Operational Review of Metering and Related Registry Processes

Decision

15 December 2020

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1 The Authority has decided to make a number of improvements to the Code

1.1 The Electricity Authority (Authority) has decided to amend the Electricity Industry Participation Code 2010 (Code) to make a number of improvements to the Code.

1.2 These improvements stem from the Operational Review of Metering and Related Registry Processes – a set of 28 proposed Code amendments, which we consulted on in the last quarter of 2018.[1] Most of the Code amendment proposals addressed a discrete issue, but in some places, proposals intersected or overlapped. Where there were related issues, we addressed them as multi-part problem statements with solutions for each problem within a single proposal grouping.

1.3 There were five additional technical and non-controversial amendments under section 39(3)(a) of the Electricity Industry Act 2010 (Act), which did not require a regulatory statement, or consultation. In each case this was because the proposed amendment was a technical drafting change and would either have no impact on current industry practice or would not change any participant's obligations. Though not required to do so, the Authority included these amendments in the consultation paper to alert participants to the Authority's intention to make them. These five Code amendments will come into force on 1 February 2021.

1.4 In addition to the issues that would need a Code amendment to resolve, seven further issues that participants had previously raised were addressed without a Code amendment. We have addressed these by providing participants with additional explanations to help them interpret the Code and apply it to their practices.

1.5 Table 1 lists our decision for each of the Code amendment proposals consulted on, including the intended date the Code amendment will come into force.

Table 1: Operational Review of Metering and Related Registry Processes decisions

Reference Number	Topic	Decision	Date Code amendment comes into force
001	Electrically Disconnecting Other Traders' ICPs	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
002	Prohibition of Net Metering	Implement an amended form of the proposal	1 February 2021
003	Recovering Certification Costs	Implement an amended form of the proposal	1 February 2021
004	Distributor NSP Information Notifications to Reconciliation Manager	Implement the proposal without change	1 February 2021

1 Electricity Authority, Review of metering and related registry processes https://www.ea.govt.nz/development/work-programme/operational-efficiencies/market-enhancement-omnibus/consultations/#c17636.

005	Like-for-Like Replacements and Consultation	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
006	Metering Issue Resolution Timing	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
007	Minimum Voltage Requirements	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
008	Prevailing Load Checks	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
009	ISO 9001 Sync with Class B ATH Application Period	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
010	Selected Component Recertification	Not to implement the proposal, but instead to undertake further work	N/A
011	Raw Meter Data and Compensation Factors	Implement the proposal without change	1 February 2021
012	Monitoring of Event Logs	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
013	Raw Meter Data Output Test	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
014	HHR Certification and Interrogation Cycles	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
015	Comparative Recertification	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
016	Error Calculations at Certification	Not to implement the proposal, but instead to undertake further work	N/A
017	Application of Error Compensation	Implement the proposal without change	1 February 2021
018	Certification Validity Periods	Implement the proposal without change	1 February 2021

019	Measuring Transformers and Burdens	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
020	Alternative Certification for POC to the Grid	Implement an amended form of the proposal	1 February 2021
021	Obsolete Sticker Removal	Implement the proposal without change	1 February 2021
022	Inspection Periods	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
023	Combining Certification Stickers	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
024	NSP Decommissioning Timeframes	Implement the proposal without change	1 February 2021
025	MEP updates of HHR/NHH and AMI flags	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
026	Excluding non-market-related meter registers	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
027	Meter Resealing by Traders	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021
028	Meter Bridging	Implement the proposal with no change to its policy intent, but with revised Code drafting	1 February 2021

Source: Electricity Authority

1.6 The primary economic benefit of our decision to proceed with most of the Code amendment proposals is a reduction in transaction costs across the industry, which is a productive efficiency benefit. In addition, by improving the clarity and operation of the Code, we expect our decisions may 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 our statutory objective and provide both static and dynamic efficiency benefits to the economy, for the long term benefit of consumers.[2]

[2] 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,

We considered 14 submissions before making our decisions

1.7 We received 14 submissions on the consultation paper. Most submitters made comments on multiple proposals, and all proposals received some comments. We carefully considered each of these submissions before making our decisions. Table 2 lists the parties that made submissions.

1.8 We received three comments on the technical/non-controversial proposals notified to participants. One comment was out of scope of the proposed change, but will be treated as a separate Code amendment request to be included in a future Code change consultation. The other two were comments in support of the proposals.

Table 2: List of submitters

Submitter	Category
Contact Energy Limited	Electricity generator and retailer
Electric Kiwi Limited	Electricity retailer
Financial Corporation Limited	Metering equipment provider
Genesis Energy Limited	Electricity generator and retailer
Meridian Energy Limited and Powershop New Zealand Limited	Electricity generator and retailer
Metrix Limited	Metering equipment provider
Northpower Limited	Electricity distributor
Nova Energy Limited	Electricity generator and retailer
Orion NZ Limited	Electricity distributor
Powerco Limited	Electricity distributor
Transpower NZ Limited	Grid owner and system operator
Unison Networks Limited	Electricity distributor
Vector Limited	Electricity distributor
Wellington Electricity Limited	Electricity distributor

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.

1.9 All submissions are available on our website at: https://www.ea.govt.nz/development/work-programme/operational-efficiencies/market-enhancement-omnibus/consultations/#c17636.

1.10 We found the submissions on the consultation paper of great assistance in our consideration of the matters that we consulted on. We thank submitters for their input.

The remainder of this paper gives the reasons for our decisions

1.11 The remainder of this paper describes each of our decisions and sets out the reasons for them. This includes our responses to key issues raised in submissions.

1.12 Some of our decisions are for an amended form of the proposal. Where there is a change from the proposed Code drafting that was in the consultation paper, that change is indicated in red font.

