2025

Multiple Trading Relationships: Executive Summary

Ara Ake

In collaboration with

Energy Centre of the University of Auckland

Executive Summary

Today, New Zealand consumers' attitudes towards electricity are changing, with many end-users moving beyond being passive consumers. They are actively seeking to consume and produce a variety of energy services. Even though consumers' choices have been largely restricted to selecting a single provider that offers a bundled service, they are increasingly shaping the future of the electricity industry by investing in technologies like electric vehicles (EVs), batteries, and solar PV systems. The substantial growth in these distributed energy resources highlights the need to shift from the traditional centralized single-relationship model to Multiple Trading Relationships (MTR). MTR would enable consumers to engage with multiple service providers, fostering a more flexible and competitive market. This approach would facilitate the integration of diverse energy services, enhance consumer choice, and support the efficient management of distributed energy resources, aligning with the evolving landscape of New Zealand's energy sector.

In New Zealand, Multiple Trading Relationships (MTR) is gaining attention as a potential method for enabling consumers to engage multiple suppliers for different energy services at a single premises. This approach contrasts with the global trend towards peer-to-peer (P2P) electricity trading, which promotes decentralized energy exchanges directly between consumers. The Electricity Authority uses the following definition for 'MTR':

> "A multiple trading relationship involves the consumer having the option to have separate contracts with different retailers, one for the consumption of electricity, and another potentially with a different retailer who would buy electricity generated from the premises for export. This Multiple Trading Relationship trial aims to evaluate how consumers could benefit from having more choice in how and where electricity is being used and exported" (Electricity Authority Website).

The multiple trading relationships (MTR) framework in New Zealand introduces new avenues for customers to provide or receive electricity services from various entities. MTR represents a significant innovation in market design and regulatory structures to promote more active demand-side participation in electricity markets. From the consumer's perspective, it disrupts the traditional model where a single supplier dominates at the distribution grid's connection point. MTR focuses on the consumer's needs and the services they desire, recognizing the new choices available, such as self-generation, energy storage, and potentially shared distributed generation. MTR contrasts with the conventional, decades-old framework that starts with large power stations and suppliers and only later considers the needs of households, businesses, and communities at the end of the supply chain (Campbell, 2023).

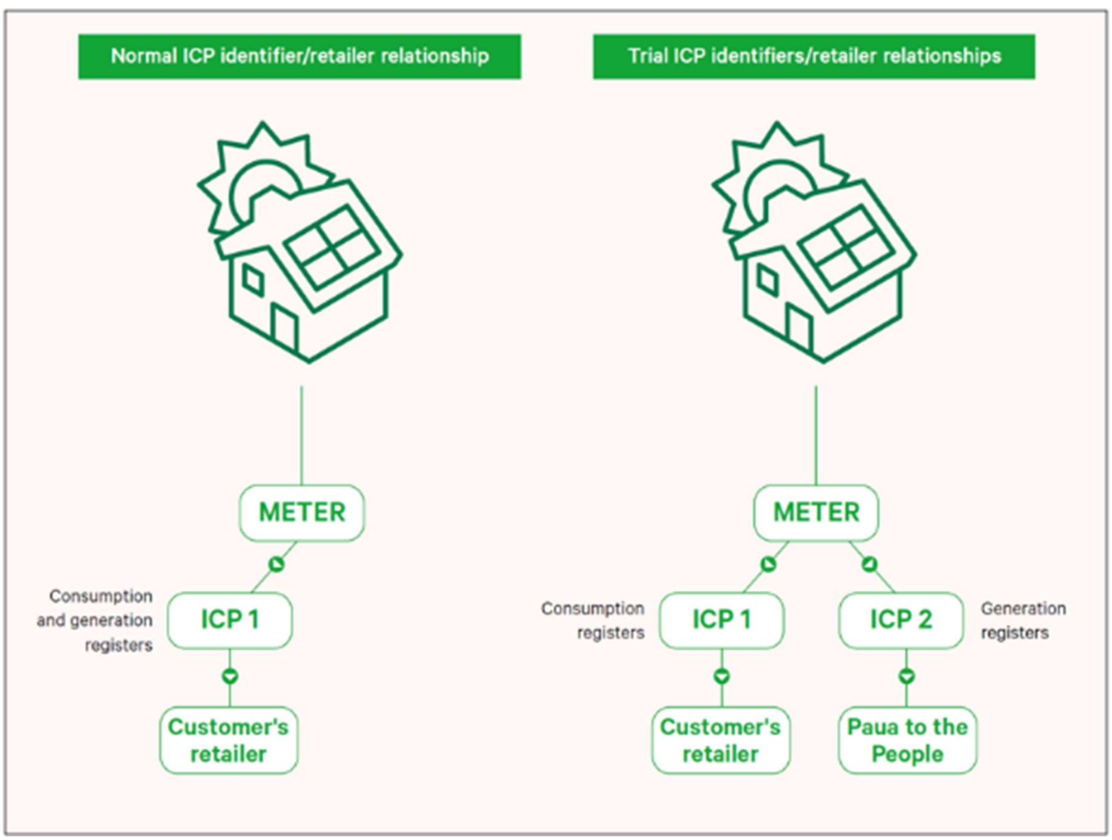

Figure 1- MTR basic pilot in comparison to current market design (Ara Ake Website)

Figure 1 illustrates a schematic of how the basic MTR pilot differs from the current market design in New Zealand. Consumers must contract with a single retailer for all electricity services at one specific installation control point (ICP) (Left image).

1. Multiple Trading Relationships Pilots in New Zealand

In 2022, Ara Ake partnered with Kāinga Ora to create a trial environment for Multiple Trading Relationships. This pioneering initiative separates the import and export registers at installation control points (ICPs) (Right image) where solar panels are installed on social housing (Ara Ake Website). By doing so, Kāinga Ora can capture the value of excess solar energy exported to the grid, which helps support other customers experiencing energy hardship (Ara Ake Website; Kāinga Ora, 2024).

Figure 2- Kāinga Ora Multiple Trading Trial (Ara Ake Website)

Another notable project currently exploring the implementation of Multiple Trading Relationships in New Zealand is the Franklin Energy Sharing Pilot, which is a collaboration between Ara Ake, Climate Connect Aotearoa, and Counties Energy. This pilot aims to enable community organisations in Franklin to access surplus energy gifted by others, reducing their power bills through a combination of MTRs and community battery storage (Climate Connect Aotearoa, 2024).

2. Multiple Trading Relationships: Opportunities and Challenges

By allowing consumers to contract with more than one electricity service provider, MTR is expected to enhance competition among electricity service providers, improve supply reliability, quality, and resilience of electricity supply, and reduce carbon emissions. Meanwhile, medium-to-long-term impacts may include improved customer satisfaction due to access to a broader range of products that will more closely align with individual preferences and needs. Figure 3 summarizes multiple trading relationships' expected outcomes and benefits (Ara Ake, 2021; Electricity Authority, 2018; Energyshare Ltd, 2018; ERANZ, 2018; Orion, 2018; Vector, 2018).

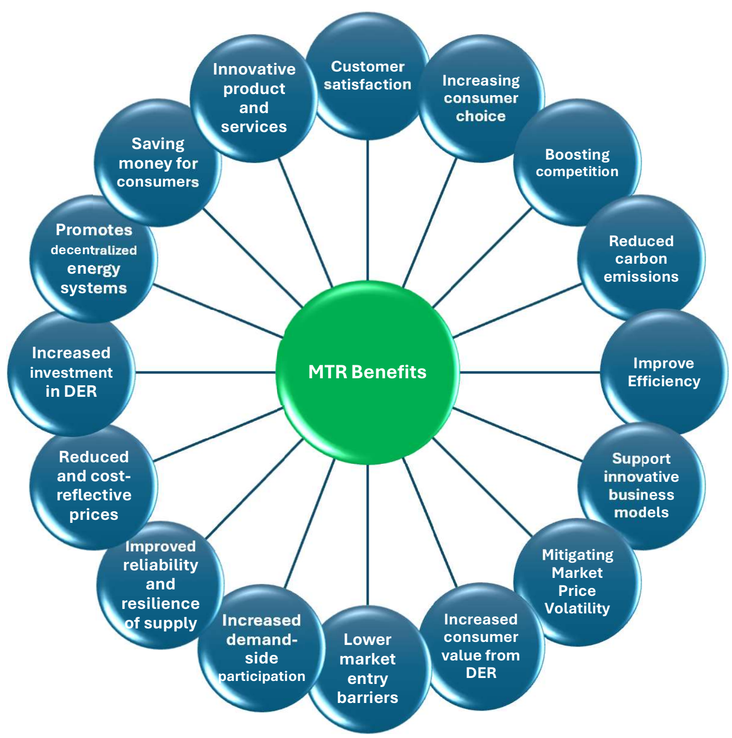

Figure 3- The expected outcomes and benefits of MTR

Despite the potential benefits, implementing MTR within the current regulatory framework has several challenges and barriers in New Zealand. One key challenge is the current regulatory framework, which is not fully aligned with the requirements of MTR. The regulatory framework includes limitations in the Electricity Industry Participation Code (Electricity Authority, 2010) that may hinder the integration of multiple service providers at a single Installation Control Point (ICP). Additionally, submissions from electricity industry stakeholders to the Electricity Authority (Energyshare Ltd, 2018; ERANZ, 2018; Orion, 2018; Vector, 2018; Electricity Authority, 2018) have highlighted some concerns and risks, such as fair allocation of market responsibilities and issues related to data privacy. Detailed discussions on the barriers and challenges of MTR in New Zealand are provided in Figure 4.

