Operational Review of Metering and Related Registry Processes

Consultation proposal for Code amendment

Submissions close: 5pm, Tuesday 13 November 2018

4 September 2018

Contents

1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this consultation paper is to consult with interested parties on a set of proposed changes to Part 10 and Part 11 of the Electricity Industry Participation Code (Code). These proposed changes follow on from an issues paper we released in July 2017.[1] Many of these issues were previously identified by industry participants.

1.2 Part 10 regulates how metering installations are used to accurately measure and record electricity conveyed. This promotes the accurate clearing and settlement of the wholesale electricity market. Part 11 regulates the management of information in the registry of installation control points (ICPs) and the switching of ICPs between traders.

1.3 The proposed changes to Parts 10 and 11 address a number of operational problems that impede the efficient operation of the electricity industry. Fixing these problems will further the Electricity Authority's (Authority) statutory objective.

1.4 Section 39(1) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and the corresponding regulatory statement. The regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the proposed amendment's costs and benefits, and an evaluation of alternative means of achieving the proposed amendment's objectives.

1.5 Under section 39(3)(a) of the Act, if the Authority is satisfied a proposed amendment is technical and non-controversial, the Authority need not provide a regulatory statement or consult on the proposed amendment. The Authority considers that five of the 33 proposals in the Operational Review of Metering and Related Registry Processes are technical and non-controversial. Therefore, we have not provided a regulatory statement for them. Although we are not required to consult on the technical and non-controversial changes, we invite comment on all proposals in the Operational Review of Metering and Related Registry Processes.

How to make a submission

1.6 The Authority's preference is to receive feedback via our online consultation platform. In this platform, each of the issues in Table 1 (below) has a separate form for feedback, and general feedback on the consultation and issues from Tables 2 and 3 are grouped into a single form each. If you do not have access to the platform, an electronic copy (Microsoft Word) in the format shown in Appendix D is available on our website.

1.7 Submissions in electronic form should be emailed to submissions@ea.govt.nz with "*Operational Review of Metering and Related Registry Processes*" in the subject line.

1.8 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

[1] https://www.ea.govt.nz/development/work-programme/operational-efficiencies/operational-review-of-metering-and-related-registry-processes/.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

1.9 Please note we want to publish all submissions we receive. If you consider that we 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 we can publish (if we agree not to publish your full submission).

1.10 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.11 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.12 Please deliver your submissions by **5pm** on Tuesday **13 November 2018**.

1.13 We will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2 Operational Review of Metering and Related Registry Processes

This paper follows an issues paper published in 2017

2.1 This consultation paper follows on from an issues paper we released in July 2017.[2] The issues paper sought feedback on a number of issues that related primarily to Part 10. Many of these issues had been previously identified by industry participants. Industry participants also identified additional issues as a result of the issues paper.

2.2 We have considered the submissions we received on the July 2017 paper. From this review of submissions, we now propose a number of changes to the Code.

2.3 We have not proposed a Code change for every issue identified in last year's issues paper and/or in submissions on that paper. In some instances, we consider that amending the Code is not necessary to resolve the identified issue and we have explained our reasons. In four instances we wish to investigate the issue further, and so have not included these four issues in this omnibus consultation. Please refer to Table 4.

We expect the proposed changes will further our objective

2.4 The proposed Code changes are intended to:

(a) clarify participants' obligations, leading to increased participant compliance at lower cost

(b) remove from the Code some outdated, ineffective, or obsolete metering-related requirements on participants

(c) ensure the Code's metering-related provisions are not inhibiting innovation in metering technology and related services.

2.5 As discussed in section 3, we expect these changes will promote our statutory objective, particularly by promoting the efficient operation of the electricity industry.

We have set out our proposed resolution of the issues in three appendices

2.6 We have set out our proposed resolution of the issues related to Part 10 in three appendices, as follows:

(a) Appendix A: Code amendment proposals that require a regulatory statement

(b) Appendix B: Code amendment proposals that are technical and non-controversial, which do not require a regulatory statement

(c) Appendix C: Issues that we propose to resolve without a Code amendment.

2.7 Tables 1—3 below list the issues that we propose to address via one of the three options listed above.

2.8 Most of the proposed Code amendment proposals address a discrete issue, but in some places proposed changes intersect or overlap. Because each proposal stands on its own, some may proceed while others may not. Showing the drafting changes separately

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2 https://www.ea.govt.nz/development/work-programme/operational-efficiencies/operational-review-of-metering-and-related-registry-processes/.

allows submitters to assess how each proposed amendment would affect Code obligations.

Table 1: Code amendment proposals requiring a regulatory statement

Reference number	Topic	Page
001	Electrically disconnecting other traders' ICPs	14
002	Prohibition of net metering	29
003	Recovering certification costs	32
004	Distributor NSP information notifications to reconciliation manager	35
005	Like-for-like replacements and consultation	38
006	Metering issue resolution timing	42
007	Minimum voltage requirements	46
008	Prevailing load checks	49
009	ISO 9001 sync with class B ATH application period	55
010	Selected component recertification	59
011	Raw meter data and compensation factors	62
012	Monitoring of event logs	67
013	Raw meter data output test	71
014	HHR certification and interrogation cycles	74
015	Comparative recertification	79
016	Error calculations at certification	83
017	Application of error compensation	86
018	Certification validity periods	89
019	Measuring transformers and burdens	97
020	Alternative certification for POC to the grid	106
021	Obsolete sticker removal	108
022	Inspection periods	110

Reference number	Topic	Page
023	Combining certification stickers	114
024	NSP decommissioning timeframes	117
025	MEP updates of HHR/NHH and AMI flags	121
026	Excluding non-market-related meter registers	129
027	Meter resealing by traders	132
028	Meter bridging	139

Table 2: Technical and non-controversial Code amendment proposals

Reference number	Topic	Page
029	Reconciliation manager file format specifications	145
030	Distributor notifying reconciliation manager of new NSPs	147
031	Content of interrogation logs	150
032	Automatic cancellation of metering certification	152
033	Measuring transformer terminology	158

Table 3: Issues proposed to be addressed without a Code amendment

Reference number	Topic	Page
034	Certification of metering installations and trading	161
035	Designating and Metering Network Interconnection Points	163
036	Alternative load checks after component recertification	165
037	Regulating metering used for non-reconciliation purposes	166
038	Daylight savings and time switches	167
039	Metering records	169
040	In-situ recertification	171

Table 4: Issues the Authority is investigating further

Reference	Topic
MEP assuming responsibility	Issues with how and when an MEP takes responsibility for an ICP, and the timing of traders' MEP notifications to the registry.
Initial energisation date necessity	Issues with distributors populating the registry with the correct initial electrical connection date.
NHH decimal places	Issues with how decimal places in raw meter data are managed.
MEP change of ownership	Issues with MEPs wanting to arrange for an orderly exit from the electricity market.
Main switch checks	Safety checking and sealing main switches as part of metering installation certification
Alternative load checks after component recertification	Whether prevailing load checks or an alternative process can be uses in situations where no changes have been made to wiring, configuration, or multipliers.

3 Assessment of the costs and benefits of the proposed Code amendments

We have prepared a single cost benefit analysis for all of the proposals

3.1 Many of the Code amendment proposals in this paper have the same, or similar, costs. Similarly, many of the proposals have the same or similar benefits. Therefore, we have undertaken one cost-benefit analysis (CBA) for all the Code amendment proposals that require a regulatory statement. This is set out here.

We have prepared a qualitative CBA

3.2 We have undertaken a qualitative assessment of the expected benefits and costs of the proposals. We have compared the proposals against the status quo arrangements. We have undertaken a qualitative CBA because it has not been practicable for us to obtain sufficiently robust information on which to base a quantitative CBA. We welcome such information from submitters.

Assessment of proposals' costs

3.3 We expect the majority of proposals would impose relatively minor costs on industry participants, when compared with the status quo arrangements.

3.4 Table 5 summarises our qualitative assessment of the proposals' costs.

Table 5: Assessment of proposals' costs

Material costs
1. Cost on participants for the installation of burden resistors in metering installations.
Minor costs
1. Updating procedures (ATHs, distributors, MEPs, and traders) and template certification reports (ATHs only) 2. Minor process change cost for MEPs if their methodology for calculating recoverable certification costs was inconsistent with the methodology set out in Proposal 004 (Recovering certification costs) 3. Relatively minor operational cost for MEPs who mistakenly do not currently consult with the relevant trader and/or distributor when making a like-for-like replacement of a metering component 4. Relatively minor ongoing operational cost for some MEPs and reconciliation participants who mistakenly do not currently review event logs for metering installations they are responsible for. 5. Some one-off costs for MEPs who need to recertify metering installations on the rare occasions that fail the raw meter data comparison test. 6. Occasional very minor cost for ATHs to note, in the certification report for a metering installation, the reason for a shorter validity period. 7. Very minor ongoing cost for ATHs to remove or obscure an obsolete certification sticker at a metering installation when the ATH is attaching a new certification sticker to the metering installation 8. Relatively minor cost on MEPs to change their processes to ensure the HHR/NHH and AMI flags in the registry are updated within 30 days of a change in the status of the metering installation.

Assessment of proposals' benefits

3.5 We expect the majority of proposals would deliver relatively minor benefits, when compared with the status quo arrangements.

3.6 Table 6 summarises our qualitative assessment of the proposals' benefits.

Table 6: Assessment of proposals' benefits

Material benefits
Material benefits relating to competition in the electricity industry
1. Reducing the transaction costs that a retailer may face in determining whether it can offer services to a potential customer at an ICP
Material benefits relating to the efficient operation of the electricity industry

1. Improving the accuracy of submission information, which would lead to more accurate reconciliation and wholesale market settlement, and more accurate invoicing of participants and consumers 2. Reducing participants', and the Authority's, audit and compliance costs 3. Removing an unnecessary cost for MEPs, arising from their obligation to record metering data in the registry that is not used for reconciliation and settlement of the wholesale electricity market 4. Removing an unnecessary cost for traders, arising from their billing systems managing the additional metering data recorded in the registry 5. Removing unnecessary costs on participants, and ultimately consumers, arising from the unnecessary displacement, or duplication, of metering installations at points of connection where a distributor wishes to bill consumers directly using information that traders' systems cannot accommodate.
Minor benefits
Minor benefits relating to competition in the electricity industry
1. Reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs 2. Ensuring that traders always receive raw meter data from import and export metering in a format that allows for flexibility in the design of consumer products.
Minor benefits relating to reliable supply by the electricity industry
1. Facilitating the timely electrical connection of consumers 2. Reducing the number of times traders electrically disconnect consumers that are not the traders' customers 3. Helping ensure consumers' metering installations are fit-for-purpose for their connection type.
Minor benefits relating to the efficient operation of the electricity industry
1. Reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs 2. Ensuring a trader or distributor that electrically disconnected a responsible trader's customer would be required under the Code to reconnect the customer. This would avoid the potential for unnecessary transaction costs on the responsible trader and its customer, if the party at fault did not reconnect the customer 3. Helping to ensure consumers pay for the services they use from, and/or the costs they impose on, the New Zealand electricity market 4. Making the Code easier to understand thereby reducing participants' cost of transacting in the electricity market 5. Making it easier for MEPs to calculate the certification costs payable by an MEP taking responsibility for a metering installation 6. Helping to ensure MEPs consider other participants' needs when changing existing metering installations 7. Promoting the timely resolution of metering issues, thereby minimising adverse effects on customers and unaccounted for electricity in the wholesale electricity market 8. Making it easier for participants to understand the testing requirements for metering components 9. Helping ensure the appropriate tests are performed, in order to have accurate

metering installations

10. Reducing the cost and instances of errors associated with calibrating metering components
11. Reducing unnecessary duplication of effort between MEPs and reconciliation participants around the reviewing of metering event logs
12. Helping ensure ATHs undertake a raw meter data output test appropriately, thereby better ensuring the accuracy of the metering installation being tested
13. Reducing testing costs for some ATHs because of a simplification of the raw meter data output test for electronic meters
14. Ensuring a check to validate the accuracy of volume information provided to the reconciliation manager is performed
15. Removing the possibility of participants incurring unnecessary transaction costs associated with an ATH wrongly using alternative certification for a metering installation at an NSP
16. Improving the accuracy of metering installations by clarifying what is needed to correctly calculate the error of the metering installation
17. Removing the possibility of participants applying error compensation to metering installations that are not at a point of connection to the grid
18. Reducing the possibility of an electronic meter failing because of there being an extended period of time between when the meter was certified and when it was installed
19. Helping ensure metering installations with measuring transformers are accurate by clarifying ATHs' obligations in regard to the treatment of the in-service burden during the certification of a measuring transformer and metering installation
20. Removing an impossible obligation on ATHs to certify measuring transformers in a test laboratory
21. Reducing the number of consumer queries that retailers and the Authority receive, by reducing confusion for consumers about whether their metering installation is certified, and therefore is accurately recording electricity quantities
22. Helping ensure ATHs undertake inspections of category 1 metering installations appropriately and in a timely manner, thereby better ensuring the ongoing accuracy of the metering installation
23. Lowering the cost of certifying metering components and metering installations
24. Establishing clear requirements in the Code around the restoration of communications between an AMI meter and an MEP's back office
25. Reducing the cost faced by some traders in winning customers, by avoiding the need for them to replace a potential customer's metering installation(s)
26. Reducing unaccounted for electricity, thereby improving the accuracy of wholesale market settlement and customer invoicing.

Source: Electricity Authority

3.7 The primary economic benefit identified above is a reduction in transaction costs across the electricity industry. This is a productive efficiency benefit.

3.8 Having said this, by improving the clarity and operation of the Code, the proposed amendments could also deliver dynamic efficiency benefits. A clear, predictable, and up-to-date set of industry rules is good regulatory practice, and can facilitate increased participation in the electricity markets. This in turn might be expected to facilitate all three limbs of the Authority's statutory objective, and provide both static and dynamic efficiency benefits to the economy.[3]

We believe the proposals will deliver a net benefit

3.9 Based on the qualitative assessment of costs and benefits, we consider the proposed Code amendments in this consultation paper will, in aggregate, deliver a net benefit.

3.10 We welcome submitters' feedback on our assessment of the costs and benefits of the proposals. In particular, we are interested in whether submitters consider any individual proposals do not have a net benefit.

3.11 Please see questions 5, 7, and 8 in Appendix D for specific questions on the costs and benefits of the proposals.

[3] Static economic efficiency benefits can be broken down into allocative and productive efficiency benefits. Allocative efficiency is achieved when the marginal value consumers place on a product or service equals the cost of producing that product/service, so that the total of individuals' welfare in the economy is maximised. Productive efficiency is achieved when products and services that consumers desire are produced at minimum cost to the economy. That is, the costs of production equal the minimum amount necessary to produce the output. A productive efficiency loss results if the costs of production are higher than this, because the additional resources used could instead be deployed productively elsewhere in the economy. Dynamic efficiency is achieved by firms having appropriate (efficient) incentives to innovate and invest in new products and services over time. This increases their productivity, including through developing new processes and business models, and lowers the relative cost of products and services over time.

Appendix A Code amendment proposals that require a regulatory statement

<table>
<tr><td>Reference number(s)</td><td>001 – Electrical Connection and Disconnection of Points of Connection</td></tr>
<tr><td>Relevant Clause(s)</td><td>Clause 10.29 – When grid owner may connect point of connection to grid

Clause 10.29A – When grid owner may temporarily electrically connect point of connection to grid

Clause 10.30 – When distributor or embedded network owner may connect NSP that is not point of connection to grid

Clause 10.30A – When distributor may temporarily electrically connect NSP that is not point of connection to grid

Clause 10.31 – When distributor may connect ICP that is not NSP

Clause 10.31A – When distributor may temporarily electrically connect ICP that is not NSP

Clause 10.31B – When distributor may electrically connect ICP that is not NSP[1]

Clause 10.33 – When reconciliation participant may temporarily electrically connect point of connection

Clause 10.33A – When reconciliation participant may electrically connect point of connection

Clause 19 of Schedule 11.1 – “Inactive status”</td></tr>
<tr><td>Problem definition</td><td><u>Problem 1</u>

Clauses 10.30 and 10.30A of the Code set out, respectively, when a distributor or embedded network owner may:
a) connect an NSP that is not a point of connection to the grid
b) temporarily electrically connect an NSP that is not a point of connection to the grid.

The Energy Innovation (Electric Vehicles and Other Matters) Amendment Act 2017 (Energy Innovation Act) means these clauses are now less clear.

Amongst other things, the Energy Innovation Act amended the Electricity Industry Act 2010 (Act) to clarify that secondary network providers are captured by the Act’s definition of “distributor”.

Since the Code adopts this definition, an embedded network owner, as a secondary network provider, is a distributor for the purposes of the Code. Therefore, the reference to “distributor” in clauses 10.30 and 10.30A includes embedded network owners.

These clauses are intended to refer to local network owners and embedded network owners. The clauses use the term “distributor” to refer to a local network owner. The clauses’ intended differentiation between local network owners and embedded network owners is less clear since the Energy</td></tr>
</table>

1 Clause 10.31B has been approved by the Authority but has not yet been gazetted, and will likely be gazetted during the consultation period. This consultation is based on 10.31B in the form approved by the Authority.

	Innovation Act became law. This is because any reference to "distributor" in the Code now includes embedded network owners in its meaning. <u>Problem 2</u> Clause 10.33 of the Code sets out when a reconciliation participant may: a) temporarily electrically connect an ICP or an NSP b) authorise the temporary electrical connection of an ICP or an NSP. Clause 10.33A of the Code sets out when a reconciliation participant may: a) electrically connect an ICP or an NSP b) authorise the electrical connection of an ICP or an NSP. Part 1 of the Code defines a reconciliation participant to mean a participant (excluding the Authority, even if the Authority acts as a market operation service provider, and the Rulings Panel) who is any of the following: a) a retailer when purchasing electricity from, or selling electricity to, the clearing manager b) a generator c) a network owner d) a distributor e) a person who purchases electricity from or sells electricity to the clearing manager. The use of "reconciliation participant" in clause 10.33 is not appropriate because the Code provides for the appropriate network owners and distributors to temporarily connect a point of connection elsewhere. Specifically: a) clause 10.29A specifies when a grid owner may temporarily electrically connect a point of connection to the grid b) clause 10.30A specifies when a distributor may temporarily electrically connect an NSP that is not a point of connection to the grid. The policy intent underpinning clause 10.33 is that a trader, rather than a reconciliation participant, may temporarily electrically connect an ICP or NSP. Part 1 of the Code defines a trader to mean a retailer or a generator or a purchaser who— a) buys electricity from the clearing manager; or b) sells electricity to the clearing manager; or c) enters into an arrangement with another retailer or generator or purchaser to buy or sell contracts (or parts of contracts) for electricity for the purposes of the Code. The Authority believes the use of "reconciliation participant" in clause 10.33A may be inadvertently causing confusion for participants. For

	example, in relatively recent times a distributor closed an interconnection point without being requested by the reconciliation participant responsible for the interconnection point. At the time, the metering at the interconnection point was out of service for maintenance. The reconciliation participant responsible for the interconnection point did not notice the distributor's actions for several days, at which point electricity volumes at the interconnection point had to be estimated. Any such confusion could be removed by setting out in separate clauses when a trader, a distributor, and a grid owner may electrically connect a point of connection. <u>Problem 3</u> The example above about the interconnection point also raises a related issue. Currently, clauses 10.31B and 10.33A do not require there to be a certified and operational metering installation at an NSP that is not a point of connection to the grid, before that NSP is electrically connected. <u>Problem 4</u> Under clauses 10.33(1)(a) and 10.33A(1)(a), respectively, only a trader recorded in the registry as being responsible for an ICP may: a) temporarily electrically connect the ICP b) electrically connect the ICP. This means that a gaining trader at an electrically disconnected ICP will be in breach of the Code if it electrically connects the ICP before the switch is completed.[2] A delay in electrically connecting an electrically disconnected ICP is an inconvenience for the customer or embedded generator at the ICP. To avoid this inconvenience, retailers have informal arrangements with each other to allow electrical connection of an electrically disconnected ICP with an incoming customer, prior to the switch completing. This practice ensures customers are not inconvenienced. This practice may, however, inconvenience the losing trader at the ICP unless the event date for the ICP switch is set to be the same date the gaining trader arranges for the ICP to be electrically connected. Should this not occur, the losing trader may end up purchasing electricity from the wholesale market for consumption at the ICP, but with no contractual means to invoice the consumer at the ICP. Aligning the switch event date with the date the incoming trader arranges to electrically connect the ICP requires the gaining trader to inform the losing trader of the date of electrical connection. In addition, there are no protections for the losing trader if the switch is later withdrawn, or the ICP was electrically connected in error. <u>Problem 5</u>

2 This practice is commonly referred to in the electricity industry as "reconnecting" the ICP.

	The Authority has received, and subsequently considered, a complaint that a trader electrically disconnected another trader’s ICP. The Code implies this is prohibited, because only the relevant trader is allowed to change an ICP’s status in the registry (see clause 19 of Schedule 11.1). However, there is no explicit Code provision preventing a trader from electrically disconnecting, or physically disconnecting, another trader’s ICP / point of connection. Therefore, in relation to the above complaint, the Authority found the electrical disconnection was not a breach of the Code. When a trader electrically disconnects the wrong point of connection, the issue is usually resolved between the relevant traders. The Authority acknowledges this typically happens. However, without a specific prohibition on electrically disconnecting the wrong point of connection, there is no compliance process for a trader to rely on if it is unable to agree a resolution with the other trader. Similarly, a trader cannot fall back on the compliance process if a distributor electrically disconnects the trader’s point of connection for reasons other than set out in the distributor’s agreement with the trader or consumer (which will include the reasons set out in Part 8 of the Code).
Proposal	<u>Problem 1</u> To address problem 1, the Authority proposes to amend clauses 10.30 and 10.30A to clarify that the types of distributor each clause is referring to are: a) local network owners b) embedded network owners. <u>Problem 2</u> To address problem 2, the Authority proposes to: a) replace “reconciliation participant” in clauses 10.33 and 10.33A with “trader” b) create new clauses 10.29B and 10.30B to: (i) explicitly set out when a grid owner or distributor may electrically connect an NSP and to provide that only a grid owner or distributor may do so (except where clause 10.33A (electrical connection by trader) applies). <u>Problem 3</u> To address problem 3, the Authority proposes to require a distributor that initiates an NSP under Part 11 to ensure a certified metering installation is in place and operational at an NSP that is not a point of connection to the grid, before: a) electrically connecting the NSP; or b) authorising the electrical connection of the NSP. <u>Problem 4</u>

	To address problem 4, the Authority proposes to amend clause 10.33A as follows: a) to explicitly permit a gaining trader to electrically connect an electrically disconnected ICP where the trader is not recorded in the registry as being responsible for the ICP, provided the gaining trader: i) has an arrangement with a customer or embedded generator at that ICP ii) has initiated a switch within 2 business days of the time of electrical connection and at the same time or before, advises the losing trader of the date of the electrical connection (to enable the losing trader to set the switch event date to be the same date as when the electrical connection occurs) iii) accepts responsibility for the electricity conveyed at that ICP from the time of electrical connection. b) in the situation where a gaining trader electrically connects an electrically disconnected ICP in error, or the switch is withdrawn or reversed, to require the gaining trader to: i) restore the ICP to being “electrically disconnected”, using the same method used by the losing trader ii) reimburse any direct costs of the losing trader. The same changes as in paragraph (a) above are also proposed to clause 10.33 (temporary electrical connection by trader of a point of connection). Problem 5 To address problem 5, the Authority proposes to: a) Insert new clauses 10.29C, 10.30C, and 10.31C into the Code to expressly set out the circumstances under which a distributor or grid owner may electrically disconnect, or physically disconnect, a point of connection the distributor or grid owner is responsible for. b) Insert new clause 10.33B into the Code, to expressly prohibit a trader from electrically disconnecting, or physically disconnecting, an ICP the trader is not responsible for.
Proposed Code amendment	**10.29B Grid owner may electrically connect point of connection to grid** (1) Subject to clause 10.33A, only a **grid owner** may **electrically connect** a **point of connection** to the **grid** that it owns or operates. (2) A **grid owner** may only **electrically connect** a **point of connection** under subclause (1) if (a) in the case of the **electrical connection** of a **direct consumer** or **grid** connected **generator**, there is a **trader** identified as responsible under Part 15 for the delivery of **submission information** for the **electricity** conveyed at the **point of connection** from the time of **electrical connection**.

	(b) in the case of the **electrical** connection of a **local network** that has one or more **consumers** connected to the **local network** or to an **embedded network** that is connected to the **local network** (either directly or through another **embedded network**), one or more **traders** are identified as responsible under Part 15for the delivery of **submission information** for the **electricity** conveyed at the **point of connection** from the time of **electrical connection**. (c) in the case of the **electrical connection** of a **local network** that has no **consumers** connected to the **local network** or to an **embedded network** that is connected to the **local network** (either directly or through another **embedded network**), if the **distributor** for that **local network** is identified as responsible under Part 15 for the delivery of **submission information** for the **electricity** conveyed at the **point of connection** from the time of **electrical connection**. *Disconnecting and electrically disconnecting points of connection to the grid* **10.29C Grid owner may electrically disconnect or disconnect point of connection to grid** (1) Subject to subclause (2), a **grid owner** may— (a) **electrically disconnect** the **point of connection**; or (b) disconnect the **point of connection** ; or (2) A **grid owner** may take one of the actions under subclause (1) in respect of a **point of connection** to the **grid** that it owns or operates only if the action is required for the **grid owner** to meet its obligations— (a) under an enactment, including this Code; or (b) under its contract with the party or parties identified in clause 10.29B(2) as responsible in accordance with Part 15 for the delivery of **submission information** for the **electricity** conveyed at the **point of connection** to the **grid**. **10.30 When ~~distributor~~local network owner or embedded network owner may connect NSP that is not point of connection to grid** (1A) Only a ~~**distributor**~~**local network** owner that initiates, under Part 11, the creation of an **NSP** on ~~the **distributor's**~~ its **local** **network** that is not a **point of connection** to the **grid** may connect the **NSP** to— (a) an **embedded network**, but only if the **embedded network**

owner has agreed to the connection; or

(b) another **local network**, but only if the owner of the other **local network**~~ owner~~ has agreed to the connection.

(1B) Only an **embedded network** owner that initiates, under Part 11, the creation of an **NSP** on its **embedded network—**

(a) may connect the **NSP** to another **embedded network**; but

(b) can only do so if the other **embedded network** owner has agreed to the connection.

(1) ~~Despite subclause (1A), a~~A ~~**distributor**~~**local network** owner or an **embedded network** owner must not connect an **NSP** on its **network** under subclause (1A) or (1B) ~~that is not a **point of connection** to the **grid**~~ unless requested to do so by the **reconciliation participant** responsible for ensuring there is a **metering installation** for the ~~**point of connection**~~**NSP**:

(2) A ~~**distributor**~~**local network** owner or an **embedded network** owner must, within 5 **business days** of connecting an **NSP**, advise the **reconciliation manager** of the following:

(a) the **NSP** that has been connected; and

(b) the connection date; and

(c) the **participant identifier** of the **metering equipment provider** for each **metering installation** for the **NSP**; and

(d) the **certification** expiry date of each **metering installation** for the **NSP**.

10.30A When ~~distributor~~local network owner or embedded network owner may temporarily electrically connect NSP that is not point of connection to grid

(1) Subject to clause 10.33, only a ~~**distributor**~~**local network** owner that initiates, under Part 11, the creation of an **NSP** on~~ the **distributor's**~~ its **local** **network** that is not a **point of connection** to the **grid** may temporarily **electrically connect** the **NSP** to—

(a) an **embedded network**, but only if the **embedded network** owner has agreed to the temporary **electrical connection**; or

(b) another **local network**, but only if the owner of the other **local network**~~ owner~~ has agreed to the temporary **electrical connection**.

(2) Subject to clause 10.33, only an **embedded network** owner that initiates, under Part 11, the creation of an **NSP** on its **embedded network—**

(a) may temporarily **electrically connect** the **NSP** to another **embedded network**; but

(b) can only do so if the other **embedded network** owner has agreed to the temporary **electrical connection**.

(3) A ~~**distributor**~~**local network** owner or an **embedded network** owner may only temporarily **electrically connect** an **NSP** under subclause (1) or (2) ~~that is not a **point of connection** to the **grid**~~ if a **metering equipment provider** requests that the ~~**distributor**~~**local network** owner or **embedded network** owner temporarily **electrically connect** the **NSP** for the purposes of—

(a) **certifying** a **metering installation** at the **NSP**; or

(b) maintaining, repairing, testing, or **commissioning** a **metering installation** at the **NSP**.

(4) Despite subclause (3), a **metering equipment provider** must not request that a ~~**distributor**~~**local network** owner or an **embedded network** owner temporarily **electrically connect** an **NSP** under subclause (1) or (2)~~that is not a **point of connection** to the **grid**~~ unless—

(a) the **reconciliation participant** responsible for the **NSP** authorises the **metering equipment provider** to do so; and

(b) the **metering equipment provider** has an arrangement with that **reconciliation participant** to provide **metering** services.

10.30B When distributor may electrically connect NSP that is not point of connection to grid

(1) Subject to clause 10.33A, only a **distributor** may, on its **network**, **electrically connect** an **NSP** that is not a **point of connection** to the **grid**.