2 Proposal 001 - Electrically Disconnecting Other Traders' ICPs

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

2.1 We have decided to make the changes set out below.

(a) For problem 1: amend clauses 10.30 and 10.30A to clarify that the types of distributor each clause is referring to are:

(i) local network owners

(ii) embedded network owners.

(b) For problem 2:

(i) replace "reconciliation participant" in clauses 10.33 and 10.33A with "trader"

(ii) create new clauses 10.29B and 10.30B to 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).

(c) For problem 3: 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 electrically connecting the NSP.

(d) For problem 4: amend clause 10.33A as follows: 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 (including direct costs) at that ICP from the day of electrical connection.

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:

(iv) restore the ICP to being "electrically disconnected", using the same method used by the losing trader

(v) reimburse any direct costs of the losing trader.

(e) For problem 5:

(i) 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 for which the distributor or grid owner is responsible

(ii) insert new clause 10.33B into the Code, to expressly prohibit a trader from electrically disconnecting, or physically disconnecting, an ICP for which the trader is not responsible.

2.2 These are the proposals we consulted on, with:

(a) the correction of minor drafting errors

(b) minor drafting changes for clarity in response to submissions

(c) changes to the proposed new provisions in clauses 10.33 and 10.33A from “time” to “date” to account for the registry functionality only working in whole days, and to permit traders to reach mutual agreements for the costs of electricity conveyed

(d) accounting for meter bypass in clause 10.33A(5)(a), when ensuring traders restore a meter to the previous state when a switch does not proceed.

We have decided to revise the proposal following submitters’ feedback

Submitter’s view

2.3 One submitter called attention to minor drafting errors.

Our decision

2.4 We have corrected these drafting errors.

Submitters’ views

2.5 Most submitter comments were regarding problem 4.

2.6 Several submitters raised concerns around the current switching process and the related timeframes. This is due to the fact that the actual reconnection date is often unknown until the return of field paperwork and because generation of files in response to a switch are automated.

Our decision

2.7 Accounting for current industry practice using the current switching framework will give imperfect results due to the nature of fieldwork, which is one of the reasons this practice is not allowed under the current Code. Because participants are engaging in this practice despite the Code not allowing it, we consider it more practical to put protections in place rather than continue to allow non-compliance to continue.

2.8 Gaining traders are given 2 days after connecting an ICP they intend to switch to themselves to receive paperwork from the field. If gaining traders’ contractors are not providing the appropriate lead time to prevent the traders breaching this timeframe, the traders can either revise their contractual arrangements so they meet the timeframes, or not reconnect an ICP until after the switch is complete.

2.9 We recognise that this solution still requires manual communication between traders in many cases, and could require process changes.

2.10 We also agree that it may not always be possible for a gaining trader to accept responsibility for market submissions from the date of the reconnection due to the limitations of the current switching processes. We have added into clauses 10.33 and 10.33A the option for the gaining trader to reimburse the losing trader for the direct costs of the electricity consumed. This permits traders to reach mutual agreements to charge for the electricity consumed or waive cost recovery, and ensures a losing trader is not left out of pocket without the right to seek recompense for the cost of the electricity consumed.

2.11 Future changes as part of the switch process review can introduce further efficiencies to these processes.

Submitter’s view

2.12 Also regarding problem 4, Meridian/Powershop were concerned about the potential “closing out” of options for evolution in the switching process considering the switching process review is still underway, but were not opposed to an interim solution. Genesis proposed amending the transfer switch notification to better allow for backdating switches and reconnections to make the process smoother and easier to automate.

Our decision

2.13 We recognise the switching process review has the potential to make further changes – the suggestion to allow backdating (including the correct switch date) is being considered in that review. It is not our intention for the switching process review to be limited by the changes proposed here. The current changes are intended to:

(a) allow for current industry practice to continue without every instance presenting as a compliance issue, as there is a benefit to ensuring consumers are connected as quickly as possible but

(b) place sensible limits and protections on the process to ensure all electricity is appropriately accounted for and the losing trader is not unduly inconvenienced if a consumer is reconnected in error.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

2.14 Transpower believes the issues in Problem 2 (and 5) have already been addressed in a prior Code amendment which came into force on 1 November 2018. They do not believe clauses 10.29B and 10.29C are required as a result of the prior changes.

Our decision

2.15 There has been some crossover of changes to these clauses between consultations and some changes already accepted, but the changes from "reconciliation participant" to "trader" must still be made. We have revised the Code drafting (as shown below) to ensure the Code amendment reflects the Code as it currently stands.

2.16 We have decided to add clauses 10.29B and 10.29C for completeness to account for all variations of connecting and disconnecting. There were no compliance problems encountered with the lack of either clause, but we have decided to add them to improve clarity, consistency, and readability.

Submitters' views

2.17 Submitters did not have objections to the solutions proposed for problems 1 or 3.

Our decision

2.18 We are implementing these proposals without change.

The amendment will contribute primarily to the efficient operation of the electricity industry

2.19 The Code amendment will promote the efficient operation of the electricity industry by:

(a) reducing transaction costs faced by retailers and consumers when switching electrically disconnected ICPs

(b) ensuring a trader or distributor that electrically disconnects a responsible trader's customer in error will be required under the Code to reconnect the customer. This will 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) clarifying the Code requirements relating to electrical connection and disconnection of points of connection and requiring metering to be operational before electrically connecting. This will make the Code easier to understand and reduce participants', and the Authority's, compliance costs.

2.20 The Code amendment may promote competition, by reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs.

2.21 The Code amendment would promote reliability of supply for consumers by facilitating the timely electrical connection of consumers and because it is expected to reduce the number of times traders electrically disconnect consumers that are not the traders' customers.