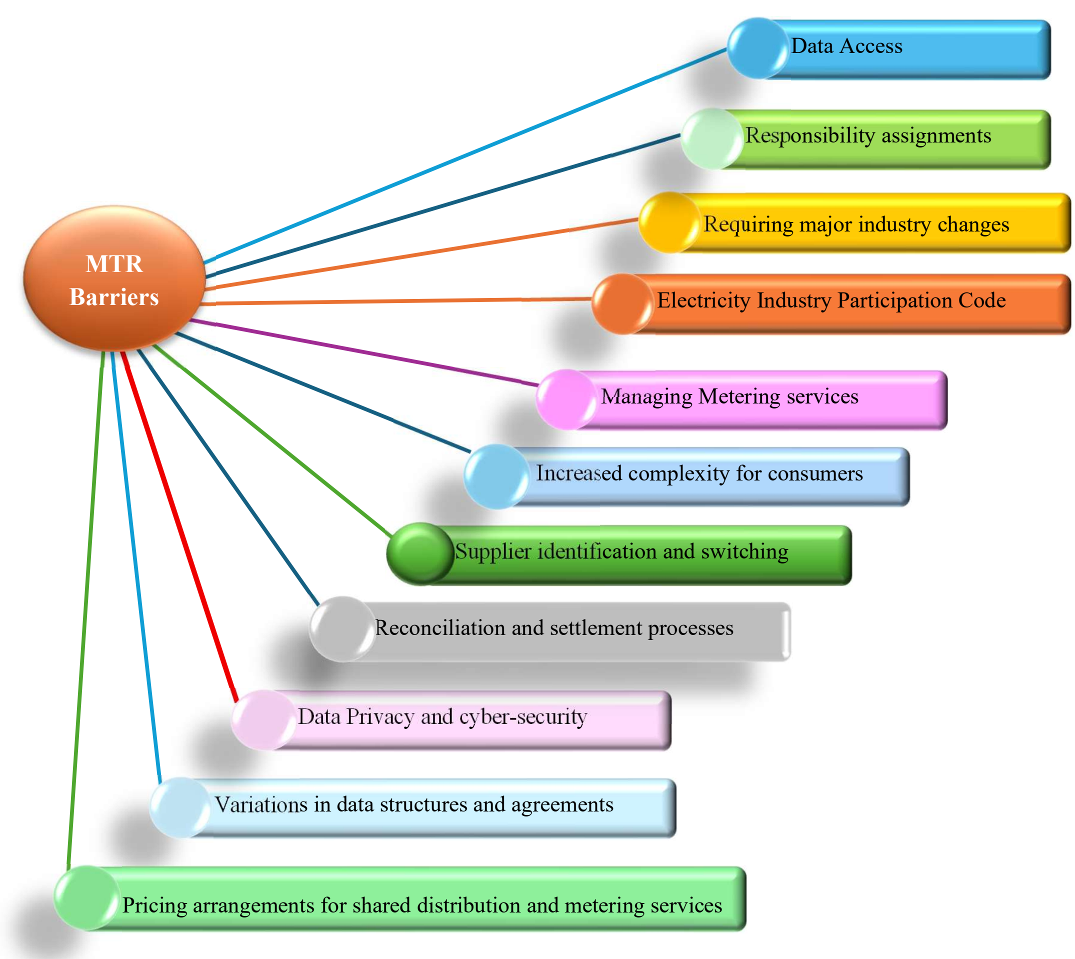

Figure 4- Key barriers of Multiple Trading Relationships

As depicted in Figure 4, the implementation of Multiple Trading Relationships (MTR) presents several challenges across the electricity industry. Metering equipment providers (MEPs) currently lack methods to allocate costs for distribution and metering services among multiple suppliers. This gap leads to challenges in establishing fair and transparent pricing arrangements for shared distribution and metering infrastructure. Addressing this requires significant industry reforms that support flexible, consumer-centric models. Data access is restricted due to existing contractual frameworks. Moreover, the Electricity Industry Participation Code presents structural barriers to enabling multiple suppliers at a single connection point. Assigning responsibilities for consumer obligations such as disconnections is complex, particularly for vulnerable consumers. Additionally, data privacy and cyber-security become more critical as data sharing increases and inconsistent tariff structures may impede market entry for niche providers. Managing metering services among multiple suppliers also introduces logistical difficulties. From the consumer's perspective, MTR adds complexity that may discourage adoption. Furthermore, identifying and switching between suppliers is challenging due to system limitations and coordination issues. Lastly, reconciliation and settlement processes are more complicated under MTR, as suppliers struggle to accurately track energy usage and billing across shared ICPs. Addressing these obstacles is crucial for fostering greater competition and efficiency in the electricity market. As a temporary solution to the Code's constraints as a barrier to Multiple Trading Relationships, the Electricity Authority has granted exemptions to Bluecurrent Assets NZ Limited, Paua to the People, and Intellihub (Electricity Authority Website). These exemptions allow them to bypass specific provisions of the Electricity Industry Participation Code, typically for pilot projects or unique operations that strict regulations could hinder.

3. Multiple Trading Relationships: Projects and Consultations Overview

3.1. Additional Consumer Choice of Electricity Services (ACCES Project)

Furthermore, the Electricity Authority implemented the ACCES [1] project (Electricity Authority, 2019) to address the barriers to expanding consumer

[1] Additional consumer choice of electricity services (the ACCES Project)

choice, increasing competition, and enabling access to new electricity services driven by distributed generation, battery storage, electric vehicles, and smart energy management devices. The Electricity Authority, through the ACCES project, introduced the Connection Agent/Channel Trader model, which was generally well-received by stakeholders, with most considering it practical and fit for purpose. The model allows end-users to buy and sell electricity services from multiple providers at a single ICP. The model separates whole-of-ICP services currently provided by retailers from sub-ICP services and allows sub-ICP reconciliation in central market processes. The model supports two distinct use cases:

- **EV Consumer**: A consumer with an electric vehicle (EV) purchases energy and services specifically for the EV, separate from the household electricity supply
- **Onsite Generation Consumer**: A consumer with onsite generation sells excess energy to a different party, separate from the retailer they purchase their supply from

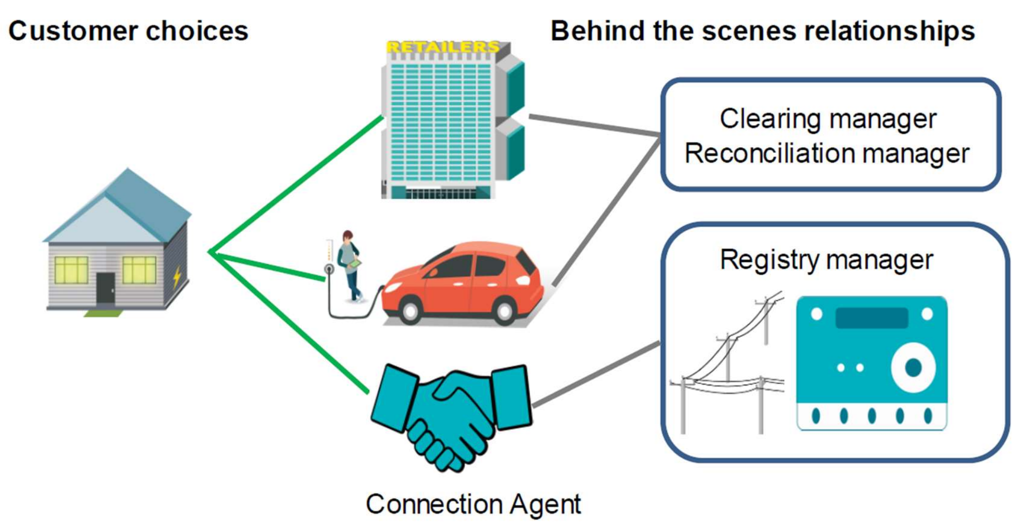

Figure 5- Overview of Connection Agent trader model (Electricity Authority, 2019)

Key elements include:

- **Channel Traders** trade sub-ICP volumes in central processes associated with specific meter channels.
- **Switching at sub-ICP level** is facilitated by a central record of who is providing services for each meter channel
- **A Connection Agent** manages ICP-level responsibilities, including engagement with the Metering equipment providers (MEP) and distributor and consumer obligations. The Connection Agent may also act as a Channel Trader.

The main new feature of this model is the ability to reconcile sub-meter quantities, which is not possible under the current system. This means that new service providers can participate in the market without being responsible for all the services at the entire ICP level.

The model is opt-in, meaning existing retailers are not required to facilitate Channel Trading at any ICP. It also would involve moderate changes to the Code and central Registry system. However, it avoids the higher costs of centralizing sub-ICP reconciliation and immediate needs to address default arrangements for sharing input services costs. Additionally, the model provides a flexible structure supporting new commercial models without blocking existing options. Participants who prefer to engage via traditional contractual models can still do so.

Under the Connection Agent/Channel Trader model, the key responsibilities are as follows:

- Customers can designate a Connection Agent for their ICP and a Channel Trader for each meter channel.
- Sub-ICP volumes must be reconciled through market processes, with data recorded for each meter channel.
- The registry would be updated to allow the Channel Trader to be recorded for each meter channel.

Connection Agent Responsibilities:

- Manage relationships (procurement and ongoing commercial agreements) with the MEP and distributor for input services at the ICP.
- Use channel-level meter data to distribute and pass on costs of input services to Channel Traders.
- Use channel-level meter data to determine ICP-days splits among Channel Traders.
- Handle responsibilities for medically dependent and financially vulnerable customers.
- Control disconnection and reconnection of the ICP.
- Can also act as a Channel Trader if desired.

Channel Trader Responsibilities:

- Act as a Reconciliation Participant and use channel-level data to reconcile its sales through the central processes.
- Reconcile channel trading using only half-hourly data, not profiles.

The contractual and financial flows of the model are depicted in Figures 6 and 7.

