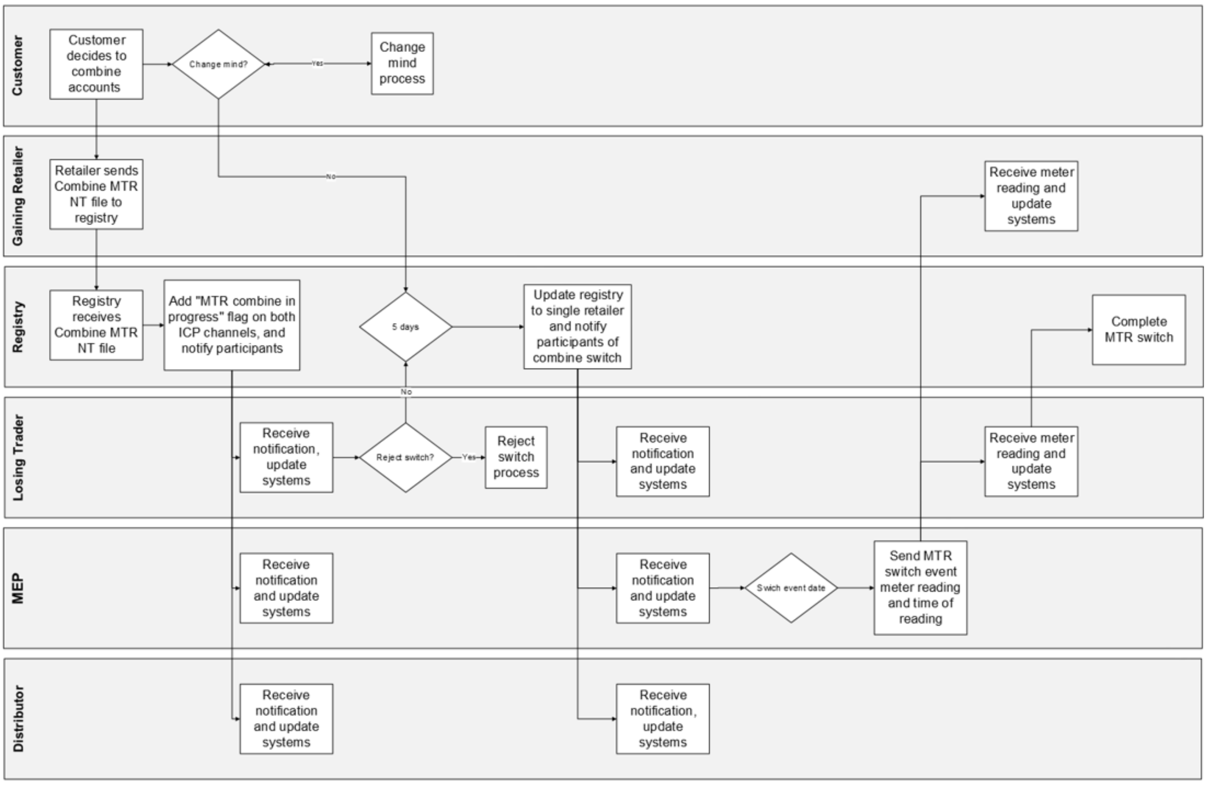
(r) The registry would notify the distributor, MEP, and losing trader(s).

(s) The distributor, MEP and losing trader(s) would update their systems.

(t) The MEP would send a generation switch event meter reading, and time of reading (if intraday switching) or midnight reading to the gaining and losing traders.

(u) The registry would make the switch event date the date of the meter reading and complete the switch. The registry notifies both traders.

Figure 3: Combining a multiple trading relationship to a single retailer



New connections that will have multiple traders

3.16. When a new ICP is created, this is done as if there was a single trader for all meter channels. In the “New” or “Ready” status, the distributor will know from the property owner’s applications if there is distributed generation and will populate the appropriate fields in the registry.

3.17. The registry manager would need to make provision for a temporary field for a new connection to allow the trader(s) to claim responsibility for ‘consumption’, and if there is distributed generation information, ‘generation’ or ‘both’ (consumption and generation). If the ICP is in “New” or “Ready” status without distributed generation, and the distributor adds distributed generation, the registry manager must add the ‘generation’ and ‘both’ temporary fields.

3.18. If the ICP is in “Inactive – new connection in progress” status, this indicates the consumption trader has already claimed responsibility for the ICP. If the distributor then adds distributed generation information, the registry manager would notify the consumption trader, and the consumption trader must manage both consumption and generation or remove its claim and the ICP would then revert back to “Ready”. This trader would nominate the MEP.

3.19. If the customer chooses a MTR after the ICP is in “Inactive – new connection in progress” status, the second trader (likely the generation) would initiate a MTR switch in the same way as if the ICP was an existing ICP.

3.20. When the metering records are advised to the registry manager, the registry would populate the appropriate trader for each meter channel from the temporary fields and then disable these fields as they are only used for new connections.

Benefits of proposed solution

3.21. The primary benefit of the proposed solution is to allow customers to have separate traders for distributed generation and consumption in order to take advantage of pricing and services that meet their needs.

3.22. The proposed solution will also set the foundations for future stages of the MTR project and allow innovative retailing and third-party reconciled energy sharing.

3.23. The proposed solution mitigates the risks and issues that could arise from multiple traders (and retailers for future MTR stages) supplying services to a property with a single metering installation and network connection.

Disadvantages of proposed solution

3.24. The primary disadvantage of the proposed solution is the cost of system changes needed in participants’ systems, the registry, and the Authority’s monitoring system.

3.25. One of the main benefits of this solution is that it sets the foundation and systems needed for future stages of MTR and would reduce the cost of implementing those stages. As this benefit would only be realised if the Authority proposes introducing these stages, and that proposal, if made, is subject to consultation, it is difficult to quantify this benefit at this stage

3.26. To assist in assessing the costs and benefits of this solution, the Authority is interested in receiving submitters details of costs and/or a high-level description of the changes that need to be made, to implement the proposed solution. Equally, the Authority is interested in receiving submitters details of the benefits either quantified, or a high-level description of the benefits.

Q3. Do you agree with the proposed solution? If not, what would you change and why?

Q4. 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?

Q5. 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?

Option 2 – Assign trader to the meter channel only for MTR ICPs

3.27. We have also considered assigning a trader to the meter channel only for MTR ICPs and an alternative option. This solution is the same as option 1 but only for any ICP that enters a multiple trading arrangement.

3.28. All ICPs that are not in a multiple trading arrangement would retain the current functionality and have the trader assigned at ICP level.

3.29. When the second trader initiates a MTR switch, the current trader will need to convert the ICP into a MTR type ICP where the trader is assigned to the meter channel. When the customer chooses to combine all channels under one trader, or moves into a (likely vacant) property that was a MTR ICP, the gaining trader would need to combine the MTR ICP and convert the ICP so the trader is assigned at ICP level.

3.30. There is a potential sub-option where once an ICP is converted into a MTR ICP, it always remains a MTR ICP even if all channels combine under one trader.

Advantage of this option

3.31. The advantage of this option is for traders that do not want to participate in MTR. The only change a trader would need to make to their system is to be able to identify a MTR ICP so that it can reject any switch or other activity that would result in the trader having a customer at channel level.

Disadvantages of this option

3.32. Traders that want to accommodate customers that have MTR in their systems would need to incorporate both the current ICP setup for non-MTR customers, and the MTR setup for their MTR customers.

3.33. Traders that do not want to accommodate MTR in their systems would need to refuse to supply a customer that wanted to participate in MTR. Where an existing customer moved into an MTR ICP, the trader would need to have a separate process (or modify its system) to combine the channels before it initiates the switch.

3.34. From a consumer’s perspective, this would reduce competition in the retail market simply because a potential trader’s system could not manage being the consumption only trader. This reduction in retail competition by mainstream consumption traders would be exacerbated if the Authority proposed implementing changes to permit the more granular stages of MTR.

3.35. Traders that subsequently decided to trade MTR ICPs would face increased software development costs and would lose the collaboration advantage of making software changes and testing those changes at the same time as other traders.

Option 3 – Create new ICP identifiers for MTR ICPs

3.36. A further option we have considered is to create new ICP identifiers for MTR ICPs. This solution is the same as is being used in the MTR trial in the Wellington region. This trial started in 2023 and is scheduled to last for five years.

3.37. When an ICP enters onto a multiple trading arrangement a second ICP identifier would be created and the data entity for the ICP would be duplicated for each ICP identifier. The metering equipment would be split so that only the relevant meter channel would appear on each ICP data entity (consumption channel(s) on the consumption ICP and generation channels on the generation ICP). No physical metering work is required.

3.38. Either a separate new ICP identifier could be created, or an additional character appended to the current ICP identifier.

3.39. When a customer chooses to combine all channels under one trader, or moves into a (likely vacant) property that was an MTR ICP, the gaining trader would need to combine the MTR ICP and decommission the unused ICP identifier and associated data entity. The surviving ICP data entity would need to have the other meter channels re-inserted so all electricity flowing into or out of the ICP is accounted for. No physical metering work is required.

3.40. The creation of the new ICP identifier, data entity and splitting of the metering channels would be done by the responsible participants (distributor for ICP identifier and data entity, MEP for metering information), or could be done by the registry manager. There are the same options (participants or registry manager) for the combining of ICPs when a MTR arrangement ends.

Advantage of this option

3.41. The advantage of this option is that existing systems functionality would largely be unchanged. A trader would need to be able to identify a MTR ICP (especially if separate ICP identifiers are used) to ensure it makes appropriate product offers to its prospective customers.

Disadvantages of this option

3.42. Extreme care would be needed to ensure prospective customers were ‘signed up’ to both ICPs. If not, the customer would risk being disconnected by the previous trader if the consumption ICP was not switched, as this ICP would appear to be vacant. If the generation ICP was not switched, the customer would not receive payment for generation exported into the grid.

3.43. If the participants perform the creation and population of the second ICP, there is an increased administration cost. There are additional costs in identifying and tagging second ICPs to ensure there is no duplication of lines charges and metering costs, and that appropriate incremental costs of managing a second ICP (if any) are charged correctly.

3.44. If the registry manager automatically performs the creation and population of the second ICP, distributors and MEPs will need processes to validate the setups, populate their systems and manage any errors and exceptions. Additionally, there would need to be an exception management process (likely manual) to deal with unusual setups that the registry manager's automation cannot deal with.

3.45. This solution becomes more unworkable if the Authority proposed implementing changes to permit the more granular stages of MTR. The number of ICP identifiers and associated data entities would exponentially increase and become more unwieldly to manage and monitor. The risk of an ICP being 'forgotten' and the electricity not being accounted for (both for the wholesale market and for the customer's invoicing) becomes exponentially higher with the more granular stages of MTR.

3.46. Reconciliation, especially unaccounted for electricity (UFE), would become inaccurate, and once errors were discovered, there would be additional administration and customer inconvenience during washups. Additionally, other traders would face financing costs for any additional UFE allocated to them and would incur a total loss once the 14-month washup period had passed and reconciliation washups were not permitted.