2.22 The Code amendment will come into force on 1 February 2021.

The Code amendment

2.23 The Code amendment is as follows:

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**; or~~.~~

(b) in the case of the **electrical connection** ~~**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 15 for the delivery of **submission information** for the **electricity** conveyed at the **point of connection** from the time of **electrical connection**; or~~.~~

(c) in the case of the **electrical connection** of a **local network** that has no **consumers** connected to the **local network** or to any **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), only a **grid owner** may—

(a) **electrically disconnect** a ~~the~~ **point of connection** to the **grid**; or

(b) disconnect a ~~the~~ **point of connection** to the **grid**~~; or~~.

(2) A **grid owner** may disconnect or **electrically disconnect** ~~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 that initiates the creation of an **NSP** under Part 11 on the owner's **network** and connects the **NSP** under this clause must, within 5 **business days** of connecting ~~an~~ the **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)~~ 1 or more **traders** 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 that trader or those traders have—

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

(~~iii~~ii) ~~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** ~~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), only a **distributor** may, on its **network**—

(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), only a **distributor** may, on its **network**—

(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 **~~reconciliation participant~~** **trader** temporarily **electrically connecting** the **point of connection**; or

(ii) the **~~reconciliation participant~~** **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 ~~**reconciliation participant**~~ **trader** temporarily **electrically connecting** the **point of connection**; or

(ii) the ~~**reconciliation participant**~~ **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~~ date of **electrical connection**; and

(3) accepts responsibility to provide **submission information** under Part 15, or for the losing **trader's** direct costs for the **electricity** conveyed at the **ICP**, from the ~~time~~ date of **electrical connection**; and

(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

(iii) if the **ICP** 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**.

(b) *[Revoked]*

(c) *[Revoked]*

(2) A ~~**reconciliation participant**~~ **trader** described in subclause (1) 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** ~~participant~~ authorised by a **trader** may ~~authorise the~~ **electrically connection** ~~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 ~~**reconciliation participant**~~ **trader** **electrically connecting** the **point of connection** ~~connection~~ to the **grid** that the **grid owner** owns or operates; or

(ii) the ~~reconciliation participant~~ **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 ~~reconciliation participant~~ **trader** **electrically connecting** the **point of connection** to the **network** that the **distributor** owns or operates; or

(ii) the ~~reconciliation participant~~ **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~~ date of **electrical connection**; and

(3) accepts responsibility to provide **submission information** in accordance with Part 15 of this Code, or for the losing **trader's** direct costs for the **electricity** conveyed at the **ICP** from the ~~time~~ date of **electrical connection**; and

(ii~~i~~) 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

(iii~~v~~) if the **ICP** 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) [*Revoked*]

(c) [*Revoked*]

(d) ~~if a~~ the **point of connection** supplies **electricity** ~~electricity~~ to a load that is assigned to multiple **ICPs** ~~ICPs~~ as **shared unmetered load**, and 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 ~~**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**~~:~~; or

(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** ~~electrically connect~~ or authorise the **electrical connection** of a **point of connection** in ~~either~~ 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~~ described in subclause (1)(a)(i)(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** in the circumstances ~~as~~ described in subclauses (1)~~, (2)~~ to (3)~~:~~; or

(b) a **distributor** in the circumstances ~~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—**

(i) ~~to~~ using the same method of **electrical disconnection** as the losing **trader** used; or

(ii) by, if the method of **electrical connection** was bypass, removing the bypass; 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 an ~~the~~ **ICP** or is meeting its obligation under clause 10.33A(5)(a) in respect of an ~~the~~ **ICP**, the **trader** must not—

(a) **electrically disconnect** the ~~an~~ **ICP**; or

(b) disconnect the ~~an~~ **ICP**; or

(c) authorise a **metering equipment provider**—

(i) to **electrically disconnect** the **ICP**; or

(ii) to disconnect the **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**.~~

3 Proposal 002 - Prohibition of Net Metering

We have decided to implement an amended form of the proposal

3.1 We have decided to amend the Code so that imported and exported electricity are separately metered and recorded for each phase at an ICP with a category 1 or 2 metering installation, thereby prohibiting net metering by prescribing how the MEP must meter export-capable ICPs.

3.2 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.

3.3 The proviso is that any such aggregation must not combine import and export amounts.

3.4 This is the proposal we consulted on, but limited to categories 1 and 2 instead of being applicable for all metering installations.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

3.5 In one submitter's view, they did not agree with the Authority's definition of net metering as it did not reference the time the electricity is consumed. They also felt the issue was incorrectly conflated with phasing on a metering installation.

3.6 Two submitters also advised that in some situations, metering by phase could result in less accuracy than aggregating the consumption within the meter.

Our decision

3.7 Although we do not believe the Wikipedia definition of net metering is the complete definition of the type of metering we are concerned with, we agree that the use of the words 'net metering' may cause confusion, especially in some unusual and technical situations. Therefore we will not use the term 'net metering' in the Code wording. However, for convenience, we will use the term 'net metering' in our guidelines and discussion documents, including this decision document, to describe instances under which subtracting recorded imported quantities from recorded exported quantities (both across phases and/or across time) would cause costs to be inaccurately reflected to customers.

3.8 We agree that we could have more strongly linked time and consumption in our initial definition, however, the submitter is correct that it is our intent to ensure imported quantities are separately recorded from exported quantities (both across phases and/or across time). The purpose of disallowing net metering is to ensure that customers pay for what they use when they use it, and generators get paid when they generate.

3.9 Other concerns raised by two submitters regarding accuracy have been raised in the past, including in Authority compliance investigations. In the cases of rarer technical situations occurring on category 1 and 2 sites, clause 10.13 still applies, and more appropriate metering must be installed to ensure an installation is accurate. Additionally, clause 10.43 contains an overarching requirement for MEPs to investigate any metering installation that is defective, inaccurate, or not fit for purpose.

We have decided to revise the proposal following submitters' feedback

Submitter's view

3.10 Two submitters advised that for category 3 metering sites and above, this proposal is not appropriate and could require reconfiguration of existing metering at significant cost with no benefit to accuracy. One submitter asserts they have not seen meters that "net" import and export into one figure.