(2) A **distributor** may only **electrically connect** an **NSP** under subclause (1) that is not an **interconnection point** between two **local networks**, if—

(a) each **distributor** whose **network** is directly connected to the **NSP** has agreed to the **electrical connection**; and

(b) for an **embedded network**, one or more **traders**:

(i) are identified as responsible under Part 15 for the delivery of **submission information** for the **electricity** conveyed at the **NSP** from the time of **electrical connection**; and

(ii) that **trader** or those **traders** have requested the **electrical connection**; and

(iii) that **trader** or those **traders** have confirmed to the **distributor** that the **metering installation** at the **NSP** is **certified** and operational.

(3) A **distributor** may only **electrically connect** an **NSP** under

	subclause (1) that is an interconnection point between two **local networks**, if the **reconciliation participant** responsible for the delivery of **submission information** for the **NSP**: (a) has requested the **electrical connection**; and (b) has confirmed the **metering installation** at the **NSP** is **certified** and operational. *Disconnecting and electrically disconnecting NSPs* **10.30C Distributor may electrically disconnect or disconnect NSP that is not point of connection to grid** (1) Subject to subclause (2), a **distributor** may— (a) **electrically disconnect** an **NSP** that is not a **point of connection** to the **grid**; or (b) disconnect an **NSP** that is not a **point of connection** to the **grid**. (2) A **distributor** may take one of the actions under subclause (1) only if the action is required for the **distributor** to meet its obligations— (a) under an enactment, including this Code; or (b) under its contract with the **trader** or **traders** responsible for the delivery of **submission information** under Part 15 for the **electricity** conveyed at the **NSP**. *Disconnecting and electrically disconnecting ICPs* **10.31C Distributor may electrically disconnect or disconnect ICP that is not an NSP** (1) Subject to subclause (2), a **distributor** may— (a) **electrically disconnect** an **ICP** that is not an **NSP**; or (b) disconnect an **ICP** that is not an **NSP**. (2) A **distributor** may take one of the actions under subclause (1) only if the action is required for the **distributor** to meet its obligations— (a) under an enactment, including this Code; or (b) under its contract with the **trader** recorded in the **registry** as being responsible for the **ICP**; or (c) under its contract with the **consumer** at the **ICP**. **10.33 When ~~reconciliation participant~~ trader may temporarily electrically connect point of connection**

(1) A ~~**reconciliation participant**~~ **trader** may temporarily **electrically connect** a **point of connection**, or ~~authorise~~ a **metering equipment provider** authorised by a **trader** under subclause (2) may ~~to~~ temporarily **electrically connect** a **point of connection** ~~under subclause (2)~~, only if—

(aa) for an **NSP** that is a **point of connection** to the **grid**, the **grid owner** has approved–

(i) the **trader** temporarily **electrically connecting** the **point of connection**; or

(ii) the **trader** authorising the temporary **electrical connection** of the **point of connection**:

(ab) for an **NSP** that is not a **point of connection** to the **grid**, the **distributor** that gave notice to the **reconciliation manager** under clause 25 of Schedule 11.1 has approved–

(i) the **trader** temporarily **electrically connecting** the **point of connection**; or

(ii) the **trader** authorising the temporary **electrical connection** of the **point of connection**:

(a) for a **point of connection** that is an **ICP**, but which is not an **NSP**,–

(i) either:

(A) the ~~**reconciliation participant**~~ **trader** is recorded in the **registry** as being responsible for the **ICP**; ~~and~~ or

(B) if the **ICP** has been **electrically disconnected**, the **trader**–

(1) has an arrangement with a customer or **embedded generator** at the **ICP**; and

(2) initiates a switch under one of clauses 2, 9, or 14 of Schedule 11.3 within 2 **business days** of the time of **electrical connection**; and

(3) accepts responsibility to provide **submission information** under Part 15 for the **electricity** conveyed at the **ICP** from the time of **electrical connection**; and

(~~b~~ii) if the **ICP** has metered load, 1 or more operational **certified metering installations** are ~~in place~~ connected at the **ICP** in accordance with this Part; and

(~~c~~iii) ~~in the case of an~~ if the **ICP** ~~that~~ has not previously been **electrically connected**, the owner of the **network** to which the **point of connection** is connected has given written approval ~~of~~ to the temporary **electrical connection**.

(2) A ~~**reconciliation participant**~~ **trader** described in subclause (1)~~(a)~~ may authorise a **metering equipment provider**, with which the ~~**reconciliation participant**~~ **trader** has an arrangement, to request the temporary **electrical connection** of a **point of connection** only for the purposes of—

(a) **certifying** a **metering installation** at the **point of connection**; or

(b) maintaining, repairing, testing, or **commissioning** a **metering installation** at the **point of connection**.

(3) *[Revoked]*

(4) *[Revoked]*

10.33A When ~~reconciliation participant~~ trader may electrically connect point of connection

(1) A ~~**reconciliation participant**~~ **trader** may **electrically connect** a **point of connection**, or another participant authorised by a **trader** may **electrically connect**~~ion of~~ a **point of connection**, only if–

(aa) for an **NSP** that is a **point of connection** to the **grid**, the **grid owner** has approved—

(i) the **trader electrically connecting** the **point of** connection to the **grid** that the **grid owner** owns or operates; or

(ii) the **trader** authorising the **electrical connection** of the **point of connection** to the **grid** that the **grid owner** owns or operates:

(ab) for an **NSP** that is not a **point of connection** to the **grid**, the **distributor** that gave notice to the **reconciliation manager** under clause 25 of Schedule 11.1 has approved—

(i) the **trader electrically connecting** the **point of connection** to the **network** that the **distributor** owns or operates; or

(ii) the **trader** authorising the **electrical connection** of the **point of connection** to the **network** that the **distributor** owns or operates:

(a) for a **point of connection** that is an **ICP**, but which is not an **NSP**,—

(i) Either:

(A) the ~~**reconciliation participant**~~ **trader** is recorded in the **registry** as being responsible for the **ICP**; or

(B) if the **ICP** has been electrically **disconnected**, the **trader**—

(1) has an arrangement with a **customer** or **embedded generator** at the **ICP**; and

(2) initiates a switch under clause 2, 9 or 14 of Schedule 11.3 within 2 **business days** of the time of **electrical connection**; and

(3) accepts responsibility to provide **submission information** in accordance with Part 15 of this Code for the **electricity** conveyed at the **ICP** from the time of **electrical connection**; and

(iii) if the **ICP** has metered load, 1 or more operational

certified metering installations are ~~in place~~connected at the **ICP** in accordance with this Part; and

(iv) ~~in the case of an~~if the **ICP** ~~that~~ has not previously been **electrically connected**, the owner of the **network** to which the **point of connection** is connected has given written approval of the **electrical connection**:

(b) if a **point of connection** supplies electricity to a load that is assigned to multiple ICPs as **shared unmetered load**, the **distributor** to whose **network** the **point of connection** is connected has advised all **traders** that are assigned the **shared unmetered load** of the **trader's** intention to **electrically connect** the **point of connection**.

(2) Further to subclause (1), ~~A~~a ~~**reconciliation participant**~~ **trader** described in subclause (1)(a)(i)—

(a) may authorise the **electrical connection** of an **ICP** if—

(i) a **metering installation** is in place at the **ICP**; and

(ii) the **metering installation** is operational but not **certified**; and

(iii) the ~~**reconciliation participant**~~ **trader** arranges for the **certification** of the **metering installation** to be completed within 5 **business days** of the **ICP** being **electrically connected**:

(b) may **electrically connect** an **ICP** if the **point of connection** is solely for **unmetered load**.

(3) A ~~**reconciliation participant**~~ **trader** must not electrically connect or authorise the **electrical connection** of a **point of connection** in any of the following circumstances —

(a) a **distributor** has **electrically disconnected** the **point of connection** for safety reasons, and has not subsequently approved the **electrical connection** of the **point of connection**:

(b) **electrically connecting** the **point of connection** would breach the Electricity (Safety) Regulations 2010:

(c) a switch under subclause (1)(a)(B)(i)(2) has been withdrawn or reversed.

(4) No **participant** may **electrically connect** a **point of connection**, or authorise the **electrical connection** of a **point of connection**, other than:

(a) a ~~**reconciliation participant**~~ **trader** as described in subclauses (1)~~, (2)~~ to (3):

(b) a **distributor** as described in clause 10.31B.

(5) Under subclause (1)(a)(i), if a **trader** or a person **authorised** by a **trader electrically connects** an **electrically disconnected**

	point of connection in error, or prior to the switch being withdrawn or reversed, the **trader** must— (a) **electrically disconnect** the **ICP** to using the same method of **electrical disconnection** as the losing **trader** used; and (b) reimburse the losing **trader** for any direct costs the losing **trader** incurred because of the **electrical connection** of the **point of connection**— (i) in error, or (ii) prior to the switch being withdrawn or reversed. *Disconnecting and electrically disconnecting points of connection* **10.33B Trader must not disconnect or electrically disconnect ICP for which it is not responsible** (1) Unless a **trader** is recorded in the **registry** as being responsible for the **ICP** or is meeting its obligation under clause 10.33A(5)(a) in respect of the **ICP**, the **trader** must not— (a) **electrically disconnect** an **ICP**; or (b) disconnect an **ICP**. (2) Unless the **trader** is recorded in the **registry** as being responsible for the **ICP** or is meeting its obligation under clause 10.33A(5)(a) in respect of the **ICP**, a **trader** must not authorise a **metering equipment provider**— (a) to **electrically disconnect** an **ICP**; or (b) to disconnect an **ICP**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of, and reliable supply by, the electricity industry. It may also have a positive effect on competition. The proposed amendment would improve the efficient operation of the electricity industry by: a) reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs b) ensuring a trader or distributor that electrically disconnected a responsible trader's customer in error would be required under the Code to reconnect the customer. This would avoid the potential for unnecessary transaction costs on the responsible trader and its customer, if the party at fault would otherwise not reconnect the customer c) by clarifying the Code requirements relating to electrical connection and disconnection of points of connection and requiring metering to

	be operational before electrically connecting, thereby making the Code easier to understand and reducing participants', and the Authority's, compliance costs. The proposed Code amendment may promote competition, by reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs. The proposed Code amendment would promote reliability of supply for consumers: a) by facilitating the timely electrical connection of consumers b) because it is expected to reduce the number of times traders electrically disconnect consumers that are not the traders' customers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Some of the costs and benefits of the proposed Code amendment can be quantified, but it has not been practicable to quantify others. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below). It has not been practicable to quantify the costs and benefits of the proposed Code amendment. Therefore, the regulatory statement below contains a qualitative assessment of the proposed amendment's costs and benefits. It has not been practicable to quantify the costs and benefits of the proposed Code amendment. Therefore, a qualitative assessment of the proposed amendment's costs and benefits has been undertaken (see below). A qualitative assessment of the proposed Code amendment's costs and benefits has been undertaken, because it has not been practicable to quantify the proposed amendment's costs and benefits (see below).
Regulatory statement	
Objectives of the proposed amendment	The objectives of the proposal are: a) to clarify the Code requirements relating to electrical connection and disconnection of points of connection b) regularise a current industry practice regarding reconnecting

	switching customers and offer protection for the losing trader c) to enable all appropriate persons to electrically connect a point of connection d) to prohibit all appropriate persons electrically disconnecting or physically disconnecting a point of connection.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* We expect there may be a minor cost associated with traders, distributors, MEPs, and possibly the grid owner, updating their procedures. *Benefits* The proposed amendment would improve the efficient operation of the electricity industry by: a) reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs b) ensuring a trader or distributor that electrically disconnected a responsible trader's customer would be required under the Code to reconnect the customer. This would avoid the potential for unnecessary transaction costs on the responsible trader and its customer, if the party at fault did not reconnect the customer c) by clarifying the Code requirements relating to electrical connection and disconnection of points of connection, thereby making the Code easier to understand and reducing participants', and the Authority's, compliance costs. The proposed Code amendment may promote competition, by reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs. The proposed Code amendment would promote reliability of supply for consumers: a) by facilitating the timely electrical connection of consumers b) if the proposed amendment were to reduce the number of times traders electrically disconnected consumers that are not the traders' customers. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**002 - Prohibition of Net Metering**
Related Clause(s)	New clause 10.13A – Metering installation must record imported electricity separately form exported electricity 10.13(3) – Electricity conveyed 10.24(b) and (c) – Responsibility for ensuring there is metering installation for ICP that is not also NSP 4(2)(a) of Schedule 10.7 – Metering equipment provider obligations
Problem definition	"Net metering" is commonly used to refer to the practice of subtracting the volume of any electricity a consumer has generated from the volume of electricity the consumer has imported from the network. Net metering results in consumers being charged only for the net amount. The problem with net metering is that it obscures the full range of services used by a consumer and makes it difficult to charge the appropriate costs of each of the services. To give a practical example, if a consumer generates and exports to the network 5 kWh from their solar PV installation and consumes 5 kWh from the network in the same 30 minute period, the use of net metering will record zero consumption for the half hour. Therefore, the metering data will show the consumer using no services from the NZ electricity market in that half hour when clearly it has used several services, such as a backup service from the local network, transmission services from the national grid and energy from a generator. If charges for these services are based on metered consumption then net metering results in an under-charging for these services. Likewise, if a consumer has non half hour metering and generates 5 kWh during an off-peak electricity demand period, and consumes 5 kWh during a peak electricity demand period, in addition to the metered data recording zero, it will also not account for the difference in electricity spot prices between the peak and off-peak periods. The same situation applies at a multi-phase metering installation, if generation on one phase is subtracted from consumption on another phase: a) Instantaneously; or b) during a trading period; or c) in different trading periods. This subtraction will show the consumer using less (or no) services from the market, or mask spot price differences between trading periods. Therefore, net metering is not cost-reflective on an ICP basis. It results in consumers being unable to see the services they use from, or the costs

	they impose on the electricity market. Although several clauses of the Code[1] currently imply that an MEP must not use net metering when providing raw meter data to the trader responsible for the ICP, the Code does not specifically prohibit net metering. By contrast, clause 10.24(c) prohibits traders from using subtraction to determine submission information.
Proposal	The Authority proposes to amend the Code so that imported and exported electricity are separately metered and recorded for each phase at an ICP, thereby prohibiting net metering by prescribing how the MEP must meter export-capable ICPs. We also propose to amend the Code to clarify that, subject to one proviso, an MEP may, when preparing raw meter data that has been measured and recorded in a multi-phase metering installation: a) aggregate all import quantities for the different phases into one amount b) aggregate all export quantities for the different phases into another amount. The proviso is that any such aggregation must not combine import and export amounts.
Proposed Code amendment	**10.13A Metering installation must record imported electricity separately from exported electricity** (1) A **metering equipment provider** must, for each **point of connection** at which it is the **metering equipment provider**, ensure that if the **metering installation** is capable of importing and exporting **electricity**,— (a) the **metering installation** measures and records the imported **electricity** separately from the exported **electricity**; and (b) the **metering installation** measures and records the imported **electricity** and exported **electricity** separately for each connected phase if the **metering installation** contains multiple phases. (2) Despite subclause (1), if the **metering installation** contains multiple phases, the **metering equipment provider** for the **metering installation**— (a) may aggregate together the amounts of imported **electricity** recorded on different phases; or (b) may aggregate together the amounts of exported **electricity** recorded on different phases; but (c) must not aggregate together imported and exported **electricity**

[1] Clauses 10.13(3) and 10.24(b) and (c), and clause 4(2)(a) of Schedule 10.7.

Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objective because it will contribute to the efficient operation of the electricity industry. It will help ensure that consumers pay for the services they use from, and/or the costs they impose on, the New Zealand electricity market. The proposal will also clarify the Code, by clearly prohibiting net metering rather than leaving industry participants to infer this from multiple clauses. This will lead to improved operational efficiency and reduced compliance costs for participants. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment may have a small positive benefit for competition, by ensuring that traders always receive raw meter data in a format that allows for flexibility in the design of consumer products. The amendment would have no effect on reliability.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	To clarify the policy intent in the Code, currently spread over multiple clauses, that net metering is not permitted. To clarify how MEPs must measure and record electricity in multi-phase metering installations.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.

Reference number(s)	**003 - Recovering Certification Costs**
Relevant clause(s)	Clause 10.22 – Change of metering equipment provider
Problem definition	MEPs pay certification costs for metering installations and then recover these costs over the life of the certification, usually from the retailer at the point of connection. If the MEP for a point of connection changes, the outgoing MEP ("losing MEP") is unable to recover these costs from the retailer, even if the costs may have only recently been incurred. This places a financial penalty on the losing MEP. It also acts as a disincentive on an MEP to recertify a metering installation, if the MEP perceives it may be displaced by a new MEP ("gaining MEP"). The Code seeks to address this issue. Under clause 10.22(2)-(3) the gaining MEP must pay the losing MEP a proportion of the costs attributable to the certification tests and calibration tests of the metering installation or its components. However, the wording of clause 10.22(2)-(3) is not entirely clear about: a) when this obligation arises, and b) which costs are covered. In particular, the wording is unclear about which costs are covered when the gaining MEP replaces all or part of the metering installation after assuming responsibility for it.
Proposal	The Authority proposes to amend clause 10.22 so that, should the MEP at a point of connection change: a) if the gaining MEP retains, and continues to use, any of the metering components in the metering installation (without having the components or the installation recertified) for more than three business days after the MEP change event date, the gaining MEP must pay to the losing MEP the certification/calibration costs of those components, prorated for the remainder of the certification validity period b) if the gaining MEP removes from use, or recertifies, any metering components in the metering installation within three business days of the MEP change event date, the gaining MEP is not required to pay to the losing MEP the certification/calibration costs for the removed or recertified components c) if the gaining MEP removes from use, or recertifies, any metering components in the metering installation later than three business days after the MEP change event date, the gaining MEP must still pay to the losing MEP the certification/calibration costs of those components, prorated for the remainder of the certification validity period, even if that period is no longer valid due to the removal or recertification. We propose to use a timeframe of three business days because this gives certainty for the losing MEP, while allowing the gaining MEP a buffer to complete any planned metering equipment changes. The gaining MEP will know in advance it will be the MEP. Therefore, prior

	to assuming responsibility for the metering installation, the gaining MEP will have time to decide whether to reuse, or displace, some or all of the losing MEP's metering components. A short timeframe also ensures the losing MEP's metering equipment is not used for an extended period without any reimbursement from the gaining MEP.
Proposed Code amendment	**10.22 Change of metering equipment provider** … (2) The **gaining metering equipment provider** must, within 20 **business days** of assuming responsibility for a **metering installation**, pay the **losing metering equipment provider** the proportion of the costs described in subclause (3) and subclause (4). (3) The costs payable under subclause (2) are those directly and solely attributable to the **certification** tests and **calibration** tests of— (a) the **metering installation**: ~~or~~ (b) any ~~of its~~ **metering components** in the **metering installation** ~~from the period beginning on the date the **gaining equipment provider** assumes responsibility for the **metering installation** for the remainder of the **certification** validity period for the **metering installation** or the **metering component**~~. (4) However, when calculating the costs payable under subclause (2)— (a) no costs are payable for a **metering component** if the **gaining metering equipment provider**, within three **business days** of assuming responsibility for the **metering installation**,— (i) replaces the **metering component**; or (ii) removes the **metering component** from use; or (iii) **certifies** the **metering component**: (b) no costs are payable for a **metering installation** if the **gaining metering equipment provider**, within three **business days** of assuming responsibility for the **metering installation**,— (i) replaces the **metering installation**; or (ii) removes the **metering installation** from use; or (iii) **certifies** the **metering installation**: (c) the costs must be prorated for the longer of— (i) the remainder of the **certification** validity period for the **metering installation**; and ~~or~~ (ii) the remainder of the **certification** validity period for the **metering component**.
Assessment of	The proposed Code amendment is consistent with the Authority's objective,

proposed Code amendment against section 32(1) of the Act	and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by making it easier for participants to understand clause 10.22(3) of the Code, and calculate the amounts payable. The proposed amendment is expected to have little or no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The proposal's objective is to clarify when a gaining MEP must pay for certification and calibration costs attributed to metering components the MEP assumes responsibility for and uses.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**004 – Distributor NSP Information Notifications to Reconciliation Manager**
Relevant Clause(s)	Clause 10.25(2) and (3) – Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid Clause 10.30(2) – When distributor or embedded network owner may connect NSP that is not point of connection to grid
Problem definition	Under clause 10.25(2) of the Code, a distributor must, if it proposes the creation of a new NSP that is not a point of connection to the grid, advise the reconciliation manager of— a) the reconciliation participant for the NSP b) the participant identifier of the metering equipment provider for each metering installation for the NSP c) the certification expiry date of each metering installation for the NSP. The distributor must advise the reconciliation manager of the information under paragraphs a) and b) no later than 20 business days after: a) assuming responsibility for being the MEP for each metering installation at the NSP; or b) contracting someone to be the MEP for each metering installation at the NSP. The distributor must advise the reconciliation manager of the certification expiry date of the metering installation no later than 20 business days after the date of certification of each metering installation. Under clause 10.25(3) of the Code, a distributor must, no later than 20 business days after a metering installation at the NSP is recertified, advise the reconciliation manager of: a) the reconciliation participant for the NSP: b) the participant identifier of the metering equipment provider for the metering installation: c) the certification expiry date of the metering installation. In contrast to the 20 business day timeframes under clause 10.25(2) and(3), under clause 10.30(2) of the Code, a distributor must, within five business days of connecting an NSP, advise the reconciliation manager of: a) the NSP that has been connected b) the connection date c) the participant identifier of the metering equipment provider for each metering installation for the NSP d) the certification expiry date of each metering installation for the NSP.

	Currently, under clauses 10.25(2) and 10.30(2), a distributor must provide the following information to the reconciliation manager in accordance with two different timeframes: a) the participant identifier of the metering equipment provider for the metering installation b) the certification expiry date of the metering installation. This increases the likelihood of a distributor inadvertently breaching one of these clauses while in the process of complying with the other clause. It also causes confusion for auditors that are trying to assess distributors' compliance with the Code. This is increasing audit costs.
Proposal	The Authority proposes to amend clause 10.25(2) and (3) of the Code, to require a distributor to advise the reconciliation manager of the following information within five business days of the date on which the NSP is connected: a) the participant identifier of the metering equipment provider for the metering installation b) the certification expiry date of the metering installation. This would make the timeframe for providing this information consistent between clause 10.25(2) and (3) and clause 10.30.
Proposed Code amendment	**10.25 Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid** … (2) A **distributor** must, if it proposes the creation of a new **NSP** that is not a **point of connection** to the **grid**,— (a) for each **metering installation** for the **NSP**, either— (i) assume responsibility for being the **metering equipment provider**; or (ii) contract with a person who, in that contract, assumes responsibility for being the **metering equipment provider**; and (b) ~~no later than~~ within 20 **business days** after assuming responsibility or entering into the contract under paragraph (a), advise the **reconciliation manager** of~~—~~ ~~(i)~~ the **reconciliation participant** for the **NSP**~~; and~~ ~~(ii) the **participant identifier** of the **metering equipment provider** for the **metering installation**~~; and (c) ~~no later than 20~~ within 5 **business days** after the date of certification of each **metering installation**, advise the **reconciliation manager** of— (i) the **participant identifier** of the **metering equipment provider** for the **metering installation**; and

	(ii) the certification expiry date of the **metering installation**. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would make it easier for distributors to understand their obligations to update metering information about NSPs. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to improve the efficient operation of the electricity industry by clarifying when distributors must advise the reconciliation manager of certain metering information for an NSP.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**005 - Like-for-Like Replacements and Consultation**
Relevant clause(s)	Clause 10.34 – Installation and modification of metering installations Clause 19(2) of Schedule 10.7 – Modification of metering installations
Problem definition	Clause 10.34 provides that if an MEP proposes to install or modify a metering installation at a point of connection (other than a point of connection to the grid), it must first consult with the distrbutor and the trader. The MEP, distributor, and trader must attempt to reach agreement on the design of the metering installation. Metering installations in existance as at 29 August 2013 are not required to have their design agreed. Clause 10.34 applies to: a) all new metering installations installed on and after that date b) all metering installations modified on and after that date. Some MEPs have replaced metering equipment with a like type, believing they were not required to consult with the distributor and trader before they did so, because the metering installation existed as at 29 August 2013. We do not believe clause 10.34 is sufficiently clear that: a) the consultation requirement applies when an MEP replaces an existing metering installation or metering component on a like-for-like basis b) even when the MEP has consulted with the distributor and trader for a like-for-like replacement,— i) the certification for the metering installation may still be cancelled under clause 19 of Schedule 10.7; and if so ii) the metering installation must be recertified in order to comply with the Code c) if the MEP has already consulted with a distributor and trader for a metering component or metering installation with a particular design and functionality (ie, a ‘standard design’), there is no requirement for the MEP to consult that distributor or trader again in respect of another metering component or metering installation that will use that standard design.
Proposal	We propose to amend the Code as follows: a) amend clause 10.34 to clarify that the clause covers like-for-like metering installation and component replacements as well as new installations and other changes to existing installations b) amend clause 10.34 and clause 19 of Schedule 10.7 to clarify that, even if an MEP consults on a modification, the certification of the metering installation may still be cancelled c) amend clause 10.34 to clarify that an MEP that consults with a distributor and trader for a metering component or metering installation with a particular design and functionality need not consult with that distributor or trader again for another metering component or metering installation that has the same design and

	functionality (ie, an MEP only needs to consult once with a trader and distributor over a “standard design” for metering installations).
Proposed Code amendment	**10.34 Installation and modification of metering installations** (1) This clause applies to a **metering equipment provider** that proposes to install or modify a **metering installation** at a **point of connection** other than a **point of connection** to the **grid**. (2) The **metering equipment provider** must consult with the **distributor** and the **trader** for the **point of connection** on the matters specified in subclause (2A), before— (a) finalising the design of a **metering installation** for the **point of connection**; (b) modifying the design of a **metering installation** installed at the **point of connection**; (c) subject to subclause (2B), replacing a **metering component** or **metering installation** with a new **metering component** or new **metering installation**, even if the new **metering component** or **metering installation** has the same or similar design and functionality as the existing **metering component** or **metering installation**. (2A) The matters referred to in subclause (2) are the **metering component’s** or **metering installation’s**— (a) required functionality; and (b) terms of use; and (c) required interface format; and (d) integration of the ripple receiver and the **meter**; and (e) functionality for controllable load. (2B) If a **metering equipment provider** replaces a **metering component** or **metering installation** with a new **metering component** or new **metering installation**, clause 19 of Schedule 10.7 applies despite the **metering equipment provider** having consulted with the **distributor** and the **trader** on the replacement. (2C) Despite subclause (2), the **metering equipment provider** does not need to consult with— (a) the **distributor**, if the **metering equipment provider** has already consulted with the **distributor** on the design of the **metering component** or **metering installation** or another **metering component** or **metering installation** with the same or similar design and functionality as the replacement **metering component** or **metering installation**; (b) the **trader**, if the **metering equipment provider** has already consulted with the **trader** on the design of the **metering component** or **metering installation** or another **metering component** or **metering installation** with the same or similar design and functionality as the replacement **metering**

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<u>**component** or **metering installation**;</u>

…

Schedule 10.7

…

19 Modification of metering installations

…

(2) For the purposes of this <u>Part</u> ~~clause~~, a modification of a **metering installation** includes~~,~~ any 1 or more of the following:

(a) any change to the **software**, ROM, or firmware in the **metering installation** that may affect the operation of the **metrology layer** unless the change is made under subclause (3):

(b) replacement, installation, removal, repair, or modification, of a **metering component** in the **metering installation**, other than the temporary connection of testing or monitoring equipment by using a **test facility**:

<u>(ba) replacing a **metering installation** with a new **metering installation**:</u>

(c) any change to the burdening of a **measuring transformer** in the **metering installation**, unless changed under clause 31(6):

(2C) The replacement of a **metering compenent** or a **metering installation** is a modification of a **metering installation** under sub-clause (2) even if:

(a) the replacement **metering compenent** or **metering installation** has the same or similar design and functionality as the existing **metering compenent** or a **metering installation**; or

(b) the **metering equipment provider** complied with clause 10.34(2C).

…

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Assessment of proposed Code amendment against section 32(1) of the Act

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The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry.

It would do this by making it easier for MEPs to understand:

a) their obligation under clause 10.34 to consult on metering installation design
b) that the like-for-like replacement of a metering component or metering installation is a modification to the existing metering installation.

It could also increase the reliability of supply for consumers as it would help ensure their metering installations are fit-for-purpose for their connection type.