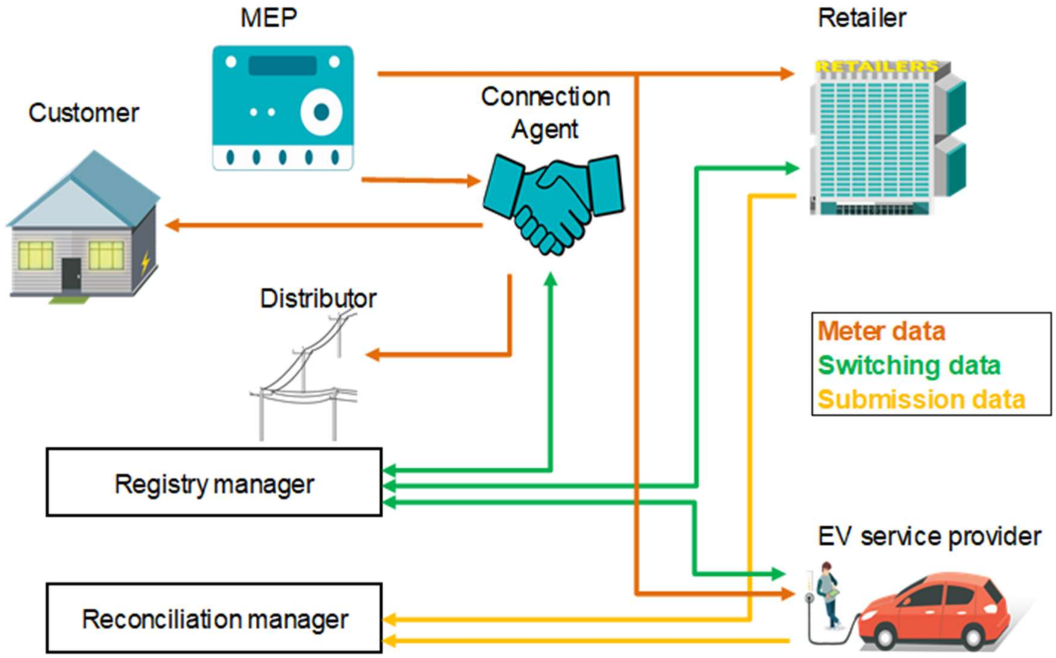

Figure 6- Data flows for Connection Agent Model

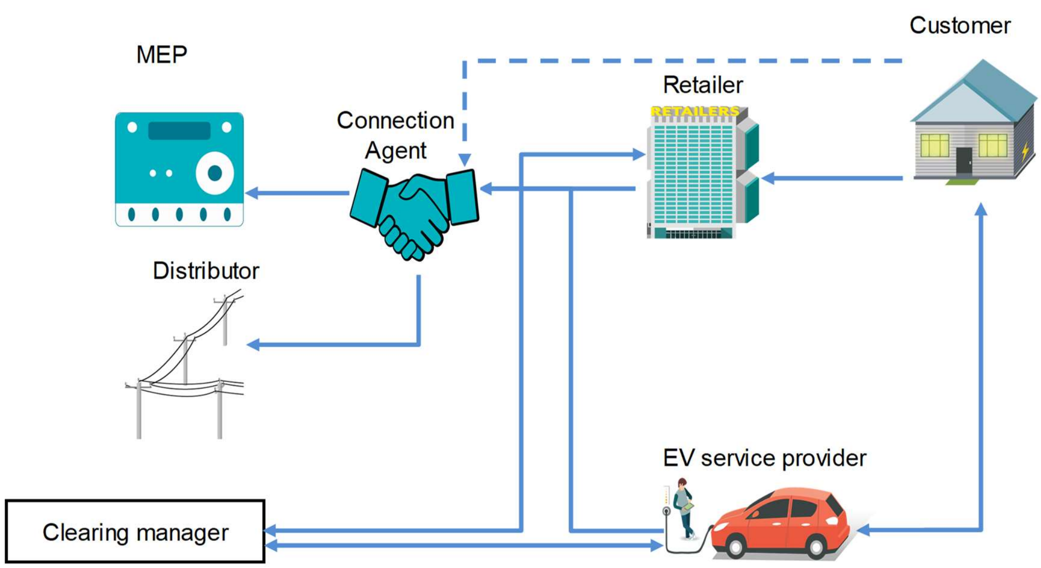

Figure 7- Financial flows for the Connection Agent model

3.2. Evolving Multiple Retailing and Switching: Consultation paper (The Electricity Authority, 2025)

The Electricity Authority is proposing changes to the Electricity Industry Participation Code 2010 (Code) and market systems to empower consumers in a more dynamic and competitive electricity market. This initiative, called "consumer mobility," aims to give households and businesses the ability to:

- Use data and smart technologies to compare and switch plans or providers easily.
- Select different providers for various services.
- Sell excess electricity back to the grid.

Recently, the Electricity Authority published a consultation paper proposing the first stage of multiple trading relationships, allowing consumers to buy and sell electricity with different retailers for consumption and generation to enable a more flexible energy future. The proposed changes aim to boost retailer competition and rewards for active consumers with distributed generation while protecting those who opt not to participate.

The consultation paper is organised into three main sections: (a) enable multiple trading relationships; (b) present proposed changes to switching processes; and (c) discuss implementation options and the regulatory statement (Figure 8).

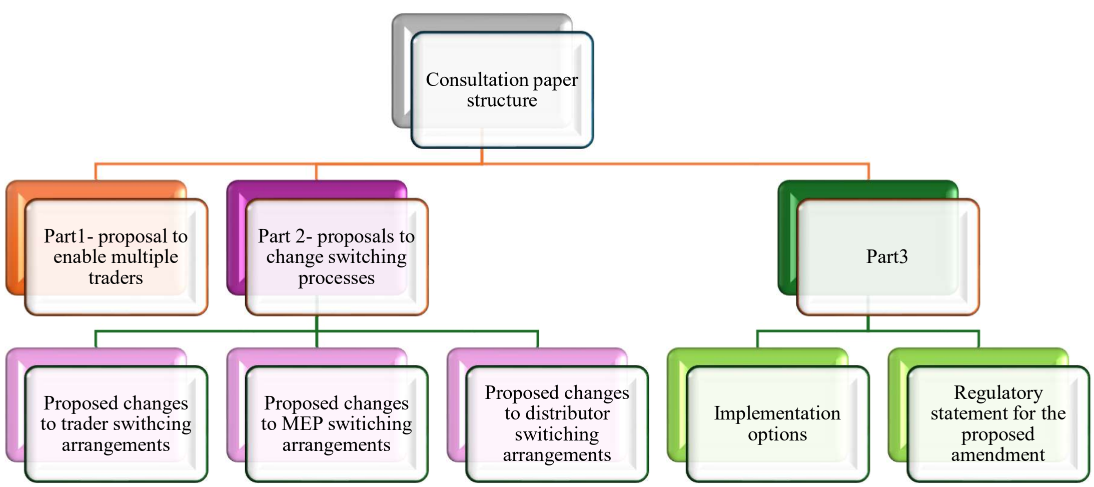

Figure 8- Structure of the *Evolving Multiple Retailing and Switching* Consultation Paper

3.2.1. Proposed Reforms to Enable Multiple Trading Relationships

The proposals aim to allow consumers to buy electricity from two providers, one for consumption and one for generation, and make switching between providers easier to access better deals. It also enhances customer experience and choice when selecting a new retailer, lays the groundwork for future stages of MTR, and delivers these benefits while minimising change impacts and costs for market participants.

MTR, referring to a customer's ability to hold contracts with multiple retailers for different services at the same property, can take several forms, including:

- 1-Two traders – distributed generation and consumption
- 1A-Separate retailers with full central energy sharing
- 2-Separate traders for each consumption meter channel
- 3-Separate retailers for designated appliance
- 4-Full MTR by trading period

Figure 9 provides a schematic overview of the MTR types and their associated benefits and issues. The Authority has approved Code exemptions for Wellington trial allowing separate traders for consumption and generation, forming the basis of MTR Stage 1. The current proposal aims to make this dual-trader model a formal Code option for the wider industry.

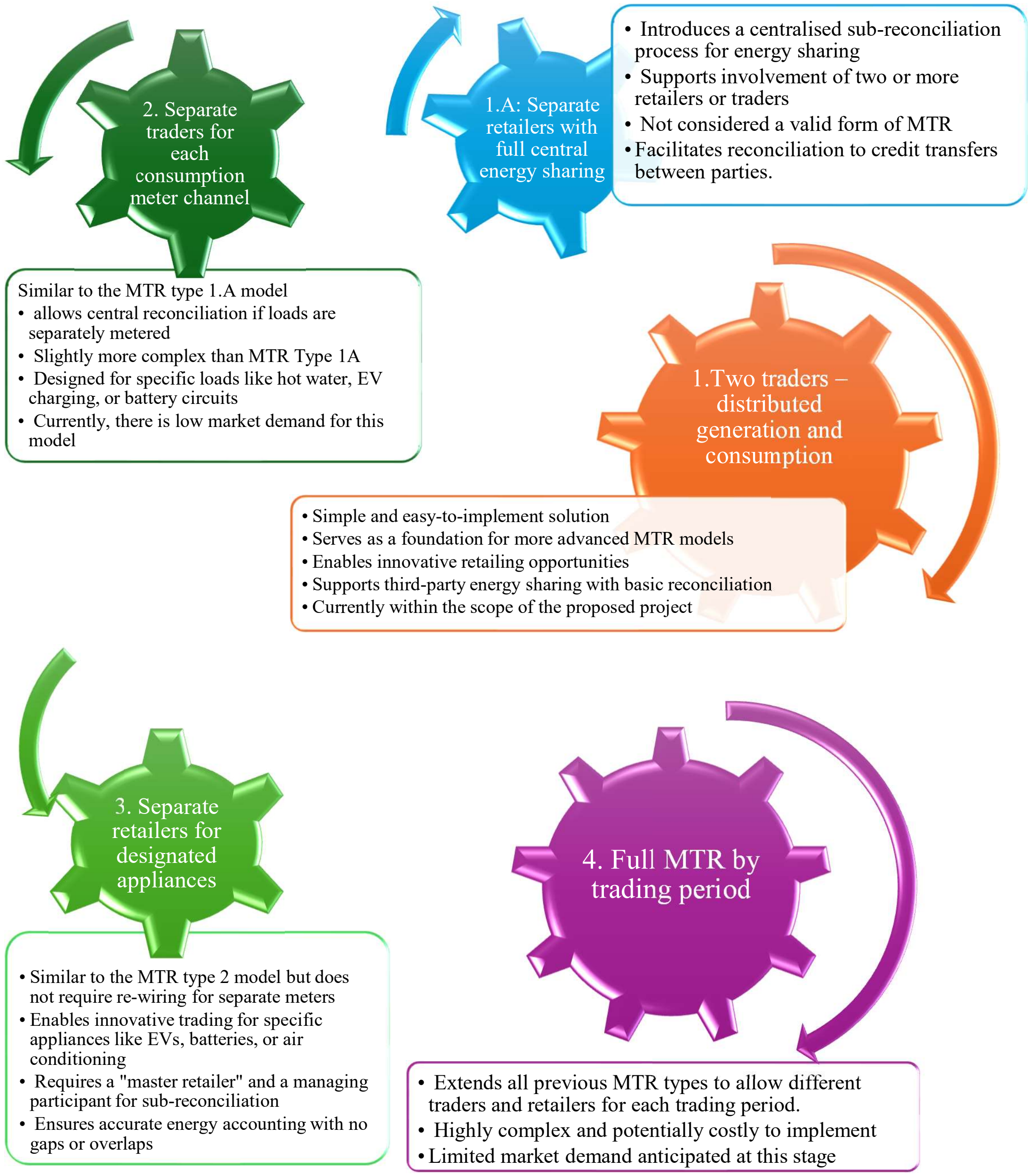

Figure 9- Different MTR types and their characteristics

While multiple trading represents the next phase in the electricity market's evolution, the current Code and supporting systems are not equipped to support this model, creating obstacles to innovation. Figure 10 highlights three main barriers to enabling Multiple Trading Relationships (MTR).