Our decision

3.11 We have decided to amend the proposal so there are different provisions for category 1 and 2 metering installations, and category 3 and above metering installations.

3.12 The Authority has likewise not seen examples of meters which function by "netting off" generation from consumption for some time and believes in general that the industry is aware of, and has been complying with, the policy intent. The Code already prohibits traders from using subtraction to determine submission information in clauses 10.24 and 4(2)(a) of Schedule 10.7 – this proposal was simply intended to make the separate metering requirements for import and export quantities absolutely explicit. We agree that the proposal as written could have the unintended consequence of introducing significant costs to higher category metering installations with no corresponding benefits to accuracy, and have changed it accordingly.

3.13 To ensure that the amended wording is not interpreted as permitting net metering for category 3 and higher, we have limited the main clause to category 1 and 2 metering installations, and we have included a more general requirement category 3 and above.

The amendment will contribute primarily to the efficient operation of the electricity industry

3.14 The Code amendment will promote the efficient operation of the electricity industry by ensuring 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, removing unnecessary compliance costs for distributors in reporting breaches of clause 8 of Schedule 11.1, and for the Authority in processing such breaches.

3.15 The Code 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.

3.16 The Code amendment will come into force on 1 February 2021.

The Code amendment

3.17 The Code amendment is as follows:

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~~ a **category 1 metering installation** or **category 2 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) A **metering equipment provider** for a category 3 or higher **metering installation** must ensure that the **metering installation** measures and records the imported **electricity** separately from the exported **electricity**.

(~~2~~3) Despite subclauses (1) and (2), if the **metering installation** contains multiple phases, the **metering equipment provider** for the **metering installation**—

(a) may aggregate together—

(i) the amounts of imported **electricity** recorded on different phases; or

(ii~~b~~) ~~may aggregate together~~ the amounts of exported **electricity** recorded on different phases; but

(b~~c~~) must not aggregate together imported and exported **electricity**.

4 Proposal 003 – Recovering Certification Costs

We have decided to implement an amended form of the proposal

4.1 We have decided to amend clause 10.22 of the Code so that, should the MEP at a metering installation change:

(a) if the gaining MEP retains and uses any of the metering components (including retaining and using an entire metering installation) without recertification for more than three business days after the MEP change event date, the gaining MEP must pay the losing MEP the certification and 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 components (including retaining and using an entire metering installation) within three business days after the MEP change event date, they are not required to pay to the losing MEP the certification and calibration costs for those components

(c) if the gaining MEP removes from use or recertifies any components later than three business days after the MEP change event date, the gaining MEP must still pay the losing MEP's certification and calibration costs for those components, prorated for the remainder of the certification validity period, despite the component being later removed or recertified

(d) the losing MEP must advise the gaining MEP in writing within 2 months (40 business days) of the MEP change event date to activate the provisions in this clause. The losing MEP may choose to make other contractual arrangements with the gaining MEP, or simply not to pursue the gaining MEP for costs.

4.2 This is the proposal we consulted on, with the addition of (d) above, based on submitter feedback to allow MEPs to manage risks commercially instead of via Code mechanisms. We have also made very minor drafting changes for clarity.

We have decided to revise the proposal following submitters' feedback

Submitter's view

4.3 In its submission, Contact suggested that currently there are other ways to recover these costs, including contractual relationships between MEPs and MEOs.

4.4 The Authority considers this possibility was always an available option. The Code does not prevent participants from entering into agreements that confer benefits over what is mandated in the Code to recover costs due to equipment displacement or takeover of responsibilities. The Authority considers clause 10.22 should be treated as a safety net, and if participants wish to come to other commercial arrangements that are more beneficial to them in some way, they should be able to do so without a technical breach of clause 10.22.

Our decision

4.5 We agree that the proposal should be amended to make it clear the requirement to pay costs is optional at the discretion of the losing MEP, and to clarify the circumstances in which the requirement applies.

4.6 The Authority agrees with other submitters that:

(a) the proposal could leave losing MEPs significantly out of pocket if a gaining MEP should displace a losing MEP's newly-recertified assets within the 3-day timeframe. In this case, the gaining MEP would not be liable to pay costs to the losing MEP

(b) in many cases, retailers are driving the MEP changes and related displacements.

4.7 The current arrangements that allow for a competitive market for MEPs also creates a risk of displacement, which MEPs should build into their business models in some way. This could include passing costs of displacement, and reimbursement of losing MEPs, on to retailers requesting displacement. Likewise, retailers have the freedom to make the commercial decision to retain an existing MEP and not to displace the metering installation or components (or to displace it within the three day window), should they not wish to shoulder the additional costs of displacement and/or pass them on to consumers.

4.8 The intent of this clause is to create an incentive for gaining MEPs (and, by proxy, the retailers behind them) to come to a timely resolution regarding whether to retain on-site assets in the case of an MEP change, as well as mitigate some of the risk to the losing MEPs. This risk has always been mitigated through this clause, but these changes make it clearer.

4.9 The intent of this clause is not to discourage MEP switching or displacement of assets. The proposal also purposefully does not consider ownership of assets, as:

(a) costs incurred by MEOs when calibrating their own metering components are already generally passed on to MEPs or retailers directly. If the MEO passes calibration costs on to the gaining MEP (pro-rated across the life of the calibration) as part of its charges there is no loss incurred by the losing MEP to recover under clause 10.22

(b) MEOs can recover assets that are no longer in use or satisfying contractual arrangements

(c) the MEO could recover the physical asset costs if it installs the asset at another site.

4.10 The Authority also notes that MEPs generally to not have contracts with each other, but there are no Code provisions preventing this. Therefore, this clause is intended to be a safety net and should allow participants to make contractual arrangements that are more suitable, should they choose.