Comparison of preferred solution (Option 1) to alternative options

3.47. We prefer Option 1 for implementing MTR over the other options because:

(a) Option 1 mitigates all of the risks and complexities that have been identified

(b) Option 1 provides the foundation for future stages of MTR

(c) Option 2 requires traders to either cater for both channel and ICP assignment of traders or they need to develop a separate process to combine a MTR ICP before accepting the customer or refusing to accept the customer

(d) Option 3 does not mitigate the complexities identified, increases the risks of errors and omissions as higher numbers of MTR ICPs are created, and becomes more unworkable for future stages of MTR.

Q6.	Do you agree with the advantages and disadvantages of options 2 and 3? If not, why not or how would you overcome the disadvantages?
Q7.	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?

Part 2 – Switching processes

4. Proposed changes to trader switching arrangements

Benefits of these proposals

4.1. We are proposing changes that will improve customer experience when choosing a new retailer by ensuring switching processes are fit for purpose for the current and future electricity market.

4.2. The proposed changes will improve information provided to gaining traders, MEPs and distributors during the trader switch process

4.3. The proposed changes provide opportunities for participants to simplify systems, improve system and process efficiency, reduce manual interventions and workarounds, and reduce exceptions to manage and reduce compliance costs

4.4. These proposals should lead to cost savings which can be directed towards innovation and cost relief for consumers

Issues with current trader switching arrangements

4.5. There are a significant number of issues with trader switching arrangements, which can generally be grouped into constraints imposed by current configuration of the registry, inconsistent or ineffective processes, reporting inaccuracies, impractical rules for switch notifications and Code ambiguity.

4.6. The switching process in the registry requires an exchange of files between participants and the registry. These files have unique names (and codes) to identify the purpose of the file. The proposals in this section seek to change how many of these files operate.

4.7. A brief description of the current meaning and operation of these files is in the table below:

Name	Code	Current Description
Notice of transfer	NT	The gaining trader notifies it now has an arrangement with its customer. This file starts the switching process. Within this file there is a code that identifies the "switch type": TR – 'transfer', the standard switch where customer at an ICP changes retailer MI – 'move in', the customer is moving into an ICP that doesn't have a current customer (ie a 'vacant' ICP) HH – 'half hour', the new trader needs to control the switch timeframes to align with its contract with the customer. Limited to medium and large businesses

Acknowledgement	AN	The losing trader acknowledges the request, and may provide additional information to the gaining trader
Completion of switch	CS	The trader that is responsible for completing the switch sends meter readings and the switch event date
Notice of withdrawal	NW	Either trader may initiate the withdrawal of the switch. There are a number of codes that are used in the file to identify the reason for the request
Acknowledgement of withdrawal	AW	The receiving trader sends its response to the requesting trader
Request a replacement switch event meter reading	RR	The gaining trader requests the switch event meter reading based on new information it has. Usually used to replace an estimated meter reading with an actual meter reading

Registry constraints

4.8. Currently the registry locks the trader records for an ICP identifier as soon as the registry receives a gaining trader switch request, the “NT file”. This means the losing trader cannot update any of the ICP attributes in the registry (for example, if an ICP is disconnected) unless the ICP switch is withdrawn.

4.9. Where two updates occur for the same event type, on the same day, for the same ICP, the registry will only show the latest event as earlier events are replaced by more recent events. Although the registry holds the information on both updates, the first update is no longer visible and is treated by the registry as if it had not occurred.

Timing and scheduling constraints

4.10. For trader ICP switches that use the switch type ‘Transfer’ (ie TR) or “Move-In” (MI), Schedule 11.3 of the Code mandates that the losing trader completes the switch and determines the switch event date.

4.11. However, the losing trader may set a different switch event date than the one proposed by the gaining trader if the losing trader disagrees with the date on which the switch should commence, or the arrangement with the MEP for any metering equipment changes.

4.12. Additionally, the losing trader might delay the switch completion for various reasons such as discrepancies between metering records, prior invoicing beyond the proposed switch date, or agreed contract termination dates.

4.13. These constraints pose challenges for gaining traders that aim to offer new technology or advanced services. The gaining trader usually prefers the switch event date to match either the start of their arrangement with the customer (or embedded generator), or the metering reconfiguration date, which may involve meter replacement or reconfiguration.

4.14. When a customer accepts an offer from a trader, the customer may agree to specific service requirements that mean changes are needed to the metering equipment at the ICP. As traders develop new services and metering technology evolves, gaining traders may need to change MEPs if the current provider cannot (or will not) supply the required metering service.

4.15. To operate efficiently under the current Code, gaining traders need to coordinate meter changes to align with a trader ICP switch. This may not be possible because the gaining trader requires a specific MEP that is unavailable, or there are challenges coordinating meter changes on the switch event date. The need to align metering changes with an ICP switch event date is operationally inefficient. There are several implications of this issue:

(a) The MEP may not deal with the gaining trader if the registry still lists the losing trader against the ICP.

(b) The Code prevents modifying or replacing metering installations until an ICP switch is complete (as only the current trader can nominate a new MEP) and contractual arrangements between the trader and MEP may prevent this too.

(c) MEPs may be unaware of a trader ICP switch commencing.

(d) A gaining trader may be forced to start trading at an ICP with an unwanted metering configuration or MEP, especially if the switch is backdated.

(e) A MEP may change a metering configuration before a trader ICP switch is complete.

(f) A gaining trader may amend a proposed switch event date.

Inconsistent or ineffective processes

4.16. When a losing trader completes an ICP switch, the Code requires it to provide the switch event meter reading in the “CS file”[2], but only if the metering installation at the ICP has a channel recorded in the registry with an accumulator type of "C" and a settlement indicator of "Y".

4.17. There are several issues with this requirement and the current process that mean gaining traders have difficulty ensuring switch event meter readings are accurate:

(a) The gaining and losing traders may have different meter readings for the date of the ICP switch.

(b) Switch event meter readings are not allowed to have decimal places, and the Code does not specify a process for truncating or rounding to the nearest whole number. This can reduce the accuracy of the meter readings.

(c) An estimated reading may be used as the switch event meter reading even when actual data is available.

[2] Clauses 5, 10 and 11 of Schedule 11.1

(d) The MEP may not provide an accumulating channel read for the start of the day of the ICP switch.

(e) The losing trader may provide a switch event meter reading from a different meter than the one used by the gaining trader, especially if the ICP has two metering installations or the meter was changed as part of the switch.

4.18. If a trader has arranged with a MEP to access raw meter data from a metering installation, the Code requires the MEP to provide the trader with access to the MEP's services access interface within 10 business days of receiving the request from the trader[3], although this should ideally be provided as soon as practicable.

4.19. Delays in providing this data cause operational inefficiencies and if provided more than five business days after receipt of the "CS file", the gaining trader cannot require the losing trader to accept a revised switch event meter reading.

4.20. Advanced metering infrastructure (AMI) switch event meter readings are not necessarily midnight meter readings, which is the assumption under a whole-of-day operation model. Losing traders are not always using actual AMI reads (some still use estimates in line with historical practice).

4.21. MEPs are not always providing midnight reads to the correct trader due to the timing of the switch being processed in the registry, which means the losing trader ends up estimating the switch event meter reading. This means that when the actual data becomes available, there are administrative costs on the participants to correct the records. If records are not corrected, volumes are incorrectly allocated, which for small retailers, can be a material cost to their business.

4.22. The Code allows either the gaining or losing trader to withdraw an ICP switch within two months after the switch event date[4], provided both traders agree.

4.23. However, the number of withdrawals has been increasing, and several problems have been identified with the process:

(a) The two-month time limit for the trader to initiate a switch withdrawal is too short if switches are backdated more than two months or if there is a significant delay in completing the switch. This results in a new switch and off-market settlement between traders for cost differences.

(b) The switch withdrawal process is operationally inefficient and prone to errors, as some information must be exchanged directly between traders, usually via email or telephone call.

(c) The unclear switch withdrawal codes and business rules in the registry functional specification cause issues such as the wrong code can be used causing the recipient trader to decline the withdrawal.

[3] Clause 1 of Schedule 10.6

[4] Clause 17 of Schedule 11.3

(d) Not requiring the losing trader to accept an ICP withdrawal when the withdrawal is required because of an error (eg when the gaining trader has provided an incorrect ICP identifier) causes issues such as the requesting trader needing to re-initiate a withdrawal to resolve the underlying reasons causing inconvenience for the customer.

(e) Problems arise when the losing trader is unaware of a price category code change made before a switch withdrawal as the trader's information in its systems may be different, causing incorrect billing and market reconciliation. This requires manual intervention to resolve the problem when eventually discovered or when the customer complains.

4.24. When a non-half-hourly (NHH) meter reading is used for a switch event for an NHH-metered ICP, the reading is considered to apply from midnight (00:00) on the switch event date for the gaining trader. For the losing trader, it applies at midnight (24:00) on the day before the switch. This means that for the losing trader, the meter reading applies the day before it is used for reconciliation and the consumption can be allocated to the wrong day.

4.25. The Code does not cater for circumstances where a losing trader cannot provide a switch event meter reading despite its best endeavours. In rare instances, a losing trader may be unable to get a validated meter reading (eg if the meter is inaccessible or destroyed), or they may not have enough information to provide a permanent estimate (eg if the ICP was switched recently and there is insufficient historical data).

4.26. Inaccurate switch event readings can happen for various reasons. The Code allows the gaining trader in a trader ICP switch to inform the losing trader about an inaccurate switch event meter reading. The replacement read process is frequently used by traders and there are several issues at this time:

(a) The four-month time limit on the gaining trader providing replacement reads[5] is too short for some backdated ICP switches.

(b) Losing traders cannot use replacement reads for switches of the gaining trader type (ie the HH switch type).

(c) There is no materiality threshold for the gaining trader replacing a NHH switch event meter read with an AMI read within five business days, meaning the replacement read process can be used even if the new meter reading differs from the old meter reading by a fraction of a kWh.

(d) The materiality threshold for replacement reads (other than those in (c) above) may be too high.

[5] Clauses 6A(1) and 12(3) of Schedule 11.3

(e) MEPs may not provide AMI meter readings to traders within five days meaning the gaining trader cannot use the replacement read process for AMI meter readings.[6]

(f) MEPs may not provide backdated meter readings to traders for contractual or privacy reasons.

(g) The replacement read process has no clear timelines for resolving issues with erroneous meter readings.

(h) A losing trader cannot use the replacement read process if it discovers the switch event meter reading it supplied was incorrect.

4.27. Delays in updating the registry with the nominated MEP at a new ICP can cause delays in meter installation or electrical connection.

4.28. A gaining trader can only take responsibility for an ICP when the distributor marks it as "Ready" in the registry.[7]

4.29. Some distributors keep the ICP in the "New" status to prevent the trader from connecting it without their consent. This can last a long time, stopping the trader from nominating a MEP and updating the metering information. When the status finally changes to "Ready", there might not be enough time for the trader to arrange metering and connection, causing inconvenience for the customer.

4.30. Clause 10.33A of the Code prevents a trader (as a reconciliation participant) from electrically connecting an ICP that has not been electrically connected before (ie a new connection) until the distributor gives written approval, therefore there is no need for the distributor to hold an ICP in “Ready” status just to ensure the trader follows the correct process to electrically connect.

4.31. Average daily consumption for an ICP is not being calculated consistently. It is intended to reflect the average daily kWh over the last read period, which is the consumption between the last two NHH actual reads divided by the days between those reads. This method works well with manually read NHH meters. However, it does not work well when traders use only HHR information or use too short a period between reads.