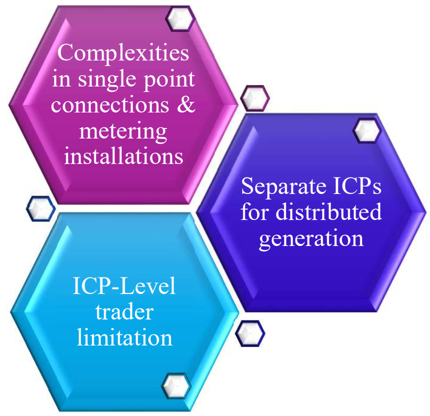

Figure 10- Issues with current arrangements for enabling MTR

ICP-level trader limitation prevents multiple traders from supplying different services to the same property as the registry links traders to properties at the individual ICP level. Moreover, in cases where distributed generation has its network connection, which is common in large commercial installations, a second ICP and separate metering are used to keep generation and consumption data distinct. Furthermore, most properties have only a single point of connection and metering installation, which creates several challenges for participants and market systems. These include:

(a) the risk of electricity being lost or double-counted.

(b) dual responsibilities for reconciliation between generation and consumption ICPs or channels.

(c) challenges for MEPs when multiple traders initiate metering changes. Additional complications arise when separate meter installations with different MEPs are later merged under one trader. The need for multiple metering and distribution agreements may result in overcollection of line service and meter lease charges, ultimately raising costs for the customer.

To avoid these complexities, three options (Figure 11) were identified to enable MTR, with option one preferred for its ability to support MTR while avoiding added complexities.

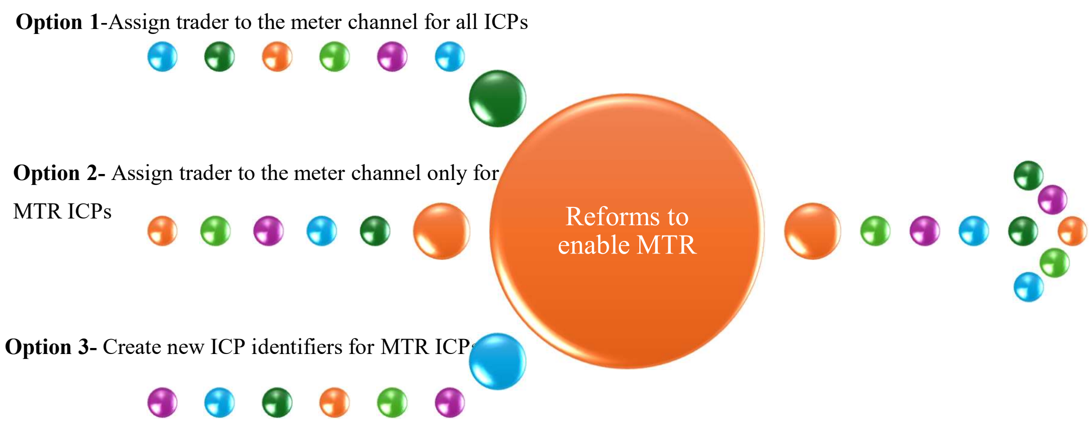

Figure 11- Proposed options to enable MTR

Option 1- Assign trader to the meter channel for all ICPs: The preferred solution is to amend the Code and reconfigure the registry to allow:

(a) assignment of different traders to individual meter channels

(b) adding a field in the gaining trader switch requests to indicate whether the customer opts for MTR or a single trader arrangement

(c) when a point of connection and metering installation at an MTR property serves both consumption and generation, this clause restricts metering installation changes to consumption traders only. It also prevents generation traders from initiating MEP changes if generation and consumption ICP channels share the same meter. Moreover, it restricts distributed generation traders from changing the installation point of supply.

Furthermore, while generation traders can modify generation equipment and wiring, they are prohibited from disconnecting or reconnecting the ICP, which the consumption trader must handle. They also must notify the consumption trader of supply disconnections to installation and route any metering or network change requests through the consumption trader. Distributors must involve all relevant traders in outage notifications. Finally, distributors and MEPs must not charge twice for the same service at a multiple trader ICP.

The proposed processes in Figure 12 to Figure 15 outline the detailed steps for initiating MTR (Figure 12), switching either generation or consumption to a new trader (Figure 13), exiting MTR to return to a single trader (Figure 14), and process flow for new ICPs that will have multiple traders (Figure 15).

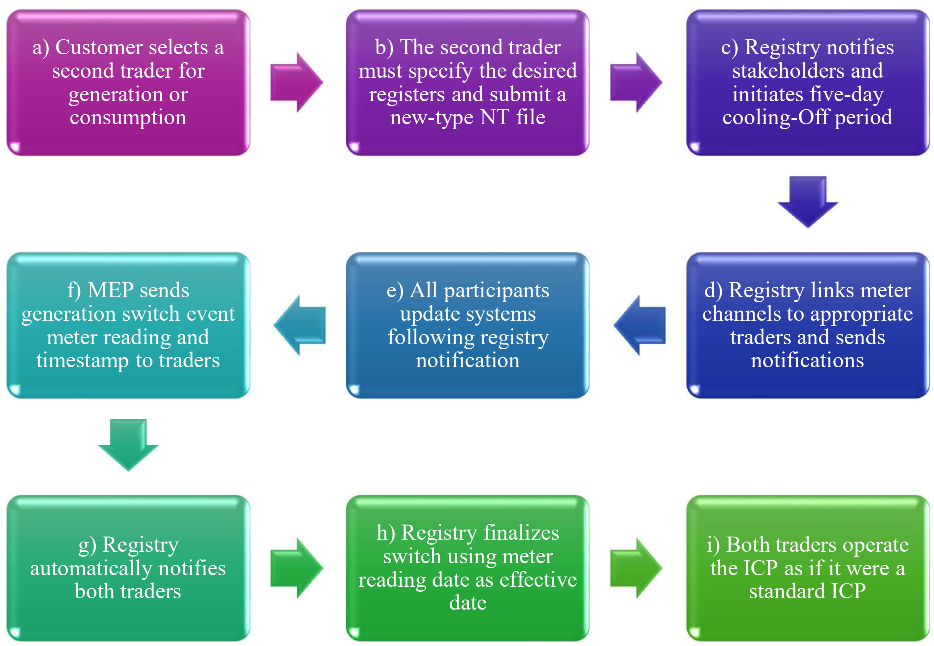

Figure 12- Process flow for initiating MTR

Figure 13- Customer switching process for transferring consumption or generation to a new trader

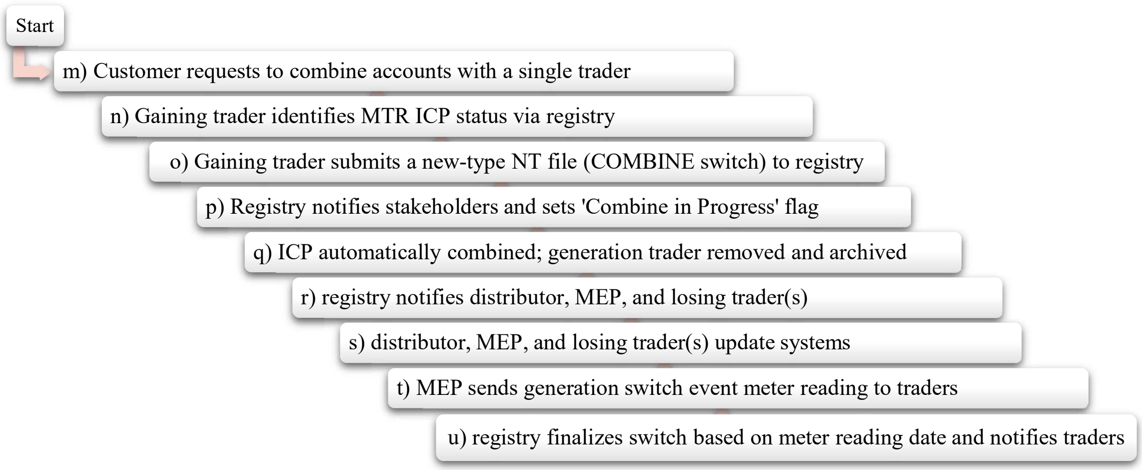

Figure 14- Process flow for combining a MTR to a single trader

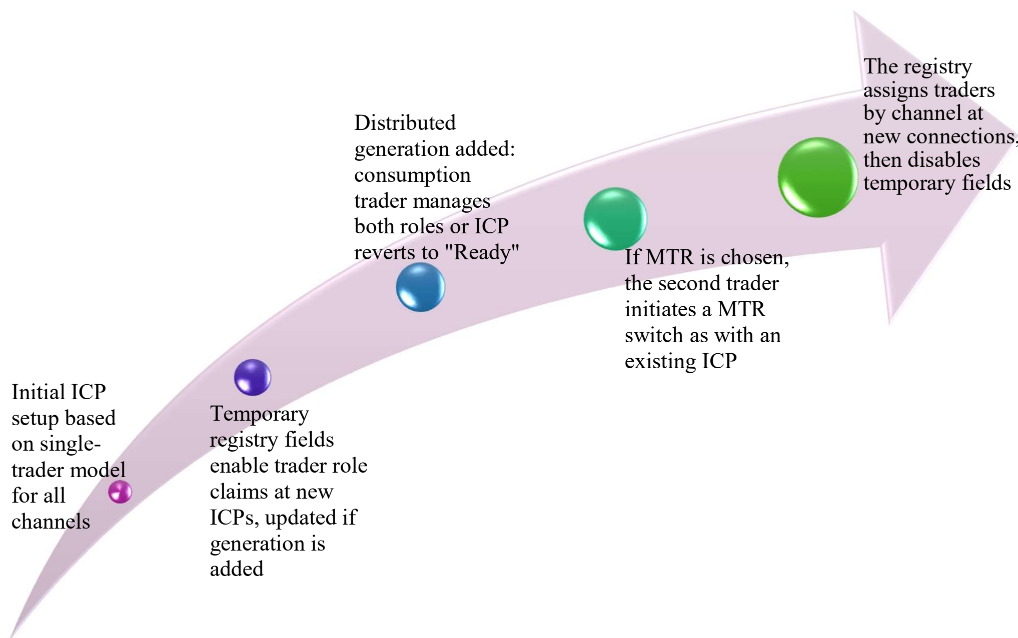

Figure 15- Process flow for new connections that will have multiple traders

Option 2- Assign trader to the meter channel only for MTR ICPs: The Authority considered a variant of Option 1 that applies meter channel-level trader assignment only to ICPs in a multiple trading arrangement, while others retain the current ICP-level assignment. Under this approach, ICPs would be converted to MTR status when a second trader initiates a switch and could be reverted if one trader later manages all channels. However, a potential sub-option suggests that MTR status may remain permanent once assigned.