We have decided against making an additional change suggested by a submitter

4.11 One submitter proposed a 10-day window in which to manage exceptions before the reimbursement of a losing MEP would apply. The Authority considers 10 business days would unnecessarily increase the costs to the losing MEP (and, in aggregate, the market) in cases of displacement. A gaining MEP will have advance notice of an MEP switch either through the registry process or through prior arrangements with the retailer, and traders should be arranging access with the customer prior to proposing the MEP change. A short window encourages the gaining MEP to make a decision about its continued use of the losing MEP's metering components to the benefit of all parties.

The amendment will promote the efficient operation of the electricity industry

4.12 The Code amendment will promote the efficient operation of the electricity industry by:

(a) encouraging timely MEP decision making

(b) providing an unambiguous mechanism for cost recovery for losing MEPs

(c) removing unnecessary compliance costs for technical breaches of clause 10.22, and for the Authority in processing such breaches, where MEPs do not want to pursue other MEPs for recoverable costs.

4.13 The Code amendment will come into force on 1 February 2021.

The Code amendment

10.22 Change of metering equipment provider

…

(1A) The **losing metering equipment provider** must within 40 **business days** of the **gaining metering equipment provider** assuming responsibility for a **metering installation**:

(a) calculate any proportion of costs described in subclause (3) and subclause (4); and

(b) notify the **gaining metering equipment provider** in writing of those costs.

(1B) The **losing metering equipment provider** does not need to comply with subclause (1A) if the **losing metering equipment provider** does not wish to charge the **gaining metering equipment provider** a proportion of costs

(1C) If the **losing metering equipment provider** does not carry out the calculation and notify the **gaining metering equipment provider** under subclause 1(A) within the time frame in that subclause, the gaining metering equipment provider does not need to comply with subclause (2).

(2) The **gaining metering equipment provider** must, within 20 **business days** of ~~assuming responsibility for a **metering installation**~~receiving a notice provided under subclause (1A), 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 metering 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** in a **metering installation** 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) **recertifies** the **metering component**; and~~.~~

(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) **recertifies** the **metering installation**:

(c) the costs for a **metering component** must be prorated for ~~the longer of—~~

~~(i) the remainder of the **certification** validity period for the **metering installation**; and~~

~~(ii)~~ the remainder of the **certification** validity period for the **metering component**~~.~~; and

(d) the costs for a **metering installation** are the sum of the prorated costs payable under this clause for each **metering component** in the **metering installation**.

(5) Despite subclause (2), a **gaining metering equipment provider** is not required to pay the costs if—

(a) it has agreed in writing with the **losing metering equipment provider** that the **gaining metering equipment provider** is not required to pay costs under this clause; or

(b) the **losing metering equipment provider** has failed to provide notice of the costs to the **gaining metering equipment provider** in accordance with subclause (1A).

5 Proposal 004: Distributor NSP Information Notifications to Reconciliation Manager

We have decided to implement the proposal without change

5.1 We have decided to amend clause 10.25(2) 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.

5.2 This would make the timeframe for providing this information consistent between clause 10.25(2) and clause 10.30. The current Code's first timeframe is no later than 20 business days after a metering installation at the NSP is certified, and the second is within five business days of connecting an NSP.

5.3 Please note the original proposal advised the Authority was going to amend 10.25(3), however this was in error and we did not propose any changes to this clause in the consultation paper. Clause 10.25(3) deals with recertification and is not in conflict with 10.30, which deals with new connections.

5.4 This is the proposal we consulted on.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

5.5 Only one submission was received, and the submitter agreed with the proposal without any comments.

The amendment will promote the efficient operation of the electricity industry

5.6 The Code amendment will promote the efficient operation of the electricity industry by making it easier for distributors to understand their obligations to update metering information about NSPs.

5.7 The Code amendment will come into force on 1 February 2021.

The Code amendment

5.8 The Code amendment is as follows:

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**.

…

6 Proposal 005 - Like-for-Like Replacements and Consultation

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

6.1 We have decided 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 the certification of the metering installation will still be cancelled if clause 19 applies

(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).

6.2 This is the proposal we consulted on with minor drafting modifications for clarity.

We have decided to revise the proposal following submitters' feedback

Submitter's view

6.3 Three of the four submitters on this proposal supported the proposal without changes. Intellihub does not believe distributors should dictate to MEPs when certification should be cancelled.

Our decision

6.4 Clause 19 of Schedule 10.7 specifies when certification is cancelled due to modification – the distributor does not have any discretion as to when this applies. However, we consider the proposed wording of clause 10.34(2B) may be confusing and have amended it to be clear that this clause is meant to be a clarifying clause and does not place any new obligations on participants.

6.5 Changing metering components, including a like-for-like replacement, as detailed in clause 19 of Schedule 10.7, constitutes a modification and the site must be recertified according to the Code, unless one of the exceptions in this clause applies. The distributor and MEP agreeing on the design is not one of these exceptions, and does not override the need to recertify after a modification.

The amendment will promote the efficient operation of the electricity industry

6.6 The Code amendment will promote the efficient operation of the electricity industry 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.

6.7 The Code amendment will come into force on 1 February 2021.

The Code amendment

6.8 The Code amendment is as follows:

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**~~.~~; or

(c) ~~subject to subclause (2B),~~ finalising or modifying the design of a **metering installation** when 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) In addition to subclause (2), any consultation carried out under subclause (2), and any agreement that may be reached in that consultation, does not affect the application of clause 19 of Schedule 10.7~~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—~~

(i) a **metering component** or **metering installation** ~~or another **metering component** or **metering installation** with~~ that has the same or similar design and functionality as the replacement **metering component** or **metering installation**; or

(ii) the new **metering installation**; or

(b) the **trader**, if the **metering equipment provider** has already consulted with the **trader** on the design of ~~the—~~

(i) a **metering component** or **metering installation** ~~or another **metering component** or **metering installation** with~~ that has the same or similar design and functionality as the replacement **metering component** or **metering installation**; or

(ii) a new **metering installation**~~;~~.