Reporting inaccuracies

4.32. There is no mechanism in the registry to identify the sale and transfer of mass customer accounts (either transfer of ICPs between traders, or the internally within a trader’s system(s)), which may result from acquisitions or system changes. To record this event, traders currently use standard ICP switching processes which distorts switching statistics and inhibits effective monitoring of customer switching by the Authority.

[6] Clause 6(3)and 12(2B) of Schedule 11.3

[7] A status of “Ready” signifies the distributor is satisfied the physical connection is ready for the trader and MEP to take responsibility and perform their permitted actions, such as energisation.

Impractical rules for switch notifications

4.33. Of the three trader ICP switch types, two types including standard (TR) switches (where a customer switches retailers at an existing premises) and move-in (MI) switches (where a customer moves into a new premises) are driven by the losing trader. The third type, gaining trader (HH switches), are currently restricted to larger consuming ICPs, and the gaining trader drives the process.

4.34. When a losing trader is involved in an ICP switch, they might provide a switch acknowledgement (AN file) for TR switches, but they **must** provide one for MI and HH switches.[8] These MI and HH switches cannot be completed without the AN file first. There are some problems with the switching process for these types of switches:

(a) Not requiring an AN file for a TR switch type means the gaining trader might miss out on important details that could cause incorrect customer invoicing or other customer inconvenience.

(b) Requiring an AN file for an HH switch type is unnecessary.

4.35. Currently, different notification timeframes apply to the different retailer ICP switch processes (that is, TR, MI and HH switches) which causes confusion and rework when incorrectly applied. These timeframes range from ≤ 2 business days to ≤ 5 business days depending on the switch type and notification.

Code ambiguity

4.36. The Code is unclear about whether a switch event meter reading is needed for certain ICPs with category 3–5 metering installations. In the gaining trader switch process (HH), the gaining trader completes the switch using a switch completion (CS file). This switch type is usually for ICPs without a cumulative register, only absolute (HHR) registers, so there's no requirement to provide a switch event meter reading.

4.37. However, some of these ICPs also have category 1 or 2 metering installations, non-half hour (NHH) or advanced metering infrastructure (AMI) metering installations/components (eg, separately metered common area lighting in large office buildings). The ambiguity about providing NHH and AMI meter readings in the switch completion file for ICP switches using the HH switch type process leads to confusion and manual intervention.

4.38. The Code does not require participants to use the registry functional specification as the required file format. The Code currently refers to the "… file formats determined and published by the Authority", however the registry functional specification is approved by the Authority but published by the registry manager and contains the formats and business rules required for the registry to function correctly.

[8] Clauses 10 and 15 of Schedule 11.3

Alternative options for retailer, MEP, and distributor switching

4.39. The sections on retailer, MEP, and distributor switching below contain only a description of the Authority's preferred option, which is either the only practical solution available or was the preferred option in the Authority's 2019 Switch Process Review issues paper ('2019 Issues paper") and remains as the Authority's preferred option following consultation on that paper Switch process review - Issues and options | Our consultations | Our projects | Electricity Authority.[9] A copy of the 2019 Issues paper is attached as Appendix D to this paper.

4.40. In this paper, we have identified where the preferred option in sections 4, 5, and 6 is the only practical solution available. Where we have arrived at the preferred option in those sections following the earlier consultation, we rely on that earlier description of the options in the Switch Process Review issues paper and our responses to submissions for the purposes of the Regulatory Statement in this paper.

4.41. Where our preferred option was not fully described in the 2019 Issues paper we have noted the reasons in this paper. Where the alternative options were not identified or identified but not fully considered in the 2019 Issues paper, we have noted that and considered the alternatives in this paper.

4.42. For the MTR proposals in Section 3 above, we have evaluated alternative options and the regulatory statement at section 8 applies

Summary of proposed changes for trader switching

4.43. The issues above can be solved by amending the Code, and where relevant reconfiguring the registry to:

(a) Require the losing trader to advise the registry manager if there is a change to the attributes of an ICP when a trader ICP switch is in progress, then require the registry manager to update registry records and notify the gaining trader and other relevant participants (losing trader, MEP and distributor) of the change.

(b) If the switch has been completed (ie it is a backdated update), the losing trader's attribute change would be required only to apply for the losing trader's tenure. The current trader would need to assess the changed attributes once they receive the notification and update the attribute for their period of tenure if the data is correct.

(c) Ensure that if two trader ICP switches occur on the same day for the same ICP (ie the first switch completed before the second switch request is processed), and the second switch is subsequently withdrawn, the first (prior) switch on that day is reinstated as the current trader ICP switch.

(d) All trader events (including switch events) would be required to have a time stamp for the event in addition to the date stamp to enable the registry manager

[9] https://www.ea.govt.nz/projects/all/switch-process-review/consultation/switch-process-review-issues-and-options/

to identify which event should be reinstated. The requirement for time stamping was not explicitly identified in the 2019 Issues paper but is the mechanism by which the proposal is implemented.

(e) Require the losing trader (if completing the ICP switch) to use the gaining trader's proposed switch event date but allow losing and gaining traders to agree an alternative switch event date without the need for manual workarounds such as a full switch withdrawal.

The 2019 Issues paper did not discuss the refinement to this option of allowing both traders to agree an alternative date. This refinement does not alter the original assessment but arose during SDFG discussion of this paper. This is a practical refinement to ensure the proposal did not cause inadvertent issues where the losing trader cannot use the gaining trader's proposed switch event date, for example a disconnection meant no meter reading was available for that day but was available for the previous or next day, or access was not available on the proposed day to change a meter. To ensure the losing trader does not use this provision to subvert the intent of the obligation, both traders must agree to the change in switch event date.

(f) Clarify that a gaining MEP may change a metering installation at an ICP prior to completion of an ICP switch.

(g) Require the MEP at an ICP being switched to provide the switch event meter readings to the losing trader and the gaining trader, if the MEP is responsible for interrogating the meters (ie the services access interface is the MEPs back office[10]).

This would require the MEP to receive the switch notification files – see paragraph 5.33. When there is a MEP or meter change coincidental with the switch, each MEP would be required to supply meter readings for their meter(s). The registry manager would be required to send all notices to both MEPs.

If there is a subsequent switch withdrawal after the meter has been changed, the responsibility is on the requesting trader (after the withdrawal is processed) to ensure their system can accept the configuration. If a MEP switch is in progress, the requesting trader may need to contact the MEP to confirm the metering configuration[11].

(h) Require the trader completing the switch to use the meter reading:

(i) provided by the MEP for AMI meters; or

(i) obtained by the trader completing the switch for non-AMI meters

[10] The MEP is responsible for the meter reading if a metering installation at the ICP is category 1 or 2, and contains a channel recorded in the registry with AMI flag = "Y" and at least one channel with an accumulator type = "C"

[11] See paragraphs 4.74 and 4.79 of the Switch Process Review Issues with the ICP switching processes and possible options to address these issues Discussion paper

We note this proposal was not explicitly discussed in the 2019 Issues paper. The requirement to use the provided meter reading is implicit in the options discussed in the 2019 Issues paper at paragraph 4.311 to allow estimates in limited circumstances, and paragraph 4.267 to require the use of midnight switch event meter readings from AMI meters. This proposal also reduces the need for the replacement read process arising from some traders' preference to use an estimated reading even if actual meter readings are available as discussed at paragraph 4.233(d) of the 2019 Issues paper.

There is no practical alternative to this proposal that meets the objective of increasing the accuracy of metering and switching information as described below in paragraph 8.10 of this paper.

(i) Only allow the trader completing the switch to provide an estimated switch event meter reading when despite best endeavours a validated reading cannot be obtained or a permanent estimate created.

(j) Standardise switch event meter readings to be the actual read up to two decimal places.

(k) Require initiation of delivery of a switch completion file, including switch event meter readings by the latter of either, the receipt of the NT file from the registry, or the switch event date.

(l) Allow the provision of AN files for the HH (gaining trader driven) switch type to be optional.

(m) Allow a trader ICP switch to be withdrawn at any time prior to the 14-month reconciliation revision cycle for the month in which the switch event date falls.

(n) Require response codes for AN files to use the relative priorities specified in the functional specification to ensure the most relevant response is selected.

(o) Amend the registry functional specification to clarify the use of withdrawal codes.

(p) Require a trader to accept a switch withdrawal request within five business days of the switch withdrawal (NW file) date, but only under specified circumstances; if the requesting trader uses the reasons "invalid ICP status" (IN), "metering issue" (MI) "wrong premises" (WP), or "losing trader not current trader" (WR), "temporary withdrawal code" (MG), "customer error" (CE), "customer cancellation" (CX), or "trader default" (TD). We note the 2019 Issues paper only includes some examples of the circumstances that would trigger this obligation. The proposal above lists all the circumstances that would trigger the obligation on the trader to accept a switch withdrawal request.

(q) Require the registry manager to send an automated notification to a losing trader if a completed trader ICP switch is withdrawn and the current registry information for the ICP is different from what it was when the switch was first completed.

(r) Require all non-AMI meter readings to be time stamped at 00:00 hours on the day of the meter reading/switch event regardless of what time of the day they were actually taken.

(s) Permit either trader to use the RR process to correct inaccurate switch event readings, and permit multiple replacement reads for an ICP up to four months after the switch completion file (CS file) was delivered. Currently, only the gaining trader may use the RR process, and it must be within four months of the switch event date. This proposal extends the provision to both retailers, and the four months starts from the CS file delivery, meaning switches backdated more than four months can still use the RR process if necessary.[12]

(t) Require a trader to respond to an RR request within five business days to remove the need for requesting traders to manually follow up on requests.

(u) Lower the threshold for starting the RR process to ±50kWh per channel and set a threshold of ±1kWh for replacing a NHH switch event meter read with an AMI read within five business days. Implementing other proposed solutions to use actual midnight reads for switches should reduce the need for the RR process.

We note the proposed threshold of ±1kWh for replacing a NHH switch event meter reading was discussed in the 2019 Issue paper. The issue of the threshold for general use of the RR process being too high (at 200kWh) was discussed but there was no proposed level for a changed threshold. We have proposed the threshold be reduced from 200kWh to 50kWh. This value represents approximately 2½ days average household consumption (at ~8000kWh/year) and reduces the inaccuracies for customer billing and wholesale market reconciliation by 75%. We welcome submitters' feedback on this proposed threshold, with supporting reasons if you prefer a different value.

(v) Allow a trader to carry out the initial assignment of an ICP identifier that is in the "New" status. In carrying out this assignment, the trader would be required to move the ICP status from "New" to "Inactive" with a status reason code of "New connection in progress" and would only be permitted to request electrical connection if the distributor is satisfied the property is physically ready to electrically connect.

(w) Require traders to provide the average daily consumption value if the registry metering records include a channel with accumulator type = "C" and settlement indicator = "Y". The average daily consumption would need to be calculated for at least 30 days of actual consumption, or the full period of tenure with the trader if there have been less than 30 days of actual consumption, or use the average daily consumption from the previous retailer if the full period of tenure with the trader is less than 30 days and two meter readings are not available.[13]

(x) Require the gaining trader to use a different switch type code in the switch request (NT file) that indicates that it is the result of a mass customer acquisition or system transfer to distinguish it from standard retailer ICP switch events.