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	The proposed amendment is expected to have no effect on competition.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The proposal's objective is to clarify: a) when an MEP must consult on the design of a metering installation, and b) that a like-for-like replacement of a metering component or metering installation is a modification to an existing metering installation.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**006 - Metering Issue Resolution Timing**
Relevant clause(s)	Clause 10.43 – Metering installations that are inaccurate, defective,or not fit for purpose to be investigated Clause 10.47 – Correction of defects and inaccuracies in metering installation
Problem definition	<u>Problem 1</u> Clause 10.43 provides that when an MEP becomes aware that a metering installation for which it is responsible is either inaccurate, defective, or not fit for purpose, the MEP must investigate the metering installation and provide a report to all affected participants. The timeframe for the MEP's investigation and report is set out in subclause (5). The MEP's obligation to investigate and report is not affected if the metering installation's certification is cancelled under clause 20 of Schedule 10.7. Some participants are misinterpreting clause 10.43(5). They read it as setting the timeframe for an MEP to <u>resolve</u> the underlying metering issue, when in fact it is only specifying the timeframe for the MEP to complete the investigation and report. <u>Problem 2</u> From its heading, clause 10.47 appears to relate to correcting defective or inaccurate metering installations. However it only addresses what records an ATH must keep when it corrects defects or inaccuracies in a metering installation. The heading of this clause does not reflect its contents.
Proposal	<u>Problem 1</u> To address the first problem identified above, the Authority proposes to add a new clause 10.46A to the Code. This clause would require an MEP to use its best endeavours to resolve a metering issue within 25 business days. This will make it clear that the timeframe in clause 10.43 is for investigating and reporting on a metering issue, while the timeframe in the proposed new clause would be for resolving the issue. The Authority acknowledges it is inappropriate to impose an absolute obligation on MEPs to resolve a metering issue within a certain timeframe. Each metering installation is different and may have different problems associated with correcting it. Some issues can be complex and it can take time to arrange the shutdown of, and access to, a metering installation. Having said this, the Authority notes that MEPs often resolve a metering issue as part of the investigation process.

	The Authority considers a Code amendment setting out a timeframe for resolving metering issues is appropriate, and would reduce confusion for participants, provided the obligation on MEPs is a ‘best endeavours’ requirement. Problem 2 To address the second issue identified above, the Authority proposes to amend the heading of clause 10.47, so that it more accurately reflects the contents of the clause.
Proposed Code amendment	**10.46A Timeframe for correcting defects and inaccuracies in metering installation** (1) This clause applies to a **metering equipment provider** that becomes aware, or is advised under clause 10.43, that a **metering installation** for which it is responsible, is— (a) inaccurate; or (b) defective; or (c) not fit for purpose. (2) A **metering equipment provider** to which this clause applies— (a) must undertake remedial action to make the **metering installation**— (i) accurate: (ii) not defective: (iii) fit for purpose: (b) must use its best endeavours to complete the remedial action under paragraph (a) no later than 25 **business days** after the date on which it is required to provide a report to all affected **participants** under clause 10.43(4)(c). **10.47 ATH to keep records of modifications to correct~~Correction of~~ defects and inaccuracies in metering installation** An **ATH** must, when taking action to remedy an inaccuracy or defect within a **metering installation**, ensure that records of any modifications that are carried out to the **metering installation** are kept for each **metering component** of the **metering installation** in the **metering records** and in a manner reasonable in the circumstances to ensure that further investigation can be carried out.
Assessment of proposed Code amendment against section	The first proposed Code amendment is consistent with the Authority’s objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by promoting the timely resolution of metering issues,

32(1) of the Act	thereby minimising: a) adverse effects on customers b) unaccounted for electricity in the wholesale electricity market. The first proposed Code amendment is expected to have no effect on competition or reliability of supply. The change to the heading of clause 10.47 is technical and non-controversial. As with the first proposed amendment, it is also consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by making the Code easier to understand and thereby easier to comply with. This second proposed Code amendment would have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendments are consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendments are consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendments are consistent with principle 2 in that they address an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the first proposal is to ensure that any issues with metering installations that are inaccurate, defective, or not fit for purpose are remedied within a reasonable timeframe. The objective of the second proposal is to make the Code easier to understand and thereby easier to comply with.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendments.

amendment	

Reference number(s)	**007 - Minimum Voltage Requirements**
Relevant clause(s)	Table 1 of Schedule 10.1 – Metering installation characteristics and associated requirements
Problem definition	Table 1 of Schedule 10.1 of the Code sets out, for the different categories of metering installation a) the defining characteristics of a metering installation (eg, maximum current conveyed through a metering installation) b) permitted combinations of metering components in a metering installation c) a metering installation's accuracy tolerances / maximum permitted errors d) how often an ATH must inspect a metering installation e) the maximum period for which a metering installation's certification is valid f) the types of metering certification permitted for a metering installation. Currently, Table 1 of Schedule 10.1 omits a defining characteristic of some metering installations—namely the existence of a voltage transformer as part of a metering installation at a site with a voltage of under 1kV. As a result of this omission, the various requirements in Table 1 of Schedule 10.1 do not apply to some metering installations. This is contrary to the policy intent of Table 1 of Schedule 10.1, and also of Part 10, which is to provide for accurate clearing and settlement in the wholesale electricity market by regulating how existing and new metering installations are used to accurately measure and record electricity conveyed.[1]
Proposal	The Authority proposes to amend Table 1 of Schedule 10.1, to include a voltage transformer in the defining characteristics of category 3 and category 4 metering installations at sites with a voltage of under 1kV.
Proposed Code amendment	Refer to attached Table 1 of Schedule 10.1.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry by clarifying the Code requirements for category 3 and category 4 metering installations at sites with a voltage of under 1kV. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements

[1] Refer to clause 10.1 of the Code.

	set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified regulatory failure, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of this proposal is to include all metering installation types in Table 1 of Schedule 10.1.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Schedule 10.1: Table 1: Metering installation characteristics and associated requirements

Defining Characteristics				Associated Requirements of active energy metering								
Metering installation category	**Primary voltage (V)**	**Primary current (I)**	**Measuring transformers**	**Metering installation certification type**	**Accuracy tolerances**		**Selected component metering installation minimum IEC class (more accurate components may be used)**		**Metering installation certification and inspection**		
					Maximum permitted error	**Maximum site uncertainty**	**Meter**	**Current Transformer**	**Maximum metering installation certification validity period**	**Maximum sample inspection and recertification period**	**Inspection period**
1	V < 1kV	I ≤ 160A	None	NHH or HHR	± 2.5%	0.6%	2	N/A	180 months	84 months	120 months ± 6 months
2	V < 1kV	I ≤ 500A	CT	NHH or HHR	± 2.5%	0.6%	2	1	120 months	N/A	120 months ± 6 months
3	V < 1kV	500A < I ≤ 1200A	CT	HHR only	± 1.25%	0.3%	1	0.5	120 months	N/A	60 months ± 3 months
	V < 1kV	500A < I ≤ 1200A	VT & CT				N/A	N/A			
	1kV ≤ V ≤ 11kV	I ≤ 100A					~~N/A~~	~~N/A~~			
	11kV < V ≤ 22kV	I ≤ 50A									
4	V < 1kV	I > 1200A	CT	HHR only	± 1.25%	0.3%	N/A	N/A	60 months	N/A	30 months ± 3 months
	V < 1kV	I > 1200A	VT & CT								
	1kV ≤ V ≤ 6.6kV	100A < I ≤ 400A									
	6.6kV < V ≤ 11kV	100A < I ≤ 200A									
	11kV < V ≤ 22kV	50A < I ≤ 100A									
5	1kV ≤ V ≤ 6.6kV	I > 400A	VT & CT	HHR only	± 0.75%	0.2%	N/A	N/A	36 months	N/A	18 months ± 1 month
	6.6kV < V ≤ 11kV	I>200A									
	V > 11kV	I > 100A									
	V > 22kV	Any current									

Reference number(s)	**008 – Prevailing Load Checks**
Relevant clause(s)	Table 3 of Schedule 10.1
Problem definition	Table 3 of Schedule 10.1 is unclear about prevailing load tests for category 1 metering installations A prevailing load test is a test of the accuracy of an electricity meter. It forms part of the suite of tests and checks used in the "selected component certification" of metering installations. An amount of electrical energy is recorded by the meter being tested and by a working standard.[1] The amount of electrical energy recorded by the meter being tested is then compared against the amount of electrical energy recorded by the working standard. The meter being tested passes the prevailing load test if the difference in energy recorded by the meter and by the working standard is within an allowable margin of error. Table 3 of Schedule 10.1 has confusing requirements about whether a prevailing load test must be undertaken when a meter in a category 1 metering installation is replaced. Currently, row 4 says a prevailing load test is not required as part of the recertification of a category 1 metering installation following the replacement of a meter with a certified meter. However, row 5 says a prevailing load test is required as part of the recertification of any category of metering installation following a meter change. Category 1 metering installations are usually certified using the selected component certification method.[2] This method assumes that if the metering components at the metering installation are certified, and all other checks are performed (eg, wiring, raw meter data, etc), then the metering installation will perform as designed, and a prevailing load check on the meter(s) at the installation is not required. This applies to: a) the initial certification of a category 1 metering installation b) the recertification of a category 1 metering installation where: i) all meters have been replaced ii) some meters have been replaced and the remaining meter(s) have not had their respective certification end dates extended. This does not apply to the situation where some meters at a category 1 metering installation have been replaced and the remaining meter(s) have had their respective certification end dates extended. In this situation, a prevailing load check is required so the ATH can be satisfied the meter(s) will remain within the accuracy range for the new/extended certification period Row 1 of Table 3 of Schedule 10.1 clearly states that a prevailing load test for each meter at a category 1 metering installation is unnecessary for the

[1] Part 1 of the Code defines "working standard" to mean a measuring instrument that has been calibrated by an approved calibration laboratory or an ATH, which is used routinely for the calibration of metering installations and metering components.
[2] Refer to clause 11(3) of Schedule 10.7 and Table 1 of Schedule 10.1 of the Code.

	initial certification of the metering installation. However, Table 3 of Schedule 10.1 does not clearly state: a) a prevailing load test for each meter at a category 1 metering installation is unnecessary in scenarios b)i) and b)ii) above b) a prevailing load test is required for a meter that has its certification end date extended. <u>Table 3 of Schedule 10.1 does not require a control device test unless the control device is changed</u> Currently, Table 3 of Schedule 10.1 does not require a control device test to be undertaken at a metering installation, unless the control device is changed (which includes installing a control device at the metering installation for the first time). This omission is an error. A control device test is not intended to be onerous. It is intended only to confirm that the control device is likely to operate if receives a signal. The wiring check will already ensure the control device is wired correctly. <u>Table 3 of Schedule 10.1 does not require a control device certification check when the control device is changed</u> Currently, Table 3 does not require a component certification check when a control device is replaced. This omission is an error. All installed components must be certified either as part of the installation procedure or prior to installation. The component certification check is simply a check to ensure the newly installed control device is certified. <u>Table 3 of Schedule 10.1 does not require a data storage device test</u> Table 3 of Schedule 10.1 does not require a data storage device test when a category 3 metering installation is: a) initially certified b) recertified. Most category 3 meters do not include an accumulating register. In such instances, all meter readings are dependent on the data storage device. A data storage device check should not be onerous. It should simply be a check: a) that the battery is working, and b) that readings are being stored and are recoverable, and c) if the data storage device is a separate component, that it is certified. <u>Table 3 of Schedule 10.1 does not require an installation or component configuration test</u> Table 3 of Schedule 10.1 does not require an installation or component

	configuration test when additional equipment is added to any category of metering installation. This omission is an error. An installation or component configuration test is a check that the metering installation's configuration is as specified in the design report. This check should also occur when additional equipment, such as wiring, test blocks, fuses etc, are installed or added to a metering installation. This is to ensure the metering installation's actual configuration complies with the metering installation's design. <u>Table 3 of Schedule 10.1 can be simplified</u> The following three columns in Table 3 of Schedule 10.1 are unnecessary under the proposal: a) "Measuring transformer" b) "Meter" c) "Primary injection to meter". Under the proposal, the "measuring transformer" check identified in row 8 of the current Table 3 of Schedule 10.1 is included in the "measuring transformer change or ratio change" row of the proposed Table 3 of Schedule 10.1. All of the checks an ATH would have performed as part of the "measuring transformer" check are included as part of the tests and checks in the remaining columns of the proposed Table 3. Under the proposal, the "meter" checks identified in rows 5 and 6 of the current Table 3 of Schedule 10.1 are included in rows 1 to 6 of the proposed Table 3 of Schedule 10.1. All of the checks an ATH would have performed as part of the "Meter" check (except the 'Component Certification' check) are included as part of the tests and checks in the remaining columns of the proposed Table 3. To ensure the meter is certified, the 'Component Certification' check has been included for rows 7 and 8 of the proposed Table 3. Currently, the "primary injection" column is blank. The Authority does not envisage it being used, at least in the foreseeable future. Therefore, it can be deleted. <u>Table 3 of Schedule 10.1 can be restructured for clarity</u> Table 3 of Schedule 10.1 would be clearer if it were restructured: a) to group rows by metering installation category, and b) to make each row heading clearer as to its application.
Proposal	The Authority proposes to clarify Table 3 of Schedule 10.3 as follows: 1) To show prevailing load tests <u>are not required</u> for the recertification of a category 1 metering installation, when: a) all meters at the metering installation are replaced; b) one or more meters at the metering installation are replaced and each such meter is replaced with a certified meter, but: i. at least one existing meter is not replaced; and

	ii. the expiry date of the certification for the metering installation is not changed. 2) To show prevailing load tests are required for the recertification of a category 1 metering installation when: a) one or more meters at the metering installation are replaced and each such meter is replaced with a certified meter, but: i. at least one existing meter is not replaced; and ii. the expiry date of the certification for the metering installation is changed. 3) To require a control device check to be undertaken for metering installations of categories 1-3. 4) To require a component certification check when a control device is replaced at any category of metering installation 5) To broaden the meaning of “MI”, so that it applies to any type of control device installed at a metering installation, rather than just control devices that are integral with a meter. 6) To require a data storage device test when a category 3 metering installation is: a) initially certified b) recertified. 7) To require an installation or component configuration test when additional equipment is added to any category of metering installation. 8) To remove the following columns, which are unnecessary: a) “Measuring transformer” b) “Meter” c) “Primary injection to meter”. 9) To restructure Table 3 to group rows by metering installation category, and to clarify the row headings
Proposed Code amendment	Please refer to the proposed Table 3 of Schedule 10.1 at the end of this proposal.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority’s objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations set out in Table 3 of Schedule 10.1 will: a) make it easier for participants to understand the testing requirements for metering components; and b) help ensure the appropriate tests are performed, in order to have accurate metering installations. The proposed Code amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.

Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to remove ambiguity from selected component recertification requirements, in order to remove some confusion amongst participants.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Schedule 10.1: Table 3: Selected component certification and comparative recertification minimum test requirements

	Event	Design check	Prevailing load test	Data storage device check	Software security and communication equipment check	Control device check	Wiring check	Component certification check	Review of compensation factors	Raw meter data output test	Supply polarity check	Register advance test	Installation or component configuration check
Category 1 metering installations	Initial certification, or recertification with all meters replaced	M			M	MI	M	M	M	M	M	M	M
	Recertification with no meters replaced	M	M		M	MI	M	M	M	M	M	M	M
	Recertification with one or more meters replaced with a certified meter(s), at least one existing meter remains, and metering installation expiry date is not changed	M			M	MI	M	M	M	M	M	M	M
	Recertification with one or more meters replaced with a certified meter(s), at least one existing meter remains, and metering installation expiry date is changed	M	M		M	MI	M	M	M	M	M	M	M
Categories 2 – 3	Initial certification, recertification, or meter change including internal data storage devices	M	M	MI (for Cat 3 only)	M	MI	M	M	M	M	M	M	M
	Measuring transformer change or ratio change	M	M				M		M	M	M	M	
All categories	Metrology software change either onsite or remote	M		M	M			M	M	M		M	M
	External data storage device change	M		M	M		M	M	M	M		M	M
	Control device change	M		MI		M	M	M		M			M
	Additional equipment (eg wiring)	M	M				M			M	M	M	M

Key: M = mandatory, MI = mandatory if installed ~~the control device is integral with the meter~~.
Table 3: rows 6 and 8 amended, on 15 May 2014, by clause 14 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.
Table 3: row 3 amended, on 19 December 2014, by clause 21 of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

Reference number(s)	**009 - ISO 9001 Sync with Class B ATH Application Period**
Relevant clause(s)	Clause 4(1)(a) of Schedule 10.3 – Approval of class B ATHs
Problem definition	Clause 4(1)(a) of Schedule 10.3 of the Code requires an applicant applying for approval, or renewal of approval, as a Class B ATH to hold, and comply with, ISO 9001 certification for at least the requested term of approval. ISO 9001 certification is normally granted for a period of three years. The Authority's approval of a class B ATH is granted for a term of one year. Someone reapplying to be a class B ATH for a third consecutive year may not, at the time of reapplying for ATH approval, hold ISO 9001 certification for the entire ATH approval period. This mismatch comes about because: a) the applicant must have ISO 9001 certification in place before it applies to the Authority for approval as an ATH, and b) the Authority grants approval for one year periods—meaning the ATH's three-year ISO 9001 accreditation will expire before the ATH completes the third approval period. Take the example of a class B ATH with ISO 9001 certification from 30 June 2016 to 30 June 2019, and which applies for ATH approval on 30 August each year. • On 30 August 2016 it can confirm it will hold ISO certification until 30 August 2017 • On 30 August 2017 it can confirm it will hold ISO certification until 30 August 2018 • On 30 August 2018 it cannot confirm it will hold ISO certification until 30 August 2019, as its ISO certification expires on 30 June 2019. However, the ATH has full ISO processes in place and is very likely to gain ISO 9001 certification as part of its ISO recertification audit (held in May each third year). In reality, an auditor reviewing the class B ATH as part of the Authority's annual approval would, in examples like this, confirm the Class B ATH: a) intended to hold ISO 9001 certification beyond 30 June 2019, and b) had audits, etc. planned so as to continue to hold ISO certification beyond this time. This would provide the auditor with sufficient confidence that the ATH would remain fully compliant with the conditions of its approval, and would pose no risk to the accurate measurement of electricity for the duration of the approval period. However, the current drafting of the Code does not provide for the Authority to approve the applicant as a class B ATH, even when the applicant satisfies the Authority that it should be approved. The Authority considers that shortening the third approval period, to avoid an ATH breaching the requirement to hold ISO 9001 would be inefficient. It would require ATHs to reapply more frequently than is necessary, thereby

	incurring additional audit costs unnecessarily. Furthermore, this shortening would compound over time since ISO 9001 accreditation is always completed prior to the expiry of the current ISO 9001 accreditation—to ensure the ATH approval does not automatically cancel.
Proposal	The Authority proposes: a) to remove the requirement for a class B ATH to hold ISO 9001 certification for the full term of its approval by the Authority b) to require a class B ATH to confirm, at the time of the audit that is undertaken as part of the Authority's approval, that the class B ATH: i) holds ISO 9001 certification at the time of the audit, and ii) has appropriate plans in place to ensure that ISO 9001 certification continues to the end of the Authority's 12 month approval period. The ISO 9001 standard is a generic quality management standard. It focuses on the holder's commitment to quality and customer satisfaction, as well as on continuous improvement. A deterioration in a class B ATH's processes, to the point where ISO certification would not be granted at the next ISO review, would be apparent in the ATH's work and would be identified in the audit undertaken as part of the Authority's annual approval of the ATH. Also, clause 6 of Schedule 10.3 requires an ATH to advise the Authority of a reduction in the scope of the ATH's ISO accreditation, which includes a loss of accreditation entirely. An ATH's approval is automatically cancelled from the date of the reduction in scope, if the ATH fails to advise the Authority of the reduction.[1] Therefore, we consider the requirement for an applicant class B ATH to prove it holds ISO 9001 certification for the entire period of its approval as a class B ATH is unnecessary. A class B ATH that is planning to renew its ISO 9001 certification, at the current scope, will have in place the appropriate controls and certifications throughout the Authority's one year approval period, even if the existing ISO certification is only valid for some of the coming year. Any risk associated with the loss of ISO 9001 certification is managed through the requirements of clause 6 of Schedule 10.3 of the Code. We also propose to amend clause 4(1) of Schedule 10.3 to clarify that an applicant is requesting approval as a category B ATH for a pre-determined time period, rather than requesting the term of approval, which they cannot do since the Authority determines the term of approval.
Proposed Code	We propose to amend clause 4 of Schedule 10.3 as follows:

[1] An ATH has an incentive to advise the Authority of any such reduction in scope. Doing so avoids situations where the ATH's customers pay twice to have metering components and/or metering installations certified:

1) First, by the ATH whose reduced ISO accreditation means it has issued an invalid certification; and
2) Second, by an approved ATH whose ISO accreditation permits it to certify the metering component or metering installation.

amendment	**Schedule 10.3** **4 Approval of class B ATH** (1) An applicant applying for approval, or renewal of approval, as a **class B ATH** must, as part of its application to the **Authority**, confirm that— (a) it holds and complies with AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification for at least the ~~requested~~ term of the requested approval; and (b) the scope of its AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification covers the activities that it undertakes, or proposes to undertake; and (c) it will develop and at all times during the ~~requested~~ term of the requested approval maintain a conflict of interest policy in compliance with AS/NZS ISO 17025. (1A) Despite subclause (1), an applicant may apply to the **Authority** for approval as a **class B ATH** without confirming that it holds and complies with AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification for at least the term of the requested approval, provided the applicant confirms as part of its application that— (a) it holds and complies with AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification at the time of the application and that certification expires during the approval period; and (b) it has in place appropriate plans to ensure that it renews its AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification for the term of the requested approval, so that its AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification remains in place continuously throughout the approval period. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by enabling a class B ATH to obtain approval for the maximum available term. This would reduce a Class B ATH's audit and compliance costs every third year. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment

Gain or Market or Regulatory Failure	to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to ensure ATHs are able to obtain approval for the maximum available term, and the approval term is not artificially constrained by the timing of the ISO 9001 accreditation.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**010 – Selected Component Recertification**
Relevant clause(s)	Clause 7(5)(c) of Schedule 10.4 – Calibration methods Clause 9(3)(a) of Schedule 10.8 – Onsite calibration and certification
Problem definition	Under clause 7(5)(c) of Schedule 10.4 and clause 9(3)(a) of Schedule 10.8 an ATH must, when calibrating a metering component, calculate the "uncertainty of measurement".[1] The uncertainty of measurement during a metering component's calibration arises from: a) potential errors in the measuring instruments (working standards)[2] used by the ATH to calibrate the metering component b) environmental factors that might affect the accuracy of the metering component being calibrated and the working standards used to do the calibration. An ATH may have a number of working standards in use as part of its calibration activities. Under the current Code requirements, for each metering installation, an ATH's field technician must calculate the uncertainty of measurement for a metering component using the uncertainty of the working standard the technician is using to calibrate the component. This limits the ATH's ability to use a standard calibration template when calibrating a metering component. For category 2 and category 3 metering installations in particular, using a standard calibration template would lower the cost of calibrating metering components. An ATH would be able to use such a template if the Code were to prescribe a default value for a working standard's uncertainty. Having multiple working standards with different uncertainties also increases the risk of the field technician making a mistake when calculating the uncertainty of measurement. Amending the Code to enable an ATH to use a default uncertainty value would enable an ATH to use a standardised calibration template. This would lower the cost for an ATH to calibrate a metering component, while still ensuring the metering component and the metering installation meet the Code's accuracy requirements.
Proposal	The Authority proposes to amend the Code to allow an ATH to use a default value for a working standard's uncertainty, when calculating the uncertainty of measurement associated with calibrating a metering component. This will enable an ATH to use a standardised calibration template, which will: a) reduce the cost of calculating the uncertainty of measurement, by

[1] Part 1 of the Code defines "uncertainty" to mean a parameter associated with the result of a measurement that characterises the dispersion of the values that could reasonably be attributed to the quantity being measured, and must be determined to a confidence level of 95% or greater unless otherwise specifically stated.

[2] Part 1 of the Code defines "working standard" to mean a measuring instrument that has been calibrated by an approved calibration laboratory or an ATH, which is used routinely for the calibration of metering installations and metering components.

	streamlining the process for calculating the uncertainty b) lower the risk of an ATH making a mistake when calculating the uncertainty of measurement. Under the proposal, an ATH would be able to use either: a) the actual uncertainty for the working standard the ATH is using to calibrate a metering component, or b) a default value (equivalent to the maximum site uncertainty of 0.6% for category 1 and 2 metering installations and 0.3% for category 3 metering installations—refer to Table 1 of Schedule 10.1), provided: i) the ATH calibrates the working standard in accordance with the timeframes set out in Table 1 of Schedule 10.4, and ii) the uncertainty of the working standard does not exceed the relevant default value noted above, and iii) the total uncertainty for the metering installation does not exceed the maximum site uncertainty specified in Table 1 of Schedule 10.1. For the avoidance of doubt, the use of a default value for a working standard's uncertainty does not remove an ATH's obligation to regularly test and calibrate its working standards. These must still be calibrated at regular intervals in accordance with Table 1 of Schedule 10.4.
Proposed Code amendment	**Schedule 10.4** … *Requirements for calibration of metering components* **7 Calibration methods** … (5) An **ATH** must, when calibrating a **metering component**,— (a) if necessary, **adjust** and document the **error compensation**; and (b) ensure that any **adjustment** carried out under paragraph (a) is appropriate to achieve an error as close as practicable to zero; and (c) ensure that the **uncertainty** of measurement during the **calibration** of the **metering component** does not exceed one third of the maximum permitted error in the relevant standard listed in Table 5 of Schedule 10.1; and (d) if the **metering component** is intended for a **metering installation** which is to be **certified** using the **selected component certification** method, ensure that the **ATH** records the errors of a current transformer from 5% to 120% of rated primary current. … (8) An ATH, when calculating the **uncertainty** of measurement under

	subclause (5)(c— (a) for **category 1 metering installations** and **category 2 metering installations,** may use either 0.6% or the actual **uncertainty** of the **working standard** as the **uncertainty** of the **working standard**, provided the actual **uncertainty** of the **working standard** does not exceed 0.6%. (b) for category 3 **metering installations,** may use either 0.3% or the actual **uncertainty** of the **working standard uncertainty** of the **working standard**, provided the actual **uncertainty** of the **working standard** does not exceed 0.3%.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry by reducing the cost and instances of errors associated with calibrating metering components. The proposed Code amendment is expected to have little or no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of this proposal is to allow ATHs to simplify their calibration methods, thereby reducing costs, without compromising the accuracy of tested metering components.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**011 - Raw Meter Data and Compensation Factors**
Relevant clause(s)	Definition of "compensation factor " in Part 1 Definition of "raw meter data" in Part 1 Clause 8 of Schedule 10.6 – Electronic interrogation of metering installation Clause 11.8A – Metering equipment provider to provide registry metering records to registry manager Clause 7(1) of Schedule 11.4 – Metering equipment provider to provide registry metering records to registry manager Table 1 of Schedule 11.4 Clause 2(3) of Schedule 15.3 – Reconciliation participants to prepare information
Problem definition	Part 1 of the Code defines “volume information” to mean the information: a) describing the quantity of electricity generated, conveyed, or consumed that is calculated or estimated from raw meter data and supporting data; and b) in the case of unmetered load, calculated in accordance with the Code. For the purposes of Part 10 of the Code, Part 1 of the Code defines raw meter data to mean information obtained by interrogating a metering installation.[1] To produce accurate volume information, compensation factors are applied to raw meter data from a metering installation. Part 1 of the Code defines “compensation factor” to mean one of the following factors used to compensate for errors, losses, or ratios within a metering installation, to produce accurate volume information: a) error compensation: b) loss compensation: c) ratio compensation. Any combination of the three types of compensation factors can be applied to raw meter data. Normally, a metering installation component will apply error and loss compensation automatically through its internal programming, so that the raw meter data has already been adjusted by these factors prior to the interrogation. The trader responsible for the site subsequently applies any required measuring transformer ratio factor, as specified by the MEP in the registry, to the raw meter data following the interrogation of the metering installation. However, sometimes loss or error compensation is not programmed into a meter. Therefore a trader must apply more than one type of compensation factor to raw meter data. If this is the case, the trader must multiply the raw

1 Part 1 of the Code also defines “raw meter data” for the purposes of Part 15 of the Code.

	meter data quantities by the product of the applicable compensation factors to generate volume information for the site. Currently, the registry contains one field for compensation factors used in relation to a metering installation. This reflects the infrequency with which traders must apply more than one type of compensation factor to raw meter data. There are two problems with the current arrangements in the Code relating to compensation factors. <u>Problem 1</u> Traders and metering equipment providers (MEPs) are inconsistent in their interpretation and application of the definitions of “compensation factor” and "raw meter data". As a result: a) traders and MEPs are not applying compensation factors to raw meter data, which is resulting in volume information for a site that understates the correct volume information b) traders and MEPs are both applying compensation factors to raw meter data, which is resulting in volume information for a site that overstates the correct volume information c) either the trader or the MEP applies compensation factors, but with no consistent practice used across the electricity industry. The compensation factor that the MEP enters in the registry against a metering installation must be the compensation factor the trader (or trader's agent—eg, the data administrator) applies to the raw meter data. If a component of the metering installation applies a compensation factor prior to the raw meter data being obtained from the metering installation, then this compensation factor must not form part of the compensation factor recorded in the registry. Furthermore, it is the responsibility of the trader to apply the compensation factor recorded in the registry when creating volume information. It is <u>not</u> the MEP’s responsibility to apply the compensation factor recorded in the registry when delivering the raw meter data to the trader. <u>Problem 2</u> Currently, the Code does not clearly state how an MEP should record in the registry a compensation factor that represents multiple types of compensation (eg, both loss and ratio compensation). Row 19 of schedule 11.4 is potentially confusing. It requires the “compensation factor” (as defined in Part 1) to be used in the registry, but the intention is (as expressed in the description in Row 19) that this could be the product of one or more individual compensation factors. The description also uses the term “complex compensation factor” (where the words “compensation factor” are as defined in Part 1 of the Code). While this is helpful, it is not clear that all participants understand what is meant by complex. The compensation factor recorded in the registry must include all forms of compensation to be applied by the trader. So, if a component of a metering installation does not apply any required error and loss compensation, the

	compensation factor in the registry must include this form of compensation. The Code should clearly describe this. Part 15 of the Code also refers only to the term “compensation factor” (as defined in Part 1), which could be read as referring to the individual compensation factors, rather than (where applicable) the product of two or more compensation factors that are required to be applied.
Proposal	To address problem 1, the Authority proposes to amend clause 8 of Schedule 10.6 of the Code to clarify that an MEP must not apply the compensation factor recorded in the registry to raw meter data. This is the responsibility of the trader responsible for the ICP at which the metering installation is located. To address problem 2, the Authority proposes to: a) amend the definition of “compensation factor” in Part 1 b) amend Table 1 of Schedule 11.4, and c) include a reference to Table 1 of Schedule 11.4 in clause 24 of Schedule 10.7. The amendments to Part 1 and Schedule 11.4 are to clarify that an MEP must enter into the registry a compensation factor that is the mathematical product of all compensation factors that are applied externally to the metering installation.
Proposed Code amendment	**Part 1** … **compensation factor** means any of the following factors used to compensate for errors, losses, or ratios within a **metering installation** that are required to be applied to **raw meter data**~~, to produce accurate~~ ~~**volume information**~~: (a) **error compensation**: (b) **loss compensation**: (c) **ratio compensation** To avoid doubt, the **raw meter data** from a **metering installation** may require more than one **compensation factor,** if the relevant types of compensation are required. ... **Schedule 10.6** … **8 Electronic interrogation of metering installation** … (10) A **metering equipment provider** must not, when **interrogating** a **metering installation**, apply the **compensation factor** recorded in the **registry** for that **metering installation** to any **raw meter data** downloaded as part of the **interrogation**.