(2D) To avoid doubt, subclause (2C) is intended to permit a **metering equipment provider** to re-use the design of a **metering component** or **metering installation**, if—

(a) the **metering equipment provider** has already consulted the **distributor** and **trader** in accordance with subclause (2); and

(b) the **metering equipment provider** will re-use the design of a **metering component** or **metering installation**:

(i) on the **distributor's network**; and

(ii) at an **ICP** for which the **trader** is responsible.

…

Schedule 10.7

…

19 Modification of metering installations

…

(2) For the purposes of this Part ~~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**:

(ba) replacing a **metering installation** with a new **metering installation**:

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

…

(2~~C~~B) To avoid doubt, ~~The~~ replac~~menting~~ing a **metering component** or a **metering installation** is a modification of a **metering installation** under subclause (2) ~~even if~~ including when—

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

(b) the **metering equipment provider** did not need to consult with a **distributor** or **trader** because ~~has complied with~~ clause 10.34(2C) applied.

…

7 Proposal 006: Metering Issue Resolution Timing

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

7.1 We have decided to:

(a) For problem 1: amend the Code to add a new clause to require an MEP to use its best endeavours to resolve a metering issue within 10 days. This has been modified from the originally proposed 25-day timeframe but the rest of the proposal remains the same.

(b) For problem 2: amend the heading of 10.47 so it more accurately reflects the contents of the clause. This is the proposal we consulted on.

We have decided to revise the proposal following submitters' feedback

Submitter's view

7.2 Several submitters advised that, in combination with the time period allowed for MEPs to investigate and report on a metering issue, the combined time period for complete resolution could be up to 45 business days from notification to the MEP (for category 1 installations – less for categories 2 to 5).

7.3 This length of time has the potential to significantly disrupt both customer billing and market settlement. According to Electric Kiwi, it could result in an "extremely negative customer experience" for their customers.

Our decision

7.4 We considered the feedback from participants and agreed that the proposed timeframes could significantly disadvantage both consumers and market settlement. Many MEPs are able to find and correct metering issues in the investigations phase and do not require any more time.

7.5 Retailers already have an incentive to work with consumers to resolve any issues and ensure they are receiving accurate data, and consumers have contractual agreements with their retailers to provide reasonable access to metering installations.

7.6 Should the consumer prove to be a barrier to access and hinder the MEPs investigation or remediation, the Authority expects there would be appropriate documentation of on the actions the MEP has taken to prove the MEP has satisfied the "best endeavours" requirement of clause 10.46A(2)(b).

7.7 As such, we have changed the proposed 25 business days to 10 business days, which gives an MEP under normal circumstances a total of 30 business days to address (investigate, report, and correct) any metering issues for category 1 sites, 20 days for category 2, and 15 days for category 3 and higher. This will help to minimise uncertainty for customers, retailers, and the reconciliation process. Many retailers have commercial arrangements with MEPs that are shorter than this timeframe, so we consider this sufficient time to address any issues.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

7.8 Contact recommended that the proposed amendments include provisions to improve half hour volume information accuracy. They assert that MEPs are being advised of mismatched data and, if they believe the metrology of the meter is not compromised, are not appropriately incentivised to investigate further. They also noted there was no acceptable threshold for data discrepancies within the Code.

Our decision

7.9 Placing a threshold in the Code for the interval vs consumption data validation check is out of scope of the proposal and would require further consultation. The Authority thinks this should be discussed by the industry and will add it to a future Code review project. Any threshold should only account for errors in rounding or similar, as other errors indicate potentially inaccurate metering and must be investigated.

7.10 The Code does not go into detail regarding metering data validation specifically, as any event that causes a participant to believe the metering is inaccurate, defective, or not fit for purpose activates clause 10.43. This is deliberate to help ensure the Code captures all types of issues and remains current as the industry evolves. If interval data vs midnight reads show significant discrepancies, the retailer must advise the MEP of the problem, and the MEP is then required to report their investigation, conclusion, and reasoning to affected participants. Should that report not demonstrate that the metering installation operates within the acceptable error tolerance in accordance with Table 1 of Schedule 10.1, the metering is considered inaccurate and 10.44 then applies and the MEP must take further action.

7.11 The new clause proposed sets timelines for MEPs to take remedial action on installations found to be not fit for purpose. It is envisaged that this will further incentivise MEPs to quickly resolve metering issues. A data feed discrepancy is covered by 10.43(3)(a), as it constitutes an instance of "an event or circumstance that leads it to believe the metering installation is or could be inaccurate, defective, or not fit for purpose."

7.12 If MEPs are not appropriately reporting their findings to affected participants, and if the retailer is aware this is not happening, they should allege a breach against the MEP under this clause.

Other considerations from submissions

7.13 Two submitters requested that the Authority clarify "best endeavours" either with guidelines or other guidance. We will provide appropriate guidance on what the Authority considers to constitute 'best endeavours' by participants.

The amendment will promote the efficient operation of the electricity industry

7.14 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.

7.15 It would do this by promoting the timely resolution of metering issues, thereby minimising:

a) adverse effects on customers

b) unaccounted for electricity in the wholesale electricity market.

7.16 The first proposed Code amendment is expected to have no effect on competition or reliability of supply.

7.17 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.

7.18 This second proposed Code amendment would have no effect on competition or reliability of supply.

7.19 The Code amendment will come into force on 1 February 2021.

The Code amendment

7.20 The Code amendment is as follows:

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; and~~.~~

(ii) not defective~~.~~; and

(iii) fit for purpose~~;~~: and

(b) must use its best endeavours to complete the remedial action under paragraph (a) no later than ~~25~~10 **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.