(y) Permit AN files to be optional for HH (gaining trader driven) switch types.

[12] See para 4.199 of the Switch Process Review Issues with the ICP switching processes and possible options to address these issues Discussion paper

[13] See para 4.315 of the Switch Process Review Issues with the ICP switching processes and possible options to address these issues Discussion paper

(z) If an AN file is provided, require the sender to use the relative priorities specified in the functional specification for the response code, to ensure the most relevant response is selected.

(aa) Align timeframes for notifications and acknowledgements to ≤ 2 business days across retailer switching activity regardless of switch type (that is TR, MI or HH switch types).

We note the 2019 issues paper did not propose an actual timeframe. We are now proposing 2 business days as 2 business days is already the timeframe for two of the three notifications. Reducing the third notification from 3 business days and reducing the acknowledgements from 3 and 5 business days is appropriate as automation and modern software systems, including significant improvements to the registry processing response times, means these files are often sent the same day. Two business days also allows time if there are issues or exceptions that need to be managed.

(bb) Require the gaining trader in HH switch type processes to provide switch event meter readings in the switch completion (CS file), if the registry metering records include a channel with accumulator type = C and settlement indicator = "Y" to reduce confusion over when to provide a switch event meter read for an ICP with a mix of absolute register only and cumulative register metering components.

(cc) Amend the Code to explicitly note the registry functional specification as a required file format for all of Part 11.

Additional detail of changes to arrangements for trader switching

Allow losing and gaining traders to agree an alternative switch date

4.44. The following change is proposed to enable losing and gaining traders to agree an alternative switch date:

(a) The losing trader may propose a revised switch date and reason in the AN file.

(b) If this is accepted by the gaining trader, it would become the switch event date.

(c) If it is not accepted by the gaining trader, then the gaining trader would be required to:

(i) send a response file with a further revised switch event date, or

(ii) send a rejection of the losing trader's revised switch date, including a valid reason for the rejection in the response file (which means the original proposed date would stand).

(d) Traders would be under an obligation not to unreasonably reject a proposed or revised switch date.

4.45. This proposed change may require the MEP to assess a metering installation or configuration change before a switch date is set by the gaining trader and complete the meter change in line with that date.

MEP to provide one of more switch event meter readings to both traders

4.46. If a metering installation at the ICP is category 1 or 2 and contains a channel recorded in the registry with an AMI flag = "Y", and at least one channel with an accumulator type = "C", then the following proposed process would apply:

(a) When the trader sends a switch request (NT file), the registry manager would be required to copy the NT file to the MEP. An updated file with an agreed change in switch event date would also be sent to the MEP.

(b) The MEP would be required to provide an actual meter reading for each cumulative meter register as at midnight. If the MEP cannot provide the readings within the required time, it would be required to provide a "not available" response. Meter readings can be provided after the switch event date as long as it is within the trader's timeframe for providing a CS file. If a meter reading is provided after the CS file has been sent to the registry, the relevant trader would be required to use the replacement read (RR) process to update the estimate with the actual reading.

(c) For non-AMI metering, the current process requiring the trader to collect a meter reading or supply an estimate would continue to apply.

(d) The CS file would be amended to contain an additional field to indicate if the meter reading is actual or estimated.

4.47. If the change proposed under section 5.30 is accepted, to include additional flags for communication status in the registry, the MEP would only be required to provide switch event meter readings if the meter is communicating (that is, with a status of "full or "intermittent").

Require response codes to use the relative priorities specified in the registry functional specification

4.48. The following table sets out the proposed priority of response codes for AN files within the registry functional specification:

Code	Priority	Description	Explanation of use
AA	1	Acknowledge and accept	Switch is accepted; there are no relevant issues. Only to be used if no other code applies.
CO	2	Contracted customer	Alerts that this customer has a fixed-term contract at the ICP. The current trader may be contacting this customer relevant to the switch.
MP	3	Metering is pre-paid	Alerts that a meter installed at the ICP is configured as pre-paid. Note: this includes legacy pre-paid metering (which will be flagged on the registry) as well as AMI pre-paid metering (which will not be flagged on the registry).
MU	4	Unmetered supply	Alerts that supply is unmetered.

OC	5	Occupied premises	Advises that existing customer has not yet advised the losing trader that they are moving out. The premises are occupied. Only applicable to MI switch type
PD	6	Premises electrically disconnected	Alerts that the status of the ICP is electrically disconnected while the registry has recorded that the ICP is electrically connected
AD	7	Physical metering differs	Alerts that the meter either installed, or in the process of being installed, differs from that shown in the registry
CP	8	Contracted customer and premises electrically disconnected (new code)	Alerts that: i. this customer has a fixed-term contract at the ICP. The current trader may be contacting this customer relative to this switch, and ii. the status of the ICP is electrically disconnected while the registry has recorded that the ICP is electrically connected.

4.49. The relevant code with the highest numerical value would be required (eg, if codes 1, 3 and 7 are relevant to the ICP, then 7 must be supplied).

Align timeframes across switching activity

4.50. The following timeframes and statuses (either mandatory (M), optional (O), or not required (NR)) would apply for switch process notifications:

Switch notice	Standard switch process (TR), (BT) and (BI)		Move-in switch process (MI)		Gaining trader switch process (HH)	
	Status	**Time**	**Status**	**Time**	**Status**	**Time**
Gaining trader notifies registry manager of switch (NT)	M	2 business days after arrangement is effective with customer	M	2 business days after arrangement is effective with customer	M	2 business days after arrangement is effective with customer
Trader acknowledges switch (AN)	O	2 business days after receipt of NT	O	2 business days after receipt of NT	NR	

Losing trader completes switch (CS)	M	100% of all meter types on the specified event date where a date is specified, and if no date specified, 100% of non-AMI within 3 business days after switch event date, and AMI within 1 business day	M	100% on the specified event date or 1 business day after the NT file sent to the losing trader if no specified event date	M	3 business days after the switch event date

4.51. For the CS file, the Code would be amended to provide that in exceptional circumstances, where responsible traders are unable to provide the file within three business days, for reasons outside of their control, they must use best endeavours to provide the file as soon as practicable. Compliance with this requirement will be included in the participant's audit.

Require acceptance of a switch withdrawal request

4.52. Some switch withdrawals would need to be accepted in accordance with the following table:

Code	Description	Explanation of use	Acceptance mandatory?
IN	Invalid ICP Status	This code can only be used if the ICP is in the process of being decommissioned.	Mandatory if withdrawal requested by losing trader
UA	Unauthorised switch	This code can only be used for a TR or HH switch and the account holder did not authorise the switch.	Discretionary
WS	Wrong switch type	This code can only be used where the gaining trader may have used the wrong switch type in the NT file.	Discretionary
MI	Withdrawn on metering issue	The gaining trader must assess and address the current (existing) metering and MEP capability before sending the NT file.	Mandatory if withdrawal requested by gaining trader

		This code can only be used if the metering cannot be upgraded by the MEP to suit the gaining traders pricing offer.	
WP	Wrong premises	This code can only be used where the wrong ICP identifier has or is being switched due to the gaining trader or distributor address error	Mandatory if withdrawal requested by gaining trader
DF	Date failed	This code can only be used if the requested switch event date (RTD) greater than 10 business days in the future.	Discretionary
WR	Losing Trader not current Trader	This code can only be used if the ICP identifier is in the switch process to another gaining retailer.	Discretionary
MG	Temporary withdrawal code	This code can only be used if the Electricity Authority authorised its use for mass transition of ICP identifiers, to indicate that the switch was withdrawn due to transition requirements.	Mandatory if part of a transition process
CE	Customer error	This code can only be used if the customer cancels the switch because the original switch request was an error (eg customer provides incorrect information).	Mandatory if withdrawal requested by gaining trader
CX	Customer cancellation	This code can only be used if the customer cancels the switch for a reason other than that in CE (eg the customer changes their mind)	Mandatory if withdrawal requested by gaining trader
TD	Trader Default	This code can only be used if authorised by the Electricity Authority where a trader is in a situation of default. Reserved for system use.	Mandatory if authorised by the Electricity Authority

Require all ICP switch communications between traders to be recorded in the registry

4.53. The following solution is proposed to give effect to this change:

(a) The format of switch withdrawal and acceptance files would be changed to create additional text fields (with 1,000-character limits).

(b) Traders would be permitted to provide multiple switch withdrawal notifications and acceptance files, where the gaining trader is responding to queries and requests for information from the losing trader.

Traders to provide the average daily consumption value for all NHH and HHR accumulating register reads

4.54. If the registry metering records include a channel with an accumulator type = "C" and settlement indicator "Y", traders would be required to determine the average daily consumption value for a NHH accumulating register read:

(a) using two actual NHH meter reads that are a minimum of 30 days apart as close to the switch event date as possible; or

(b) using aggregated HHR meter readings over the 30-day period immediately prior to the switch event date; or

(c) for an ICP that has been with the trader for less than 30 days, using the information available to the trader for the ICP, and if no meter reads are available, use an estimate based on the average daily consumption from the CS file when the trader gained the ICP.

Benefits of proposed solutions for trader switching

4.55. The proposed solutions will provide benefits to participants involved in a retailer switch, including:

(a) reducing participant compliance costs

(b) improving information provided to gaining traders, MEPs and distributors during the ICP switch process

(c) improving a gaining trader's ability to install the technology needed to deliver contracted services

(d) improving customer experience by ensuring gaining traders can provide services from the agreed start date

(e) improving system and process efficiency, specifically:

(i) removing the need for losing traders and gaining traders to make short-term system changes to accommodate MEP or metering installation changes before or after an ICP switch

(ii) reducing or removing the need for switch event meter replacement read (RR) process for AMI metering

(iii) standardising timeframes for notifications to reduce costs associated with automating retailer ICP switching processes

(iv) replacing several manual and inefficient file exchanges with a single, semi-automated process and reducing the risk of switch withdrawal requests being missed by the losing trader

(v) reducing time taken by traders to resolve incorrect ICP switches

(vi) removing manual intervention and complexity caused by different timeframes for applying a meter reading in relation to an NHH ICP switch

(vii) removing manual workarounds during HH switch type processes for ICPs with a mix of absolute register only and cumulative register metering

(viii) reducing manual workarounds and transaction costs in relation to replacement reads components

(ix) allowing traders to set up back-office systems for a new ICP prior to the ICP being electrically connected

(f) improving the accuracy of meter readings as all switch event meter readings will be midnight readings (unless a meter change is part of the switch) and all will be actual readings to two decimal places and will be aligned to registry events

(g) improving timely access to switch event meter readings, including access to estimated meter readings where validated meter readings or permanent estimates cannot be provided despite best endeavours by the trader

(h) increasing standardisation of meter reading provision by requiring MEPs to provide readings where available, and where not available enabling the relevant trader to provide an actual meter reading for the switch event

(i) removing the requirement for losing traders to provide a completion of switch (CS) file before a future dated switch event is completed

(j) improving accuracy of electricity allocated to gaining and losing traders at the switched ICP

(k) reducing the need for off-market settlements to correct erroneous trader ICP switches

(l) reducing the risks of a trader applying the wrong charges to customer invoices after an ICP switch has been withdrawn

(m) improving consumption estimates on customer invoicing and submission information provided to the reconciliation manager

(n) enabling improved monitoring of MEP performance in delivering switch event meter readings

(o) reducing the number of trader breaches by reducing confusion and making it easier to understand, and comply with the Code

(p) improving accuracy of reporting and the effective monitoring of customer switching between traders, without the need for manual data validation, and

(q) reducing incidence of disputes between participants over switching timeframes.