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Schedule 10.7

…

24 Compensation factors

…

(3) A **metering equipment provider** must, for a **metering installation** in relation to which a **compensation factor** must be applied,—

(a) if the **metering installation** is for a **point of connection** that is an **NSP**, advise the **reconciliation participant** responsible for the **metering installation** of the **compensation factor** within 10 **business days** of the date on which the **metering installation** is **certified**; or

(b) in all other cases, update the **compensation factor** recorded in the **registry** in accordance with <u>Table 1 of Schedule</u>~~ Part~~ 11<u>.4</u>.

Schedule 11.4

…

Table 1: Registry metering records

The following table sets out the **registry metering records**:

<table>
<tr><th>No</th><th>Registry term</th><th>Description</th><th>Fully certified metering installation</th><th>Interim certified metering installation</th></tr>
<tr><td colspan="5">…</td></tr>
<tr><td colspan="5">The following details for each metering component in the metering installation for each ICP

…</td></tr>
<tr><td>19</td><td><u>registry</u> compensation factor</td><td>The <u>mathematical product of all</u> compensation factor<u>s</u>~~,~~ that ~~which in the case of a complex~~ ~~compensation factor, must be obtained from~~ ~~equipment provider~~ <u>the trader must apply to transform the raw meter data into volume information</u></td><td>Required for meter or data storage device. Optional for all other metering components.</td><td>Required for meter or data storage device. Optional for all other metering components.</td></tr>
</table>

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<tr>
<td>Assessment of proposed Code amendment against section 32(1) of the</td>
<td>The proposed Code amendment is consistent with the Authority’s objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry.</td>
</tr>
</table>

Act	It would do this by: a) making it easier for participants to understand and meet their Code obligations, which would reduce their costs of transacting in the electricity market b) improving the accuracy of submission information, which would lead to more accurate reconciliation and more accurate invoicing of participants and consumers. It could also increase the reliability of supply for consumers as it would help ensure their metering installations were fit for purpose for their connection type. The proposed amendment is expected to have little, if any, effect on competition, and no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The primary objective of the proposed Code amendment is to improve the accuracy of submission information, thereby improving the accuracy of reconciliation and invoicing of participants and consumers. A secondary objective is to make it easier for participants to understand and meet their Code obligations.
Evaluation of the costs and benefits of the proposed amendment	Should be zero cost, as MEPs are still generating the compensation factors and entering them in the registry. Benefits are increased clarity and reduced UFE through reduction in errors with compensation factors.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed Code amendment that would meet the objectives of the proposal.

Reference number(s)	**012 - Monitoring of Event Logs**
Relevant clause(s)	Clause 10.43 – Metering installations that are inaccurate, defective, or not fit for purpose to be investigated Clauses 8(5)(f) and 8(7) of Schedule 10.6 – Electronic interrogation of metering installation Clause 17(4) of Schedule 15.2 – Electronic meter readings and estimated readings
Problem definition	Clause 8 of Schedule 10.6, amongst other things, requires an MEP, when interrogating a metering installation: a) to check the event log for evidence of malfunctioning or tampering, and if this is detected, carry out the appropriate requirements of Part 10 b) to review the event log either manually or by an automated software function which flags exceptions, and— i) take appropriate action where problems are apparent; and ii) pass relevant event log entries to the reconciliation participant for the metering installation. Clause 17 of Schedule 15.2, amongst other things, requires the relevant reconciliation participant to check the validity of all meter readings obtained by electronic interrogation and estimated readings. Each such validity check must include a review of the meter and data storage device event log. Any event that could have affected the integrity of metering data must be investigated. In accordance with clause 10.43, the reconciliation participant must— a) advise the MEP responsible for the metering installation if the reconciliation participant becomes aware of an event or circumstance that leads it to believe the metering installation is or could be— i) inaccurate; or ii) defective; or iii) not fit for purpose; and b) include, with the advice (if and to the extent they are known), all relevant details. The Authority has received participant feedback indicating the current drafting of clause 8 of Schedule 10.6 and clause 17 of Schedule 15.2, is insufficiently clear in describing participant obligations. As a result, some participants are either not complying, or not fully complying, with their Code obligations.
Proposal	The Code intentionally places an obligation on both the MEP and the reconcilation participant to check the validity of a meter reading by reviewing the metering installation’s event log(s). The two parties have different responsibilities. An MEP is focussed on the integrity and operation of the metering installation. A reconcilaition participant is focussed on ensuring it submits accurate electricity volumes

	to the reconciliation manager. The Authority proposes to clarify participants' obligations under clause 8 of Schedule 10.6 and clause 17 of Schedule 15.2, by amending the Code: a) so that clause 8 of Schedule 10.6 requires an MEP, when interrogating a metering installation: i) to review event logs for any outstanding events that may affect the integrity or operation of the metering installation (eg, covers removed, loose connections, time synchronisation errors), ii) to investigate and remediate any issues identified and to advise the relevant reconciliation participant of any corrections to the raw meter data required; iii) to advise the relevant reconciliation participant of any event in the event log that it is investigating and remediating so that the reconciliation participant is aware that the raw meter data may need to be corrected; and iv) to advise the relevant reconciliation participant of any event in the event log that does not affect the integrity or operation of the metering installation but may affect the accuracy of the raw meter data so that the reconciliation participant can investigate and remediate the issue if necessary b) so that clause 17 of Schedule 15.2 requires the relevant reconciliation participant: i) to review event logs for any outstanding events that may affect the accuracy of the metering data, ii) to investigate and remediate any event that the MEP is not investigating; and iii) to revew the metering data related to such an event—since: A) any event in the event log may affect the metering data, and B) it is the reconciliation participant's responsibility to ensure it submits accurate submission information to the reconciliation manager, either: 1. in its initial submission, or 2. in a subsequent washup if the issue is not remediated in time for the initial submission.
Proposed Code amendment	We propose to amend clause 8 of Schedule 10.6 and clause 17 of Schedule 15.2 as follows: **Schedule 10.6** … **8 Electronic interrogation of metering installation** … (5) A **metering equipment provider** must, when **interrogating** a **metering installation**,— … (e) download the event log; and (f) check the event log for any event that may affect the integrity or operation of the **metering installation** such as ~~evidence of~~

	malfunctioning or tampering~~ and if this is detected, carry out the appropriate requirements of this Part~~. (5A) A **metering equipment provider** must, if it finds an event that may affect the integrity or operation of a **metering installation**,— (a) investigate and remediate the event; and (b) advise the relevant **reconciliation participant** that it is investigating and remediating the event; and (c) advise the relevant **reconciliation participant** of any corrections to the **raw meter data** required; and (d) advise the relevant **reconciliation participant** of any event that does not affect the integrity or operation of the **metering installation** but which may affect the accuracy of the **raw meter data**. … **Schedule 15.2** … **17 Electronic meter readings and estimated readings** (1) All **meter readings** obtained by electronic **interrogation** and **estimated readings** must be checked for validity by the relevant **reconciliation participant**. … (4) Each validity check of a **meter reading** obtained by electronic **interrogation** or an **estimated reading** must include the following: … (f) a review of the **meter** and **data storage device** event log~~.~~ for any~~Any~~ event that could have affected the integrity of the **metering data**~~ must be investigated~~: (g) a review of the relevant **metering data** if there was an event that could have affected the integrity of the **metering data**. (4A) A **reconciliation participant** must, if it finds an event that could have affected the integrity of the **metering data**,— (a) investigate and remediate the event if the **metering equipment provider** responsible for the **metering installation** does not have responsibility for investigating and remediating the event and (b) advise the **metering equipment provider** responsible for the relevant **metering installation** of the event if the investigation finds that the event may affect the integrity or operation of the **metering installation**
Assessment of proposed Code amendment against section 32(1) of the	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would make it easier for MEPs and reconciliation participants to understand their respective obligations to review metering event logs.

Act	The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to improve the efficient operation of the electricity industry by clarifying the respective obligations on MEPs and reconciliation participants to review metering event logs.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed Code amendment.

Reference number(s)	**013 – Raw Meter Data Output Tests**
Relevant clause(s)	Clause 9(1)(c) of Schedule 10.7 – Certification tests
Problem definition	During the certification of metering installations, a number of tests are performed to ensure the installation is performing correctly. A raw meter data output test is one of these. It forms part of the suite of tests and checks used in the “selected component certification” of metering installations. The purpose of the test is to check the meter is recording an amount of electricity that is reasonably close to the amount of electricity observed to be flowing. A raw meter data test is not a meter accuracy test. Instead, it is an indication of whether the: a) metering installation is working; b) meter has failed or been damaged after it was calibrated. Some participants have advised the Authority that clause 9(1)(c) of Schedule 10.7 is insufficiently clear about how this test should be performed. They consider the clause does not say how much load should be used in order to have appropriate confidence in the test result. Some are using zero load as the initial reference point. They believe the clause is open to more than one interpretation, which can lead to inconsistencies in testing. When clause 9(1)(c) of Schedule 10.7 was originally drafted, Ferraris disc meters were the norm. These meters needed to be tested at two different loads to ensure: a) the meter measurement (disc speed) changed with the change in load b) the disc shaft or bearings had not been damaged. In 2018 electronic meters are the norm and Ferraris disc meters, although still in use, are relatively rare. There is not the same risk of physical damage to an electronic meter as there is for a Ferraris disc meter. Therefore, a test at two different loads is not needed for electronic meters, while it needs to be retained for Ferraris disc meters.
Proposal	The Authority proposes to amend the Code: (a) to require that the load used in a raw meter data output test must be greater than 5% of the meter's certified maximum load (b) to specify that the raw meter data output test must be carried out using either the working standard in clause 9(1)(a) of Schedule 10.7 or an ammeter in good working order and with an accuracy within +/- 5 % (c) to require that, when undertaking a raw meter data output test, the meter register must change by at least “1” in the least significant digit (which may require many pulses of the meter) (d) if a Ferraris disc meter is being tested, to require that a second raw meter data output test be undertaken at double the load of the first test.

Proposed Code amendment	**Schedule 10.7** … **9 Certification tests** (1) An **ATH**, when carrying out a test set out in Table 3 or 4 of Schedule 10.1,— … (c) to carry out a **raw meter data** output test for a **category 1 metering installation** or **category 2 metering installation**, must do so by– (ia) applying a measured increase in load ~~and measuring~~ that is greater than 5% of the **meter's** maximum rated current; and (ib) using either the **working standard** referred to in subclause (1)(a) or an ammeter in good working order with an accuracy range of +/- 5% to measure the load applied to the **metering installation**; and (A) recording the resulting increment of the **meter** register value over a measured period of time; or (B) recording the resulting accumulation of pulses from the load over a measured period of time; and (ic) ensuring that the change in the **meter** register that occurs under subclause (ib)(A) or subclause (ib)(B) is at least "1" in the least significant digit of the **meter** register; and (id) if the **meter** is a Ferraris disc **meter**, undertaking two **raw meter data** output tests where the second test must have a load applied to the **meter** that is double the load applied to the **meter** in the test carried out in accordance with subclause (c)(ia): (i) the increment of the sum of the **meter** registers; or (ii) the accumulation of pulses resulting from the increase in load: …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. Clarifying how an ATH is to undertake a raw meter data output test would help ensure ATHs undertook the test appropriately, thereby better ensuring the accuracy of the metering installation being tested. There should also be a reduction in testing costs for some ATHs because the proposed Code amendment reduces the complexity of the test for electronic meters. The proposed Code amendment is expected to have no effect on

	competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a lack of clarity in the Code that is leading to market inefficiency. Accordingly, the proposed Code amendment will lead to an efficiency gain.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to reduce ambiguity in the Code requirements for undertaking a raw meter data output test, and to reduce confusion amongst participants.
Evaluation of the costs and benefits of the proposed amendment	The costs are nil as participants are already doing the tests. The benefit is reduction is costs for some ATHs as the change reduces the complexity of the test for electronic meters.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed Code amendment that would meet the objectives of the proposal.

Reference number(s)	**014 - HHR Certification and Interrogation Cycles**
Relevant clause(s)	Clause 8 of Schedule 10.6 – Electronic interrogation of metering installation Clause 9 of Schedule 10.7 – Certification tests Clause 20 of Schedule 10.7 – Cancellation of certification of metering installations
Problem definition	Clause 8(2)(b) of Schedule 10.6 requires an MEP to interrogate a metering installation for which it is responsible at least once in each maximum interrogation cycle in the registry. This is to ensure data is not lost when the meter runs out of memory and overwrites previous data. Clause 8(9) of Schedule 10.6 requires the MEP to ensure that each electronic interrogation of a metering installation that retrieves half hour metering information compares the sum of that information against the increment of the metering installation's accumulating meter registers for the same period. This comparison check ensures both the half hour and the non-half hour parts of the metering installation are recording the same amount of electricity for the same time period. An ATH must perform a raw meter data output test when certifying a category 1 or category 2 metering installation as a half hour metering installation. If an ATH does so, then clause 9(1)(d) of Schedule 10.7 requires the ATH to either: a) compare the output from a working standard to the raw meter data from the metering installation for a minimum of 1 trading period; or b) if the raw meter data is to be used for the purposes of Part 15 of the Code, confirm that the MEP's back-office processes compare: i) the increment of the (accumulating) meter registers, with ii) (the sum of) the half-hour metering raw meter data (for the same period). Note: the words in brackets have been added to make clear the intent of the Code wording. This ambiguity in the Code drafting is an issue we wish to address. Under clause 9(1)(d) of Schedule 10.7, an ATH assesses an MEP's compliance with the obligation under clause 8 of Schedule 10.6 by determining whether the MEP's back office system <u>is capable of</u> performing the comparison check. However, the ATH does not determine whether the back office system <u>actually</u> interrogates the meter and performs the comparison check. Sometimes, the MEP cannot perform a comparison check because the MEP cannot get a meter read from the meter. If an MEP's back office system is unable to perform a comparison check, because the MEP cannot interrogate the meter, the metering installation should not be certified as a half hour metering installation. This is because the MEP cannot verify the accuracy of the metering installation's half hour data. However, currently the Code does not state that a half hour metering

	installation should lose its certification in such instances. In addition, the Code does not specify what is an acceptable result for a comparison check.
Proposal	The Authority proposes to amend the Code: a) to clarify clause 8(8) and (9) of Schedule 10.6 and clause 9(1) of Schedule 10.7, to say that if raw meter data is to be used for the purposes of Part 15, an MEP's back-office processes must compare: i) the increment of the accumulating meter registers, to ii) the sum of the half-hour metering raw meter data for the same period. b) to amend clause 20 of Schedule 10.7 to state that a half-hour metering installation's certification is automatically cancelled if an MEP: i) does not read each meter within the meter's maximum interrogation cycle; or ii) reads each meter within the meter's maximum interrogation cycle but— A) does not perform a comparison check; or B) performs a comparison check that shows the difference between the half hour metering information and the increment of the metering installation's accumulating meter registers is greater than one kilowatt hour.
Proposed Code amendment	**Schedule 10.6** … **8 Electronic interrogation of metering installation** … (8) Subclause (9) applies when— (a) a **metering equipment provider interrogates** a **half-hour metering installation** which is a **category 1 metering installation** or a **category 2 metering installation**; and (b) the **certifying ATH** confirmed, as a part of the **metering installation's** most recent **certification**, that the **metering equipment provider's back office** processes include, for each **interrogation** cycle, a comparison of: (i) the ~~difference in the~~ increment of the accumulating **meter** registers; ~~to~~ and (ii) the sum of the **half-hour metering raw meter data** for the same period. (9) When this subclause applies, the **metering equipment provider** must ensure that each electronic **interrogation** of the **metering installation** that retrieves **half hour raw meter~~ing information~~ data** compares the sum of that data ~~information~~ against the

increment of the **metering installation's** accumulating **meter** registers for the same period.

…

Schedule 10.7

…

9 Certification tests

(1) An **ATH**, when carrying out a test set out in Table 3 or 4 of Schedule 10.1,—

…

(d) to carry out a **raw meter data** output test for a **half-hour metering installation** which is a **category 1 metering installation** or for a **half-hour metering installation** which is a **category 2 metering installation**, must either—

(i) compare the output from a **working standard** to the **raw meter data** from the **metering installation** for a minimum of 1 **trading period**; or

(ii) if the **raw meter data** is to be used for the purposes of Part 15, confirm that the **metering equipment provider's back office** processes include a comparison of:

(A) the ~~difference in the~~ increment of the accumulating **meter** registers; ~~to~~ and

(B) the sum of the **half-hour metering raw meter data** for the same period~~, if the **raw meter data** is to be used for the purposes of Part 15~~:

…

20 Cancellation of certification of metering installations

(1) The **certification** of a **metering installation** is automatically cancelled on the date on which any 1 of the following events takes place:

…

(j) if the **metering installation** is a **half-hour metering installation** and was **certified** after 29 August 2013, at the end of any **interrogation** cycle in which a **metering equipment provider's back office** processes within that **interrogation** cycle—

(i) fail to perform any electronic **interrogation** of the **metering installation** that retrieves **half-hour metering information**; or

(ii) perform an electronic **interrogation** of the **metering installation** and the difference between the sum of the **half-hour metering information** and the increment of the **metering installation's** accumulating **meter** registers for the same period is greater than one kilowatt

	hour. (2) A **metering equipment provider** must, within 10 **business days** of becoming aware that 1 of the events in subclause (1) has occurred in relation to a **metering installation** for which it is responsible~~,~~: (a) update the **metering installation's certification** expiry date in the **registry**; and (b) if either of the events in subclause (1)(j) has occurred, update the **metering installation's** AMI flag to "N" in the registry. (3) The obligations in subclause (2) do not apply if the **metering installation** has been **recertified** within the 10 **business days**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by ensuring a check to validate the accuracy of volume information provided to the reconciliation manager is performed, which in turn would promote accurate wholesale market settlement and accurate consumer invoicing. The proposed amendment is expected to have little effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of this proposal is to ensure that raw meter data from half hour metering installations is validated as part of an MEPs interrogation and shown to be accurate.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the	The Authority has not identified any alternatives to the proposed Code amendment that would meet the objectives of the proposal.

proposed amendment	

Reference number(s)	**015 - Comparative Recertification**
Relevant clause(s)	Clause 12 of Schedule 10.7 – Comparative recertification
Problem definition	Comparartive recertification is a type of recertification used only for category 2 metering installations. Comparative recertification uses an in-situ test, which relies on a working standard[1] that includes calibrated test current transformers (CTs).[2] Meter data from the working standard is compared against meter data obtained from the on-site meter to determine if the on-site metering installation (CTs, meter(s) and the connecting wiring) is measuring electricity accurately. The actual load of the site is used as long as it is above the minimum test point. Comparative recertification was originally permitted under the Code to cater for instances when in-situ current transformers could not be disconnected for calibration purposes. Comparative recertification has allowed for category 2 metering installations with inaccessible CTs (eg, behind a wall) to be recertified with minimal cost/adverse effect on the metering installation site. <u>Problem 1</u> Modern metering installations should not be built in a manner that restricts access to metering components. The Authority has received suggestions that comparative recertification is no longer relevant and therefore no longer necessary. However comparative recertification has become an important tool for ATHs to use where CTs cannot easily be replaced. <u>Problem 2</u> It is unclear from the wording of clause 12(2) of Schedule 10.7 that comparative recertification: a) can be used for only category 2 metering installations b) can be used if the component certification of the CTs at a category 2 metering installation has expired c) can only be used for a category 2 metering installation if the meter and data storage device have been recertified as part of the comparative recertification process. This is usually done by installing a new meter and data stroage device.
Proposal	<u>Problem 1</u> The Authority considers that comparative recertification has become an important tool for ATHs to use in instances when CTs cannot be easily replaced. Therefore, we propose to retain the Code provisions permitting the use of comparative recertification. <u>Problem 2</u> The Authority proposes to amend the Code to make it clear that

[1] Part 1 of the Code defines "working standard" to mean a measuring instrument that has been calibrated by an approved calibration laboratory or an ATH, which is used routinely for the calibration of metering installations and metering components.
[2] The test CTs can usually be clamped to the mains cables at the metering installation being tested.

	comparative recertification can by used: a) only for category 2 metering installations, and b) where the certification of the CTs at a category 2 metering installation has expired.
Proposed Code amendment	**12 Comparative recertification** (1) This clause only applies when an **ATH** uses the **comparative recertification** method. <u>(1A) An **ATH** may use the **comparative recertification** method to **recertify** only a **category 2 metering installation**.</u> (2) An **ATH** may ~~only~~ use the **comparative recertification** method to **recertify** a **category 2 metering installation** in accordance with this Part if— (a) the **certification** of the current transformers in the **metering installation** expires before the **meter certification** expiry date; and (b) each of the following **metering components** in the **metering installation** has been **certified** in accordance with Schedule 10.8 <u>as part of the **comparative recertification** method</u>: (i) **data storage device**: (ii) **meter**. <u>(2A) For the avoidance of doubt, an **ATH** may use the **comparative recertification** method to **recertify** a **category 2 metering installation** in accordance with this Part if the **certification** of the current transformers in the **metering installation** has expired.</u> (3) An **ATH** must, when **recertifying** a **category 2 metering installation** under this clause, ensure that— (a) the **metering installation** has passed the tests set out in Table 3 of Schedule 10.1, using a **working standard** connected to the **metering installation**; and (b) the current measurement sensor connected around the cables or bus-bars adjacent to the **metering installation** is sufficiently accurate so that the sum of the measured **metering installation** accuracy, the **uncertainty** of the **metering installation**, and the **uncertainty** of the current measurement sensor does not exceed the maximum permitted error set out in Table 1 of Schedule 10.1 for the category of the **metering installation**; and (c) the overall **metering installation** accuracy meets the requirements of Table 1 of Schedule 10.1. (4) An **ATH** must, before it uses the **comparative recertification** method— (a) check the design report of the **metering installation** to—

	(i) confirm the **metering installation** functions in accordance with the design report; and (ii) ensure the **metering installation** complies with this Part; and (b) check and confirm that the **metering installation** is correctly wired in accordance with all applicable requirements and enactments; and (c) carry out any tests and checks required to confirm the integrity of the **metering installation** and record these and their results in the **metering installation certification report**. (5) An **ATH** must, for each **metering installation** it **certifies** under this clause,— (a) prepare a **certification report**; and (b) ensure that each **metering component** in the **metering installation** is fit for purpose.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it will contribute to the efficient operation of the electricity industry. Clarifying the Code obligations relating to comparative recertification will: a) make it easier for participants to understand the testing requirements for category 2 metering installations, and b) help ensure that metering installations are not inadvertently certified incorrectly. The proposed Code amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to clarify when an ATH may use comparative recertification to recertify a metering installation.

Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**016 - Error Calculations at Certification**
Relevant clause(s)	Clause 22 of Schedule 10.7 – Error calculation
Problem definition	Under clause 22 of Schedule 10.7, an ATH must, before it certifies a metering installation under clauses 12 or 13, calculate the percentage error of the metering installation using appropriate mathematical methods. The error calculation must include uncertainty in measurement, with the ATH required to calculate uncertainty at a 95 % level of confidence and in compliance with JCGM 100:2008. Calculating the uncertainty in a metering installation's measurement of electricity helps to ensure the metering installation: a) is accurate within a certain percentage of error b) will remain so at the levels of electricity that will typically flow through the metering installation. <u>Problem 1</u> Some class B ATHs have requested the Authority review the error calculation obligations in clause 22(1) of Schedule 10.7. We have been asked to consider a simplified process for category 2 metering installations in particular. <u>Problem 2</u> Clause 22(1)(a) requires an ATH to calculate the percentage error of a metering installation taking account of "the estimated total quantity of electricity to be conveyed through the metering installation over the next 12 months". The use of the words "total quantity" is not strictly correct. An ATH needs to take account of: a) the ICP's load profile, including the ICP's upper and lower load limits b) the upper and lower limits of the ICP's power factor. This information is required to determine whether the expected load or power factor will exceed the accurate operating range of the metering installation's components. For example, a metering installation: a) that is oversized can become inaccurate at low loads b) supplying a load that varies between being high and low, especially outside the normal test points, may be inaccurate c) that is expected to supply a load with power factors that vary outside the normal test points, may be inaccurate. Some ATH audits show the ATH is not taking into account the correct load and power factor information listed above. ATHs should be requesting this information from the MEP responsible for the metering installation. However, MEPs are not required to give expected load information to ATHs. MEPs can source load information from the retailer or customer for new and existing metering installations, or from their meter reading records for existing metering installations.

Proposal	Problem 1 The Authority proposes to take no further action in relation to the first problem described above. This is based on advice from New Zealand's Chief Metrologist. The Chief Metrologist has advised us that the requirements of clause 22(1) of Schedule 10.7 are necessary to ensure the metering installation is accurate at the extremes of its expected range of operation. Problem 2 The Authority proposes to address the second problem described above by amending clause 22(1)(a) to specify that an ATH must take account of: a) the estimated load profile at the ICP over the next 12 months, and b) the estimated power factor of the load at the ICP over the next 12 months. The Authority does not propose to make any changes to the Code to require MEPs or retailers to supply expected load information under clause 22 of Schedule 10.7. This is because there are likely to be varying sources for this information, depending on the characteristics of the ICP. The Authority expects ATHs to request this information for an ICP from the most appropriate information source for that ICP.
Proposed Code amendment	**22 Error Calculation** (1) An **ATH** must, before it **certifies** a **metering installation** under clauses 12 or 13, calculate the error of the **metering installation** in accordance with the following: (a) the **ATH** must calculate the percentage error of the **metering installation** using appropriate mathematical methods, taking account of— (i) all sources of measurement error; and (ii) the expected profile of the **electricity** expected to be conveyed through the **metering installation** over the next 12 months including, for the avoidance of doubt, the estimated maximum and minimum load amounts ~~total quantity~~ of **electricity** expected to be conveyed at any one time through the **metering installation** over the next 12 months; and (iii) the estimated maximum and minimum power factors for the **electricity** expected to be conveyed at any one time through the **metering installation** over the next 12 months; and (b) the error calculation must include **uncertainty** in measurement; and (c) for the purposes of paragraph (b), the **ATH** must calculate **uncertainty** at a 95% level of confidence and in compliance with JCGM 100:2008.
Assessment of proposed Code amendment against	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry.

section 32(1) of the Act	It would do this by clarifying what is needed to correctly calculate the error of the metering installation, thereby improving the accuracy of metering installations. The proposed Code amendment is expected to have little or no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to clarify the information that ATHs must use when calculating the uncertainty in a metering installation's measurement of electricity.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

<table>
<tr><td>Reference number(s)</td><td>017 - Application of Error Compensation</td></tr>
<tr><td>Relevant clause(s)</td><td>Clause 24 of Schedule 10.7</td></tr>
<tr><td>Problem definition</td><td>Clause 24 of Schedule 10.7 places certain obligations on ATHs and MEPs over recording, applying, and notifying compensation factors that must be applied in relation to specified metering installations.

The Authority has identified two problems with the current drafting of clause 24 of Schedule 10.7.

<u>Problem 1</u>

Compensation factors should be used to correct for errors in the accuracy of metering (error compensation) only in certain instances, regardless of whether they are applied:
a) internally to the meter; or
b) externally to the meter, as a multiplier.

The reasons for the selective use of error compensation are:
a) to ensure participants use metering equipment that is of an appropriate quality
b) error compensation can be complex and it may not be possible to:
i) apply all forms of error compensation in traders’ systems; or
ii) convey the correct error compensation in the registry’s fields.