8 Proposal 007: Minimum Voltage Requirements

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

8.1 We have decided to amend Table 1 of Schedule 10.1 to include a voltage transformer in the defining characteristics of category 2, 3, and 4 metering installations at sites with a voltage under 1kV.

8.2 This is the proposal we consulted on, with the addition of the possibility of voltage transformers on category 2 metering.

We have decided to revise the proposal following submitters' feedback

Submitter's view

8.3 Accucal have advised us they agree with the solution, but that it needs to include category 2 sites as well as 3 and 4. They have encountered the stated combination for category 2 in the field.

Our decision

8.4 We have further revised the chart to account for this combination of equipment. The purpose of this amendment is to include all existing metering installations in the application of the existing Code framework. Omitting voltage transformers from the table where some exist in the field means the Code does not accurately reflect the situation in the market.

The amendment will promote the efficient operation of the electricity industry

8.5 The Code amendment will promote the efficient operation of the electricity industry by clarifying the Code requirements for category 2, category 3 and category 4 metering installations at sites with a voltage of under 1kV.

8.6 The Code amendment will come into force on 1 February 2021.

The Code amendment

8.7 The Code amendment is as follows:

NB: Table 1 is also amended under Proposals 018 and 022. The changes shown here are only those from this proposal. We will amalgamate the changes from the three proposals in the final 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 and where applicable, VT	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~~	N/A ~~N/A~~			
	1kV ≤ V ≤ 11kV	I ≤ 100A									
	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									

9 Proposal 008: Prevailing Load Checks

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

9.1 We have decided to amend Table 3 of Schedule 10.1 as follows:

(a) to show prevailing load tests <u>are not required</u> for the recertification of a category 1 metering installation, when:

(i) all meters at the metering installation are replaced; or

(ii) one or more meters at the metering installation are replaced and each such meter is replaced with a certified meter, but at least one existing meter is not replaced and the expiry date of the certification for the metering installation is not changed

(b) to show prevailing load tests <u>are required</u> for the recertification of a category 1 metering installation when:

(i) one or more meters at the metering installation are replaced and each such meter is replaced with a certified meter, but at least one existing meter is not replaced and the expiry date of the certification for the metering installation is changed

(c) to require a control device check to be undertaken for metering installations of categories 1-3

(d) to require a component certification check when a control device is replaced at any category of metering installation

(e) 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 the meter

(f) to require a data storage device test when a category 3 metering installation is:

(i) initially certified; or

(ii) recertified

(g) to require an installation or component configuration test when additional equipment is added to any category of metering installation

(h) to remove the following columns, which are unnecessary:

(i) “Measuring transformer”

(ii) “Meter”

(iii) “Primary injection to meter”.

(i) to restructure Table 3 to group rows by metering installation category, and to clarify the row headings.

9.2 This is the proposal we consulted on with minor drafting modifications to address some minor issues raised by submitters.

We have decided to revise the proposal following submitters' feedback

Submitter's view

9.3 Transpower called attention to a drafting omission that did not have the installation or component configuration check or component certification check for a measuring transformer change or ratio change as a mandatory check.

Our decision

9.4 We agree this was in error, and have amended the table to make this check mandatory in those circumstances.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

9.5 FCLM believes that more definitions should be added to Part 1 of the Code to support the meaning of the checks in the table.

9.6 FCLM also considers that having a battery in a data storage device does not ensure the data will be retained.

Our decision

9.7 Adding definitions to Part 1 is not necessary to proceed with this proposal. The checks are generally understood by the industry and ATHs.

9.8 Regarding the battery, we agree that simply having a battery does not provide certainty that the data will not be lost, however a battery that is not working properly guarantees data loss. We consider checking that the battery is functional is a sensible measure.

Submitter's view

9.9 Accucal disagreed with the Authority's problem definition, as a prevailing load test is not a test of the accuracy of an electricity meter.

Our decision

9.10 We agree that a prevailing load test is not a full accuracy/calibration test, this was an error in our wording of the problem definition. It is a sense check that the metering installation and its components have been installed correctly and are working correctly at the load being conveyed at the time of the test. The use of a working standard for the test does ensure the results can be relied on.

Submitter's view

9.11 Metrix agrees with most of the changes, with the exception of the proposed changes to row 4 of Table 3, which suggests that certification expiry can be extended, including for pre-existing meters. Metrix would like more information in relation to this issue, to confirm that an unchanged meter could remain fit-for-purpose for a further 15-year period just by performing a prevailing load test.

Our decision

9.12 Row 4 does provide for extending the certification expiry date for the entire installation, including for "pre-existing" meters that were already installed at the metering installation at the time of recertification. This is deliberate. However, all the requirements for certification of a metering installation must be completed. This means all the appropriate tests must be carried out and all the pre-existing meters must be certified under Schedule 10.8. In effect, extending the certification is recertifying each component for the new validity period, and this is only possible if the calibration will remain current throughout that new period. Metrix is correct in that simply carrying out a prevailing load test is not enough to recertify the metering installation. Although recertifying pre-existing meters is possible, an MEP may decide not to do this and to change all meters.

Submitter's view

9.13 Intellihub had two drafting suggestions as it did not agree a prevailing load test is required when meters are not being replaced, i.e. when bridging. Intellihub suggested:

(a) row 2 needs to be split to differentiate between recertification with a new installation expiry date and recertification with an existing installation expiry date

(b) row 6 may need to reference burden changes, since a burden resistor change is a "modification" to the metering installation.

Our decision

9.14 We note the first drafting suggestion, however we believe that when recertifying, there needs to be some overarching check that the metering installation is still working correctly. A prevailing load test coupled with the raw meter data output check performs this function.

9.15 Regarding burden resistors – if a meter is changed, row 5 applies, if the burden is changed without changing the meter (adding/removing resistors and/or wiring) then it's a modification and recertification is required, so row 5 still applies. For clarity, row 5 applies for category 2 or 3 metering installations for:

- initial certification
- recertification
- meter change including internal data storage devices.