Q8. Should the provision of the average daily consumption remain mandatory, or should it be optional? If optional, please explain why?

Q9. 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?

Q10.	Do you agree with the proposed solutions? If not, what would you change and why?
Q11.	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?
Q12.	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?

5. Proposed changes to metering equipment provider switching arrangements

Benefits of these proposals

5.1. We are proposing changes that will improve customer experience by giving traders better metering information to inform customer offers and reduce poor customer experience when the actual metering does not support the offer made.

5.2. The proposed changes will result in more accurate metering records and customer invoicing.

5.3. The proposed changes increase the transparency of metering equipment providers switches and reduce rework and correction of incorrect data resulting from issues with the change of meters and metering equipment providers.

5.4. The proposed changes provide opportunities for participants to improve system and process efficiency, reduce manual interventions and workarounds, and reduce exceptions to manage and reduce compliance costs.

Issues with current meter equipment provider switching arrangements

5.5. Issues with the current MEP switching process are broadly related to:

(a) constraints imposed by current configuration and functionality of the registry

(b) inconsistent meter reading file formats across MEPs

(c) untimely access to accurate metering records, which occurs for a range of reasons.

Registry constraints

5.6. Data within the registry is currently grouped by “event” under each ICP. When one field in the event changes, the registry requires all fields to be updated. To manage this, when the registry receives an update to data within an event (eg a switch of MEP at an ICP), it ends the previous event and creates a new event that is effective from that point forward.

5.7. The registry is currently configured to hold only one event per day: if multiple event changes are submitted by the **same** participant, each event is recorded in the registry and the last event’s data is used in reports and summaries.

5.8. If event changes are submitted by **different** participants on the same day, one of the submissions is rejected or overwritten by the registry. This means the participant is required to use an inaccurate event date. In practice for MEP switches this means the gaining and losing MEP cannot use the same MEP event date for a MEP switch meaning metering records do not reflect the physical metering.

5.9. Currently the registry metering records do not allow for differentiation of metering type beyond a flag for advanced metering infrastructure (AMI) and some additional implied fields that are created by business rules using other data.

5.10. AMI capability differs across meters ranging from full, regular two-way communications to intermittent, unavailable or no capability for two-way communication. AMI meters are read by the MEP. In the commercial and industrial sector, half-hour (HHR) metering can be read by anyone with authorised access and usually has no accumulating registers. Certain meter types are required to enable specialised offers to customers, so retailers need accurate data about the meter type to understand what services can be offered, in advance of contracting a customer.

5.11. In the registry at present, a MEP's responsibility for the metering at an ICP (regardless of who owns the physical metering equipment) is denoted by a MEP participant identifier. To update an MEP participant identifier against an ICP:

(a) the ICP's trader, as recorded in the registry, must notify the registry of the nomination of a new MEP, and

(b) the new MEP must accept the nomination then upload new metering records.

5.12. We note the above issue was phrased differently in the 2019 Issues paper. This issue is described in "Issue 29: Gaining MEP unable to accept notification and update registry metering records" in the 2019 paper. There is no practical alternative to this proposal that meets the objective of increasing the accuracy of metering and switching information as described below in paragraph 8.10 of this paper.

5.13. Many MEPs have more than one participant identifier (due to mergers, acquisitions, or deliberate meter fleet segmentation). If a MEP wishes to transfer metering from one participant identifier to another, it cannot do this directly. The standard process for updating a participant identifier applies, even if the metering is not changing. This creates unnecessary work for traders and MEPs, particularly when bulk changes to MEP participant identifiers are required.

Inconsistent meter reading file formats

5.14. Where only a MEP can read a meter (for example an AMI meter), the MEP provides the meter reading information to the trader in accordance with the agreement between them. This format may differ between MEPs requiring traders to create interfaces/translations to standardise the data across MEPs within their systems, creating operational inefficiencies, increased risk of error and barriers to entry for new retailers. These factors contribute to reduced competition and innovation in the market. Currently, the Code does not regulate the format of this information.

5.15. Following feedback from the SDFG that the file formats are now well embedded in participants systems, the Authority has decided not to require a standardised file format for meter readings. The Authority will monitor the MEPs' use of different file formats and may consult on standardisation in the future, if increased differences in file formats present a barrier to entry for new retailers.

5.16. The Authority encourages MEPs to work together to ensure differences in file formats are minimised, and a retailer or MEPs' competitive advances and products can be accommodated easily without major disruption to non-participating retailers. However, participants must take care to work constructively to ensure MEPs can operate efficiently, but without limiting competition in any way, to ensure compliance with the Commerce Act 1986, enforced by the Commerce Commission.

Untimely access to accurate metering records

5.17. The provision of initial metering data by MEPs to gaining traders is not always timely, which results in operational inefficiencies such as needing reverse customer invoices once accurate data is provided.

5.18. Additionally, MEPs do not always deliver backdated meter readings (where meter readings had been missing at the time of regular data delivery). A contributing factor to the delays in providing this data is that MEPs do not currently receive advance notice of a trader ICP switch.

5.19. The time taken by MEPs to update registry metering records affects ICP switching. The Code specifies maximum timeframes of 15 business days for a gaining MEP, or 10 business days for an existing MEP, to update changes to registry metering records.

5.20. However, the Authority expects MEPs to update these records as soon as new or changed information is available. Although in most cases metering records are updated in a timely manner, in cases where updates are delayed, this can result in delays to trader ICP switching, customer invoicing errors, or market settlement errors.

5.21. When an ICP is decommissioned, it appears that most MEPs do not remove the metering record from the registry. This may be caused by current registry functionality that locks the record once the status is changed to ‘decommissioned’. In rare cases, an ICP may have been decommissioned in error, and a distributor would then reinstate the ICP by removing its decommissioned status in the registry.

5.22. However, the MEP may have removed metering components from the installation, meaning the meter is no longer functional or safe for electrical connection.

5.23. In these cases, unless the MEP has updated registry metering records with a removal event, the registry will incorrectly show a functional and safe metering installation is in place. This means a trader, relying on these inaccurate records could have the ICP electrically connected (if necessary) and commence trading, creating electrical safety risks and operational inefficiencies.

5.24. While this risk is mitigated to some extent by the requirement on the registry manager to notify the MEP when a decommissioning event is reversed, delays in processing this status change to update registry metering records give time for the issue to arise.

5.25. Currently some traders do not nominate the MEP at an ICP until they receive paper copies of metering records for new metering that has been installed by the gaining MEP. This nomination can be 10 business days, and in some cases significantly longer, after the new metering has been installed, preventing the gaining MEP from updating registry metering records for the ICP.

5.26. Where a trader does nominate a MEP, the Code requires MEPs to respond to the notification within a maximum timeframe of 10 business days if they accept the nomination, and there is no obligation to respond if they decline the nomination. Some MEPs do not accept the nomination until they are sure they can install (or have installed) the new metering, and some MEPs do not decline the nomination if they cannot install the metering.

5.27. A losing MEP is still recorded as being the responsible MEP for an ICP in the registry during this period. If the losing MEP updates metering records, the presence of the metering event prevents the gaining MEP from taking over responsibility for providing metering services at the ICP on the MEP ICP switch date, unless the losing MEP reverses their event. This constraint has significant consequences, namely:

(a) The losing MEP incorrectly retains responsibility under the Code for the accuracy of metering records for the ICP, certification of the metering installation, and delivery of meter readings for an AMI meter.

(b) The ICP's metering records in the registry are incorrect which may lead a prospective retailer to make an incorrect decision about acquiring the customer at the ICP, and in extreme cases mean they are unable to provide contracted services to a customer without a further meter change (often at the customer's cost).

We note this issue was phrased differently in the 2019 Switch Process Review paper. This issue is one of the consequences from "Issue 28: The time taken by some MEPs to update registry metering records affects ICP switching" in the 2019 paper. There is no practical alternative to this proposal that meets the objective of increasing the accuracy of metering and switching information as described below in paragraph 8.10 of this paper.

(c) The ICP could switch to another trader before the losing trader has notified the registry manager of the new MEP participant identifier. Once the trader ICP switch occurs, the losing trader is unable to notify the registry manager of the change in MEP. While there are two workarounds available currently to overcome this constraint, they are manual and time consuming.

(d) The trader ICP switch process may not work for the ICP because the meter readings sent in the switch completion file (ie the "CS file") do not match the registry's metering records for the ICP.

Summary of proposed changes for MEP switching

5.28. The issues above can be solved by amending the Code and the registry to:

(a) Allow both a gaining MEP and a losing MEP to populate a separate meter event for the same day provided each MEP event has a time stamp in addition to the date.

(b) Create new fields with associated business rules to identify specific meter types and communication capability/status, linked to the meter component level, with a business rule driven summary at ICP level.

(c) Permit a change of MEP participant identifier when both participant identifiers belong to the same MEP, allowing MEPs to manage these changes directly (without trader involvement) and without changing the metering records.

(d) Require the registry manager to provide MEPs with additional notifications including gaining trader ICP switch requests (NT file), losing trader switch acknowledgements (AN file), and switch withdrawals (AW file), and ensuring the notifications contain both the losing and gaining trader identifiers.

(e) Require MEPs to provide gaining traders with access to the services access interface and meter readings within specific timeframes.

(f) Require MEPs to supply both gaining and losing traders with meter readings for the switch event date, and then to gaining traders going forward. We note in the 2019 Issues paper, we only proposed requiring provision of meter readings to the gaining trader. Expanding the proposal to include the losing trader is to align with the proposal in the Trader Section of this paper where we are proposing the MEP supplies the switch event meter reading to the losing trader (see paragraph 4.43(g) above). We have expanded the proposal in this section to include the losing trader for completeness and alignment with the earlier proposal.

(g) Require MEPs to supply relevant traders with revised meter readings or backfilled meter readings (ie readings from a metering installation interrogated by the MEP which were not previously delivered to the relevant trader).

(h) Place obligations on traders to notify the registry manager of a MEP nomination, and on MEPs to accept the nomination on or before the date the metering is installed or decline the nomination if the metering cannot be installed. This would be supported by a registry enhancement to automatically decline unaccepted MEP nominations in specified timeframes, and a new obligation on traders and MEPs to include this requirement in the trader's and MEPs audits.

(i) Require MEPs to populate new or amended registry metering events for ICPs for 75% within five business days of the metering installation being certified/modified, or from when the ICPs status changes to "active" and 100% within 10 business days. These percentages are to be calculated over any 12-month period. As some delays are outside the control of the metering equipment provider, provision for these delays will reduce compliance costs. For clarity, the MEP has control of the performance of their agents (eg contractors and technicians), and the certifying ATH through the terms of their arrangements. Compliance with this requirement will be included in the MEP's audit.