Because the current wording of clause 24(1)(b) of Schedule 10.7 specifies that compensation factors may be applied externally to the meter in certain situations, it could be interpreted to mean there are no restrictions on compensation factors being applied internally to a metering installation.

<u>Problem 2</u>

Clause 24(3) of Schedule 10.7 currently applies to all compensation factors. However, it should not apply to internal compensation factors.

This is because an internal compensation factor adjusts the meter reading before it becomes raw meter data. An internal compensation factor must then not be applied again to the raw meter data by the reconciliation participant.</td></tr>
<tr><td>Proposal</td><td><u>Problem 1</u>

To address the first problem, the Authority proposes to amend clause 24 of Schedule 10.7 to clarify that compensation factors can only be applied to metering installations in specific circumstances.

<u>Problem 2</u>

To address the second problem, we propose to amend clause 24 of Schedule 10.7, to clarify that only external compensation factors are to be advised to reconciliation participants and to the registry manager.</td></tr>
<tr><td>Proposed Code amendment</td><td>Schedule 10.7
…</td></tr>
</table>

	24 Compensation factors (1) An **ATH** must, before it **certifies** a **metering installation** that requires a **compensation factor** ~~to adjust **raw meter data**—~~ (a) advise the **metering equipment provider** responsible for the **metering installation** of the **compensation factor**; and (b) ensure that the **compensation factor,** whether internally or externally applied, is only applied ~~to be applied to **raw meter data** external to the **metering installation** can only be applied~~ as follows: (i) for **ratio compensation**, on a **category 1 metering installation**, or higher category of **metering installation**; or (ii) for **error compensation**, on a **metering installation** that quantifies **electricity** conveyed through a **point of connection** to the **grid**; or (iii) for **loss compensation**, only on a category 3 or higher **metering installation**. ... (3) A **metering equipment provider** must, for a **metering installation** in relation to which an external **compensation factor** must be applied,— (a) if the **metering installation** is for a **point of connection** that is an **NSP**, advise the **reconciliation participant** responsible for the **metering installation** of the **compensation factor** within 10 **business days** of the date on which the **metering installation** is **certified**; or (b) in all other cases, update the **compensation factor** recorded in the **registry** in accordance with Part 11.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by clarifying the Code, to make it easier for participants to know they cannot apply error compensation to a metering installation unless the metering installation is at a point of connection to the grid. This should remove the possibility of participants applying error compensation to metering installations when it is inappropriate to do so. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.

Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that may lead to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of this proposal is to clarify the Code to ensure compensation factors can only be applied in relation to a specified metering installation, and that the registry or NSP table are only updated with external compensation factors.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	**018 – Certification Validity Periods**
Relevant clause(s)	Table 1 of Schedule 10.1 Table 2 of Schedule 10.1 Clause 16 of Schedule 10.7 – Recertification of group of category 1 metering installations by statistical sampling expiry date Clause 27 of Schedule 10.7 – Meter certification expiry date Clause 45 of Schedule 10.7 – Category 1 metering installation inspection requirements Clause 1 of Schedule 10.8 – Meter certification requirements
Problem definition	The Authority has identified several problems with the Code requirements relating to the validity period of a metering component or installation, as follows: <u>Problem 1</u> Clause 27 of Schedule 10.7 specifies how a meter's certification expiry date must be calculated. This clause also specifies that, if an electromechanical meter has not been installed in a metering installation within 24 months of the date of the meter's certification report, the meter must be recertified before it is installed. This effectively creates a "shelf life" for electromechanical meters. There is no basis for differentiating electromechanical meters from any other type of meter in this regard. The chief metrologist at the Measurement Standards Laboratory of New Zealand has advised the Authority that other meter types (eg, electronic) may also fail over time, and so the 24 month restriction could apply equally to them. <u>Problem 2</u> Clause 1(d)(ii) of Schedule 10.8 specifies that a meter certification report must include the certification validity period for the meter for each category of metering installation the meter may be used in. Certifying a meter for less than the maximum validity period shown in Table 1 of Schedule 10.1 (for a category of metering installation the meter may be used in) could indicate the meter is not fit for certification. However, it is only an indication, since a certification report contains no information on why there is a shorter validity period. Under clause 1(2) of Schedule 10.8, an ATH has the discretion to set a certification validity period for a meter that is less than the maximum validity period. However, should an ATH do so, it should have to note in the certification report the reason for the shorter validity period, to avoid participants believing the meter is not fit for purpose. <u>Problem 3</u> In Table 1 of Schedule 10.1, the requirements in the column with the heading "Maximum sample inspection and recertification period", relates solely to: a) category 1 metering installations that are certified under the statistical sampling provisions of clause 16 of Schedule 10.7, and

	b) category 1 metering installations that are inspected under the statistical sampling provisions of clause 45 of Schedule 10.7. Although not specified in Table 1 of Schedule 10.1, the statistical sampling recertification process contains certification validity periods that are shorter than the maximum validity period of 84 months. The length of these shorter certification validity periods depends on the test results of the sample meters used. The standard AS/NZS 1284[1] specifies the range of test results and associated certification validity periods. The Code would be more readable if this information was part of clauses 16 and 45 of Schedule 10.7 respectively. Someone reading either clause would see at a glance the timeframe to which the obligation relates, rather than needing to refer to Table 1 of Schedule 10.1. <u>Problem 4</u> Table 2 of Schedule 10.1 specifies the maximum certification validity period for the classes of meter[2] permitted to be used in each category of metering installation. We believe the readability of the Code would be improved by including in Table 1 of Schedule 10.1 the requirements set out in Table 2 of Schedule 10.1. For example, clause 27(2) refers to Table 1 of Schedule 10.1 for the maximum certification period for the relevant category and Table 2 of Schedule 10.1 for the maximum certification period for the relevant meter class. This is unnecessary when the requirements in Table 2 could be easily accommodated by inserting an additional column in Table 1.
Proposal	The Authority proposes to address each of the problems described above as follows. <u>Problem 1</u> Remove the reference to "electromechanical" from clause 27(4) of Schedule 10.7, so that the clause applies equally to all meter types. <u>Problem 2</u> If an ATH determines that a shorter certification validity period for a meter than the maximum validity period shown in Table 1 of Schedule 10.1, the ATH must note in the meter certification report: a) the shorter validity period for the meter b) the reason for the shorter validity period. <u>Problem 3</u> In Table 1 of Schedule 10.1 remove the column headed "Maximum sample inspection and recertification period". In clause 16(2) of Schedule 10.7, add a new paragraph (ab) stating that the ATH must use the appropriate maximum validity period from Table 5 of the Australian/New Zealand standard "AS/NZS 1284". In clause 45 (1)(b) of Schedule 10.7, replace the reference to Table 1 of

1 "Electricity metering – Part 13: In-service compliance testing".
2 Being class 0.2, class 0.5, class 1.0, and class 2.0.

	Schedule 10.1 with the threshold of 84 months before the statistical sample inspection regime is required. Moving the maximum sample inspection and recertification period requirements from Table 1 of Schedule 10.1 to clause 16 of Schedule 10.7 is appropriate because these requirements only apply to category 1 metering installations in the unique circumstance when the metering installation is being recertified using statistical sampling. In this instance, the entire Table 5 from AS/NZS 1284 applies, not just the 84 months required by Table 1 of Schedule 10.1. <u>Problem 4</u> In Table 1 of Schedule 10.1, insert a new column to the right of column 5 ("Metering installation certification type") headed "Maximum meter class for installation category" and include the meter class appropriate to each metering installation category, as shown in Table 2 of Schedule 10.1. Revoke Table 2 of Schedule 10.1 and change each reference to this table to be a reference to Table 1 of Schedule 10.1.
Proposed Code amendment	Refer to attached Table 1 of Schedule 10.1 and Table 2 of Schedule 10.1. **Schedule 10.7** … **16 Recertification of group of category 1 metering installations by statistical sampling** (1) A **metering equipment provider** may arrange for an **ATH** to **recertify** a group of **category 1 metering installations** for which the **metering equipment provider** is responsible using a statistical sampling process set out in subclause (2). (2) To **recertify** a group of **category 1 metering installations**, an **ATH** must— (a) select a sample from the group, using a statistical sampling process— (i) prescribed in AS/NZS 1284; or (ii) that is approved and **published** by the **Authority**; and (aa) use the pass/fail criteria in AS/NZS 1284 to evaluate whether the group meets the **recertification** requirements of this Part; and <u>(ab) use the appropriate maximum validity period set out in Table 5 of AS/NZS 1284; and</u> … **27 Meter certification expiry date** … (2) The **meter certification** expiry date must be the earliest end date of the following periods, calculated from the date of **commissioning** of the **metering installation**:

(a) the maximum **metering installation certification** validity period set out in Table 1 of Schedule 10.1 for the relevant category of **metering installation**; or

(b) the maximum **meter certification** validity period set out in Table 1~~2~~ of Schedule 10.1 for the relevant class of **meter** for the **metering installation**; or

(c) the **certification** period specified in the **meter certification report**.

(3) Despite subclause (2), the **meter certification** expiry date for a **meter** that has been **certified** and subsequently installed in, but then removed from, a **category 1 metering installation**, remains the **meter certification** expiry date determined for that **meter** when it was installed in the **category 1 metering installation**.

(4) Despite subclauses (2) and (3), if a~~n electromechanical~~ **meter** is not installed in a **metering installation** within 24 months of the date of the **meter's certification report**, the **meter** must be **recertified** before it is installed.

…

45 Category 1 metering installation inspection requirements

(1) A **metering equipment provider** must ensure that—

(a) each **category 1 metering installation** for which it is responsible, other than an **interim certified metering installation**, has been inspected by an **ATH** within the period set out in Table 1 of Schedule 10.1 starting from the date of the **metering installation's** most recent **certification**; or

(b) for each 12 month period commencing 1 January and ending 31 December, a sample, selected under subclause (2), of the **category 1 metering installations** for which it is responsible has been inspected by an **ATH** ~~within the period set out in Table 1 of Schedule 10.1~~ starting from the date of the earliest **certification** date of a **metering installation** in the group that is at least 84 months old.

…

Schedule 10.8

…

1 Meter certification requirements

(1) An **ATH** must, before it **certifies** a **meter**, ensure that—

…

(d) it produces a **meter calibration report** that includes—

(i) the date on which it **certified** the **meter**; and

(ii) the **certification** validity period for the **meter** for each category of **metering installation** that the **meter** may be used in; and

(iia) if the **certification** validity period referred to in

	subparagraph (ii) is less than the maximum **certification** validity period permitted under Table 1 of Schedule 10.1, the reasons for the shorter **certification** validity period; and (iii) the maintenance requirements for the **meter**; and (iv) the **meter calibration report**; and (v) whether the **certification** was based on batch test certificates; and (vi) if the **certification** was based on batch test certificates, confirmation that the manufacturer's batch testing facility is, in the **ATH's** opinion, of an acceptable standard; and … (2) The **certification** validity period referred to in subclause (1)(d)(ii) must not be greater than the maximum **certification** validity period set out in Table 1~~2~~ of Schedule 10.1 for the relevant class of **meter**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by: a) reducing the possibility of an electronic meter failing because of there being an extended period of time between when the meter was certified and when it was installed b) reducing participants' compliance costs by making the Code easier to understand and comply with. The proposed Code amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to reduce: a) the possibility of an electronic meter failing because of there being

	an extended period of time between when the meter was certified and when it was installed b) participants' compliance costs by making the Code easier to understand and comply with.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Schedule 10.1: Table 1: Metering installation characteristics and associated requirements

Defining Characteristics				Associated Requirements of active energy metering								
Metering installation category	Primary voltage (V)	Primary current (I)	Measuring transformers	Metering installation certification type	Maximum meter class for installation category	Accuracy tolerances		Selected component metering installation minimum IEC class (more accurate components may be used)		Metering installation certification and inspection		
						Maximum permitted error	Maximum site uncertainty	Meter	Current Transformer	Maximum metering installation certification validity period	~~Maximum sample inspection and recertification period~~	Inspection period
1	V < 1kV	I ≤ 160A	None	NHH or HHR	Class 2.0	± 2.5%	0.6%	2	N/A	180 months	~~84 months~~	120 months ± 6 months
2	V < 1kV	I ≤ 500A	CT	NHH or HHR	Class 2.0	± 2.5%	0.6%	2	1	120 months	~~N/A~~	120 months ± 6 months
3	V < 1kV	500A < I ≤ 1200A	CT	HHR only	Class 1.0	± 1.25%	0.3%	1	0.5	120 months	~~N/A~~	60 months ± 3 months
	1kV ≤ V ≤ 11kV	I ≤ 100A	VT & CT		Class 0.5			N/A	N/A			
	11kV < V ≤ 22kV	I ≤ 50A						N/A	N/A			
4	V < 1kV	I > 1200A	CT	HHR only	Class 0.5	± 1.25%	0.3%	N/A	N/A	60 months	~~N/A~~	30 months ± 3 months
	1kV ≤ V ≤ 6.6kV	100A < I ≤ 400A	VT & CT									
	6.6kV < V ≤ 11kV	100A < I ≤ 200A										
	11kV < V ≤ 22kV	50A < I ≤ 100A										
5	1kV ≤ V ≤ 6.6kV	I > 400A	VT & CT	HHR only	Class 0.2	± 0.75%	0.2%	N/A	N/A	36 months	~~N/A~~	18 months ± 1 month
	6.6kV < V ≤ 11kV	I>200A										
	V > 11kV	I > 100A										

	V > 22kV	Any current										

Schedule 10.1: ~~Table 2: Maximum certification validity periods for the purposes of clause 1(2) of Schedule 10.8~~

~~**Metering installation category**~~	~~**Class 0.2 meter (months)**~~	~~**Class 0.5 meter (months)**~~	~~**Class 1.0 meter (months)**~~	~~**Class 2.0 meter (months)**~~
~~1~~	~~180~~	~~180~~	~~180~~	~~180~~
~~2~~	~~120~~	~~120~~	~~120~~	~~120~~
~~3 where V<1kV~~	~~120~~	~~120~~	~~120~~	~~N/A~~
~~3 where V≥1kV~~	~~120~~	~~120~~	~~N/A~~	~~N/A~~
~~4~~	~~60~~	~~60~~	~~N/A~~	~~N/A~~
~~5~~	~~36~~	~~N/A~~	~~N/A~~	~~N/A~~

Reference number(s)	019 – Measuring Transformers and Burdens
Relevant clause(s)	Clause 28(4)(b) and (i) of Schedule 10.7 Requirements for a metering installation incorporating measuring transformer Clause 31(7) of Schedule 10.7 Measuring transformer burden and compensation requirements Clause 2(1)(c) of Schedule 10.8 Measuring transformer certification requirements
Problem definition	Metering installations are only accurate within certain parameters. If the electrical load on a metering installation is too low, or too high, the metering installation can measure electricity less accurately than permitted by the Code. The same limitation applies to the accuracy of measuring transformers. If the load (burden) on a measuring transformer is less than, or more than, the design burden, the measuring transformer may not meet the accuracy requirements set out in the Code. The Authority has identified a number of problems with the Code provisions relating to measuring transformer burdens. <u>Problem 1</u> Under clause 28(4)(i) of Schedule 10.7, the ATH who certifies a metering installation that includes a measuring transformer must ensure the total burden on the measuring transformer is not too high. Under clause 31(7) of Schedule 10.7, an ATH must, before it certifies a measuring transformer, ensure the in-service burden is not too low. These requirements would be easier to track and follow if they were contained within the same clause. <u>Problem 2A</u> Clause 31(7) of Schedule 10.7 requires an ATH certifying a measuring transformer to ensure the in-service burden on the measuring transformer is within the requirements of the standards specified in Table 5 of Schedule 10.1. This obligation incorrectly relates to certifying a measuring transformer. The obligation should instead relate to certifying a metering installation. This is because Schedule 10.7 deals with the requirements for metering installations, while Schedule 10.8 deals with the requirements for metering components. <u>Problem 2B</u> Clause 2(1)(c) of Schedule 10.8 requires the ATH who certifies a measuring transformer to confirm the accuracy of the measuring transformer at the in-service burden, if the in-service burden is lower than a specified test point. However, many measuring transformers are certified by an ATH in a test laboratory prior to being installed in the metering installation. An ATH certifying a measuring transformer in a test laboratory will not know what the actual in-service burden will be for that measuring transformer.

	A better approach would be for the ATH certifying: a) a measuring transformer, under clause 2(1) of Schedule 10.8, to specify the applicable burden range of the measuring transformer in the certification report for the measuring transformer, and b) a metering installation with a measuring transformer, to ensure the in-service burden on the measuring transformer is within the range specified in the measuring transformer's certification report. <u>Problem 3A</u> Clause 31(7)(b) of Schedule 10.7 permits a class A ATH to confirm by calibration that the accuracy of a measuring transformer will not be adversely affected by the in-service burden being less than the lowest burden specified by the manufacturer. Clause 2(1)(c)(ii) of Schedule 10.8 permits a class A ATH to calibrate a measuring transformer at the in-service burden if the primary voltage of the measuring transformer is greater than 1 kV. The two clauses are slightly different. Clause 2(1)(c)(ii) of Schedule 10.8 is limited to measuring transformers with a primary voltage greater than 1 kV. However, this limitation was accidentally omitted from clause 31(7)(b)(i). The policy intent of the Code amendment that incorporated these two clauses into the Code was to only permit a class A ATH to calibrate a measuring transformer if the primary voltage of the measuring transformer is greater than 1 kV. The reasons for this policy intent were: • To mitigate the risk of damage to the measuring transformer and other components in the metering installation should burden resistors fail on high voltage current transformers. This risk is mitigated if a class A ATH can confirm accuracy at the in-service burden as then burden resistors will not need to be installed. • The difficulty and cost of sourcing new measuring transformers for high voltage equipment, especially older such equipment. <u>Problem 3B</u> The Authority has received a request to amend the Code to permit class B ATHs to calibrate measuring transformers that have a lower burden than specified by the manufacturer. The benefit the requestor has identified from making this Code change is to lower the cost of the metering installation in such circumstances. If the requested change is made, an MEP can elect to get a class B ATH to calibrate the measuring transformer instead of installing burden resistors. <u>Problem 4A</u> Under clause 28(4)(b) of Schedule 10.7, an ATH must, before it certifies a metering installation incorporating a measuring transformer, use the fully calibrated certification method to ensure that the ATH uses the measuring transformer's actual accuracy (rather than class accuracy) when calculating the maximum permitted error for the relevant metering installation category.

	However, clause 7(2)(b) of Schedule 10.7 permits an ATH to use the approved comparative recertification method under clause 12 of Schedule 10.7 to recertify a category 2 metering installation. Category 2 metering installations incorporate measuring transformers. Therefore, clause 28(4)(b) of Schedule 10.7 needs to recognise that an ATH may also use the approved comparative recertification method when certifying a category 2 metering installation, because this is a form of calibration performed onsite at metering installations. <u>Problem 4B</u> Clause 28(4)(b) of Schedule 10.7 refers to using a measuring transformer's actual accuracy rather than class accuracy. This reference is only one of the factors that need to be used to calculate the error. The full requirements are contained in Clause 22 of Schedule 10.7. Clause 28(4)(b) of Schedule 10.7 should instead require an ATH to carry out the error calculation in clause 22 of Schedule 10.7 when calculating the maximum permitted error of the metering installation. This ensures the certification takes into account the actual error on the metering installation, rather than just the measuring transformer's actual accuracy.
Proposal	<u>Proposal to address problem 1</u> To address problem 1, the Authority proposes to: a) amend clause 28(4)(i) of Schedule 10.7 to refer to clause 31(7) of Schedule 10.7 b) amend clause 31(7) of Schedule 10.7 to also require an ATH certifying a metering installation with a measuring transformer to ensure the total burden on the measuring transformer is not too high. <u>Proposal to address problem 2A</u> To address problem 2A, the Authority proposes to amend clause 31(7) of Schedule 10.7 so that the clause relates to the certification of a metering installation and not the certification of a measuring transformer. <u>Proposal to address problem 2B</u> To address problem 2B, the Authority proposes to: a) amend clauses 28(4)(a)(i) and 31(7) of Schedule 10.7 so that clause 31(7) of Schedule 10.7 requires an ATH certifying a metering installation with a measuring transformer: i) to ensure the total in-service burden on the measuring transformer is within the range specified in the measuring transformer's certification report; or ii) to ensure the total in-service burden on the measuring transformer does not exceed the lower of: A) the measuring transformer's nameplate rating, and B) an alternative rating lower than the nameplate rating, if specified in the metering installation's design report or the measuring transformer's certification report,

whichever is the lower

iii) if the primary voltage of the measuring transformer is greater than 1kV, is a burden at which a class A ATH calibrating the measuring transformer certifies the metering installation is accurate.

b) replace clause 2(1)(c) of Schedule 10.8 with:

i) new clause 2(1)(ca) of Schedule 10.8, requiring an ATH certifying a measuring transformer to determine the burden range for the measuring transformer from one of the following:

A) the measuring transformer's nameplate rating

B) the calibration report for the measuring transformer

C) the manufacturer's documentation for the measuring transformer

D) the standard the measuring transformer was manufactured to; and

ii) new clause 3(c)(vi) of Schedule 10.8, which requires an ATH certifying a measuring transformer to specify the burden range for the measuring transformer on the certification report.

Making these proposed Code changes will:

a) oblige the ATH certifying a measuring transformer to ensure this metering component meets the accuracy standards specified in the Code, and

b) enable the ATH certifying a metering installation with a measuring transformer to know the metering installation will be accurate if the in-service burden on the measuring transformer falls within the burden range specified in the measuring transformer's certification report.

Proposal to address problem 3A

To address problem 3A, the Authority proposes to amend clause 31(7)(b)(i) of Schedule 10.7 to limit this provision to measuring transformers with a primary voltage greater than 1 kV.

Proposal to address problem 3B

The Authority does not propose to amend the Code to give effect to the requested Code change described under problem 3B.

The key reasons for this may be summarised as follows:

a) It is not appropriate for a Class B ATH to calibrate measuring transformers with primary voltages greater than 1 kV because Class B ATHs are not required to comply with ISO 17025. While Class A ATHs must comply with ISO 17025, Class B ATHs must comply with the more general quality standard ISO 9001:

i) For high voltage ICPs, the effect of any testing error by an ATH is magnified by the compound ratio multiplication factor for the ICP. The best way for an ATH to minimise the

	iii) risk of this type of error is by complying with ISO 17025. ii) The management of, and accuracy of, the specialised equipment required to calibrate high voltage measuring transformers are best managed under the specific test laboratory standard ISO 17025. iii) The test accuracy requirements for calibrating high voltage measuring transformers are better managed under ISO 17025. b) We consider the cost for a class B ATH to calibrate a measuring transformer on site will usually be higher than the cost of installing one or more burden resistors. A burden resistor set costs less than $50. <u>Proposal to address problem 4A</u> To address problem 4A, the Authority proposes to amend clause 28(4)(b) of Schedule 10.7 so that it also applies to an ATH that uses the approved comparative recertification method when certifying a category 2 metering installation. <u>Proposal to address problem 4B</u> To address problem 4B, the Authority proposes to amend clause 28(4)(b) of Schedule 10.7 to require an ATH to carry out the error calculation in clause 22 of Schedule 10.7 when calculating the maximum permitted error of the metering installation.
Proposed Code amendment	**Schedule 10.7** **28 Requirements for metering installation incorporating measuring transformer** … (4) An **ATH** must, before it **certifies** a **metering installation** incorporating a **measuring transformer**,— (a) ensure that— (i) the **measuring transformer** is connected to a **meter** through a **test facility** that has provision for isolation; and (ia) the **test facility** and the provision for isolation are installed as physically close to the **meter** as practicable in the circumstances; and (ii) the **test facility** has a transparent cover that is not obscured; and (b) using the **fully calibrated certification** method <u>or the **comparative certification** method</u>, ensure that the **ATH** ~~uses the **measuring transformer's** actual accuracy (rather than class accuracy) when calculating~~ <u>calculates</u> the maximum permitted error <u>in accordance with clause 22</u> ~~for the relevant **metering installation** category set out in Table 1 of Schedule~~

~~10.1~~; and

…

(i) ensure that the total in-service burden (magnitude and phase angle, where appropriate) on the **measuring transformer** complies with clause 31~~does not exceed—~~

~~(i) its name plate rating; or~~

~~(ii) an alternative rating lower than the name plate rating, if specified in the **metering installation** design report~~.

31 Measuring transformer burden and compensation requirements

…

(7) An **ATH** must, before it **certifies** a **metering installation** containing a **measuring transformer**, ~~if the in-service burden is less than the lowest burden test point specified in a standard set out in Table 5 of Schedule 10.1, —~~

(a) ensure that the in-service burden on the **measuring transformer** is within the range specified in the **certification report** for the **measuring transformer**, by installing burdening resistors to increase the in-service burden if necessary ~~to be equal to or greater than the lowest test point specified in the standard~~; or

(b) confirm that—

(i) if the primary voltage of the **measuring transformer** is greater than 1kV, a **class A ATH** has confirmed by **calibration** that the accuracy of the **measuring transformer** will not be adversely affected by the in-service burden being less than the lowest burden test point specified in the standard; or

(ii) the **measuring transformer's** manufacturer has confirmed that the accuracy of the ~~**metering**~~ **measuring transformer** will not be adversely affected by the in-service burden being less than the lowest burden test point specified in the standard~~.~~; and

(c) ensure that the in-service burden (magnitude and phase angle, where appropriate) on the **measuring transformer** does not exceed the lower of—

(i) the nameplate rating for the **measuring transformer**; and

(ii) an alternative rating lower than the nameplate rating for the **measuring transformer**, if specified in the design report for the **metering installation** or the **measuring transformer's certification report**, whichever is the lower if both specify a different lower rating.

Schedule 10.8

2 Measuring transformer certification requirements

(1) An **ATH** must, before it **certifies** a **measuring transformer**,—

(a) ensure, by testing, that a current **calibration report** sets out the **measuring transformer's** errors at a range of primary values at their rated burdens; and

(b) that is a multi-tap current transformer, carry out the **calibration** tests and only **certify** the transformer for the ratios that have been **calibrated** if the test is passed; and

~~(c) if the in-service burden is lower than a test point specified in a standard listed in Table 5 of Schedule 10.1, confirm the accuracy of the **measuring transformer** at the in-service burden by—~~

~~(i) obtaining confirmation of accuracies at the in-service burden from the **measuring transformer's** manufacturer; or~~

~~(ii) if the primary voltage of the **measuring transformer** is greater than 1kV, a **class A ATH** calibrating the **measuring transformer** at the in-service burden; and~~

(d) determine the **measuring transformer certification** validity period under clause 3(c)(ii); and~~.~~

(e) determine the highest and lowest values that the in-service burden must fall between to ensure the **measuring transformer** remains accurate, by using one of the following:

(i) the **measuring transformer's** nameplate rating; or

(ii) the **calibration report** for the **measuring transformer**; or

(iii) the manufacturer's documentation for the **measuring transformer**; or

(iv) the standard the **measuring transformer** was manufactured to.

3 Measuring transformer certification report

An **ATH** must, before it **certifies** a **measuring transformer**, ensure that—

(a) the **measuring transformer** has a current **calibration report** issued by an **approved calibration laboratory** or an **ATH** approved to carry out **calibration** under Schedule 10.3; and

(b) the **measuring transformer calibration report**—

(i) confirms that the **measuring transformer** complies with the standards listed in Table 5 of Schedule 10.1; and

(ii) records any tests the **ATH** has performed to confirm compliance under subparagraph (i) and the results of

	those tests; and (iii) confirms that the **measuring transformer** has passed the tests; and (iv) records any recommendations made by the **ATH** on **error compensation**; and (v) includes any manufacturer's **calibration** test reports; and (c) it produces a **measuring transformer certification report** that includes— (i) the date on which it **certified** the **measuring transformer**; and (ii) the **certification** validity period for the **measuring transformer** which must be no more than 120 months; and (iii) the **measuring transformer calibration report**; and (iv) whether the **certification** was based on batch test certificates; and (v) if the **certification** was based on batch test certificates, confirmation that the manufacturer's batch testing facility is, in the **ATH's** opinion, of an acceptable standard; and (vi) the highest and lowest values that the in-service burden must fall between; and (d) it confirms that it has inspected the manufacturer's test certificates, and carried out any additional tests it considers necessary, to satisfy itself that the **measuring transformer** meets the accuracy requirements of this Part.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by clarifying ATHs' obligations in regard to the treatment of the in-service burden during the certification of a measuring transformer and metering installation. This would help ensure the metering is accurate. The proposal would also remove an impossible obligation on ATHs to certify measuring transformers in a test laboratory. The proposed Code amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment

Regulatory Failure	to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objectives of the proposal are to clarify: a) who must take into account in-service burdens during the certification of a measuring transformer and metering installation b) certification requirements when in-service burdens are outside the burden test point range.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed Code amendment that would meet the objectives of the proposal.