Option 3- Create new ICP identifiers for MTR ICPs: This proposes creating new ICP identifiers for MTR ICPs, similar to a trial currently underway in Wellington. When an ICP adopts MTR, a second ICP identifier would be generated, the data entity associated with the original ICP would be duplicated for each ICP identifier, and meter channels would be separated between consumption and generation ICPs without requiring physical metering changes. The new ICP identifier can be entirely new or an extension of the existing one. If a customer later combines all channels under one trader or moves into a vacant MTR ICP, the identifiers and data entities should be merged back, reinserting all meter channels to track electricity flow accurately. Responsible participants or the registry manager can manage the creation and splitting of the metering channels.

Table 1 compares the preferred solution (Option 1) to alternative Options. As depicted in Table 1, option 1 is the preferred approach for implementing MTR because it effectively addresses the key risks and complexities associated with MTR while laying a strong foundation for future development stages. Unlike the first option, Option 2, which requires traders to manage both channel-level and ICP-level trader assignments or establish a separate process to combine an MTR ICP before accepting or rejecting a customer, introduces added complexity and operational burden. Finally, Option 3 fails to address existing complexities, increases the risk of errors with more MTR ICPs, and is unsustainable for future MTR stages.

Table 1- Overview of the proposed options for enabling multiple trading relationships (MTR)

Option	Description	Advantages	Challenges
Option 1 (Preferred)	Assign trader to the meter channel for all ICPs	-Enabling customer choice through separate traders for generation and consumption -Sets foundation for future MTR stages -Minimizes risk of errors from MTR	-Requires system changes for all participants' systems, the registry, and the Authority's monitoring system. -Current challenge in quantifying the benefit -Requires stakeholders to provide detailed inputs on the expected costs and benefits
Option 2	Assign trader to the meter channel only for MTR ICPs	Minimal impact on non-participating traders	-Participating traders should handle both traditional ICP setups for non-MTR customers and the MTR configurations for participating customers -Non-participating traders should refuse customers wanting to participate and develop processes to combine channels before switching -Reduces retail competition -Higher software development costs for traders choosing to support MTR ICPs later
Option 3	Create new ICP identifiers for MTR ICPs	-Preserving existing functionality while supporting MTR ICP identification by a trader	- Customers must be signed up to both ICPs in an MTR setup to avoid disconnection or loss of generation payments due to unswitched ICPs appearing vacant - Creating and managing a second ICP by participants increases administrative costs and requires safeguards to prevent duplication of charges and ensure accurate cost allocation. - If the registry manager automates second ICP creation, distributors and MEPs will need validation processes and exception handling unusual setups that the registry's automation cannot process. - The approach becomes impractical at more granular MTR stages, as the proliferation of ICPs and data entities increases monitoring challenges, and the risk of overlooked ICPs and unaccounted electricity. - It may lead to reconciliation inaccuracies, increased administrative burdens, and financial losses for traders from unaccounted electricity, especially after the washup period.

3.2.2. Proposed Reforms to Switching Processes

3.2.2.1. Proposed Reforms to Trader Switching Arrangements

The proposed changes to trader switching arrangements aim to enhance the customer experience by modernizing the switching process to suit current and future electricity markets. They will improve information flow among traders, MEPs, and distributors, streamline systems to reduce manual handling and compliance costs, and enable cost savings to support innovation and lower consumer prices.

As depicted in Figure 16, the existing trader switching arrangements face numerous challenges, including registry limitations, timing and scheduling constraints, inconsistent processes, reporting errors, unclear switch notification rules, and ambiguous codes. These issues primarily stem from the current file-based exchange system between participants and the registry.

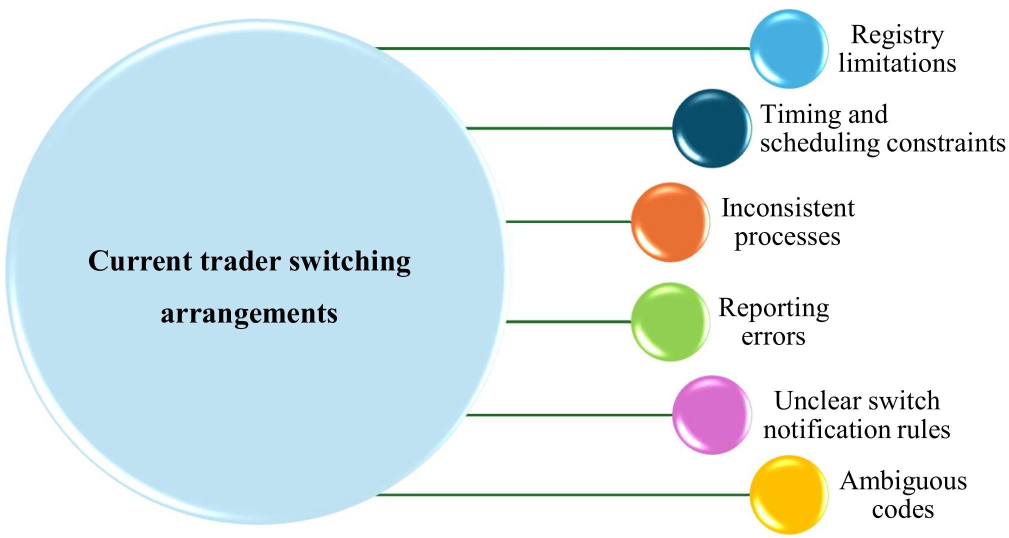

Figure 16- Main issues with the current trader switching arrangements

- **Registry constraints:**

Figure 17 shows the two registry constraints that should be addressed through proposed changes. When a gaining trader switch request is received, the registry locks the trader records for ICP, preventing the losing trader from making updates unless the switch is withdrawn. Moreover, if two updates of the same event type occur on the same day for an ICP, only the most recent one is shown, causing earlier updates to be hidden despite being stored.

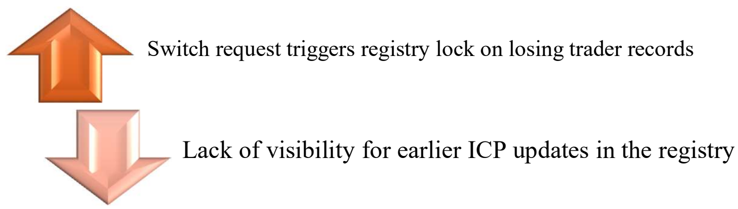

Figure 17- Summary of issues with registry constraints

- **Timing and scheduling constraints**

Figure 18 provides a summary of the key issues related to timing and scheduling constraints within the current trader switching arrangements. For 'Transfer' or 'Move-In' switch types, the Code requires the losing trader to finalize the switch and determine the event date. The losing trader can override the switch event date proposed by the gaining trader if there is disagreement over the switch timing or metering arrangements with the MEP. Moreover, metering discrepancies, invoicing beyond the proposed switch date, or contractual end-date agreements can cause the losing trader to delay the switch completion. These timing misalignments can create challenges for gaining traders, particularly when the switch date does not align with their intended service commencement or metering reconfiguration dates.

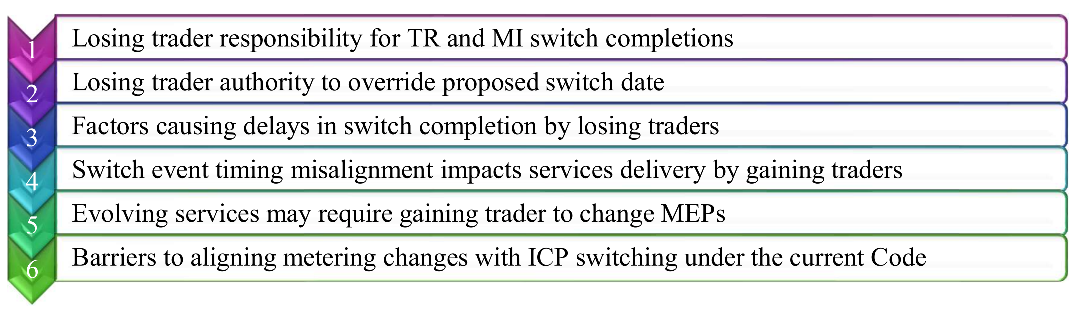

Figure 18- summary of issues with timing and scheduling constraints

Customers may agree to services that require metering equipment changes, and gaining traders might need to replace the MEP if the existing one cannot meet those metering service requirements. Aligning metering changes with the ICP switch event date is also often inefficient due to the unavailability of the preferred MEP or coordination challenges on the switch date. Under the current Code, gaining traders face several inefficiencies when aligning metering changes with trader ICP switches. These include MEPs refusing to engage if the losing trader is still listed in the registry, restrictions on modifying metering installations until the switch is complete, and limitations imposed by contractual arrangements. Gaining traders may also be forced to begin service with unsuitable metering configurations or MEPs, particularly in the case of backdated switches. Additionally, MEPs may be unaware that a switch has commenced or may alter the metering configuration before the switch is finalised. In some cases, gaining traders may also need to amend the initially proposed switch event date to manage these constraints.

- **Inconsistent processes**

The summary of key issues with the meter reading processes in the current trader switching arrangements is depicted in Figure 19. The Code mandates losing traders to submit a switch event meter reading in the “CS file” only if the ICP’s metering has a registered channel with accumulator type “C” and settlement indicator “Y”. Moreover, the current requirements make it difficult for gaining traders to ensure the accuracy of switch event meter readings. Discrepancies often arise due to traders may have different readings for the same switch date, lack of clear guidance on rounding values, and reliance on estimated readings even when actual data is available. Additionally, MEPs may not provide the accumulating channel reads for the start of the switch day, and traders may reference different meters for the switch event meter reading.

Traders are entitled under the Code to access raw meter data via the MEP’s services access interface within 10 business days of request. Nevertheless, delays beyond five business days from receipt of the CS file prevent the gaining trader from requiring the losing trader to accept a revised switch event meter reading. Additionally, AMI switch event readings are not always taken at midnight, conflicting with whole-of-day operation assumptions. Another issue arises from losing traders who often continue using estimates instead of actual AMI reads.

Figure 19- Summary of inconsistent and ineffective processes in current trader switching arrangements

Switch timing issues in the registry can cause MEPs to send midnight reads to the wrong trader, forcing the losing trader to estimate readings. This results in administrative overhead to correct records and, if left uncorrected, can cause incorrect volume allocation, impacting small retailers significantly.

The Code allows either gaining or losing traders to withdraw an ICP switch within two months of the switch event, provided both parties agree. However, the rising number of withdrawals reveals several problems, including that the two-month time limit is inadequate for backdated or delayed switches; the process relies heavily on manual communication, leading to inefficiencies and errors; and unclear registry codes and business rules cause confusion and lead to rejections by recipient traders. Moreover, issues arise when the losing trader is not required to accept a withdrawal caused by errors such as incorrect ICP identifiers. Then, the requesting trader must re-initiate the withdrawal, causing customer inconvenience. Additionally, unnotified price category changes before a withdrawal lead to billing and reconciliation errors that require manual intervention.