(j) Require MEPs to populate metering component removal events in the registry whether the ICP is decommissioned or not, and ensure the registry can be updated once the status has been changed to decommissioned if the metering components have been removed before decommissioning.

(k) Ensure the registry automatically end-dates the metering certification when a distributor changes an ICP identifier's status to "decommissioned", and in the event it was decommissioned in error, automatically reinstate the original expiry date of the metering certification. If the metering equipment has been removed the registry will automatically notify the MEP of the reinstatement.

Additional detail of changes to arrangements for MEP switching

Allow gaining and losing MEPs to populate metering events for same day

5.29. The Code would be amended, and the registry reconfigured to allow both a losing MEP and a gaining MEP to populate a separate meter event for the same day (intra-day operation). Registry functionality would be amended to ensure the removed meter/losing MEP event is inserted before the installed meter/gaining MEP event. Time stamps would also be required for new metering installations, so participants are aware of the start time for meter readings.

Create new registry fields for meter types

5.30. The Code would be amended, and registry reconfigured, to include new fields to identify more specific information about meter types, capability and status. The registry would allow more than one "metering type" for a metering installation, if there is more than one metering component installed. These codes would be linked to the meter component level, with a summary at the ICP level. Proposed new registry fields are as set out in the following table:

Field name	Field options	Field description
Communication status	Local	Meter must be interrogated at site, for example, manual channel (register) read, drive-by or opto-port
	Full	Full remote two-way communications
	Intermittent	Remote communications available at least once during the maximum interrogation cycle but not daily. One of the four below options must be selected: I7 communication expected once per week or less I14 communication expected once per fortnight or less IM communication expected once per month or less I communication period unknown or erratic but at least once during the maximum interrogation cycle
	Temporarily unavailable	MEP investigating communications issues
	Unavailable	No communications, for example a communications provider issue, or communications module removed
Metering type	C&I	Commercial & Industrial meter. A HHR metering installation that does not incorporate a smart meter, and does not require back office infrastructure. Usually incorporates kVAh or kVArh measurement, and may include a cumulative kWh register C&I meters may be locally or remotely read as indicated by the communication status.

	AMI	Smart meter plus communications capability (as indicated by the communication status field) only the MEP can do the interrogation
	Non-AMI	All other metering installations that do not contain AMI or C&I meters. Despite being non-AMI, the meters may still be locally or remotely read as indicated by the communication status

5.31. The services access interface for:

(a) AMI meters with a communication status of full, intermittent and temporarily unavailable is the MEP's back office, and the MEP is responsible for meter interrogation

(b) non-AMI meters is the meter register, and the trader is responsible for meter interrogation

(c) C&I meters is determined by the MEP and ATH depending on communication status and who is given the access passwords.

MEP participant identifier changes when both belong to the MEP

5.32. The Code would be amended, and the registry configured to allow a MEP to update a MEP participant identifier against an ICP in the registry, if both identifiers belong to that MEP. When a MEP changes a MEP participant identifier, the registry will automatically notify relevant retailers and distributors of the change.

Registry manager to provide additional notifications to MEPs

5.33. The Code would be amended, and the registry configured, to allow MEPs to subscribe to the following automated notifications to enable them to begin preparing for a new trader at the ICP being switched and to send switch event meter readings to both traders (this is also a solution for the retailer switching issues: see paragraph 4.43(g)). The notification files would contain the identifiers for both the losing and gaining traders:

Notification name	Notification description	Notification timeframe
NT file	Gaining trader makes ICP switch request	On receipt of NT file
AN file	Losing trader acknowledges ICP switch request	On receipt of AN file
AW file	Switch withdrawal is accepted	On receipt of AW file

5.34. There is no change to the current Code requirement to provide the CS file (completion of switch) to the MEP.

Q13. Are there any other files that should be added to this list?

Timeframes for MEPs to provide service access interface and meter readings

5.35. The Code would be amended to require MEPs to provide gaining traders with access to the services access interface and meter readings as soon as practicable, but no later than (measured over a rolling 12 month period):

No. of calendar days from the date the registry manager sends switch completion notification	Service level: Percentage of switch meter readings
4	95%
6	96-99%
10	100%

5.36. The Code would be amended to provide for exceptional circumstances so that where a trader cannot be provided with access by the MEP within 10 days, through no fault of the MEP, the MEP must use best endeavours to enable access as soon as practicable after the 10th day. Compliance with this requirement would be included in the MEP's audit.

Obligations on traders and MEPs for MEP nominations

5.37. Details of the changes to the rights and obligations for MEPs, traders and the registry manager in the proposed solution are set out in the following table:

Right or obligation	Participant	Timeframes
Notify the registry manager of a request for a MEP to install or modify a metering installation at the ICP subject to the trader ICP switch	Trader	On or before the date the trader provides a service request to the gaining MEP
Accept or decline the trader's MEP nomination	Gaining / existing MEP	On or before the date that metering equipment is installed or modified
Automatically decline unaccepted trader MEP nomination	Registry manager	After 11 business days if nomination is not accepted

Automatically decline accepted trader MEP nomination	Registry manager	After 3 months if nomination is accepted by MEP but registry metering records not updated by MEP
Scope of audits to include compliance with the MEP nomination and accept/decline obligations	Traders and MEPs	During the participant’s audit

Benefits of proposed solutions for MEP switching

5.38. The proposed solutions will provide benefits to participants involved in a MEP switch, and to potential participants, including:

(a) more accurate metering records, including metering data and metering equipment installations, leading to safety, efficiency and customer experience improvements, and more accurate customer invoicing, wholesale electricity market settlement and lines charge settlement

(b) greater transparency and automation in the MEP switching process, leading to greater efficiency

(c) enhanced ability for participants to meet their obligations under the Code.

Q14. Do you agree with the proposed solutions? If not, what would you change and why?
Q15. 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?
Q16. 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?

6. Proposed changes to distributor switching arrangements

Benefits of these proposals

6.1. We are proposing changes that will improve customer experience by improving operational efficiency and transparency for traders of customers involved in a distributor switch.

6.2. The proposed changes will increase the transparency and accuracy of information about the network and distributor switching process.

6.3. The proposed changes will reduce the cost of the Authority manually processing distributor switches.

6.4. The proposed changes provide opportunities for participants to improve system and process efficiency, reduce manual interventions to manage and reduce compliance costs.

Issues with current distributor switching arrangements

6.5. Several opportunities exist to improve arrangements for switching ICPs between distributors to make switches more operationally efficient.

6.6. The current process is manual, meaning that transactions between participants are not supported by automated workflows, or accurate and transparent information about the switch process or the network. For example:

(a) If a distributor switch is pending, and a gaining trader switches an ICP, the gaining trader may find itself in breach of the Code. This would happen if the gaining trader did not have an arrangement with the gaining distributor for line function services in relation to the ICP. The gaining trader may also end up having contractual issues with its customer, as it would not have agreed network pricing for the ICP with the gaining distributor.

(b) This situation would need to be addressed through a number of manual corrective actions and creates a possibility that a consumer's bad switching experience may discourage them from seeking out the best electricity deal in the future, which dampens competitive pressure in the retail electricity market.

(c) A losing distributor has limited visibility of ICPs that are to be switched to another distributor and could be unaware of which ICPs are proposed to be switched and any changes made to the proposed switch dates. A gaining distributor could also incorrectly identify which ICPs are to be switched, which could leave the losing distributor with the responsibility to maintain an ICP identifier in the registry that is no longer connected to its network.

(d) The trader responsible for that ICP could also be unaware that the ICP should have been switched to another network and, on finding out about this, would face the inefficiencies described in subparagraph (a).

(e) The Code requires a gaining distributor to obtain the consent of the traders responsible for the ICPs that are subject to a proposed distributor ICP switch.

Operational inefficiencies can arise when, for example, gaining traders refuse to consent to the distributor ICP switch, which may be underway but not yet completed, or if a pending distributor ICP switch has to be reversed.

(f) The Authority has to rely on documentation provided by gaining distributors that trader approvals have been received in order to update the registry in relation to distributor ICP switches.

6.7. No information is recorded in the registry about network extensions (ie 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.

6.8. Further issues in the process of switching ICPs between distributors arise from ICP status changes that occur part-way through a day and cannot be recorded accurately in trader or MEP systems configured for whole of day operations. For example:

(a) Currently, when a distributor updates the registry to record that an ICP has been decommissioned, the registry prevents any updates to the information for that ICP from the time the distributor status update is made. This prevents a MEP from updating the registry metering records for the ICP to show the removal of metering equipment occurred on the day the ICP was decommissioned.

(b) If the MEP is using the registry to convey a removal meter reading to the trader that was responsible for the ICP, the MEP must backdate the metering event by one day for the removal of the metering components from the ICP and the removal meter reading.

(c) The electrical connection and disconnection of ICPs typically occurs at a time other than 00:00 hours. If an ICP's status in the registry changes from "Active" to "Inactive", there is likely to be electricity flowing at the ICP on the day the ICP's status is recorded as changing. If the ICP's status has moved from "Inactive" to "Active", the registry will record the ICP as "Active" for the whole day and if its status has moved from "Active" to "Inactive", the registry will record the ICP as "Inactive" for the whole day.

(d) At this time, not all traders adopt the same convention, which can result in a trader's count of ICP days not matching what is recorded in the registry and the potential for the volume of electricity recorded at the ICP on the day of the electrical connection/disconnection to be incorrectly accounted for in the settlement of lines charges and the wholesale electricity market.

Summary of proposed changes for distributor switching

6.9. The issues above can be solved by amending the Code to:

(a) include a new distributor switching process that uses the registry as a central hub for transactions between the relevant participants

(b) require distributors to allocate a reconciliation type in the registry to ICP identifiers, when the ICP is connected to a network extension (eg, XN)

(c) move to intra-day status changes which would require distributor events to have a time stamp for the event in addition to the date stamp

(d) require distributors to record the decommissioned date in the registry as the first full day that the ICP is decommissioned (that is, the day after the physical work was performed to decommission the ICP).

6.10. The proposed amendment at paragraph 6.8(c), to introduce intra-day status changes, was not an option that was assessed in our 2019 Issues paper. We do not consider there to be any genuine alternatives as introducing a time stamp in addition to a date stamp would increase the accuracy of recording and address the problems discussed at paragraph 6.7. We are particularly interested in submitters' views on this proposed solution.

Detailed changes to distributor switching using the registry as a central hub

6.11. Further detail about the proposed distributor switch process is set out below:

(a) The gaining distributor would apply to the losing distributor and obtain their consent to commence the switch. This step would remain manual, usually via email or application for the embedded network's ICP (for an embedded network) or through the contracting process (for a sale/purchase).

(b) The gaining distributor would send a file (the same as the current DS-010 file) to the registry containing all the ICPs that it intends to switch at least 60 days before the intended switch event date. We note this timeframe is shorter than the 70 days proposed in the 2019 Issues paper. The proposed timeframe of 60 calendar days is very similar to the current requirement of 40 business days for trader consent (clause 5A of Schedule 11.2) and 3 business days for notifying the Authority (clause 4 of Schedule 11.2). We welcome submitters' feedback on this proposed threshold, with supporting reasons if you prefer a different timeframe.

(c) The registry manager would mark the ICPs status as "distributor switch in progress" and "awaiting trader consent" and advise the ICPs trader and MEP of the proposed distributor switch.