Reference number(s)	020 – Alternative Certification for POC to the grid
Relevant clause(s)	Clause 32 of Schedule 10.7
Problem definition	Clause 32 of Schedule 10.7 permits an ATH to certify a metering installation if the ATH cannot obtain physical access to test a measuring transformer at the metering installation. The clause lists various requirements that must be met before the ATH may certify the metering installation. This "alternative certification" can only be used once for a measuring transformer. The policy intent behind the use of alternative certification is for it to be used only for an ICP that is not an NSP. However, although clause 32 of Schedule 10.7 implies this, by requiring the MEP to update the registry,[1] the clause does not explicitly state this. The reason for this policy intent is that NSPs play a central role in the reconciliation and settlement processes, and in the pricing process in the case of NSPs connected to the grid. It is important that all NSPs are certified with an appropriate level of accuracy at all times.
Proposal	The Authority proposes to amend clause 32 of Schedule 10.7 to explicitly state that alternative certification can only be used for metering installations at ICPs that are not also NSPs.
Proposed Code amendment	**Schedule 10.7** … **32 Alternative certification requirements for metering installation incorporating measuring transformer** (1) For an **ICP** that is not also an **NSP**, ~~A~~an **ATH** may, if it cannot comply with the requirements of clause 2 of Schedule 10.8 due solely to its inability to obtain physical access to test an installed **measuring transformer** in a **metering installation**, **certify** the **metering installation** for a period not exceeding 24 months, if— (a) the **measuring transformer** has not previously been **certified** under this clause; and (b) the **ATH** is satisfied, having made due enquiry, that the **metering installation** will comply with the applicable accuracy requirements as set out in Table 1 of Schedule 10.1; and (c) the **ATH** has advised the **metering equipment provider** responsible for the **metering installation** that this clause applies; and (d) the **metering equipment provider** has updated the **metering installation's certification** in the **registry**. …
Assessment of proposed Code	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to

1 Refer to clause 32(1)(d) of Schedule 10.7.

amendment against section 32(1) of the Act	the efficient operation of the electricity industry. It would do this by clarifying the Code, to make it easier for participants to know they cannot use alternative certification for a metering installation at an NSP, even if that NSP is also an ICP. This should remove the possibility of participants incurring unnecessary transaction costs associated with an ATH wrongly using alternative certification for a metering installation at an NSP. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that may lead to market inefficiency, which would require a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to ensure that alternative certification is used only for an ICP that is not also an NSP.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

<table>
<tr><th>Reference number(s)</th><th>021 - Obsolete Sticker Removal</th></tr>
<tr><td>Relevant clause(s)</td><td> Clause 16 of Schedule 10.7 – Recertification of category 1 metering installations by statistical sampling Clause 41 of Schedule 10.7 – Certification stickers </td></tr>
<tr><td>Problem definition</td><td> Clause 41(1) of Schedule 10.7 requires an ATH that has certified a metering installation under Part 10 to confirm the certification by attaching a metering installation certification sticker. The sticker must be attached as physically close as practicable to (including, if practicable, on) the meter, while maintaining reasonable visibility of the certification sticker and the meter. There are two exceptions to the obligation under clause 41(1) of Schedule 10.7. First, under clause 41(4), if attaching a metering installation certification sticker is not practicable, an ATH must— a) devise and use an alternative means of documenting, providing, and maintaining information in a manner at least equivalent in its effect to that required under clause 41(1) of Schedule 10.7
b) keep any metering component certification sticker with this information. Second, under clause 16(6) of Schedule 10.7, an ATH who recertifies a group of metering installations using a statistical sampling process is not required to apply a certification sticker to a metering installation in the group that was not part of the sample. The Code does not require invalid certification stickers to be removed. This is causing untrained persons, especially consumers, to incorrectly believe some metering installations are uncertified and therefore potentially inaccurate or unsafe. These people are imposing a cost on retailers and the Authority from phoning with queries or complaints. </td></tr>
<tr><td>Proposal</td><td> The Authority proposes to amend the Code to require an ATH affixing a new certification sticker to a metering installation to, as part of the same site visit, remove or obscure any invalid or expired certification stickers. We note there are a relatively small number of metering installations in New Zealand (being category 1 metering installations) recertified using statistical sampling. In such cases, the stickers will not be altered but the metering installation will have current certification - this problem will continue to exist until someone goes out to site to physically change the sticker. </td></tr>
<tr><td>Proposed Code amendment</td><td> Schedule 10.7 … 41 Certification stickers (1) An ATH must, except as provided for in clause 16(6) and subclause (4), if it has certified a metering installation under this Part, confirm the certification by attaching a metering installation certification sticker as physically close as practicable to (including, </td></tr>
</table>

	if practicable, on) the **meter** while maintaining reasonable visibility of the **certification sticker** and the **meter**. … (5) An **ATH** must, when attaching a **metering installation certification sticker** under subclause (1), remove or obscure any invalid or expired **certification stickers**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by reducing confusion for consumers about whether their metering installation is certified, and therefore is accurately recording electricity quantities. This would reduce the number of consumer queries that retailers and the Authority receive. This will save consumers, retailers and the Authority time and effort. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objectives of the proposal are: a) to remove confusion for consumers as to whether their metering installation is certified; and b) to increase consumer confidence in meter readings.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.

<table>
<tr><th>Reference number(s)</th><th>022 - Inspection Periods</th></tr>
<tr><td>Relevant clause(s)</td><td>Table 1 of Schedule 10.1 – Metering installation characteristics and associated requirements

Clause 45(1) of Schedule 10.7 – Category 1 metering installation inspection requirements</td></tr>
<tr><td>Problem definition</td><td>Clause 45(1) of Schedule 10.7 of the Code requires an MEP to ensure its category 1 metering installations are inspected by an ATH within the period set out in Table 1 of Schedule 10.1. An MEP can choose to have an ATH inspect:

a) individual category 1 metering installations; or

b) a sample of category 1 metering installations.

<u>Problem 1</u>

Some participants are waiting until the expiry of a category 1 metering installation’s inspection period before performing the required work to inspect.

Conversely, some participants are performing inspections in much shorter timeframes than Table 1 of Schedule 10.1 provides for. The table includes a +/- time, effectively creating a window during which inspections must be performed. As a result, participants performing more frequent inspections are non-compliant with the Code, despite inspecting on a more rigorous schedule.

<u>Problem 2</u>

The Code requirements for inspections of category 1 metering installations undertaken using statistical sampling are insufficiently clear as to when and how the sample inspections must be performed and completed. Although the combined effect of clauses 45(1) and (2) cover the requirements, clause 45(1)(b) is not clear that all metering installations in the sample must be inspected within the 12 calendar month period, or that the trigger for the statistical inspection process is the oldest installation in the population reaching the maximum inspection period specified in Table 1 of Schedule 10.1. Additionally, participants have queried the Authority about whether an MEP may create several populations of category 1 metering sites (eg 2 sets of meter types) so they can be inspected/treated separately.

Problem 3

Any previously interim-certified metering installations are now expired, but there is still a reference to these installations in clause 45(1)(a).</td></tr>
<tr><td>Proposal</td><td><u>Problem 1</u>

To address problem 1, the Authority proposes to amend the Code to:

a) clarify that inspections must be <u>completed</u> within the maximum timeframe set out in Table 1 of Schedule 10.1
b) allow participants to inspect metering installations as often as they want, so long as the maximum inspection period is not exceeded, by adjusting Table 1 of Schedule 10.1 to make the +/- a maximum</td></tr>
</table>

	period. Problem 2 To address problem 2, the Authority proposes to amend the Code to clarify that if an MEP chooses to use statistical sampling for the inspection of its category 1 metering installations: a) the MEP must ensure that: (i) the sample is selected from the entire population of the MEP's category 1 metering installations (ii) an ATH inspects all of the selected metering installations between 1 January and 31 December each year b) no inspections based on statistical sampling are required until the certification of one or more of the MEP's category 1 metering installations is at least 84 months old. Problem 3 The reference to interim certified metering installations in 45(1)(a) will be removed, as all of these installations are expired and this reference is no longer valid.
Proposed Code amendment	Refer to attached Table 1 of Schedule 10.1. **Schedule 10.7** … **45 Category 1 metering installation inspection requirements** (1) A **metering equipment provider** must ensure that— (a) an **ATH** has completed an inspection of each **category 1 metering installation** for which the **metering equipment provider** ~~it~~ is responsible~~, other than an **interim certified metering installation**, has been inspected by an **ATH**~~ within the period set out in Table 1 of Schedule 10.1, starting from the date of the **metering installation's** most recent **certification** or inspection; or (b) for each 12 month period commencing 1 January and ending 31 December, an **ATH** has completed inspecting within that same 12 month period a sample, selected under subclause (2), of the **category 1 metering installations** for which the **metering equipment provider** ~~it~~ is responsible, provided— (i) the **metering equipment provider** ensures that the sample is selected from the entire population of the **metering equipment provider's category 1 metering installations**; and (ii) no such inspections are required until the **certification** of one or more of the **category 1 metering installations** is at least 84 months old ~~has been inspected by an **ATH** within the period set out in~~

	~~Table 1 of Schedule 10.1 starting from the date of the earliest~~ **~~certification~~** ~~date of a~~ **~~metering installation~~** ~~in the group~~. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. Clarifying the requirements for inspecting category 1 metering installations will help ensure ATHs undertake inspections appropriately and in a timely manner, thereby better ensuring the ongoing accuracy of the metering installation. The proposed Code amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to clarify the inspection requirements for category 1 metering installations.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed Code amendment that would meet the objectives of the proposal.

Schedule 10.1: Table 1: Metering installation characteristics and associated requirements

Defining Characteristics				Associated Requirements of active energy metering							
Metering installation category	**Primary voltage (V)**	**Primary current (I)**	**Measuring transformers**	**Metering installation certification type**	**Accuracy tolerances**		**Selected component metering installation minimum IEC class (more accurate components may be used)**		**Metering installation certification and inspection**		
					Maximum permitted error	**Maximum site uncertainty**	**Meter**	**Current Transformer**	**Maximum metering installation certification validity period**	**Maximum sample inspection and recertification period**	**Maximum ~~I~~ inspection period**
1	V < 1kV	I ≤ 160A	None	NHH or HHR	± 2.5%	0.6%	2	N/A	180 months	84 months	126~~0~~ months ~~± 6 months~~
2	V < 1kV	I ≤ 500A	CT	NHH or HHR	± 2.5%	0.6%	2	1	120 months	N/A	126~~0~~ months ~~± 6 months~~
3	V < 1kV	500A < I ≤ 1200A	CT	HHR only	± 1.25%	0.3%	1	0.5	120 months	N/A	63~~0~~ months ~~± 3 months~~
	1kV ≤ V ≤ 11kV	I ≤ 100A	VT & CT				N/A	N/A			
	11kV < V ≤ 22kV	I ≤ 50A					N/A	N/A			
4	V < 1kV	I > 1200A	CT	HHR only	± 1.25%	0.3%	N/A	N/A	60 months	N/A	33~~0~~ months ~~± 3 months~~
	1kV ≤ V ≤ 6.6kV	100A < I ≤ 400A	VT & CT								
	6.6kV < V ≤ 11kV	100A < I ≤ 200A									
	11kV < V ≤ 22kV	50A < I ≤ 100A									
5	1kV ≤ V ≤ 6.6kV	I > 400A	VT & CT	HHR only	± 0.75%	0.2%	N/A	N/A	36 months	N/A	19~~8~~ months ~~± 1 month~~
	6.6kV < V ≤ 11kV	I>200A									
	V > 11kV	I > 100A									
	V > 22kV	Any current									

Reference number(s)	**023 - Combining Certification Stickers**
Relevant clause(s)	Clause 41 of Schedule 10.7 – Certification stickers Clause 8 of Schedule 10.8 – Metering component certification stickers
Problem definition	Under clause 8(1) of Schedule 10.8, an ATH must, when certifying a metering component under Part 10, confirm the certification by attaching a metering component certification sticker to the metering component. If this is not practicable, the ATH must provide the sticker with the metering component. An ATH may certify a metering component on the same day the ATH certifiies the metering installation the component is part of. Some ATHs have requested they be permitted to use a single certification sticker for a metering component and a metering installation, in instances when the ATH certifies both on the same date. They consider this to be more efficient that using separate certification stickers.
Proposal	The Authority proposes to amend the Code to permit an ATH to use a single certification sticker for both a metering component and the metering installation the component is part of, if the ATH certifies the component and the installation on the same day. The expiration date of the single certification sticker would be the earlier expiration date of the: a) metering component's certification; or b) metering installation's certification. The single certification sticker would become invalid immediately if: a) any part of the metering installation were to change, so that the metering installation's certification expiry date changed; or b) the metering component to which the sticker related were to be removed. However, the certfication of any metering components that were not removed would remain valid even if the sticker itself is no longer valid. new replacement single certification sticker for the metering installation must include the details of these unchanged metering components. These components would not need recertifying.
Proposed Code amendment	**Schedule 10.7** … **41 Certification stickers** (1) An **ATH** must, except as provided for in clause 16(6) and subclause (4), if it has **certified** a **metering installation** under this Part, confirm the **certification** by attaching a **metering installation certification sticker** as physically close as practicable to (including, if practicable, on) the **meter** while maintaining reasonable visibility of the **certification sticker** and the **meter**.

	… (5) If an **ATH certifies** a **metering component** of a **metering installation** on the same day that the **ATH certifies** the **metering installation**, the **ATH** may combine the **metering installation certification sticker** under subclause (1) with the **metering component certification sticker** under clause 8(1) of Schedule 10.8. (6) If an **ATH** combines a **metering installation certification sticker** with the **metering component certification sticker** under subclause (5), the **ATH** must: (a) ensure that the combined sticker shows all the information required by subclause (2) and clause 8(2) of Schedule 10.8; and (b) meet the requirements of subclauses (1), (3) and (4), as if the combined sticker were a **metering installation certification sticker**. (7) Unless clause 16(6) applies, the combined sticker described in subclause (6) expires on the earlier of— (a) the expiration of the **metering installation's certification**: (b) the expiration of the **metering component's certification**. (8) The combined sticker under subclause (6) is immediately invalid if— (a) the **metering installation** certification expiry date changes; or (b) a **metering component** to which the combined **certification sticker** relates is removed from the **metering installation**. (9) For the avoidance of doubt, the **certification** of any **metering component** that is not removed from the **metering installation** does not become invalid under subclause (8). **Schedule 10.8** … **8 Metering component certification stickers** (1) An **ATH** must, when **certifying** a **metering component** under this Part, confirm the **certification** by attaching a **metering component certification sticker** to the **metering component** or, if not practicable, provide the sticker with the **metering component**. … (4) If an **ATH** certifies the **metering component** on the same day that it certifies the **metering installation** the **metering component** is installed in, the **ATH** may combine the and attach the **metering component certification sticker** under subclause (1) and the **metering installation certification sticker** under clause 41 of Schedule 10.7 for the **metering installation** in accordance with clause 41 of Schedule 10.7.

Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would contribute to the efficient operation of the electricity industry, by lowering the cost of certifying metering components and metering installations. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to reduce the cost of certifying metering components and metering installations.
Evaluation of the costs and benefits of the proposed amendment	There are no costs as this change is optional at the ATH's discretion. The Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed Code amendment that would meet the objectives of the proposal.

<table>
<tr><td>Reference number(s)</td><td>024 - NSP Decommissioning Timeframes</td></tr>
<tr><td>Relevant clause(s)</td><td>Clause 25 of Schedule 11.1 – Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network</td></tr>
<tr><td>Problem definition</td><td><u>Problem 1</u>

Under clause 25 of Schedule 11.1, the relevant participant must give written notice to the reconciliation manager in advance of the creation or decommissioning of an NSP. However, the clause does not specify the minimum amount of notice period.

The absence of a minimum notice period has caused the following problems in the electricity market:

a) unaccounted for electricity

b) the provision of incorrect submission files to the reconciliation manager, which requires:

i) additional revisions; or

ii) a reconciliation participant to commence a volume dispute under clause 15.29 of the Code.

<u>Problem 2</u>

There have been instances where a participant has notified the reconciliation manager of the creation or decommissioning of NSP, but the participant has then not proceeded with the creation or decommissioning on the scheduled date.

This has caused the following problems in the electricity market:

a) Unaccounted for electricity.

b) The provision of incorrect submission files to the reconciliation manager, which requires at least one or more of the following:

i) time and effort to address on the part of the reconciliation manager

ii) additional revisions

iii) a reconciliation participant to commence a volume dispute under clause 15.29 of the Code.

c) If the NSP is an embedded network, issues arise for the traders that are trading on the embedded network (or proposed embedded network), such as their system submitting electricity volumes for an NSP that does not exist. Urgent system changes are often required to prevent these issues arising.</td></tr>
<tr><td>Proposal</td><td>The Authority proposes to amend the Code:

a) to require the relevant participant to advise the reconciliation manager no later than one month prior, if an NSP is to be created or decommissioned

b) to require the relevant participant to advise the reconciliation</td></tr>
</table>

	manager, as soon as practicable, of a change to the scheduled date on which an NSP is to be created or decommissioned. The first part of the proposed Code amendment will enable the reconciliation manager to convey this information to the market, and ensure the reconciliation system is ready to accept reconciliation data before any reconciliation files are received from participants. The one month notification period aligns with the time period when an NSP changes hands in clause 29 of Schedule 11.1. The second part of the proposed Code amendment will, if an NSP is to be created or decommissioned: a) enable the reconciliation manager to: i) convey this information to the market ii) ensure the reconciliation system does not reject reconciliation data inadvertently b) give traders time to make any necessary system changes in a planned manner.
Proposed Code amendment	**Schedule 11.1** **25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network** (1) If an **NSP** is to be created or **decommissioned**,— (a) the **participant** specified in subclause (3) in relation to the **NSP** must give written notice to the **reconciliation manager** of the creation or **decommissioning**; and (b) the **reconciliation manager** must give written notice to the **Authority** and affected **reconciliation participants** of the creation or **decommissioning** no later than 1 **business day** after receiving the notice in paragraph (a). … (3) The notice required by subclause (1) must be given by— (a) the **grid owner**, if— (i) the **NSP** is a **point of connection** between the **grid** and a **local network**; or (ii) if the **NSP** is a **point of connection** between a **generator** and the **grid**; or (b) the **distributor** for the **local network** who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **local networks**; or (c) the **embedded network** owner who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **embedded networks**; or (d) the **distributor** for the **embedded network**, if the **NSP** is a **point of connection** between an **embedded network** and

	another **network**. … <ins>(5) The **participant** required to give notice under subclause (1) must give notice no later than 30 days prior to the intended date of creation or **decommissioning** of the NSP.</ins> <ins>(6) If a participant changes the intended date of creation or **decommissioning** after giving notice under subclause (1), the **participant** must give a replacement notice advising the new intended date of creation or **decommissioning**, as soon as possible after the **participant** decides to change the intended date.</ins>
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective and section 32(1)(c) of the Act because it would: a) help the reconciliation manager to avoid expending unnecessary effort to identify unaccounted for electricity or incorrect submission files caused by: i) NSP changes not being notified; or ii) notified NSP changes not proceeding b) help traders to avoid adjusting their systems urgently: i) if the date of an intended creation or decommissioning of an NSP changes; or ii) to create or reverse out submission information, if the date of the intended creation or decommissioning of an NSP has passed. The proposed Code amendment is expected to have little or no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the Code amendment proposal is to facilitate the efficient operation of the electricity industry by reducing the costs incurred through late, or no, notification of NSP creation or decommissioning.

Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	025 - MEP updates of HHR/NHH and AMI flags
Relevant clause(s)	Clause 10 of Schedule 10.4 – Services access interface Clause 8 of Schedule 10.6 – Electronic interrogation of metering installation Clause 8 of schedule 10.7 – Metering installation certification requirements Clause 11.3 – Metering equipment provider to advise registry manager of changes to registry metering records Clause 3 of Schedule 11.4 – Metering equipment provider to advise registry manager of changes to registry metering records
Problem definition	Clause 10 of Schedule 10.4 requires an ATH, when preparing a metering installation certification report, to determine and record the services access interface in the certification report. However, the services access interface for an AMI meter will probably change if the meter stops communicating with an MEP's back-office systems. Under clause 8(2) of Schedule 10.7 an ATH, when certifying a metering installation, must specify in the certification report whether the metering installation is NHH or HHR. However, a metering installation with AMI metering may be both NHH and HHR. In such cases, the reconciliation participant chooses whether to submit NHH or HHR submission information from the metering installation to the reconciliation manager.[1] Clause 11.2 of the Code requires a participant to take all practicable steps to ensure that information the participant must provide to any person under Part 11 is— a) complete and accurate; and b) not misleading or deceptive; and c) not likely to mislead or deceive. The certification type of a metering installation depends on different factors (eg, where the data from a metering installation can be accessed—from the metering installation or from the MEP's back office). ATHs are responsible for certifying metering installations, including the preparation of any supporting information required under the Code (metering records). MEPs are responsible for entering these metering records into the registry. As a result, an ATH's records dictate what metering records an MEP can load into the registry to comply with clause 11.2. A metering installation may initially be certified with an AMI meter that provides HHR data. In this case, the metering records in the registry would show the certified metering installation with an AMI flag of "Y" and a certification type of "HHR". However, the AMI meter may, at some point, stop communicating with the MEP's back office. If this happened, the metering installation would no longer be AMI. The metering installation may also be subject to manual readings of the NHH register(s), which

[1] Refer to clause 9(ea) of Schedule 11.1.

	would mean it was no longer HHR. Currently, the Code is unclear as to whether an MEP is permitted to change the AMI flag, because there is no explicit link between the services access interface and the AMI flag. In addition, an MEP is unable to change the "HHR" indicator flag in the registry to reflect a change in a metering installation's capability, unless the ATH: a) updates its records; or b) recertifies the metering installation (in the case of a meter no longer communicating with the MEP's back office). In addition, the Code does not have a mandated timeframe for: a) updating the AMI flag in the registry when an AMI meter ceases to communicate with an MEP's back-office systems b) resolving communication issues between a metering installation and an MEP's back-office systems. The current Code arrangements do not promote the timely resolution of communication failures between meters and MEPs' back-office systems. This can have an adverse effect on retailers' service offerings to their customers. In addition, for some retailers it is important to know the metering services that are available at an ICP, before deciding whether to compete for the customer or embedded generator at the ICP. Some retailers' service offerings are entirely dependent on a particular type of metering being operational at the ICP. Therefore, it is important for the registry to reflect the metering services available at an ICP as soon as possible after a change, provided these services are within the metering installation's certification parameters, as determined by an ATH.
Proposal	The Authority proposes to amend the Code as follows: a) Amend clause 10 of Schedule 10.4 to require an ATH to specify: i) all possible services access interfaces for a metering installation, and ii) the conditions under which each services access interface may be used. b) Amend clause 8 of Schedule 10.6 to require an MEP to investigate any communication failure between a metering installation and the MEP's back-office systems, and: i) restore communications and download raw meter data by the earlier of: (A) the number of full days that equate to 25 % of the maximum interrogation cycle for the metering installation; and (B) 30 days from the date of the last successful interrogation; or ii) update the registry metering records to indicate that the metering component is no longer an AMI device. c) Amend clause 8(2)(b) of Schedule 10.7 to enable an ATH, when certifying a metering installation, to specify in the certification report that the metering installation is "half hour <u>and</u> non half hour". d) Amend clause 8(2)(c) of Schedule 10.7 to require an ATH, when certifying a metering installation, to specify all possible services access interfaces and the conditions under which they may be

	used. e) Amend clause 3 of Schedule 11.4 to specify when an MEP must update the registry metering records in situations where there has been a communication failure between a metering installation and the MEP's back-office systems. f) Amend row 6 of Table 1 of Schedule 11.4 to require an MEP to select whether a metering installation is half hour <u>or</u> non half hour, in the instance where an ATH has certified the metering installation as being half hour <u>and</u> non half hour. g) Amend row 18 of Table 1 of Schedule 11.4 to clarify that the AMI flag also indicates the MEP's back office is the services access interface.
Proposed Code amendment	**Schedule 10.4** … **10 Services access interface** An **ATH** must, when preparing a **metering installation certification report**, determine, and record in the **certification report**,<u>—</u> <u>(a) all</u> ~~the~~ **services access interface**<u>s; and</u> <u>(b) the conditions under which each **services access interface** may be used</u>. … **Schedule 10.6** **8 Electronic interrogation of metering installation** … <u>(10) If an electronic **interrogation** of a **metering installation** by a **metering equipment provider** does not download all of the **raw meter data** as part of the **interrogation**, the **metering equipment provider** must:</u> <u>(a) investigate the reasons for the failure, restore communications, and download all of the **raw meter data** as soon as possible and no later than the time specified in subclause (11); or</u> <u>(b) in accordance with clause 3(a) of Schedule 11.4, update the **registry metering records** to show that the **metering component** is no longer an advanced metering infrastructure device.</u> <u>(11) If a **metering equipment provider** decides to take the actions specified in subclause (10)(a), the **metering equipment provider** must complete those actions by the earlier of—</u> <u>(a) the number of full days that equate to no more than 25% of the maximum **interrogation** cycle for the **metering installation** from the date of the last successful **interrogation**; and</u>

(b) 30 days from the date of the last successful **interrogation**.

(12) If the **metering equipment provider** does not complete the investigation, restoration of communications and downloading of all of the **raw meter data** in accordance with subclause (10)(a) within the time specified in subclause (11) or determines at any time during the time period specified in subclause (11) that it will not be able to complete those tasks within that time frame, the **metering equipment provider** must update the **registry metering records** in accordance with clause 3(b) of Schedule 11.4, to show that the **metering component** is no longer an advanced metering infrastructure device.

Schedule 10.7

…

8 Metering installation certification requirements

…

(2) An **ATH** must, when **certifying** a **metering installation**,—

(a) prepare a **certification report** for the **metering installation**; and

(b) specify in the **certification report** whether the **metering installation** is ~~either—~~

(i) **half hour**; or

(ii) non **half hour**; or

(iii) **half hour** and non **half hour**; and

(c) determine the **services access interfaces** for the **metering installation** under clause 10 of Schedule 10.4 and record ~~it~~ in the **metering installation certification report**:

(i) each **services access interface**: and

(ii) the conditions under which each **services access interface** may be used; and

(d) ensure that each **metering component** in the **metering installation** functions correctly.

…

Schedule 11.4

…

3 Metering equipment provider to advise registry manager of changes to registry metering records

A **metering equipment provider** must advise the **registry manager** of the **registry metering records**, or any change to the **registry metering records**, for a **metering installation** for which it is responsible no later than ~~**10 business** days following~~:

~~(a) the **electrical connection** of an **ICP** that is not also an **NSP**:~~

~~(b) any subsequent change in any matter covered by the **metering records.**~~

(a) 3 **business days** following the most recent unsuccessful **interrogation**, if updating the **registry metering records** in accordance with clause 8(10)(b) of Schedule 10.6; or

(b) 3 **business days** following the expiry of the time period under clause 8(11) of Schedule 10.6 or the date on which the **metering equipment provider** determines in an investigation under clause 8(10)(a) of Schedule 10.6 that it cannot restore communications or fully download the **raw meter data**, if updating the **registry metering records** in accordance with clause 8(12) of Schedule 10.6; or

(c) in all other cases, 10 **business days** following:

- (i) the **electrical connection** of an **ICP** that is not also an **NSP**~~:~~; or
- (ii) any subsequent change in any matter covered by the **metering records** other than a change to which sub-paragraphs (a) and (b) apply..

Schedule 11.4 – Table 1: Registry metering records

The following table sets out the **registry metering records**:

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation

…

For each **metering installation** for an **ICP**

…

6	**metering installation certification** type	the **certification** type of the **metering installation** which ~~may~~ must be ~~either~~ **half hour** or non **half hour** as identified in the **metering installation certification report** or, where both **half hour** and **non half hour** are specified as the **certification type** in the **metering installation certification report**, must be one of those **certification types**.	Required	Required

…

The following details for each **metering component** in the **metering installation** for each **ICP**

…

18	AMI type	an identifier to identify if the **metering component** is an advanced metering infrastructure device and the MEP's back office is the **services access interface**	Required for **meter** or **data storage device**. Optional for all other **metering components**.	Required for **meter** or **data storage device**. Optional for all other **metering components**.

…

Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would: a) promote competition in the electricity industry by reducing the transaction costs that a retailer may face in determining whether it can offer services to a potential customer at an ICP b) promote the efficient operation of the electricity industry by: i) establishing clear requirements in the Code around the

	ii) restoration of communications between an AMI meter and an MEP's back office ii) making the Code easier to understand and comply with. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to promote competition and efficiency in the electricity industry by: a) establishing clear requirements in the Code around the restoration of communications between an AMI meter and an MEP's back office b) making it easier for potential retailers to assess if they can supply the service a prospective customer is asking for c) making it easier for MEPs to understand their obligations around keeping registry metering records up to date.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has identified the status quo as an alternative means of achieving the objectives of the proposed Code amendment. However the Authority has assessed this alternative as unsuitable because: 1) the current process for changing the metering type and/or the services access interface requires the ATH to amend the certification report. The cost of managing this process would exceed the proposal's cost of requiring the ATH to specify all possible metering types and service access interfaces at the time they certify the metering installation. 2) the current timeframes for updating the registry whenever there is a change to the AMI status of the metering installation is 10 business days. There is no current timeframe for determining when the AMI status has changed, and the fact that communication interruptions may be intermittent means there may be no easily identifiable trigger for the process. Different MEPs have taken different

	approaches to resolving this issue. The cost to MEPs of standardising the investigation requirement is assessed as being minimal, as they are already managing this process. These costs are offset by the benefits to retailers of standardisation and certainty over the AMI status of the metering installation.