For non-half-hourly (NHH) metered ICPs, switch event meter readings apply at different times for gaining and losing traders, potentially resulting in misallocated consumption for reconciliation. The Code also lacks provisions for situations where losing traders cannot provide switch event readings due to inaccessible or destroyed meters or insufficient data to provide a permanent estimate.

The replacement read process designed to correct inaccurate switch event readings is fraught with challenges, including a too-short four-month limit for backdated switches, restrictions preventing losing traders from using replacement reads for gaining trader (HH) switches, absence of materiality thresholds for timely AMI replacement reads in NHH switches, potentially excessive thresholds for other replacement reads, delays or refusals by MEPs to provide AMI or backdated meter readings, unclear timelines for resolving erroneous readings, and an inability for losing traders to correct their errors via replacement reads.

Delays in updating the registry with the nominated MEP at a new ICP can postpone meter installation and electrical connection. Importantly, a gaining trader cannot assume responsibility for an ICP until the distributor updates the ICP's status to "Ready" in the registry. Some distributors retain the "New" status to control connection timing, preventing traders from nominating MEPs or updating metering details. This can cause last-minute delays and customer inconvenience when the status eventually changes to "Ready." Clause 10.33A ensures that distributor approval is required before connection, reducing reliance on the "Ready" status as a control mechanism.

Lastly, while the current method of calculating average daily consumption functions well with manually read NHH meters, it becomes unreliable when traders use half-hourly register (HHR) data or have short intervals between meter reads.

- **Reporting inaccuracies:**

The absence of a registry process for mass customer account transfers leads traders to use standard switching methods, distorting statistics and hindering effective monitoring.

- **Impractical rules for switch notifications**

Figure 20 outlines a summary of impractical rules for switch notifications. Current rules governing switch notifications create some inconsistencies and switching process challenges. Standard and move-in switches are driven by the losing trader while gaining trader (HH) switches are limited to larger ICPs. Losing traders may optionally provide a switch acknowledgment (AN file) for TR switches but are required to provide one for MI and HH switches, leading to potential issues. The absence of a mandatory AN file for TR switches can lead to the gaining trader missing critical information, potentially resulting in billing errors or customer inconveniences. Conversely, requiring an AN file for HH switches is viewed as unnecessarily burdensome. Additionally, varying notification deadlines across switch types (TR, MI, and HH) create confusion and operational inefficiencies.

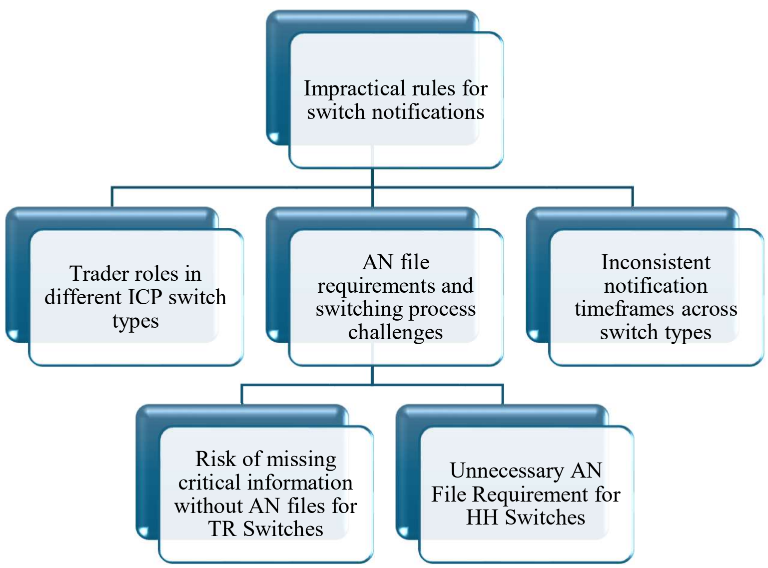

Figure 20- Summary of impractical switch notification rules

- **Code ambiguity:**

The Code lacks clarity on whether switch event meter readings are needed for category 3–5 ICPs. In the gaining trader switch process (HH), a CS file is used to complete the switch for ICPs with absolute (HHR) registers, so no switch event meter reading is required. Some ICPs include NHH/AMI meters, creating confusion over whether NHH or AMI readings must be included in switch completion files for ICP switches using HH switch type process. The Code cites file formats set by the Authority but does not mandate using the registry functional specification, causing inconsistency despite it being required for registry operations.

- **Summary of proposed changes:**

The issues identified in the trader switching process can be addressed by amending the Code and, where relevant, reconfiguring the registry to implement the proposed changes. Figure 21 outlines the main changes proposed to improve trader switching processes.

As depicted in Figure 21, key changes to trader switching include requiring the losing trader to notify the registry manager of any ICP attribute changes during a switch. The registry will update records accordingly and notify all relevant parties to ensure consistency. For completed (backdated) switches, attribute changes apply only to the losing trader’s tenure, with the current trader responsible for assessing and applying valid changes for their tenure period.

In cases where two switches occur on the same day and the second is withdrawn, the first completed switch must be reinstated as the current trader ICP switch, with event timestamps used to aid the registry in determining the correct switch to reinstate.

The process also clarifies that the losing trader must adopt the gaining trader’s proposed switch event date unless both parties mutually agree to an alternative date without necessitating a full switch withdrawal. Gaining MEPs may update or change meter installations prior to ICP switch completion. Further, MEPs responsible for meter interrogation must provide switch event meter readings to both losing and gaining traders. When a meter or MEP change coincides with the switch, both MEPs are obligated to supply readings for their meters, with the registry manager responsible for notifying all involved parties. If a switch is later withdrawn after the meter has been changed, the requesting trader must ensure system compatibility with any updated meter configuration. Traders completing a switch must use meter readings supplied by MEPs for AMI meters or obtain readings themselves for non-AMI meters, resorting to estimates only when validated readings or permanent estimates are unavailable despite best efforts.

a	Attribute change notification during trader switch
b	Attribute changes post-switch completion limited to losing trader's tenur
c	Reinstatement of first switch when second same-day switch is withdrawn
d	Time stamping for accurate event reinstatement
e	Flexibility in switch event date with mutual agreement between losing and gaining traders
f	Gaining MEP's right to modify metering before switch completion
g	MEP switch event meter reading obligations
h	Trader obligation to use MEP or self-obtained meter readings based on meter type
i	Restrictions on use of estimated switch event meter readings
j	Standardization of meter reading precision
k	Timely initiation of switch completion files delivery based on event date or NT file receipt
l	Optional provision of AN Files for HH switches
m	Withdrawal of trader ICP switches permitted within 14-month reconciliation window
n	Application of priorities in the functional specification for AN file response codes
o	Clarification of withdrawal codes use in registry functional specification
p	Trader obligation to accept switch withdrawal under defined reasons
q	Notification to losing trader on switch withdrawal with changed ICP information
r	Standardized timestamp for non-AMI meter readings
s	Expanded access to RR process for switch event reading corrections by both retailers
t	Mandatory trader response to RR requests within five business days
u	Set thresholds for initiating RR process and NHH switch event read replacements
v	Assignment of new ICPs and connection requests subject to distributor approval
w	Trader obligation to provide average daily consumption data for relevant metering channels
x	Use of distinct switch type code for mass acquisitions and system transfers
y	Optional AN files for HH switch types
z	Application of priorities in the functional specification for AN file response codes by senders
aa	Standardised two-day timeframe for notifications across retailer switching activities
bb	Mandatory switch event meter readings in CS files for HH Switches with applicable channels
cc	Code amendments to note registry functional specification as a required file format for Part11

Figure 21- Summary of key changes to the trader switching processes

Switch event meter readings must be actual reads rounded to two decimal places. The switch completion (CS) file, including event meter readings, must be submitted no later than the switch event date or the receipt of the NT file from the registry, whichever is later. The submission of AN files is optional for HH gaining trader-driven switches.

Trader ICP switch can withdraw at any time before the 14-month reconciliation revision period for the month of the switch event date. Response codes in AN files must follow the priority order outlined in the functional specification to ensure the most relevant response is selected. The registry functional specification should be updated to clarify the use of withdrawal codes. Traders must accept a switch withdrawal within five business days of the NW file date when specific reasons such as invalid ICP status, metering issues, wrong premises, or other circumstances such as customer-related errors are cited. Additionally, the registry manager must notify losing traders if a completed ICP switch is withdrawn and registry data has changed since the switch was first completed.

All non-AMI meter readings must be time-stamped at 00:00 on the day of the reading or switch event, regardless of the actual reading time. Both gaining and losing traders are allowed to use the RR process to correct inaccurate switch event readings, with multiple replacement reads up to four months after the CS file delivery, enabling corrections for backdated switches beyond four months as well. Traders are mandated to respond to RR requests within five business days, reducing manual follow-ups. The RR process initiation threshold is lowered to ±50kWh per channel, with a ±1kWh threshold introduced for replacing an NHH switch event read with an AMI read within five business days. These changes aim to reduce reliance on RR through greater use of actual midnight reads.

Traders are permitted to assign an ICP in "New" status by updating it to "Inactive" with the reason "New connection in progress," provided that the distributor confirms the site is ready for connection. Traders must supply average daily consumption for metering channels with accumulator type "C" and settlement indicator "Y," based on at least 30 days of actual data, the trader's full tenure if under 30 days, or prior retailer data when applicable.

Gaining traders must use a specific switch type code in NT files to identify mass customer acquisitions or system transfers, differentiating them from standard retailer ICP switches. AN files are optional for HH gaining trader-driven switch types. Senders of AN files must apply the relative response code priorities outlined in the functional specification to ensure the most relevant and accurate response is selected. Retailer switch notifications and acknowledgments must be uniformed in less than two business days, reflecting current system capabilities and improving the registry processing response times.

Finally, gaining traders involved in HH switch processes must include switch event meter readings in the switch completion (CS) file when the registry records a channel with accumulator type "C" and settlement indicator "Y." The Code is amended to explicitly require adherence to registry functional specification as the mandatory file format standard for all of Part 11.

3.2.2.2. Proposed Reforms to the Current Metering Equipment Provider (MEP) Switching Arrangements

The proposed changes to metering equipment provider switching arrangements offer several key benefits, including an improved customer experience by equipping traders with more accurate metering information to support appropriate and realistic offers. These enhancements will lead to more precise metering records and invoicing. Moreover, by improving the transparency of MEP switches, the changes will reduce data errors and the need for rework. Additionally, the proposals support greater system and process efficiency, minimizing manual interventions, reducing exceptions, and lowering overall participants compliance costs.