(d) The gaining distributor would contact traders with its distribution agreement and pricing. This step would remain manual.

(e) Traders would advise the registry of their consent or not to the distributor switch.

(f) The registry manager would advise the gaining distributor of the trader's consent. If consent to the distributor switch is declined, the gaining distributor would initiate a discussion with the trader to obtain its consent. If no agreement is reached, the gaining distributor withdraws the switch (in its entirety, unless the physical network configuration allows individual ICPs to be removed).

(g) If no response is received from the trader five days before the switch event date, the trader is deemed to have consented. We note this timeframe is shorter than the 30 days proposed in the 2019 Issues paper and the 2019 Issues paper did not propose deemed consent for a trader that does not respond.

The shorter timeframe and deemed consent arose during SDFG discussion of this paper to ensure traders are given longer to assess the transfer and arrange a distribution agreement if necessary. Many traders already have agreements with multiple embedded network distributors so do not need the time and may not bother responding to a new distributor switch for a known distributor. Deeming consent balances ensuring traders with genuine concerns raise these early with the applicant distributor against unnecessarily holding up switches through oversight. We welcome submitters feedback on this proposed threshold, with supporting reasons if you prefer a different timeframe.

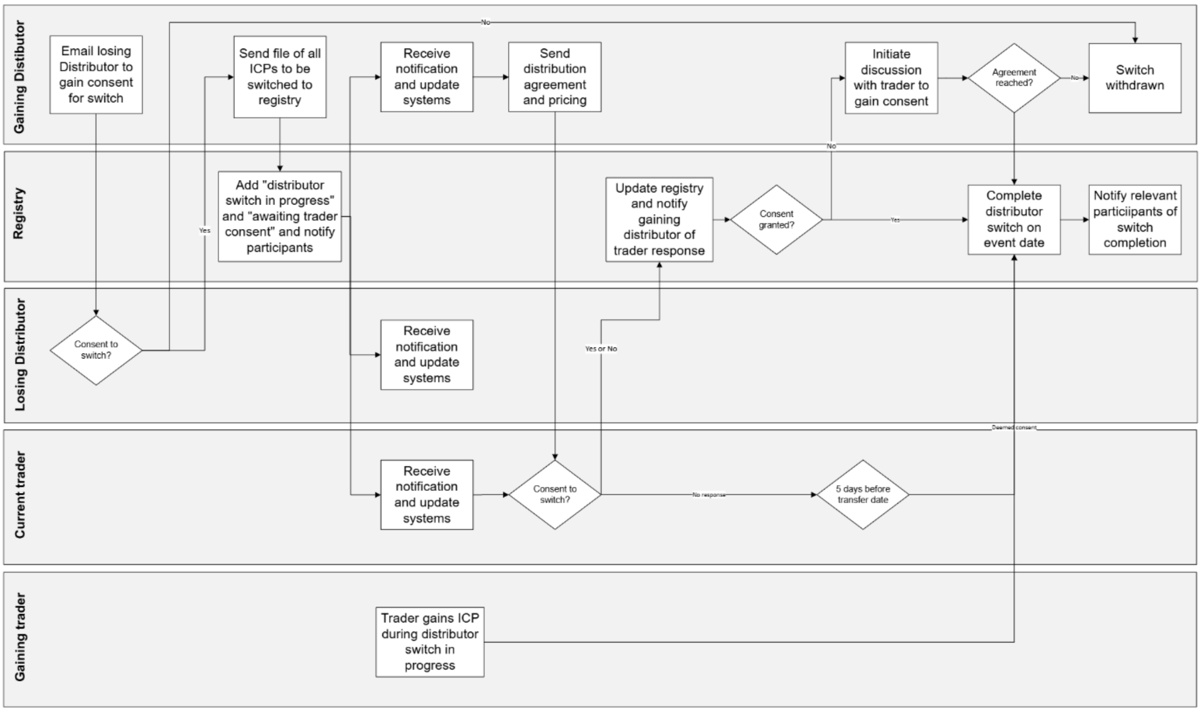
(h) If a new trader switches the ICP, the new trader is deemed to have consented.

(i) If the gaining distributor amends the switch event date, the registry manager would advise all relevant participants of the new intended switch event date. The new switch event date must not be less than 30 days from when the original notification was given to the registry or greater than 60 days after the original intended switch event date. These restrictions are to ensure the trader has sufficient time to consider its consent and set up its systems, and so that the trader's consent does not become out of date if the transfer date is amended.

We note this step was not included in the 2019 Issues paper. This proposal arose during SDFG discussion of this paper to ensure applicant distributors have some flexibility such as if a new building or complex's opening is delayed (usually outside their control such as the territorial authority not issuing building signoffs). We welcome submitters feedback on this proposed threshold, with supporting reasons if you prefer a different timeframe.

(j) If the gaining distributor amends any details other than the switch event date, the registry manager would advise all relevant participants and reset any trader consent responses. This is to ensure relevant traders can assess the new details and change its systems and resend its consent.

(k) On the switch event date, if all traders have consented (or not responded) the registry manager would automatically make the switch. If one or more traders have declined consent for the switch, the switch is automatically withdrawn, and relevant participants are advised that the switch will not be made.



6.12. A high-level summary of the rights and obligations for distributors, traders and the registry manager in the proposed solution are set out in the following table.

Right or obligation	Participant	Timeframes
Notify the registry manager of a proposed distributor ICP switch by submitting an ICP switch notification in the prescribed format (ie the DS-010 file), including a list of all ICP identifiers to be switched and the intended switch event date, distributor-only and pricing fields.	Gaining distributor	>60 days before intended switch event date
Validate distributor switch notification file.	Registry manager (automated)	
Notify relevant traders of proposed switch and facilitate acceptance or rejection.	Registry manager (automated)	
Notify MEP of proposed swich.	Registry manager (automated)	
Notify the registry manager if the intended transfer date is amended.	Gaining distributor	not less than 30 days from the original notification or greater

		than 60 days after the original intended switch event date
If only the intended switch event date is amended, existing trader consent status will be retained but the traders are advised of the new date and permitted to change their response.	Relevant traders	5 days prior to the amended intended switch event date
Notify traders of an amended intended switch event date	Registry manager (automated)	
If changes to a switch notification are required, and the amended switch event date is longer than 60 days (2 months) from the original switch event date, withdraw switch notice, and resubmit new switch notice to the Registry Manager.	Gaining distributor	
If changes to a switch notification include any data other than the switch event date, trader consent status will be changed to “awaiting consent” for all relevant ICP identifiers and traders are notified of changes to ICP fields.	Registry manager (automated)	
Accept or reject proposed distributor ICP switch. If a trader fails to accept or reject the proposed switch, the trader is deemed to have accepted the switch. A trader may choose to change its response from rejecting to accepting a switch, or to reject a switch that was accepted in error, at any time prior to 5 business days before the switch event date.	Relevant traders	>5 business days before switch event date
If a trader ICP switch occurs after a distributor ICP swich is proposed, then the gaining trader is deemed to have accepted the proposed distributor ICP switch. If a trader ICP switch withdrawal subsequently occurs after a distributor ICP switch, the original losing trader (that has gained back the ICP) is deemed to have consented to the distributor ICP switch.	Relevant traders	

Notify the gaining distributor if a trader rejects a proposed distributor ICP switch.	Registry manager (automated)	
Withdraw the distributor ICP switch if any trader rejects the proposed distributor ICP switch, and the distributor has not or is unable to extend the switch event date, and notify relevant distributors, traders and MEPs.	Registry manager (automated)	On switch event date
If all relevant traders accept the proposed distributor ICP switch, transfer ICP identifiers from the losing distributor to the gaining distributor on the switch event date, effective 00:00 hrs on that date. Notify relevant distributors, traders and MEPs.	Registry manager (automated)	On switch event date
The Authority has the right to stop a distributor switch if the circumstances reasonably require, for example the losing distributor reasonably disputes consent.	Electricity Authority	Any time during the switch process

Benefits of proposed solution for distributor switching

6.13. The proposed solution will provide benefits to participants affected by a distributor ICP switch, including:

(a) greater accuracy and transparency of information about the network and distributor switching process

(b) improving operational efficiency through:

(i) automating key elements in the switch process including a streamlined process for traders to consent to a distributor switch request

(ii) reducing errors in settlement of wholesale electricity market and lines charges

(iii) removing the need to manually resolve misaligned ICP information in the registry, and

(c) creating a more accessible audit trail.

Q17. Do you agree with the proposed solutions? If not, what would you change and why?

Q18. 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?

Q19. 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?

Part 3 – Implementation options and regulatory statement

7. Implementation options

Implementation timeframe

7.1. The Authority proposes an effective date of 18 months after the making of any of the amendments consulted on in this paper are gazetted. This allows for a full single implementation of all changes and means participants and the registry manager only need to do one system build and round of testing.

Potential staged implementation

7.2. There is a possibility, if the proposals in this paper are confirmed, of having a staged implementation. This would involve:

(a) MEP, distributor and retailer proposals become effective 9 months after the decision is gazetted

(b) MTR proposals become effective 18 months after the decision is gazetted.

7.3. A staged implementation allows for the simpler changes to be implemented sooner, enabling benefits to be realised more quickly.

7.4. As some of the proposals are interlinked, especially in the retailer and MTR sections, this will potentially mean some rework of system changes.

Q20.	Would you prefer a single implementation or a staged implementation? Please give reasons for your preference
Q21.	Do you agree with the suggested implementation timeframes? If not, please state your preferred timeframes and give reasons for your preference

8. Regulatory Statement for the proposed amendment

8.1. This regulatory statement has been prepared for the following:

(a) proposed Code amendments to enable MTR

(b) proposed Code amendments to improve the MEP, trader, and distributor switching process, to the extent that they differ from the proposed amendments in the 2019 Issues paper.

Objectives of the proposed amendments to enable MTR

8.2. Promote consumer choice by enabling consumers to contract with different providers at an ICP.

8.3. Enhance competition and innovation by allowing multiple providers to serve different aspects of a consumer's electricity usage, improving price and service quality.

8.4. 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.

8.5. Ensure there is the lowest impact possible for participants and consumers that do not want to participate in a multiple trading arrangement.

8.6. 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.

Q22. Do you agree with the objectives of the proposed amendments for MTR? If not, why not?

Objectives of the proposed amendments to improve the switching processes

8.7. Improve customer experience and choice when choosing a new retailer by ensuring retailers have accurate information and the mechanics of the switching processes do not deter consumers switching activity.

8.8. Ensure switching processes are fit for purpose for the current and future electricity market by updating and streamlining processes for an AMI dominated meter fleet (currently ~93% of all meters), align with modern business practices and software functionality and cater for evolving and innovative technology and retailers.

8.9. Support healthy competition and innovation through lowering compliance effort for current and potential participants through reducing manual processes and maximising opportunity for automation of processes.

8.10. Increase the transparency and accuracy of information about the network, metering records and switching processes.

8.11. Minimise change impacts and costs for participants through proposing the minimum changes necessary to achieve the objectives, while also laying the foundation for future development of MTR.

Q23. Do you agree with the objectives of the proposed amendments to improve switching processes? If not, why not?

