

Appendix B – Technical submission form

Improvements to switching processes

Submissions should be emailed to policyconsult@ea.govt.nz with ‘Consultation – Improvements to switching processes’ in the subject line by 5pm, Monday 14 September 2026.

The Authority invites technical submissions on the Code amendment drafting to give effect to its decisions on ICP switching process changes. We are not seeking further submissions on the intended decisions or their supporting rationale.

Organisation	Bluecurrent
Contact persons	Luz Rose Senior Regulatory and Policy Partner Luz.Rose@bluecurrent.co.nz and/or Joseph Taylor Compliance Manager Joseph.Taylor@bluecurrent.co.nz

Q1. Would you prefer an implementation timeframe longer than 12 months?

If so, please indicate if 15 or 18 months is preferred and give reasons why.

Bluecurrent welcomes the Electricity Authority’s (the Authority) decision to progress the proposed industry switching improvements separately from the introduction of multiple trading relationships (MTR). The de-linking of both workstreams reduces the level of complexity of the already complex undertaking of implementing switching process improvements.

Bluecurrent proposes a 24-month timeframe for the implementation of the proposed switching process improvements. In our 2025 submission on *Evolving multiple retailing and switching*, we identified the proposed changes to the *Electricity Industry Participation Code* (the Code) to enable these improvements that would, or are likely to, require IT system development.¹ This would require significant investment on our part.

Based on our experience in IT system development in the New Zealand and Australian electricity markets, we consider a 24-month implementation timeframe to be realistic (subject to clarification of our questions below). IT system development is, to various extents, a discovery process; its non-linear and iterative nature warrants a degree of flexibility around the technical approaches that would deliver the desired systems and outcomes.

Furthermore, the need for the various improvements to be implemented by multiple registry users at the same time injects a considerable degree of complexity to this work. We assume there will be changes to the processes between metering equipment providers (MEPs) and traders which need to be integrated in a seamless manner.

As an implementing party, we need to understand the sequence of implementing the various components of the proposed improvements: determining the resources required, estimating

¹ https://www.ea.govt.nz/documents/8084/Bluecurrent_MTR_submission.pdf, pages 7 - 10

costs, setting timeframes so we can plan for cost approvals, designing the build process, building the system, conducting testing, etc. We would be doing this in parallel with implementing complex internal projects to improve the delivery of our metering and data services that would ultimately benefit end consumers.

To inform the determination of a realistic implementation timeframe, we seek clarification from the Authority on the following matters:

- Coverage of the “implementation timeframe” – What processes/stages relating to MEPs will be captured in this timeframe? When does the clock formally start for MEPs? Do we start developing new systems alongside the Authority’s published timeframe? Do we need to have implemented all the required changes by the Authority’s go-live date?
- Whether the proposed changes will be implemented within the existing electricity registry platform or whether a new/expanded platform will emerge alongside new systems developed by traders, distributors, and MEPs. This would have a significant bearing on the complexity and timing of implementing the various components of the required systems.
- Whether the Authority’s expectations in the delivery of the improved switching processes relating to mass market customers are different from the processes for C&I customers.
- Whether the Authority expects implementing parties to continue leveraging existing arrangements, or whether an entirely new data exchange framework is contemplated. Bluecurrent currently provides validated metering data to traders for AMI-capable metering installations as part of established market processes. We query whether existing AMI meter data flows and market data exchange processes would be leveraged to deliver some of the proposed switch event reading requirements, rather than creating new MEP-to-retailer processes and interfaces. Our preference is to use existing systems as far as possible to minimise costs and avoid an unnecessarily long timeframe.

Understanding the Authority's intended approach is important to assessing implementation scope, development effort, compliance obligations, and overall industry costs. In relation to scope, it needs to be clarified whether the proposed changes and obligations will only apply to Y flagged AMI meters.

We encourage the Authority to consider the multiple reforms that implementing parties are currently facing in determining the implementation timeframe.

The determination of a realistic timeframe can benefit from technical discussions/workshops between the Authority and the implementing parties, and at least another submission process prior to the Authority finalising the Code changes.