Figure 22 illustrates issues with the current MEP switching arrangements, including:

- limitations in the configuration and functionality of the central registry
- inconsistent meter reading file formats across different MEPs
- delays in accessing accurate metering records.

Registry constraints:

As depicted in Figure 22, the registry’s structure, which groups data by “event” under each Installation Control Point (ICP), requires all fields within an event to be updated when any single field changes. The registry manages updates by ending the previous event and creating a new one effective from the update time. Moreover, the registry is limited to recording one event per day. Therefore, multiple submissions from the same participant are retained with the last used for reporting; submissions from different participants on the same day may result in one being rejected or overwritten. In the context of MEP switches, this means that both the gaining and losing MEPs cannot align on a shared event date, creating discrepancies between registry records and actual metering activities.

Additional complications arise from the limited granularity of the registry's data fields, which fail to differentiate between metering types beyond a basic advanced metering infrastructure (AMI) flag. AMI meters differ in their ability, and accurate knowledge of meter types is essential for retailers to align offers with metering capabilities before contracting.

Currently, MEP's responsibility at an ICP is indicated by a participant identifier in the registry. To update this, the ICP's trader must nominate a new MEP, who must then accept and upload updated metering records. Many MEPs hold multiple participant identifiers, but transferring metering between them requires a full update process, even without metering changes, leading to unnecessary work for traders and MEPs, especially during bulk participant identifier changes.

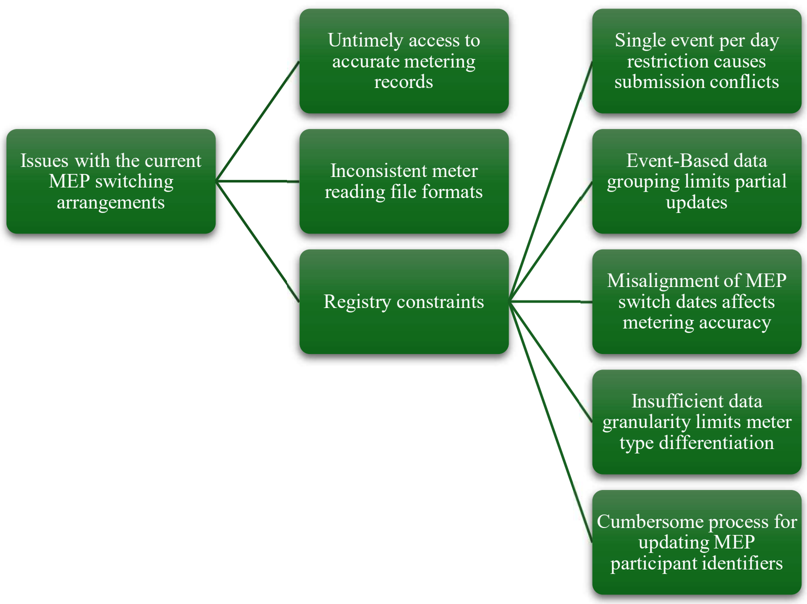

Figure 22- Summary of issues with registry's structure

- **Inconsistent meter reading file formats:**

Inconsistent meter reading file formats across MEPs lead to inefficiencies and a higher risk of errors. Since only the MEP can read a meter (e.g., AMI meters) and supply meter readings to the trader based on mutual agreement, traders must build custom interfaces to standardize the data. This issue creates barriers for new retailers and hinders market competition. The Authority encourages MEPs to collaborate to minimize format discrepancies while ensuring competition remains fair and compliant with the Commerce Act 1986.

Untimely access to accurate metering records:

Figure 23 provides a summary of issues related to untimely access to accurate metering records.

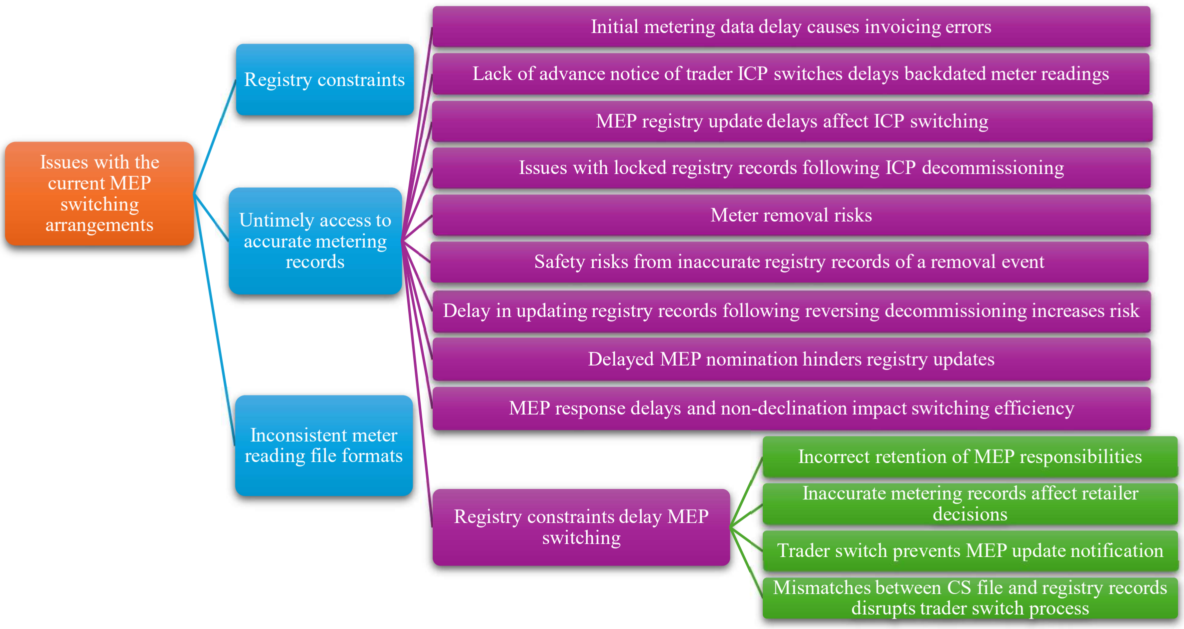

Figure 23- Summary of issues with untimely access to accurate metering records

As depicted in Figure 23, untimely access to accurate metering records creates a range of operational inefficiencies. The Authority expects prompt MEP updates, but delays can cause invoicing errors and market settlement inaccuracies. Delays in backdated meter readings often occur because MEPs lack advance notice of trader ICP switches. In addition, hindering updating registry records, despite expected Code timeframes, can affect ICP switching. Furthermore, when an ICP is decommissioned, most MEPs do not remove the metering record from the registry due to registry functionality that locks records once decommissioned. In rare cases of error, distributors can reinstate the ICP by removing its decommissioned status in the registry.

Another consequence is the risk that arises when an MEP removes metering components, rendering the installation non-functional or unsafe for connection.

Until the MEP updates the registry with the corresponding removal event, the registry may incorrectly indicate that a safe, functional meter is in place. Traders relying on this inaccurate information may reconnect the ICP and commence trading, leading to potential safety hazards and operational inefficiencies. Moreover, to mitigate risks, the registry manager must notify the MEP when a decommissioning is reversed; delays in updating metering records can still allow risks to arise.

Some traders delay the nomination of the MEP until they receive paper metering records from the gaining MEP, sometimes over 10 business days after installation, which prevents timely registry updates. MEPs have up to 10 business days to accept a nomination and are not required to respond if declining; some delay their acceptance until installation is confirmed, while others may not decline at all, creating uncertainty and delays.

During the transition period, the losing MEP remains recorded as responsible in the registry. Unless they reverse their metering event, the gaining MEP cannot assume responsibility, leading to several operational issues. As a result, the losing MEP incorrectly retains obligations under the Code, including metering accuracy, certification, and AMI meter reading delivery.

The registry may reflect outdated metering records, misleading potential retailers about the ICP's status. This can result in incorrect decisions or the need for costly meter replacements to deliver contracted services. If the ICP switches to another trader before the losing trader notifies the registry of the MEP change, the registry cannot be updated. Although manual workarounds exist, they are inefficient and time-consuming. The trader switch process may fail if the meter readings in the switch completion file (CS file) do not align with registry records.

Summary of proposed changes for MEP switching

To address barriers in the current Metering Equipment Provider (MEP) switching process, a set of amendments to the Code and registry is proposed as depicted in Figure 24.

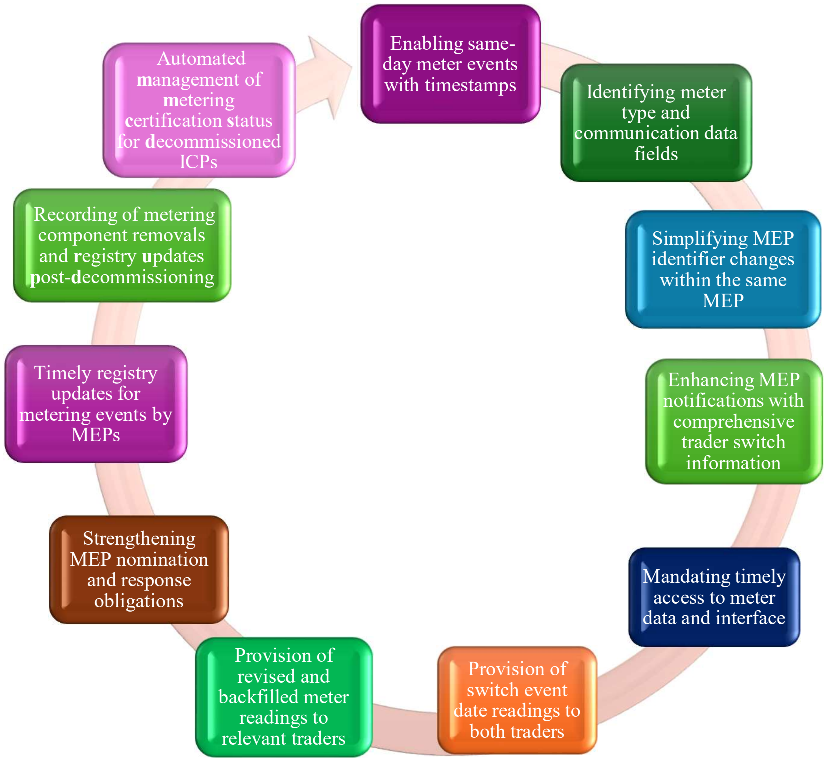

Figure 24- Summary of proposed changes for MEP switching

As depicted in Figure 24, both gaining and losing Metering Equipment Providers (MEPs) would be permitted to record events on the same day with clear timestamps. The registry would be enhanced with new fields to capture detailed meter type and communication capability data, summarized at the ICP level. MEPs may also internally update participant identifiers when both belong to the same entity, eliminating the need for trader involvement. Further, the registry must deliver additional notifications to MEPs, including both gaining and losing traders identifiers. MEPs will be obligated to grant gaining traders timely access to the services interface and meter readings, while also providing switch event meter data to both parties, subsequent readings going solely to the gaining trader. Any revised or missing readings obtained from metering installations must be shared with relevant traders. Traders must notify the registry manager of MEP nominations, and MEPs must accept either accept them by the metering installation date or formally decline them. Unaccepted nominations will be auto-declined by the registry within set timeframes, and both parties must include compliance with this process in their audits. MEPs are required to update new or amended registry metering events for 75% of ICPs within five business days and 100% within ten business days, calculated over a 12-month period. Additionally, MEPs must update the registry with metering component removal events regardless of ICP decommissioning status, ensuring accurate records even when components are removed before decommissioning. Moreover, the registry should auto-end metering certification when an ICP is decommissioned and reinstate it if it is done in error. If metering equipment was removed, the registry must notify the MEP upon reinstatement.