<table>
<tr><td>Reference number(s)</td><td>026 - Excluding non-market-related meter registers</td></tr>
<tr><td>Relevant clause(s)</td><td>Rows 23 to 31 of Table 1 of Schedule 11.4 – Registry metering records

Clause 7 of Schedule 11.4 – Metering equipment provider to provide registry metering records to registry manager</td></tr>
<tr><td>Problem definition</td><td>At least one distributor is proposing to move to charging for distribution services on a ‘time of use’ basis. The distributor has asked an MEP to create new data registers on its AMI meters that reflect the time-blocks the distributor needs for its distribution charges. These time-blocks, and therefore the data registers, are different from the register(s) the traders on the distributor’s network use for customer billing and for submission information provided to the reconciliation manager.

While developing the process for programming these new data registers into its AMI meters, the MEP has realised that any meter registers recording active energy (measured in kWh) must be recorded in the registry. At least one trader has advised the MEP it will incur a material cost to modify its billing systems to manage the additional data registers that will be recorded in the registry.

Traders that are unwilling to make the system changes to accommodate the additional data registers will have to displace the meters at the ICPs they supply. They will use another MEP’s meters that do not have the additional distributor-only registers.

The displacement of these meters will mean the distributor will not be able to get the data it needs to calculate its distribution charges, unless it pays for duplicate metering.

This situation has not been an issue to date in New Zealand because distributors’ charging:
a) aligns with the metering data that traders already receive, and/or
b) is based on metering data types not captured by the requirement to update the registry (such as kW maximum demand).

The obligation to update the registry with distributor-only registers recording active energy is an inadvertent outcome of the way the Code is worded. This is because the Code was written before it was contemplated distributors may want active energy data in time blocks that are different from those the trader uses for customer billing or for wholesale market reconciliation.</td></tr>
<tr><td>Proposal</td><td>The Authority proposes to amend the Code so that MEPs do not need to record in the registry any meter registers that are used solely for the direct billing of consumers by distributors.

The Authority notes this proposal excludes any meter registers recorded in the registry and not used by some traders, if those registers are <u>not used</u> for distributor direct billing.

For example, the trader at an ICP with an AMI meter might use only non-half hour data (eg, a UN24 register) for submission information and customer billing. However, the AMI meter will contain a half hour data register (known as a ‘7304 register’), which will be recorded in the registry.</td></tr>
</table>

	Under the proposal, the MEP responsible for the metering at the ICP would still have to ensure both the non-half hour register and the half hour register were recorded in the registry, even though the trader was not using the half hour register.
Proposed Code amendment	**Schedule 11.4** … **7 Metering equipment provider to provide registry metering records to registry manager** (1) A **metering equipment provider** must, if required under this Part, provide to the **registry manager** the information indicated in Table 1 as being "Required", in the **prescribed form**, for each **metering installation** for which it is responsible. (1A) Despite subclause (1) a **metering equipment provider** is not required to provide to the **registry manager** the information indicated in rows 23 to 31 of Table 1 as being "Required", if the information is used only for the purpose of a **distributor** direct billing **consumers** on its **network**. … Insert in the fourth and fifth column of rows 23 to 31 of Table 1 of Schedule 11.4, after the word “Required”, the words “(except where clause 7(1A) of this Schedule applies)”.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority’s objective, and section 32(1) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this primarily by: • removing an unnecessary cost for MEPs, arising from their obligation to record metering data in the registry that is not used for reconciliation and settlement of the wholesale electricity market • removing an unnecessary cost for traders, arising from their billing systems managing the additional metering data recorded in the registry • removing unnecessary costs on participants, and ultimately consumers, arising from the unnecessary displacement, or duplication, of metering installations at points of connection where a distributor wishes to bill consumers directly using information that traders’ systems cannot accommodate. The proposed Code amendment is also expected to have a positive effect on competition, by reducing the cost faced by some traders in winning customers. In the absence of the proposed amendment, traders whose systems cannot accommodate the additional meter register data in the registry would face costs associated with replacing a potential customer’s metering installation(s). The proposed amendment is expected to have little or no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.

Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to avoid industry participants incurring unnecessary costs because of an outdated requirement for all meter registers recording active energy to be recorded in the registry.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	027 - Meter Resealing by Traders and Distributors
Relevant clause(s)	Clause 10.12 – Interference with metering installation Clause 47 of Schedule 10.7 – Sealing requirements Clause 48 of Schedule 10.7 – Removal or breakage of seals
Problem definition	Clause 47 of Schedule 10.7 requires an ATH to ensure, before it certifies a metering installation, that each metering component in the metering installation that could reasonably be expected to affect the accuracy or reliability of the metering installation is sealed. This is to enable any tampering with one of these components to be easily identified and promptly corrected. Metering components with broken seals can have their integrity and accuracy adversely affected, which increases the risk of unaccounted for energy at the site of the metering installation. This unaccounted for energy adversely affects the accuracy of market settlement and customer invoicing. Clause 10.12 of the Code prohibits a participant from interfering, directly or indirectly, with a metering installation for which it is not the MEP, unless: a) it is instructed or permitted to do so by the metering equipment provider (MEP) responsible for the metering installation; or b) the participant has an arrangement with the trader responsible for the metering installation as the gaining MEP who will be responsible for the metering installation. Despite clause 10.12, clause 48(1) of Schedule 10.7 requires a participant to, within 10 business days of removing or breaking the seal without authorisation of the MEP responsible for the metering installation,— a) advise the MEP of— i) the removal or breakage ii) the reason for the removal or breakage b) reimburse the MEP for the cost of reinstating the seal and recertification if required by the MEP. Clause 48 of Schedule 10.7 recognises that it is not always practicable for participants to comply with clause 10.12. It is common practice for: a) traders to break seals to disconnect and then reconnect a metering installation when it is not possible to disconnect the ICP at the point of connection, because: i) there is no safe access to the point of connection; or ii) the correct ICP's point of connection cannot be accurately identified b) traders and distributors to break the seal on a load control device for urgent fault remediation. Often the field technician breaking or removing seals at a metering installation for a trader or distributor:

	a) is the same person the MEP responsible for the metering installation uses, but is not working under the MEP's authority or direction when the seals are broken or removed b) has sufficient skills and knowledge to ensure the metering installation remains accurate. However, traders and distributors are often not advising MEPs when they break or remove seals on a metering installation. This places the trader or distributor in breach of clause 48(1) of Schedule 10.7. Traders and distributors have informed the Authority they are not advising MEPs because the reporting requirements under clause 48 of Schedule 10.7 are administratively cumbersome. The Authority has identified the following problems with the Code arrangements and the industry practice described above. <u>Problem 1 – The Code is imposing unnecessary transaction costs on participants and the Authority</u> Clause 10.12 envisages the MEP that is responsible, or that is becoming responsible, for a metering installation will always authorise the breaking or removal of seals at a metering installation. Clause 48 of Schedule 10.7 acknowledges it is not always practicable for participants to comply with clause 10.12. However, clause 48 of Schedule 10.7 is imposing material transaction costs on participants who, for valid reasons, are: a) breaking or removing seals at metering installations; or b) authorising the breaking or removal of seals at metering installations. Some of these participants have decided it is lower cost to breach the Code than to comply with it. These breaches are imposing compliance costs on the participants and on the Authority's compliance function. <u>Problem 2 – MEPs risk being held responsible/liable for metering data inaccuracies caused by traders and/or distributors</u> Under the current industry practice, MEPs risk being held responsible/ liable for issues caused by traders or distributors. This can impose unnecessary costs on participants and the Authority, and eventually on consumers. For example, the Authority must consider alleged breaches against MEPs that result from a trader or distributor interfering with a metering installation.
Proposal	To address the first identified problem, the Authority proposes to: a) amend clause 10.12 to permit a participant to interfere with a metering installation if the participant is breaking or removing a seal in accordance with clause 48 of Schedule 10.7 b) amend clause 48(1) so it: i) permits a distributor to break or remove a seal for bridging/unbridging a load control device (excluding any device that controls a time blocked channel, eg, day/night, as this would affect the accuracy of the meter readings and market

	settlement) only where the distributor provides the load control signal. The distributor must then notify the trader, and the trader must update the profile code in the registry (refer to clause 10 of Schedule 11.1) if required. ii) permits a trader to break or remove a seal for bridging/unbridging a load control device (but not a device that controls a channel – eg day/night, as this would affect the accuracy of the meter readings and market settlement), and then require the trader to update the profile code in the registry (refer to clause 10 of Schedule 11.1) if required. iii) permits a trader to break or remove a seal: A) for electrical disconnection/electrical connection of the load or generation measured by the meter as a last resort, including if it is not possible to electrically disconnect/electrically connect at the point of connection B) for bridging meters (assuming the Authority amends the Code to permit meter bridging: refer to proposed Code amendment 051 – Meter Bridging). c) amend clause 19 of Schedule 10.7 to say that the certification of a metering component or a metering installation does not automatically cancel if clause 48(1) is complied with. In all cases: a) The participant must ensure the field technician has appropriate training (eg, including an overview of how the metering installation works, and how mistakes can affect the metering installation's accuracy). This is because of the importance of metering accuracy to electricity market settlement and consumer billing. The Authority will amend the audit template used for reconciliation participant audits and distributor audits, to include proof of training in these audits. b) The participant must replace the seal with its own seal and have a process for tracing the new seal to the field technician. This is because of the importance of seal traceability to ensuring the accuracy of the metering. The Authority will amend the audit template used for reconciliation participant audits and distributor audits, to include seal traceability in these audits. c) Traders are liable, from the date a seal was removed at a metering installation, for market wash-up costs related to inaccuracies with the metering component that were caused by the work at the ICP. In other words, traders cannot pass on any costs to the customer or the MEP at the ICP. To address the second identified problem, the Authority proposes to amend clause 48 of Schedule 10.7 to absolve an MEP/ATH from liability under the Code for any breach related to the metering component if: a) another participant has broken a metering component's seal b) the MEP/ATH can prove the seal was intact when the MEP/ATH

	last performed work at the metering installation.
Proposed Code amendment	**Part 1 – Preliminary provisions** **time block meter channel** means a **meter** channel where: (a) the volume of **electricity** conveyed is recorded on two or more registers; and (b) each register is active for a fixed period of time; and (c) only one register is active at any point in time **10.12 Interference with metering installation** Subject to clause 48 of Schedule 10.7, ~~A~~a **participant** must not directly or indirectly interfere with a **metering installation** for which it is not the **metering equipment provider**, unless— (a) it is instructed or permitted to do so by the **metering equipment provider** responsible for the **metering installation**; or (b) the **participant** has an arrangement with the **trader** responsible for the **metering installation** as the **gaining metering equipment provider** who will be responsible for the **metering installation**. **Schedule 10.7 Metering installation requirements** … **19 Modification of metering installations** … (3C) Despite subclauses (1) and 2(b), the **certification** of a **metering installation** is not cancelled if clause 48(1A) to (1H) of Schedule 10.7 applies. … **20 Cancellation of certification of metering installation** (1) The **certification** of a **metering installation** is automatically cancelled on the date on which any 1 of the following events takes place: (a) the **metering installation** is modified otherwise than under clause 19(3), 19(3A),~~ or 19(6)~~ 19(3B), or 19(3C): … **48 Removal or breakage of seals** … (1A) Despite clause 10.12, a **distributor** may interfere with the metering installation without authorisation of the **metering equipment provider** responsible for the **metering installation**, to reset a load control device or bridge or unbridge a load control device, if—

	(a) the load control device does not control a **time block meter channel**; and (b) the **distributor** provides the load control signal to the load control device. (1B) A **distributor** that removes or breaks a seal in accordance with subclause (1A) must— (a) ensure that the personnel it uses to remove or break the seal are qualified or trained to a level sufficient to ensure that they can safely remove or break the seal, bridge and unbridge the load control device, and replace the seal, in accordance with this Code; and (b) replace the seal with its own seal and have a process for tracing the new seal to the personnel that removed or broke the seal on the **distributor's** behalf; and (c) advise the **trader** responsible for the **ICP** at which the **metering installation** is located if the load control device has been bridged or unbridged. (1C) A **trader** that is advised under subclause (1B)(c) must, if required, advise the **registry manager** of the updated **profile** code for the **ICP** in accordance with clause 10 of Schedule 11.1. (1D) Despite clause 10.12, a **trader** may remove or break a seal without authorisation of the **metering equipment provider** responsible for the **metering installation**, to reset a load control device or bridge or unbridge a load control device, if the load control device does not control a **time block meter channel**. (1E) Despite clause 10.12, a **trader** may remove or break a seal without authorisation of the **metering equipment provider** responsible for the **metering installation**— (a) to **electrically connect** the load or **generation** measured by the **meter** if the load has been **electrically disconnected** at the **meter**; or (b) to **electrically disconnect** the load or **generation** measured by the **meter** if the **trader** has exhausted all other appropriate methods of **electrical disconnection**; or (c) to bridge the **meter**; or (d) to unbridge the **meter**.[1] (1F) A **trader** that removes or breaks a seal in accordance with subclause (1D) or (1E) must— (a) ensure that the personnel it uses to remove or break the seal are qualified or trained to a level sufficient to ensure that they can safely remove or break the seal, perform the permitted work described in subclauses (1D) and (1E), and replace the seal, in accordance with this Code; and

[1] Note the insertion of new subclause (1E)(c) and (d) is subject to proposal 028 - Meter bridging.

	<u>(b) replace the seal with its own seal and have a process for tracing the new seal to the personnel that removed or broke the seal on the **trader's** behalf; and</u> <u>(c) if required, advise the **registry manager** of the updated **profile** code for the **ICP** in accordance with clause 10 of Schedule 11.1.</u> (1) Despite clause 10.12, a **participant** who removes or breaks a seal without authorisation of the **metering equipment provider** responsible for the **metering installation** <u>and not in accordance with subclauses (1A) to (1F)</u> must, within 10 **business days** of removing or breaking the seal,— (a) advise the **metering equipment provider** of— (i) the removal or breakage; and (ii) the reason for the removal or breakage; and (b) reimburse the **metering equipment provider** for the cost of reinstating the seal and **recertification** if required by the **metering equipment provider**. … <u>(8) If a person removes or breaks a seal without authorisation of the **metering equipment provider** responsible for the **metering installation**, or not in accordance with subclauses (1A) to (1F), the **metering equipment provider** or the **ATH** responsible for **certifying** the **metering component** are not liable for any breach of this Code that results from the person's actions, provided the **metering equipment provider** or **ATH** can prove the seal was not removed or broken when the **metering equipment provider** or **ATH** last performed work at the metering installation.</u>
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by removing unnecessary costs, in particular compliance costs, on: a) Participants that, for valid reasons, are: i) breaking or removing seals at metering installations; or ii) authorising the breaking or removing of seals at metering installations, but follow the prescribed process to ensure the metering installation remains accurate b) Participants and the Authority, from MEPs incorrectly being held responsible/liable for issues caused by traders or distributors or consumers. The proposed Code amendment is expected to have little or no effect on competition or reliability of supply, because it reflects common practice in the electricity industry.
Assessment against	The Authority is satisfied the proposed Code amendment is consistent with

Code amendment principles	the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposal is to remove unnecessary costs, particularly compliance costs on participants and the Authority in relation to the removing or breaking of seals at metering installations, while ensuring that the metering installation remains accurate.
Evaluation of the costs and benefits of the proposed amendment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Reference number(s)	028 - Meter Bridging
Relevant clause(s)	Clause 19 of Schedule 15.2
Problem definition	Bridging meters is the practice of electrically connecting a point of connection while bypassing the meter(s) in place to record any consumption from, or generation into, the network to which the point of connection is connected. Meters that have been bridged are not measuring electricity. They may be left in this state for some time. Unless the retailer responsible for the ICP estimates the quantity of electricity consumed/generated that is not being recorded by the bridged meter, the electricity will not be reconciled in the wholesale electricity market. Network charges will also not be paid. Unreconciled electricity increases the amount of unaccounted for electricity in the market, and reduces the accuracy of market settlement, invoicing, and consumer invoicing. Therefore, the Code does not currently permit the practice of bridging meters. However, in practice, there are a small number of meters that must be bridged each year to ensure a customer is not significantly disadvantaged by their premises being electrically disconnected from a distributor's network. Two relatively common examples of where meter bridging may be necessary are: a) the unavailability of systems or staff (usually outside of normal working hours) to send a connection signal to an AMI meter that remotely disconnected a consumer's premises, thereby requiring an electrician to connect the point of connection by bridging the meter b) a meter fault where it is unsafe to perform a full meter change at the time. A Code amendment is necessary if we are to avoid a participant being in breach of the Code when bridging a meter, and to place controls around the practice. This amendment would apply in exceptional circumstances to minimise a significant disadvantage to a consumer caused by their premises being electrically disconnected from a distributor's network.
Proposal	The Authority proposes to amend the Code to permit a trader responsible for an ICP: a) to bridge a meter, in exceptional circumstances, at that ICP b) authorise the bridging of a meter, in exceptional circumstances, at that ICP. We propose the following criteria must be met for a meter to be bridged in a manner that complies with the Code: a) The MEP responsible for the meter, despite best endeavours,: (i) has been unable to remotely electrically connect the ICP; or (ii) cannot repair a meter fault because of safety issues

	so that electricity flows through the meter(s) at the ICP. b) The consumer at the ICP will be without electricity for a period of time that will cause significant disadvantage to them. c) The trader responsible for the ICP must: (i) estimate the quantity of electricity conveyed at the ICP for the period of time the meter is bridged, in accordance with the requirements set out in new clause 2A of Schedule 15.2, and (ii) submit that estimated quantity to the reconciliation manager. d) The trader responsible for the ICP must immediately advise the responsible MEP that bridging has occurred, if the responsible MEP was not the party that bridged the meter. We propose that a trader, at its discretion, should be able to grant a 'standing authorisation' to an MEP or distributor to bridge meters on the trader's behalf. This authorisation would enable the MEP or distributor to instruct their field technicians to decide, once onsite, whether it is safe to complete a full meter change. If completing a full meter change would not be safe, the field technician would then be authorised to bridge the meter. Under the proposal, an authorised MEP or distributor that has bridged a meter, would have to immediately advise the trader responsible for the ICP that the meter has been bridged. We propose that, if a meter is bridged, the trader responsible for the ICP must arrange for an MEP: a) to correct the bridged meter within five business days, and b) to monitor the reinstatement of the metering, and ensure all electricity flowing through the ICP flows through a certified metering installation.
Proposed Code amendment	**Part 10** … **<u>10.33BWhen trader may bridge meter at ICP</u>** <u>(1) Subject to subclause (2), only a **trader** that is responsible for an **ICP** or an **MEP** authorised by the **trader** or a **distributor** authorised by the **trader**, in **electrically connecting an ICP,** may **electrically connect** the **ICP** in a way that bypasses the **meter or meters** that are in place to record the **electricity** flowing through the **ICP** ("bridge" a **meter**).</u> <u>(2) A **trader** may authorise an **MEP** or **distributor** under subclause (1)–</u> <u>(a) generally for all or some of the **ICP**s that the **trader** is responsible for; or</u> <u>(b) for a specific **ICP** that the **trader** is responsible for.</u> <u>(3) A **trader** that is responsible for an **ICP**, or an **MEP** authorised by the **trader** or a **distributor** authorised by the **trader**, may only bridge a **meter** at the **ICP** if–</u> <u>(a) the **MEP** responsible for the **meter**, despite best</u>

endeavours,—

(i) is unable to remotely **electrically connect** the **ICP** so that **electricity** flows through the **meter**; or

(ii) cannot, because of safety issues, repair a fault with the **meter** that prevents **electricity** flowing through the **meter** at the **ICP**; and

(b) the **consumer** at the **ICP** will likely be without **electricity** for a period of time that will cause significant disadvantage to the **consumer.**

(4) If a meter is bridged under subclause (1) by the **trader** or **distributor**, the **trader** responsible for the **ICP** must immediately advise the **MEP** responsible for the **meter** that bridging of the **meter** has occurred.

(5) If a **meter** is bridged under subclause (1) by the **MEP** or **distributor**, the **MEP** or **distributor** (as the case may be) must immediately advise the **trader** responsible for the **ICP** that bridging a **meter** has occurred.

(6) If a **meter** is bridged under subclause (1), in all cases, the **trader** responsible for the **ICP** must—

(a) determine, in accordance with clause 2A of Schedule 15.2, the quantity of **electricity** conveyed through the **ICP** for the period of time the **meter** is bridged; and

(b) submit that estimated quantity of **electricity** to the **reconciliation manager** in accordance with clause 15.4 of this Code; and

(c) within 1 **business day** of the **meter** being bridged, notify the **MEP** responsible for the bridged **meter** that it is required to reinstate the **meter** so that all **electricity** flowing into the **ICP** flows through a certified **metering installation.**

(7) The **MEP** receiving the notice under subclause (6)(c) must reinstate the **meter** so that all **electricity** flowing into the **ICP** flows through a certified **metering installation** within 5 **business days** of receiving the notice.

Schedule 15.2 Collection of volume information

…

2A Meter readings from bridged meters

If a **meter** is bridged in accordance with clause 10.33B, the **trader** responsible for the **ICP** must determine **meter readings** for that **meter** as follows:

(a) if a check **meter** or **data storage device** is installed at the **metering installation**, by substituting data from the check **meter** or **data storage device** for the period the **meter** was bridged:

	(b) in the absence of any check **meter** or **data storage device**, by determining **meter readings** for the period the **meter** was bridged from— (i) **half hour** data from another period where the **trader** considers the pattern of consumption is materially similar to the period during which the **meter** was bridged; or (ii) a non **half hour estimated reading** that the **trader** considers is the best estimate of the quantity of **electricity** consumed during the period the **meter** was bridged.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of, and reliable supply by, the electricity industry. It may also have a positive effect on competition. The proposed amendment would improve the efficient operation of the electricity industry by ensuring a trader that bridged a meter, or authorised a meter to be bridged, had to determine the unrecorded quantity of electricity. This is expected to reduce unaccounted for electricity, thereby improving the accuracy of wholesale market settlement and customer invoicing. The proposed Code amendment may promote competition, by reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs. The proposed Code amendment would promote reliability of supply for consumers by facilitating the timely electrical connection of consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.
Regulatory statement	
Objectives of the proposed amendment	The objectives of the proposal are to allow a method for consumers to be connected in extenuating circumstances while still promoting accurate settlement of the wholesale electricity market.
Evaluation of the costs and benefits of the	Please refer to the assessment of costs and benefits in section 3 of the consultation paper.

proposed amendment	
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment. However the amendment proposes conditions on traders when bridging meters, and we have evaluated the following alternatives to these conditions: 1) The condition that the trader must determine the quantity of electricity conveyed while the meter is bridged and submit that quantity to the reconciliation manager. We assessed the alternative of not requiring the trader to make this determination. If a trader does not do this, then the electricity that is used by the customer is then not reconciled to the market and becomes part of unaccounted for electricity (UFE). UFE is a cost that is socialised across all consumers. This means that all other consumers pay for a single consumer's identifiable benefit. This is contrary to the principle of cost reflective pricing, and does not align with our statutory objective 2) The condition that the trader must, within 1 business day, arrange for the MEP to correct the bridged meter and the MEP must make that correction within 5 business days We assessed alternative longer timeframes against the risk of inaccurate submissions of the electricity consumed. The longer a meter remains bridged, the higher the risk of inaccuracies as the determination process is unlikely to take into account the variability of the consumer's consumption. Meter bridging will remain a reasonably rare occurrence, and most fieldwork is managed through electronic interfaces. Therefore, it is reasonable to assume that traders will be aware of the meter bridging the next business day. Less than 5 business days may not allow sufficient time for a MEP to arrange access (if required) to correct the meter, and longer than 5 business days increases the risk of an extended period with inaccurate market submissions.

Appendix B Code amendment proposals that are technical and non-controversial

Reference number(s)	**029 – Reconciliation Manager File Format Specifications**
Relevant clause(s)	Clause 10.16 – Metering data exchange timing and formats Clause 10.25(2) – Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid Clause 10.26(7) – Responsibility for ensuring there is metering installation for point of connection to grid
Problem definition	Clause 10.25 provides that a distributor must, if it proposes the creation of a new network supply point (NSP) that is not a point of connection to the grid, advise the reconciliation manager of certain information under subclause (2)(b) and (c). Similarly, clause 10.26 requires a participant that is responsible for providing a metering installation for a point of connection to the grid to advise the reconciliation manager of certain information under subclause (7)(a) and (c).Relevant participants must submit to the reconciliation manager the information required under clauses 10.25 and 10.26 in accordance with the timeframes set out in these clauses. Clause 10.16(1)(b) requires the participant to provide the metering data to the reconciliation manager “in the format notified to participants from time to time by the Authority”. This format is not specified in the Code. Some participants have advised the Authority they are concerned the reconciliation manager may change the format without due consideration to the cost on participants. While considering this concern, we have noticed clause 10.16 contains typographical errors—in three places the word “notified” is bolded, when this is no longer a defined term.
Proposal	The Authority proposes only to correct the typographical errors in clause 10.16. We propose to make no change to the Code in response to the concerns raised by participants over the reconciliation manager changing the format under clause 10.16. Clause 10.16 requires the Authority to notify participants of the format (subclause (1)(b)), and to provide notice of any changes to the format (subclause (2)). As part of this process the Authority, via the reconciliation manager, will always consult with participants on any proposed change to the format to ensure we are aware of the effect on participants. We consider this approach to be consistent with section 4 of Part 2 of the Authority’s consultation charter, as well as general administrative law principles.
Proposed Code amendment	We propose to amend clause 10.16 as follows: **10.16 Metering data exchange timing and formats** (1) A **participant** (other than a **market operation service provider**) must, if it is under an obligation to provide **metering data** under this Part, provide the **metering data** to the relevant person— (a) in the absence of any timeframe specified in this Code, within a reasonable timeframe ~~**notified**~~ notified by the **Authority**; and

	(b) in the format ~~**notified**~~ notified to **participants** from time to time by the **Authority**. (2) The **Authority** must provide reasonable notice of any changes to the format ~~**notified**~~ notified under subclause (1)(b). (3) Despite subclause (1)(b), a **participant** may provide the **metering data** in an alternative format if it has an arrangement with the recipient to use the alternative format. (4) Despite subclause (3), the **participant** must be able to comply with any format requirements ~~**notified**~~ notified by the **Authority** under subclause (1)(b), within 1 **business day** of ceasing to have an arrangement with the recipient under subclause (3). (5) Despite using an alternative format under subclause (3), a **participant** must still comply with all other obligations in this Code.
Grounds for not consulting	The Authority is satisfied the nature of the proposed Code amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no effect on current practice. Rather, the proposed amendment would remove the possibility of any confusion, caused by inaccurate language in the Code.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by clarifying the Code, to make it easier for participants to interpret the Code. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed Code amendment. Accordingly, a quantitative analysis has not been undertaken.

<table>
<tr><td>Reference number(s)</td><td>030 - Distributor notifying reconciliation manager of new NSPs</td></tr>
<tr><td>Relevant Clause(s)</td><td>Clause 10.30 – When distributor or embedded network owner may connect NSP that is not point of connection to grid</td></tr>
<tr><td>Problem definition</td><td>Under clause 10.30(2), a distributor must, within five business days of connecting an NSP, advise the reconciliation manager of the following information:
a) the NSP that has been connected; and
b) the connection date; and
c) the participant identifier of the metering equipment provider for each metering installation for the NSP; and
d) the certification expiry date of each metering installation for the NSP.
The policy intent of clause 10.30(2) is for the distributor that initiates the creation and connection of the NSP under clause 10.30(1A) or (1B) to advise the reconciliation manager of the information listed above.
However, in a situation where two distributors are involved in the connection of an NSP under clause 10.30(1A) or (1B), each distributor may interpret clause 10.30(2) as requiring it to advise the reconciliation manager.
This imposes unnecessary transaction costs on the distributor that does not have to advise the reconciliation manager.</td></tr>
<tr><td>Proposal</td><td>The Authority proposes amending clause 10.30 to clarify that the distributor that initiates the connection of an NSP in accordance with clause 10.30(1A) and (1B) is responsible for notifying the reconciliation manager of the information listed in clause 10.30(2).</td></tr>
<tr><td>Proposed Code amendment</td><td>10.30 When distributor or embedded network owner may connect NSP that is not point of connection to grid
(1A) Only a distributor that initiates, under Part 11, the creation of an NSP on the distributor's network that is not a point of connection to the grid may connect the NSP to—
(a) an embedded network, if the embedded network owner has agreed to the connection; or
(b) a local network, if the local network owner has agreed to the connection.
(1B) Only an embedded network owner that initiates, under Part 11, the creation of an NSP on its embedded network—
(a) may connect the NSP to another embedded network; but
(b) can only do so if the other embedded network owner has agreed to the connection.
(1) Despite subclause (1A), a distributor must not connect an NSP on its network that is not a point of connection to the grid unless</td></tr>
</table>

	requested to do so by the **reconciliation participant** responsible for ensuring there is a **metering installation** for the **point of connection**. (2) A **distributor** <u>that initiates, under Part 11, the creation of an **NSP** on the **distributor's** network, being a **local network** or an **embedded network** and which the **distributor** connects in accordance with subclause (1A) and (1B),</u> must, within 5 **business days** of connecting ~~an~~ <u>the</u> **NSP**, advise the **reconciliation manager** of the following: (a) the **NSP** that has been connected; and (b) the connection date; and (c) the **participant identifier** of the **metering equipment provider** for each **metering installation** for the **NSP**; and (d) the **certification** expiry date of each **metering installation** for the **NSP**.
Grounds for not consulting	The Authority is satisfied the nature of the proposed Code amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no effect on current practice. Rather, the proposed amendment would remove the possibility of any confusion, caused by inaccurate language in the Code.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by clarifying the Code, to make it easier for participants to know who must advise the reconciliation manager of the information required under clause 10.30(2) of the Code. This will remove the possibility of unnecessary transaction costs associated with the wrong participant advising the reconciliation manager. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative	It is not practicable to quantify the benefits of the proposed amendment.