In addition, we suggest that the Authority establish a ‘switching improvements technical group’ to help achieve alignment of expectations around the technical requirements of this complex undertaking. This technical group could provide advice on a realistic implementation timeframe and help steer the implementing parties’ work from the solutions design stage to the go-live stage and any post-implementation monitoring and necessary adjustments. This group could comprise technical representatives from traders, distributors, MEPs, and the registry manager, with oversight from the Authority.

Question 2: Are there any parts of the Code drafting that, in your view, do not accurately reflect the provisional decisions outlined in this paper?

If so, please identify the issue and set out any proposed amendment(s).

Part/ Clause	Bluecurrent's comments
Part 10 Metering Schedule 10.6 - Metering equipment provider ongoing obligations and functions	Proposed Code change: Require the registry manager to provide MEPs with additional notifications including gaining trader ICP switch requests (NT file), losing trader switch acknowledgements (AN file), switch withdrawals (AW file), and distributor switches and ensuring the notifications contain both the losing and gaining participant identifiers. Bluecurrent's comments: While this proposed change will not impose a direct requirement on Bluecurrent (which is the recipient rather than the source of the above notifications), we do not see the significant value this new/potentially redundant information will add to our operations. Under this proposed requirement, we will have to create additional storage for this new information which we may never actively use, at least under current arrangements.
	Proposed Code change: Require MEPs to provide gaining traders with access to the services access interface and meter readings within specific timeframes. Bluecurrent's comments: Traders can access Bluecurrent's data delivery via SFTP. We provide validated register and half-hourly data to losing and gaining traders for mass market customers, and monthly validated half-hourly data for C&I customers. We do not provide register reads for C&I traders. As indicated in our response to Q1, meter reading data is already available through existing market interfaces and participant data exchange arrangements. The Code should permit those existing arrangements to satisfy some or all of the proposed requirements. This would reduce implementation complexity while maintaining the intended access to metering information.
	Proposed Code change: Require MEPs to supply both gaining and losing traders with meter readings for the switch event date, and then to gaining traders going forward. Bluecurrent's comments: We currently provide meter readings to both gaining and losing traders for the switch event, assuming this is the effective date.

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Where an actual AMI meter reading exists for the switch event date, that reading should be capable of being utilised through existing market processes and notifications. In this scenario, we recommend that the Code remain technology and process neutral, allowing participants to achieve the intended outcome using existing data exchange mechanisms where those mechanisms deliver equivalent accuracy, consistency and transparency outcomes.

We wish to discuss with the Authority the extent of the data requirements to achieve the desired outcome of this proposed Code change.

Proposed Code change: Require MEPs to supply relevant traders with revised meter readings or backfilled meter readings (i.e. readings from a metering installation interrogated by the MEP which were not previously delivered to the relevant trader).

Bluecurrent's comment: We currently provide backfilled meter reads to traders that have previously not received them. We do not 'revise' meter readings but provide the reads from the meter.

Proposed Code change: Require MEPs to populate new or amended registry metering events for ICPs within five business days of the metering installation being certified/modified, or from when the ICPs status changes to "active". For clarity, the MEP has control of the performance of its agents (e.g. contractors and technicians), and the certifying ATH through the terms of their arrangements. Compliance with this requirement would be included in the MEP's audit.

Bluecurrent's comment: We recommend that the timeframes stay the same as we do not have complete control of this process end-to-end. For example, we have some issues with traders who appoint the MEP post-installation, which adds to the time required for this process to be completed. Given the complexity of C&I installations, compliance with the proposed timeframe is not realistic. Completion of this process is dependent on the verification and review of all installation documentation by the ATH, which introduces an additional step.