The proposed amendment

8.12. The drafting of the proposed amendment is contained in Appendix A.

The proposed amendment's benefits are expected to outweigh the costs

8.13. Our assessment is that the benefits of the proposed Code amendments are expected to outweigh the costs. We note the costs and benefits assessed below encompass all the proposals in this paper – the multiple trading proposals, the switch processes proposals originally made in the 2019 Issues paper, and the changes and additions to those proposals made in this paper.

8.14. The primary costs of the proposed Code amendments are implementation costs for participants. The Authority and its working group on this subject, the SFDG have been mindful of participant change impacts and costs in developing this proposal.

8.15. Implementation costs for participants are likely to be highly variable and cannot be quantified at this point. However, this proposal seeks to mitigate these costs by consolidating multiple changes at once and making certain changes optional, to allow participants choice about implementation based on the cost-benefits for their organisation. Submitters are requested to submit on the scope of changes or to provide their estimated costs.

8.16. Approximate cost estimates for changes to the electricity registry (the registry) is $700k. As the changes are closely interlinked, it is not easily possible to separate out the costs for each of the sections. This cost is paid by the Authority.

8.17. The proposed solutions are expected to provide significant benefits. These include:

For multiple trading relationships

(a) reducing barriers to entry for new participants leading to increased competition

(b) increased value to consumers for their distributed generation

(c) laying the foundation for future stages of MTR.

For trader switching proposals

(d) improved information provided to gaining traders, MEPs and distributors during the ICP switch process

(e) opportunities for participants to simplify systems leading to cost savings which can be directed towards innovation and cost relief for consumers

(f) improved ability to install the technology needed to deliver contracted services and provide contracted service es to customers from the agreed date

(g) reducing barriers to entry for new participants leading to increased competition

(h) improved system and process efficiency, reducing manual interventions and workarounds, reduced exceptions to manage and reduced compliance costs

(i) improved accuracy of meter readings at the time of switch and reduced customer complaints

For the MEP switching proposals:

(j) better metering information available to inform traders decisions for customer offers and reduction of poor customer experience when the actual metering does not support the offer made

(k) more accurate metering records and customer invoicing

(l) greater transparency and efficiency in the switching processes

(m) better transparency of MEP switches in progress and reduction in rework and correction of incorrect data

(n) enhanced ability for participants to meet their obligations under the Code

For the Distributor switching proposals:

(o) greater accuracy and transparency of information about the network and distributor switching process

(p) improving operational efficiency and transparency for traders of customers involved in a distributor switch

(q) reduced cost for the Authority manually processing distributor switches.

Q24. Do you agree the benefits of the proposed amendment outweigh its costs?

The Authority has identified other means for addressing the objectives

8.18. In our 2019 Switch Process Review consultation paper, the Authority considered and consulted on alternative options for some of the individual issues discussed in the MEP, distributor and trader switching sections. The preferred options in each of these areas have been presented in this paper for consultation.

8.19. The Authority adopts and relies on the earlier description of the options in the Switch Process Review issues paper and submissions for the purposes of this regulatory statement. The issues paper and submissions can be found at Switch process review - Issues and options | Our consultations | Our projects | Electricity Authority and is attached as Appendix D to this paper. The Authority does not consider that there have been any changes to the underlying circumstances in the industry since that earlier consultation that materially changes any part of that analysis.

8.20. We seek comments from parties on the preferred options for MEP, distributor and trader switching and the alternative options in the 2019 Issues paper. Where we have included changes and additions to these proposals, we have not identified any alternatives that would achieve the objectives.

8.21. For the MTR section, the Authority has identified two alternative options. These options are discussed in paragraphs 3.27 to 3.47. Included in this discussion is an assessment of the advantages and disadvantages of these two alternative options. For the reasons discussed in that section of the paper, the Authority prefers option 1.

Q24. Do have any comments on the preferred and alternative options discussed in the 2019 Issues paper?

The proposed amendment is preferred to other options

8.22. The Authority has evaluated the proposed solutions against the status quo and the alternative options for addressing the objectives. The proposal for changes as set out in this paper is preferred for the following reasons:

(a) while the status quo avoids change impacts and costs to participants, it does not meet any of the objectives of the proposed amendments

(b) the alternative options do not meet all of the objectives of the proposed amendments

(c) the medium to long-benefits for participants, customers and stakeholders are expected to outweigh the upfront implementation costs

(d) implementation costs are reduced because many of the proposed changes are optional, enabling participants to decide whether to proceed with the changes where the cost-benefit of doing so is favourable.

Q25. 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.

The proposed amendment complies with section 32(1) of the Act

8.23. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to the direct dealings between participants and these consumers.

8.24. Section 32(1) of the Act says that the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

8.25. The Authority considers that the proposed amendment is necessary or desirable to promote competition in, and efficient operation of, the electricity industry (Sections 32(1)(a) and 32(1)(c) of the Act). The proposed amendment does this by removing barriers to multiple traders in the Code, reducing the issues that cause a poor customer experience in the switching process, and reducing inefficiencies in participants' systems and processes.

Q26. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

The Authority has had regard to the Code amendment principles

8.26. When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to the following Code amendment principles, to the extent that the Authority considers that they are applicable. Table 1 (below) describes the Authority's regard for the Code amendment principles in the preparation of the proposal.

Table 1: Regard for Code amendment principles

Principle	
1. Lawful	The proposal is lawful, and is consistent with the Authority's statutory objectives and with the requirements set out in section 32(1) of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The efficiency gains are set out in the evaluation of the costs and benefits (section 8.13 – 8.16 above).
3. Net benefits are quantified	The extent to which the Authority has been able to estimate the efficiency gains is set out in the evaluation of the costs and benefits.
4. Preference for small-scale 'trial and error' options	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter)
5. Preference for greater competition	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter)
6. Preference for market solutions	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter)
7. Preference for flexibility to allow innovation	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter)
8. Preference for non-prescriptive options	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter)
9. Risk reporting	Principles 4 to 9 apply only if it is unclear which option is best (refer clause 2.5 of the Consultation Charter)

Appendix A Proposed amendment

The proposed Code drafting is contained in a separate document

Q27. Do you have any comments on the drafting of the proposed amendment?

Appendix B Format for submissions

Submitter	

Submissions close 5pm Tuesday 29 July 2025

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?	
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?	
Questions on Multiple trading	
Q3. (3.26) Do you agree with the proposed solutions? If not, what would you change and why?	
Q4. (3.26) Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	
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?	
Q6. (3.47) Do you agree options 2 and 3 are not preferred? If not,	

why not and how would you overcome the disadvantages?	
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?	
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?	
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?	
Q10. (4.55(q)) Do you agree with the proposed solutions? If not, what would you change and why?	
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?	
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?	

Questions on MEP switching	
Q13. (5.34) Are there any other files that should be added to this list?	
Q14. (5.38) Do you agree with the proposed solutions? If not, what would you change and why?	
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?	
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	
Q17. (6.13) Do you agree with the proposed solutions? If not, what would you change and why?	
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?	
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?	

Questions on implementation	
Q20. (7.4) Would you prefer a single implementation or a staged implementation? Please give reasons for your preference	
Q21 (7.4) Do you agree with the suggested implementation timeframes? If not, please state your preferred timeframes and give reasons for your preference	
Questions on the regulatory statement	
Q22. (8.6) Do you agree with the objectives of the proposed MTR amendments? If not, why not?	
Q23 (8.11) Do you agree with the objectives of the proposed amendments to the switching process? If not, why not?	
Q24 (8.17(q)) Do you agree the benefits of the proposed amendment outweigh its costs?	
Q25. (8.21) Do have any comments on the preferred and alternative options discussed in the 2019 Issues paper?	
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.	
Q27. (8.25) Do you agree the Authority's 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?	

Appendix C Glossary of terms and abbreviations

Consumption/load and distributed generation

Consumption (or load) is electricity that flows from the distribution network through the meter to the installation control point (ICP). This is sometimes referred to as “import”. Distributed generation is electricity that is generated within the ICP (eg from solar panels, or a battery) and flows from the ICP through the meter into the distribution network. This is sometimes referred to as “export”. In this paper, distributed generation excludes electricity that is generated and consumed within the ICP (often referred to as ‘self-consumption’).

Customer and consumer

A consumer is a person who is supplied with electricity. A customer is a person or business with the contract with the retailer. This paper uses the term customer where the context needs to exclude consumers that do not have the contract with the retailer (such as family members of the customer).

Installation control point (ICP)

An installation control point can mean either the consumer’s installation (their property), or where the context requires, the actual demarcation point between the distributor’s network and the consumer’s installation (usually the fuse where the connection is made).

The ICP identifier (also known as the ‘ICP number’) is the 15-character identifier used to ensure the ICP data record in the registry is unique. The ICP identifier is the key that enables the switching process. Retailers are required to provide the ICP identifier on every customer invoice and other associated documents.[14]

Intra-day operation

In the customer switching process currently, events such as status changes or meter changes are deemed to occur from midnight (whole of day operation) meaning only one event can occur during a day. Intra-day operation means that these events could occur at set times during the day, so more than one event can occur during a day.

Multiple trading relationships (MTR)

Multiple trading relationships (MTR) means the ability for a customer to have contracts with more than one retailer for different services at their property (or ICP).

As technology and business models continue to rapidly evolve, there is real benefit for consumers from innovative retailers and other new providers supplying specific services. This includes retailers specialising in selling distributed generation, supplying certain types of load (such as EV chargers), or supplying flexibility services that move load and distributed generation to optimise network capacity and minimise wholesale electricity costs. To improve access and choice for consumers to these evolving services, industry systems and

[14] Clause 11.30 of the Code

processes will need to change to better enable customers to hold trading relationships with multiple retailers at one time.

Participants

Electricity industry participants are defined in the Electricity Industry Act, and include traders, retailers, distributors, and MEPs.

Retailer and trader

A trader buys and/or sells wholesale electricity from and/or to the clearing manager. Although not relevant to this paper, a trader also buys and/or sells hedge contracts. A retailer sells electricity to its customer and buys that electricity from either the clearing manager or another retailer. Where a retailer buys electricity from the clearing manager, it is also a trader.

As a trader has wholesale market obligations, the registry records the person responsible for these wholesale market obligations for the electricity consumed at (or generated from) the ICP, and therefore the registry and Part 11 of the Code uses the term trader.

In this paper, we use the term trader where the context requires that the person be recorded in the registry as having wholesale market obligations. We use the term retailer where the context requires the person to sell electricity to its customer regardless of whether it sources that electricity from the wholesale market or another retailer.

Abbreviations and acronyms

Act	Electricity Industry Act 2010
AMI	Advanced metering infrastructure
Authority	Electricity Authority Te Mana Hiko
AN file	Losing trader switch acknowledgement file
AW file	Switch withdrawal acknowledgement file
C&I	Commercial and industrial (a type of metering)
Code	Electricity Industry Participation Code 2010
CS file	Switch completion file
HHR	Half-hourly register or half hour data (depending on context)
ICP	Installation control point
MEP	Metering equipment provider
NHH	Non-half-hourly register or non-half-hour data (depending on context)
NT file	Gaining trader switch request file
Regulations	Electricity Industry (Enforcement) Regulations 2010
SDFG	Switching and data formats group
SPR	Switch process review

Appendix D Switch process review, published November 2019

The 2019 Issues paper is contained in a separate document