Assessment	Accordingly, a quantitative analysis has not been undertaken.

Reference number(s)	**031 - Content of Interrogation Logs**
Relevant clause(s)	Clause 8 of Schedule 10.6 – Electronic interrogation of metering installation
Problem definition	Clause 8(3) of Schedule 10.6 requires an MEP to record in the interrogation and processing system logs of each metering installation the MEP is responsible for the: a) time b) date c) extent of any change in the internal clock setting in the metering installation. The requirement in clause 8(3) of Schedule 10.6 for an MEP to record the date and time in an interrogation log is a repeat of the obligation as set out in clause 8(7) of Schedule 10.6.
Proposal	The Authority proposes to: a) delete the reference to “interrogation log” from clause 8(3) of Schedule 10.6 b) amend clause 8(7)(c) of Schedule 10.6 to include the current obligation in clause 8(3) of Schedule 10.6 for an MEP to record “the extent of any change to the internal clock setting” in a metering installation’s interrogation log.
Proposed Code amendment	**8 Electronic interrogation of metering installation** … (3) A **metering equipment provider** must, for each **metering installation** for which it is responsible, record in the ~~**interrogation** and~~ processing system log~~s~~, the time, the date, and the extent of any change in the internal clock setting in the **metering installation**. … (7) A **metering equipment provider** must, when **interrogating** a **metering installation**,— … (c) ensure that the **interrogation** log forms part of the **interrogation audit** trail and contains the following as a minimum: (i) the date of **interrogation**; and (ii) the time of commencement of **interrogation**; and (iii) the operator of the **interrogation** system identification (where available); and (iv) the unique identifier of the **data storage device** being **interrogated**; and (v) any clock errors outside the range specified in Table 1 of subclause (5) <u>and the extent of any change in the</u>

	<u>internal clock setting</u>; and (vi) the method of **interrogation**; and (vii) the identifier of the reading device used for **interrogation** (if applicable). …
Grounds for not consulting	The Authority is satisfied the nature of the proposed Code amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by clarifying the Code, to make it easier for participants to interpret the Code. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a regulatory failure that is leading to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	A regulatory statement is not required for a technical and non-controversial Code amendment, meaning a quantitative assessment is not required.

Reference number(s)	**032 - Automatic Cancellation of Metering Certification**
Relevant clause(s)	Clause 6 of Schedule 10.7 – Determination of metering installation incorporating current transformer to be lower category Clause 20 of Schedule 10.7 – Cancellation of certification of metering installations
Problem definition	Clause 20 of Schedule 10.7 lists the triggers for a metering installation's certification to be automatically cancelled. However, clause 20 omits the cancellation provision in clause 6 of Schedule 10.7 that relates to a metering equipment provider (MEP) not receiving, in any month, a report detailing the maximum current conveyed through a point of connection for the prior month. In addition, it is not clear that certification for a metering installation that had its category determined under clause 6 can be cancelled.
Proposal	The Authority proposes to amend: a) clause 20 of Schedule 10.7 to include the missing event that causes automatic cancellation of a metering installation's certification that is contained in clause 6 of Schedule 10.7 b) clause 6 of Schedule 10.7 to clarify the meaning of the clause and, in particular, to clarify that: (i) an ATH determines the category of a metering installation as part of the process associated with certifying the metering installation, and so (ii) the certification of a metering installation with its category determined under clause 6 of Schedule 10.7 can be cancelled automatically.
Proposed Code amendment	**Schedule 10.7** **5 Determination of metering installation category** An **ATH** must, before it **certifies** a **metering installation**, determine the category of the **metering installation** in accordance with the following: (a) subject to clause 6, if the **metering installation** incorporates a current transformer, its category must be determined according to the primary current rating of the current transformer and the connected voltage set out in Table 1 of Schedule 10.1: (b) if the **metering installation** does not incorporate a current transformer and the quantity of **electricity** conveyed is measured by a **meter**, it must be category 1. **6 Determining~~ation of~~ metering installation incorporating current transformer to be lower category** (1) ~~An **ATH** may, w~~When determining the category of a **metering installation** under clause 5(a), an **ATH** may~~ determine~~ under subclause (2) determine~~ that~~ the category of a **metering installation** to be~~ is~~ lower than would otherwise be the case under clause 5(a), only in 1 of the following circumstances: (a) if a protection device, including a fuse or a **circuit breaker**, is

	installed that limits the maximum current of the **metering installation**; or (b) if the **metering equipment provider**, acting reasonably on the basis of historical **metering data**, believes that the maximum current to be conveyed through the **point of connection** will, at all times during the intended **certification** period, be lower than the current setting of the protection device for the category for which the **metering installation**— (i) is **certified**; or (ii) is required to be **certified** by this Code; or (c) if the **metering installation** uses less than 0.5 GWh in any 12 month period; or (d) if the **metering equipment provider**, acting reasonably on the basis of historical **metering data**, believes that the **metering installation** (including, for example, a **metering installation** for an emergency fire pump or flood pump) will use less than 0.5 GWh in any 12 month period. (2) ~~If an~~An **ATH** may determine~~s~~ the category of a **metering installation** to be lower than would otherwise be the case under clause 5(a), provided that— (a) if the circumstance in subclause (1)(a) applies, the **ATH** must, when **certifying** the **metering installation**, determine the category of the **metering installation** by reference to the maximum current setting of the protection device~~. The **ATH** must~~, and when doing so— (i) confirm the suitability and operational condition of the protection device; and (ii) record, in the **metering records**, the rating and setting of the protection device; and (iii) seal the protection device under clause 47; and (iv) apply, if practicable, a warning tag to the seal under clause 47(6): (b) if the circumstance in subclause (1)(b) applies, the **ATH** ~~may~~ must, ~~only if it considers it appropriate in the circumstances, at the request of the **metering equipment provider**,~~ when **certifying** the **metering installation**, determine the **metering installation** category according to the **metering installation's** expected maximum current but only~~.~~ — (i) at the request of the **metering equipment provider**; and (ii) if the **ATH** considers it appropriate in the circumstances: ~~If the **ATH** determines the category of a **metering installation** under this clause, then—~~ ~~(i) the **metering equipment provider** responsible for the **metering installation** must, each month, obtain a report from the **participant interrogating** the **metering installation**, detailing the maximum current conveyed through the **point of connection** for the prior month. For the purposes of this subparagraph, the **metering equipment provider** must determine the maximum~~

~~current from **raw meter data** from the **metering installation** by either calculation from the kVA by **trading period** if available, or from a maximum current indicator if fitted in the **metering installation**; and~~

~~(ii) if the **metering equipment provider** does not receive the report in any month, or the report demonstrates that the maximum current conveyed through the **point of connection**, at any time during the previous month, exceeded the maximum permitted current for the **metering installation** category as **certified**, **certification** for the **metering installation** is automatically cancelled from the date on which the **metering equipment provider** should have received the report, or the date on which the **metering equipment provider** received the report:~~

(c) if the circumstance in subclause (1)(c) or subclause (1)(d) applies, then when **certifying** a **metering installation**, if the primary voltage is—

~~(i) if the primary voltage is—~~

~~(A) less than 1kV, the **ATH** must determine the **metering installation** as category 2; or~~

~~(B) greater than or equal to 1kV, the **ATH** must determine the **metering installation** as category 3; and~~

(ia) less than 1 kV, the **ATH** must determine the **metering installation** as category 2; or

(ib) greater than or equal to 1 kV, the **ATH** must determine the **metering installation** as category 3.

~~(ii) the **metering equipment provider** responsible for the **metering installation** must, each month during the **certification** period, obtain a report from the **participant interrogating** the **metering installation** detailing the total kWh consumption of the **metering installation** for the prior 12 months:~~

~~(d) subclause (1)(d), if the **metering equipment provider** does not receive the report in any month, or the report identifies that the **electricity** conveyed through the **point of connection** exceeded 0.5 GWh during the previous 12 month period, the **certification** for the **metering installation** is automatically cancelled from the date on which the **metering equipment provider** should have received the report or the date on which the **metering equipment provider** received the report.~~

(2A) If, when **certifying** a **metering installation**, an **ATH** determines the category of a **metering installation** under—

(a) subclause (2)(b), then the **metering equipment provider** responsible for the **metering installation** must, each month, obtain a report from the **participant interrogating** the **metering installation**, detailing the maximum current conveyed through the **metering installation** for the prior month. For the purposes of this subclause, the **metering equipment provider** must determine the maximum current from **raw meter data** from the **metering installation** by either calculation from the kVA by **trading period** if available or from a maximum current indicator, if fitted in the **metering installation**; and

(b) subclause (2)(c), then the **metering equipment provider** responsible for the **metering installation** must, each month during the **certification** period, obtain a report from the **participant interrogating** the **metering installation** detailing the total kWh consumption of the **metering installation** for the prior 12 months.

(2B) If a **metering equipment provider** does not receive the report under subclause (2A)(a) in any month, or the report demonstrates that the maximum current conveyed through the **point of connection**, at any time during the previous month, exceeded the maximum permitted current for the **metering installation** category as **certified**, **certification** for the **metering installation** to which the report relates is automatically cancelled from:

(a) the date on which the **metering equipment provider** should have received the report; or

(b) the date on which the **metering equipment provider** received the report, if earlier:

(2C) If a **metering equipment provider** does not receive the report under subclause (2A)(b) in any month, or the report identifies that the **electricity** conveyed through the **point of connection** exceeded 0.5 GWh during the previous 12 month period, the **certification** for the **metering installation** to which the report relates is automatically cancelled from:

(a) the date on which the **metering equipment provider** should have received the report; or

(b) the date on which the **metering equipment provider** received the report, if earlier.

(3) The **ATH** must, before it determines a **metering installation** to be a lower category under this clause, visit the site of the **metering installation** to ensure that the installation is suitable for the **metering installation** to be determined to be a lower category.

(4) If an **ATH** determines a **metering installation** to be a lower category under this clause the **metering installation certification report** must include all information required to demonstrate, as at the **certification** date, compliance with this clause.

20 Cancellation of certification of metering installations

(1) The **certification** of a **metering installation** is automatically cancelled on the date on which any 1 of the following events takes place:

(a) the **metering installation** is modified otherwise than under clause 19(3), 19(3A), or 19(6):

(b) the **metering installation** is classed as outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1, defective, or not fit for purpose under—

(i) this Part; or

	(ii) any **audit**: (c) an **ATH** advises the **metering equipment provider** responsible for the **metering installation** of— (i) a **reference standard** or **working standard** used to **certify** the **metering installation** not being compliant with this Part when it was used to **certify** the **metering installation**; or (ii) the failure of a group of **meters** in the statistical sampling **recertification** process for the **metering installation**; or (iii) the failure of a **certification** test for the **metering installation**: (d) the manufacturer of a **metering component** in the **metering installation** determines that the **metering component** does not comply with the standards to which the **metering component** was tested: (e) an inspection of the **metering installation**, that is required under this Part, is not carried out in accordance with the relevant clauses of this Part: (f) if<u>, under clause 6(2)</u> the **metering installation** has been determined to be a lower category<u>,</u> ~~under clause 6~~ and<u>—</u>~~— the maximum current conveyed through the **metering installation** at any time exceeds the current rating of its **metering installation** category as set out in Table 1 of Schedule 10.1~~ <u>(i) the **metering equipment provider** has not received, in any month, the report referred to in clause 6(2A)(a); or</u> <u>(ii) the report referred to in clause 6(2A)(a) demonstrates that the maximum current conveyed through the **metering installation**, at any time during the previous month, exceeded the maximum permitted current for the **metering installation** category as **certified**; or</u> <u>(iii) the **metering equipment provider** has not received, in any month, the report referred to in clause 6(2A)(b); or</u> <u>(iv) the report referred to in clause 6(2A)(b) identifies that the **electricity** conveyed through the **point of connection** exceeded 0.5 GWh during the previous 12 month period</u>: (g) the **metering installation**— (i) is **certified** under clause 14 and sufficient load is available for full **certification** testing; and (ii) has not been retested under clause 14(4): (h) a **control device** in the **metering installation certification** is, and remains for a period of at least 10 **business days**, bridged out under clause 35(1): (i) the **metering equipment provider** responsible for the **metering installation** is advised by an **ATH** under clause 48(6)(b) that a seal has been removed or broken and the accuracy and continued integrity of the **metering installation** has been affected. (2) A **metering equipment provider** must, within 10 **business days** of becoming aware that 1 of the events in subclause (1) has occurred

	in relation to a **metering installation** for which it is responsible, update the **metering installation's certification** expiry date in the **registry**.
Grounds for not consulting	The Authority is satisfied the nature of the proposed Code amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no effect on current practice. Rather, the proposed amendment would remove the possibility of any confusion, caused by inaccurate language in the Code.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry by clarifying the Code. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it provides an identifiable efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Reference number(s)	**033 - Measuring Transformer Terminology**
Relevant clause(s)	Clause 31(7)(b)(ii) of Schedule 10.7 – Measuring transformer burden and compensation requirements
Problem definition	Clause 31(7)(b)(ii) of Schedule 10.7 of the Code incorrectly uses the term "metering transformer" instead of “measuring transformer”.
Proposal	The Authority proposes to replace the term "metering transformer" in clause 31(7)(b)(ii) of Schedule 10.7 with the term "measuring transformer".
Proposed Code amendment	**Schedule 10.7** **31 Measuring transformer burden and compensation requirements** … (7) An **ATH** must, before it certifies a **measuring transformer**, if the in-service burden is less than the lowest burden test point specified in a standard set out in Table 5 of Schedule 10.1,— … (b) confirm that— (i) a **class A ATH** has confirmed by **calibration** that the accuracy of the **measuring transformer** will not be adversely affected by the in-service burden being less than the lowest burden test point specified in the standard; or (ii) the **measuring transformer's** manufacturer has confirmed that the accuracy of the ~~**metering**~~ **measuring transformer** will not be adversely affected by the in-service burden being less than the lowest burden test point specified in the standard.
Grounds for not consulting	The Authority is satisfied the nature of the proposed Code amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no effect on current practice. Rather, the proposed amendment would remove the possibility of any confusion caused by inaccurate language in the Code.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority’s objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry by clarifying the Code. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements

	set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Appendix C Issues that we propose to resolve without a Code amendment

Reference number(s)	034 – Certification of Metering Installations and Trading
Relevant clause(s)	Clause 10.7 – Access to premises in which metering installation located Clause 10.24 – Responsibility for ensuring there is a metering installation for ICP that is not also NSP Clause 10.38 – Certification of metering installations
Problem definition	Uncertified metering installations can be inaccurate, which increases the amount of unaccounted for electricity. In turn, this affects the accuracy of wholesale market settlement and consumer billing. The following three clauses require traders and metering equipment providers (MEPs) to cooperate to ensure metering installations are certified: a) clause 10.7(2) requires reconciliation participants to arrange access for an MEP (among other parties) to a metering installation the reconciliation participant is responsible for. b) clause 10.24 includes the requirement for a trader to ensure there is one or more metering installations at each installation control point (ICP) (that is not an network supply point) the trader is recorded in the registry as being responsible for. c) clause 10.38 requires an MEP to obtain and maintain certification for each metering component and metering installation the MEP is responsible for. Traders typically assist an MEP during the metering recertification process because: a) the MEP usually does not have a direct relationship with the metered party b) the trader must arrange for the MEP to have access to a metering installation (refer to clause 10.7(2)). The trader is also able to use its contractual relationship with an MEP to ensure metering installations are appropriately certified, even though the trader has no direct control over the MEP's operations. Some MEPs are not recertifying all installations as required, either: a) as part of a business decision; or b) because of unusual access issues outside the trader's control. Although the trader could report an MEP for breaching the Code, or use contractual pressure to ensure installations are certified, the trader may be reluctant to do either of these things and risk damaging its relationship with the MEP.
Proposal	The Authority considered amending the Code to prohibit traders from trading at ICPs with uncertified metering installations to eliminate the risk of using inaccurate metering data for market settlement and consumer invoicing. We have rejected this proposal because we believe the costs outweigh the benefits. If traders were prohibited from trading on an uncertified metering

	installation, traders would be forced to electrically disconnect the metering installation. This would not be an acceptable result for the customer or the embedded generator at the ICP. However, it would be difficult for the customer or embedded generator to argue against the outcome if they were preventing access to the metering installation. After considering the matter, the Authority proposes to: a) leave the Code unchanged b) pursue MEPs and traders, respectively, for: i) Code breaches in relation to uncertified metering installations ii) failing to arrange access to a metering installation c) educate participants on their responsibilities under the Code in relation to metering certification, including: i) educating traders that they must report an alleged breach against MEPs that do not certify metering installations and metering components in accordance with clause 10.38 of the Code ii) educating MEPs that they must report an alleged breach against traders that do not arrange access to a metering installation in accordance with clause 10.7 of the Code.

Reference number(s)	**035 – Designating and Metering Network Interconnection Points**
Relevant clause(s)	Clause 10.25 – Responsibility for ensuring there is metering installation for ICP that is not point of connection to grid
Problem definition	Part 1 of the Code defines an interconnection point to mean a point of connection between— a) a local network and any other local network; or b) an embedded network that is not a gateway network supply point (NSP) and a local network; or c) an embedded network that is not a gateway NSP and any other embedded network. If a network has only one NSP, that NSP is known as a "gateway NSP". Gateway NSPs are only seen on embedded networks. The distributor responsible for an NSP that is not a point of connection to the grid, must: a) Under clause 10.25(1), ensure that: i) there is one or more metering installations; and ii) all electricity conveyed is quantified in accordance with the Code. b) Under clause 10.25(2), for each metering installation at the NSP, either: i) assume responsibility for being the MEP; or ii) contract with someone to assume responsibility as the MEP. c) Under clause 10.25(2), advise the reconciliation manager of: i) the reconciliation participant for the NSP; and ii) the participant identifier of the MEP for the metering installation; and iii) the certification expiry date of the metering installation. The Authority is aware some distributors are not designating interconnection points as an NSP. In turn, these distributors are not: a) ensuring appropriate metering is installed at interconnection points b) notifying the reconciliation manager of the existence of interconnection points c) in instances where the distributor is the reconciliation participant for the interconnection point, providing NSP metering information to the reconciliation manager. This causes inaccuracies in the reconciliation process, with traders being over-charged or under-charged for electricity.

Proposal	The Authority proposes to make no changes to the Code to address this problem. We consider the Code clearly: a) defines an interconnection point b) sets out the obligations on distributors in respect of interconnection points. We believe the best way of addressing this problem is through participant education.

Reference number(s)	036 - Alternative Load Checks After Component Recertification
Relevant clause(s)	Table 4 of Schedule 10.1
Problem definition	Clause 14 of Schedule 10.7 sets out a process to be followed if there is insufficient electricity conveyed through a point of connection to allow an ATH to complete a prevailing load test for a metering installation that is being certified as a half-hour metering installation. However, the Code does not set out an analogous process for a metering installation that is being certified as a NHH metering installation.
Proposal	The Authority considers there is no need for an analogous process to that set out in clause 14 of Schedule 10.7 for NHH metering installations. The prevalance of AMI means there are very few NHH metering installations being certified in New Zealand.[1] For these NHH metering installations, an ATH should be able to use dummy loads to successfully complete a prevailing load test.

[1] Most NHH metering installations in New Zealand are uncertified. These are generally being replaced by certified AMI metering installations. The number of metering installations being certified as NHH each year is measured in the hundreds.

Reference number(s)	037 – Regulating Metering Used for Non-Reconciliation Purposes
Relevant clause(s)	New clause – Scope of application of Part 10, and amendments to other clauses as necessary Clause 8(5) of Schedule 10.6 – Electronic interrogation of metering installations
Problem definition	The Code currently regulates only metering that is used for reconciling the wholesale electricity market. The Code does not regulate metering used for non-reconciliation purposes. Examples of metering not regulated by the Code include: • check meters used to bill consumers on customer networks • maximum demand meters used for distributor billing • meters used to self-monitor energy efficiency. Metering used for reconciliation purposes always uses the code required methodology and facilities for interrogation. Metering that is not regulated by the Code does not and, for that reason, may not be as accurate as metering used for reconciliation purposes. Some industry participants and consumers believe all metering that forms the basis for customer billing should be held to the same accuracy standards as metering regulated by the Code. Options for regulating metering installations that are currently not regulated by the Code range from: a) regulating accuracy requirements only, to b) requiring full certification of the metering installation and the provision and maintenance of the installation's metering information in the registry. If these meters were to be regulated by the Code, then depending on the scope of the regulation, mechanisms may be required in the submission processes to reduce the likelihood of participants double billing/submitting. Before these detail questions can be resolved, there is the policy question of whether the Code should be expanded.
Proposal	The Authority considers that a decision to regulate metering used for non-reconciliation purposes would have a significant effect on consumers and the electricity industry. We believe any consideration of such a change merits its own project. Therefore, the Authority has not considered this matter here. Instead, we will look to incorporate work in this area into our work programme.

Reference number(s)	**038 - Daylight Savings and Time Clocks**
Relevant clause(s)	Clause 23 of Schedule 10.7
Problem definition	Clause 23 of Schedule 10.7 applies to time keeping devices that control the switching of a meter register in a metering installation, but which are not remotely monitored and corrected. This clause requires an MEP to ensure the time keeping device: a) has a time keeping error of no more than an average of two seconds per day over a period of 12 months b) is monitored and corrected at least once every 12 months. The Authority is concerned the Code is not sufficiently clear on how these devices must handle daylight savings transitions. Not correcting for daylight savings is likely to result in electricity consumption or generation being recorded on the wrong register for one hour. This has two main effects. Firstly, customers pay for their electricity consumption at the wrong price. For some customers this can be a material cost (eg, a dairy farmer paying the daytime electricity price instead of the cheaper night rate during the morning milking). Secondly, reconciliation is inaccurate if the consumption is being profiled into time blocked profiles. The electricity volumes submitted to the reconciliation manager will be incorrect for the two trading periods when the wrong meter register is recording consumption or generation. If an MEP does not correct a meter register for daylight savings, the next day the clock will be inaccurate by 3,600 seconds (one hour). This is an average of almost 10 seconds per day over 12 months (3,600 divided by 365 days). However, the inaccuracy could range between 7.8 seconds and 11.8 seconds if the clock was already inaccurate prior to the daylight savings event, but within the time keeping error limit permitted by the Code. The clock will remain inaccurate until daylight savings reverts. This means the MEP is in breach of clause 23(a) of Schedule 10.7, even though clause 23(b) only requires the MEP to monitor and correct the time keeping device at least once every 12 months.
Proposal	The Authority does not propose to make a Code amendment. The Authority considers that the current wording of clause 23(a) of Schedule 10.7 is sufficient and does not give rise to the problem identified above. Sub-paragraph (b) does not limit or cap an MEP’s obligations under sub-paragraph (a). As the effect of a change for daylight savings would be to create an error greater than the error permitted by sub-paragraph (a), and MEP’s would know this, each MEP will need to correct each time-keeping device subject to clause 23 in order to meet their obligations under sub-paragraph (a) or ensure the time keeping device is set up to account for daylight saving changes. The requirement in clause 23(b) of Schedule 10.7 does not permit the MEP to correct the time keeping device for a meter register only once a year, even if the MEP is in breach of clause 23(a) of Schedule 10.7. The use of the words “at least” in clause 23(b) is deliberate — the intent is to

	ensure an MEP corrects the time keeping device as often as is necessary for the MEP to comply with clause 23(a). As an aside, we note our understanding that MEPs face commercial incentives through the retailers (and their customers) to ensure meter readings are accurate.

Reference number(s)	039 - Metering Records
Relevant clause(s)	Clause 4 of Schedule 10.6 – Metering equipment provider record keeping and documentation Clause 6 of Schedule 11.4 – Correction of errors in registry
Problem definition	Clause 4 of Schedule 10.6 requires MEPs to keep accurate and complete records of information relating to each metering installation for which the MEP is responsible. Clause 6 of Schedule 11.4 requires MEPs to: a) compare their metering records with the equivalent metering records in the registry, on a monthly basis; and b) make corrections to either the registry metering records or their metering records, as appropriate. Clause 6 of Schedule 11.4 facilitates accurate registry metering records, because an MEP must investigate any discrepancies between its records and those in the registry, to determine which records are correct. Discrepancies can arise in various ways, including: a) data entry errors b) accidental changes being made to the registry c) physical work being performed but not entered into the registry. The Authority has been queried as to whether an MEP could use the registry to fulfil the MEP's obligations under clause 4 of Schedule 10.6 (ie, to use the registry as the MEP's metering records database). The Code does not explicitly prohibit this. If an MEP were to use the registry to fulfil its obligations under clause 4 of Schedule 10.6, this would appear to make it difficult to fulfil the purpose of clause 6 of Schedule 11.4.
Proposal	The Authority considers a Code amendment is unnecessary to prohibit an MEP using the registry's metering records as the sole source of the MEP's "own records". If an MEP were to use the registry's metering records in this way, the MEP would have no records of its own against which to compare "the information obtained from the registry". Therefore, the MEP would be unable to comply with clause 6 of Schedule 11.4. If an MEP does not have its own database of metering records, the MEP must do one of the following options to comply with clause 6 of Schedule 11.4: a) The MEP could, for each metering installation it is responsible for: i) refer to the original metering records the MEP referred to in order to enter metering records for the installation into the registry[1]; and

[1] These records could include:
a) the metering certification report the ATH provided when the metering installation was certified
b) the purchase records from the previous MEP
c) any other records the MEP has that reflect the current state of the metering installation and which can be used to identify whether the registry metering records for the metering installation have been changed.

	ii) compare these original metering records with the registry's metering records on a monthly basis. b) The MEP could contract with an ATH to hold metering records for the metering installations for which the MEP is responsible. However, the obligation under clause 6 of Schedule 11.4, to compare these metering records with the equivalent records in the registry, on a monthly basis, would remain with the MEP.

Reference number(s)	040 - In-Situ Recertification
Relevant clause(s)	Clause 11 of Schedule 10.7 – Selected component certification of metering installation Clause 12 of Schedule 10.7 – Comparative recertification Cause 13 of Schedule 10.7 – Fully calibrated metering installation certification
Problem definition	Clauses 11 and 13 of Schedule 10.7 describe how an ATH must certify a metering installation using, respectively: a) the selected component method b) the fully calibrated method. Some participants have informed the Authority that these clauses do not explicitly state whether, for a category 2 or higher metering installation: a) the metering installation can be recertified as a whole, without the need to recertify individual metering components b) the ATH— i) must replace any current transformers that form part of a metering installation; or ii) may recalibrate the current transformers onsite / in-situ.
Proposal	The Authority considers that the identified problem can be addressed via participant education. We propose to publish an explanatory note on the meaning of clauses 11 to 13 of Schedule 10.7. Clauses 11 and 13 of Schedule 10.7 cannot be used to certify a metering installation without certifying individual components of the installation. Clauses 11(5)(b) and 13(3)(b) of Schedule 10.7 require the components of the metering installation to be certified as part of the certification of the installation. Clause 12 of Schedule 10.7 permits the certification of a metering installation without the need to certify components of the metering installation. This is known as comparative recertification. It is permitted only for the recertification of category 2 metering installations. The Code is deliberately silent on whether a metering component can be recalibrated onsite / in-situ or whether the component must be replaced. This is to allow ATHs to develop appropriate procedures that: a) suit their business b) suit the types of metering installations they recertify. The Code simply requires that an ATH must ensure: a) the overall accuracy requirements for the metering installation stipulated in the Code are met b) any specific requirements in the Code that relate to the certification of the metering installation are met.

Appendix D Format for submissions

D.1 Please complete the table below for each proposed Code amendment requiring a regulatory statement. Only include those you wish to submit on.

Note: Please use table D2 to submit on technical and non-controversial proposals.

Operational Review of Metering and Related Registry Processes	
Submitter	
Proposal Reference	
Question 1: Do you agree with the Authority's problem definition? If not, why not?	
Question 2: Do you agree with the Authority's proposed solution? If not, why not?	
Question 3: Do you have any comments on the Authority's proposed Code drafting?	
Question 4: Do you agree with the objectives of the proposed amendment? If not, why not?	

Question 5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

D.2 Please complete the table below if you wish to submit on the technical and non-controversial Code proposals in Appendix B.

Question 6: Do you have any comments on any of the technical/non-controversial changes? If so, please note which change and your comments.

D.3 Please complete the table below if you wish to submit on the CBA for the proposals that require a regulatory statement.

Question 7: Do you agree the costs and benefits identified are appropriately categorised? If you disagree, please provide reasons.
Question 8: Do you agree the benefits of the proposals in aggregate outweigh their costs? If you disagree, please provide reasons.

D.4 Please complete the table below if you wish to submit on the issues that we propose to resolve without a Code amendment.

Question 6: Do you require further clarification of any of the issues presented here? If so, please note which issues below and your questions.

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010