Proposed Code change: Require MEPs to populate metering component removal events in the registry whether the ICP is

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	decommissioned or not and ensure the registry can be updated once the status has been changed to decommissioned. Bluecurrent's comment: We need to assess the impact this required change would have on our systems. We expect a timeframe of 10 business days would be appropriate, which aligns with timeframes for similar updates. Proposed additional Code change: The Authority would amend the Code 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. Bluecurrent's comment: We seek clarification or examples from the Authority regarding what scenarios constitute, or potentially constitute, a "fault of the MEP". The wording of this proposed Code change should reflect that this is limited to ICPs with AMI meters. Non-AMI meters continue to present interface access challenges. However, as the number of non-AMI meters declines, the impact of this issue is expected to diminish.
Schedule 11.3 5 Providing final information	We seek clarification around the following proposed Code changes in relation to the provision of final information (page 46 of the consultation paper). The impact of these issues is expected to diminish as the number of non-AMI meters declines. Proposed Code change: 5(2) The switch event meter reading provided in subclause (1) must be from the following: (a) an AMI meter, in which case the meter reading must be a midnight meter reading... Bluecurrent's comment: We provide the midnight read to the losing trader in the standard consumption data file. Does this mean we will be meeting the proposed requirement or does a new process need to be established? Proposed Code change: 5(2)(b) a non-AMI meter, in which case the meter reading must have a time stamp of 00:00 hours even if the meter reading was not obtained at midnight.

Question 2: Are there any parts of the Code drafting that, in your view, do not accurately reflect the provisional decisions outlined in this paper?

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	Bluecurrent's comment: We do not provide read files for non-AMI meters. Proposed Code change: 5(3) If the metering equipment provider is responsible for interrogating the metering installation under Part 10, the metering equipment provider must provide raw meter data for each meter or data storage device that is recorded in the registry with an accumulator type of C and a settlement indicator of Y to the gaining trader and losing trader for 00:00 hours (midnight) on the event date notified by the registry manager. Bluecurrent's comment: If the final read is provided in the losing trader's data file, and is also provided to the gaining trader, will we be meeting the above requirement? Proposed Code change: 5(4) If final information is not provided on the event date, the final information must be provided no more than one business day after the date on which the registry manager, under clause 22(1)(a), makes written notice available to the losing trader. Bluecurrent's comment: This will require system development for Bluecurrent.
Schedule 11.4 Metering equipment provider switching and registry metering records	Bluecurrent's comments: The proposed amendments to Schedule 11.4 introduce several obligations and capabilities that do not exist today. These include the mandatory recording of metering component removal events, automated registry processing associated with ICP decommissioning and reinstatement, tighter audit requirements around registry metering events, and increased accountability for the timeliness of field-driven registry updates. We note that the above changes are not simply procedural adjustments or improvements to existing processes. They will require the development and implementation of new operational capabilities, including enhancements to asset management platforms, field-to-office information flows, exception management controls, system integrations, reporting frameworks, monitoring and audit. As such, we prefer considering approaches that leverage existing systems to the extent possible, while producing equivalent outcomes at lower costs for the implementing parties.

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Table 1: Registry metering records

Part 16A Audits

Proposed Code change: Part 16A Audits

Bluecurrent's comment: Bluecurrent proposes an audit-free (transitional) period of 24 months following the go-live date to ensure the improvements are fully embedded and are working as intended. This would effectively be a real marketplace testing period for all registry users and switching consumers. This period would provide sufficient time to diagnose and fix any IT system bugs that could be caused by the new systems and within the registry, ensuring the process improvements work seamlessly across all registry users.

Q3. Other feedback

If you have any other feedback on the draft Code amendments, please detail this below:

Bluecurrent suggests that the Authority consult with MEPs early in the registry design solutions process and subsequent processes, including registry user training, throughout 2027. This would help us gain an early understanding of the technical requirements and how they are intended to fit together and the resources we require for IT systems development that would enable us to deliver the new requirements as an MEP.

For the reasons stated in our response to Q2 – *Part 16A audits*, we also suggest an audit-free period of 24 months following the go-live date.

We request to meet with the Authority as soon as possible to discuss the technical issues we identified in this submission, including the Authority's expectations of how the desired technical outcomes could be delivered in practice. We also wish to discuss potential alternative approaches that could deliver some of the desired improvements more cost-effectively. This would help us accurately assess the magnitude of the programme of work we will need to plan for and implement.

Bluecurrent looks forward to engaging with the Authority and the other implementing parties on this journey of implementing cost-effective switching process improvements that benefit electricity consumers.

We are happy for the Authority to publish our submission in its entirety.