3.2.2.3. Proposed Reforms to Distributer Switching Arrangements

As depicted in Figure 25, the current distributor switching process for Installation Control Points (ICPs) is largely manual. It lacks automated workflows or transparent tracking mechanisms, creating significant operational inefficiencies and risks, including:

- If a distributor switch is underway and a trader switches the ICP without securing an agreement with the new distributor, the trader may breach the Code and face contractual issues with the customer.
- Correcting such issues requires manual intervention, potentially leading to poor consumer experiences and weakening retail competition.
- Losing distributors may be unaware of ICPs being switched or any changes to the switch schedule. Additionally incorrect ICP identification by the gaining distributor may result in the losing distributor being responsible for registry data of an ICP no longer on its network.
- Traders might not realize the ICP has switched networks, leading to inefficiencies such as missing agreements discussed above.
- The Code mandates that gaining distributors must obtain trader consent for any proposed ICP switch, which can delay or complicate the switching process.
- The Authority currently depends on gaining distributors’ documentation to confirm trader approvals before updating the registry for distributor ICP switches.

In addition to issues with manual process, the registry does not capture information on network extensions managed by parent distributors, causing confusion over responsibilities for faults, connections, and switch approvals.

The other category of existing issues with distributor switching arrangements in the Code relates to partial-day ICP status changes as follows (Figure 25):

- When a distributor marks an ICP as decommissioned in the registry, it locks out further updates, preventing the MEP from recording the same-day removal of metering equipment.

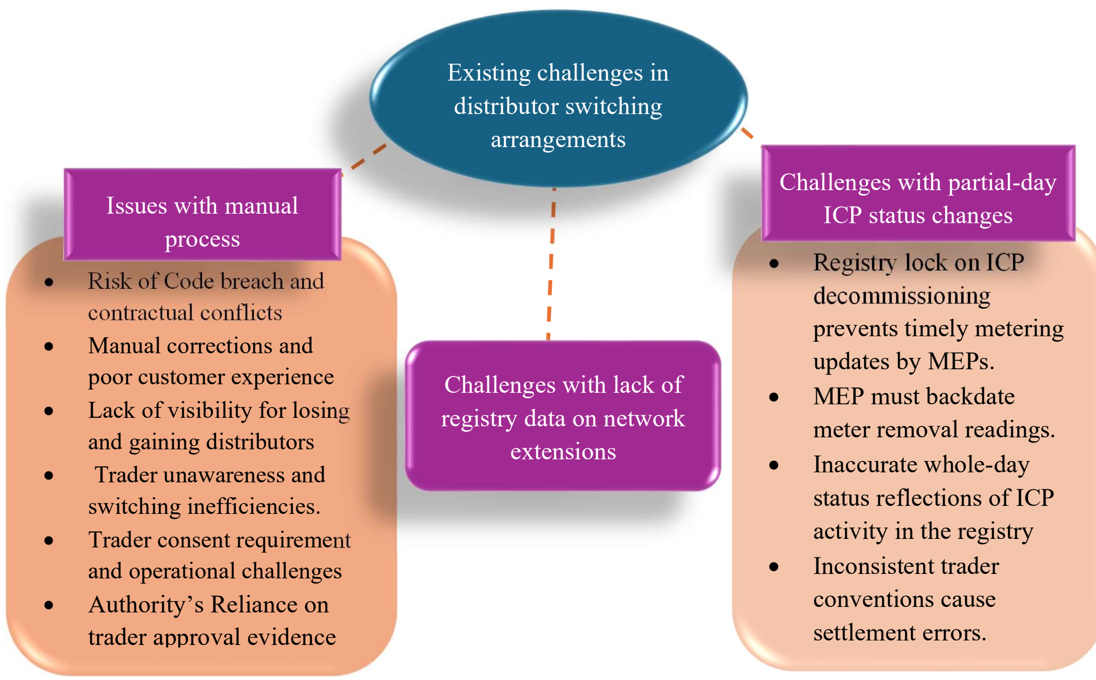

Figure 25- Summary of existing distributor switching challenges within the Code framework

- To reflect meter removal on the decommissioning day, MEPs must backdate the removal event and meter reading by one day, creating inconsistencies.

- Because ICP status changes (Active ↔ Inactive) are recorded for the whole day, actual electricity flows during partial days are not accurately reflected in the registry.

- Traders use different conventions to record status changes, leading to mismatched ICP day counts and misallocation of electricity volumes during settlement.

The issues outlined above can be effectively addressed through targeted amendments to the Code. Figure 26 shows the summary of proposed changes for distributor switching.

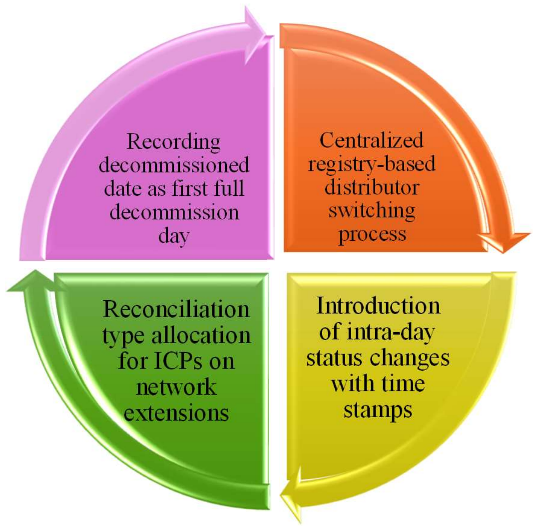

Figure 26- Summary of proposed changes for distributor switching arrangements

As depicted in Figure 26, the proposed changes introduce a new distributor switching process that will centralize all transactions through the registry. Moreover, distributors will be required to assign a reconciliation type to each ICP, especially those on network extensions. Status updates must now include both time and date stamps to accurately capture intra-day changes. Decommissioned ICPs must have their status recorded as the day after physical disconnection to ensure consistent data handling.

Figure 27 outlines the detailed process changes implemented through the Registry Hub to support and manage distributor switches effectively. As depicted in Figure 27, before initiating a distributor switch, the gaining distributor must manually obtain consent from the losing distributor, typically via email or contractual agreement. At least 60 days before the intended switch date, shorter than the previously proposed 70 days but aligned with current regulatory practices, the gaining distributor submits the list of Installation Control Points (ICPs) to the registry. Upon receipt, the registry marks the ICPs as "distributor switch in progress” and “awaiting trader consent,” subsequently notifying relevant traders and Metering Equipment Providers (MEPs). The gaining distributor then directly engages with traders, providing pricing and agreement details. Traders must submit their approval or denial of the switch directly to the registry. If a trader denies consent, the gaining distributor must engage in discussions to resolve the objection; if resolution is not reached, the switch is withdrawn. If no response is received from a trader at least five days before the switch date, consent is deemed to have been granted. Additionally, if an ICP is assigned a new trader, that trader is automatically considered to have consented to the switch. Should the switch date change, all involved parties are notified, with the new date required to fall within 30 to 60 days of the original to maintain the validity of previously granted consents. Any substantive updates, such as changes to network information, necessitate the resetting and re-obtaining all trader consents. On the event date, if all required consents, explicit or deemed, are in place, the switch proceeds automatically; however, if any trader objects, the switch is cancelled.

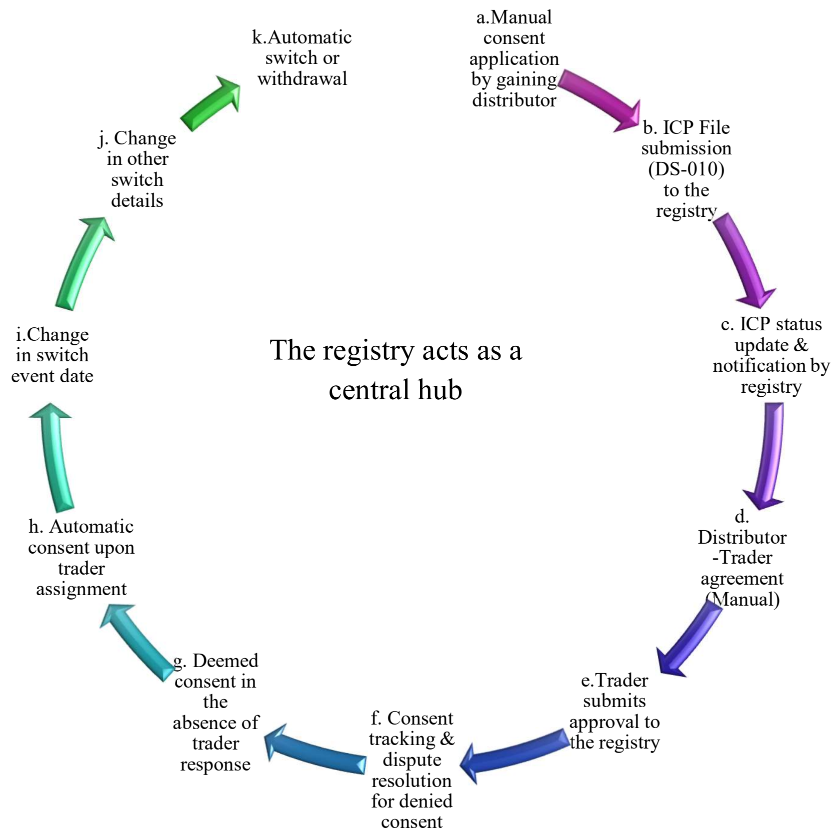

Figure 27- Detailed Process and conditions for executing a distributor switch

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