The amendment will promote the efficient operation of the electricity industry

9.16 The Code amendment will promote the efficient operation of the electricity industry by clarifying the obligations set out in Table 3 of Schedule 10.1, which will:

(a) make it easier for participants to understand the testing requirements for metering components

(b) help ensure the appropriate tests are performed, in order to have accurate metering installations.

9.17 The Code amendment will come into force on 1 February 2021.

The Code amendment

The Code amendment is as follows:

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

	Event	Design check	~~Measuring transformer~~	~~Meter~~	~~Primary injection to meter~~	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 ~~category 1~~, or recertification with all meters replaced	M						M	MI	M	M	M	M	M	M	M
	Recertification ~~of category 1 if the meter is not replaced and recertification of categories 2 and 3~~ with no meters replaced	M				M		M	MI	M	M	M	M	M	M	M
	Recertification ~~category 1 where meter is~~ 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 (which must have calibration that is valid for the new certification period), and metering installation expiry date is changed ~~**meters that remain must have calibration that is valid for the new certification period~~	M				M		M	MI	M	M	M	M	M	M	M
Categories 2 – 3	Initial certification ~~categories 2 and 3~~, recertification, or meter change including internal data storage devices	M		~~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	M	M	M

	Event	Design check	~~Measuring transformer~~	~~Meter~~	~~Primary injection to meter~~	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
~~Component change or recertification~~ ~~All categories~~ Categories 1-3	~~Meter change including internal data storage devices~~	~~M~~		~~M~~		~~M~~	~~M~~	~~M~~		~~M~~		~~M~~	~~M~~	~~M~~	~~M~~	~~M~~
	Metrology software change either onsite or remote	M		~~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.

10 Proposal 009: ISO 9001 Sync with Class B ATH Application Period

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

10.1 We have decided amend clause 4 of Schedule 10.3 to:

(a) remove the requirement for a class B ATH to hold ISO 9001 certification for the full term of its approval by the Authority

(b) 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.

10.2 Additionally, we have decided to remove the reference to the ISO 9001:2008 standard that has been superseded.

10.3 This is the proposal we consulted on, with one additional change, being the deletion of references to the obsolete standard.

We have decided to revise the proposal following submitters' feedback

Submitter's view

10.4 All four submitters agreed with the proposal. One submitter noted that the ISO 9001:2008 standard is no longer applicable and reference to it should be removed.

Our decision

10.5 The Authority agrees with removing the reference to the obsolete standard and will otherwise implement the proposal as consulted on.

The amendment will promote the efficient operation of the electricity industry

10.6 The Code amendment will promote the efficient operation of the electricity industry 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.

10.7 The Code amendment will come into force on 1 February 2021.

The Code amendment

10.8 The Code amendment is as follows:

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.

11 Proposal 010: Selected Component Recertification

We have decided not to proceed with implementing the proposal

11.1 The original intent of this proposal was to simplify the error and uncertainty calculation process for ATHs to recertify lower category metering installations.

11.2 It was proposed that ATHs could be allowed to use a default instrument uncertainty value when using a working standard to calculate the uncertainty of measurement associated with calibrating a metering component.

We have decided not to proceed with the proposal following submitters' feedback

Submitters' view

11.3 Several submitters expressed the view that the proposal would not result in an efficiency benefit, as ATHs would still need to perform calculations, just with default values instead of the actual instrument uncertainty values.

11.4 Submitters also advised that it is preferable to know and take into account the actual uncertainty and error, and that the calculation of the actual uncertainty is not too onerous or costly.

Our decision

11.5 The Authority agrees with submitters and considers the submissions demonstrate that the proposed Code amendment would not achieve the original intent of simplifying the recertification process. The Authority would still like to consider a simplified process for calculating error and uncertainty, however a new proposal will need to be drafted and considered at a later date.

We intend to consider this matter in a future project

11.6 We consider there may be efficiency gains sufficient to justify implementing a simplified calculation process, and intend to include a proposal in a future Code Review Programme.

12 Proposal 011: Raw Meter Data and Compensation Factors

We have decided to implement the proposal without change

12.1 We have decided to amend several clauses to clarify the Code obligations to apply compensation factors to raw meter data. The new clauses expand the definition of compensation factor to clarify that it may mean more than one type of compensation, and that the registry should contain the mathematical product of all of the applicable compensation factors that need to be applied externally if more than one type is required.

12.2 The new clause 8(10) of Schedule 10.6 clarifies that the obligation to apply the compensation factor does not rest with the MEP.

12.3 This is the proposal we consulted on.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

12.4 Five out of six submitters were in support of the proposal, largely without comment. Meridian/Powershop and Trustpower would like to understand the extent to which data inaccuracies may have arisen and whether remedial actions may be required.

Our decision

12.5 We consider the current proposal sufficient to address the identified issues. From time to time we have been advised of instances where errors have been made, but as there is no requirement for an MEP or trader to notify us we do not keep records of these issues. We expect that when errors are discovered the MEP and trader will work together to ensure the error is corrected and appropriate wash-ups submitted to the reconciliation manager.

We have decided against making a change suggested by a submitter

Submitter's view

12.6 Transpower believes the compensation factor should be applied in the meter, and where this is not possible, the compensation factor should be applied at the first download. They believe this would create consistency, as all data would be scaled primary values as soon as possible.

Our decision

12.7 We agree that it is beneficial to apply the compensation factor internally within the meter so that the raw meter data is already compensated, however not all meters are able to have this done, and for mass market installations the sheer volume of installations means bespoke meter programming for individual metering installations may be prone to error. Therefore it is up to the MEP to decide how the compensation factor will be accounted for, and to ensure the registry contains the actual factor the trader must apply to the raw meter data.

12.8 The Authority's proposal creates sufficient industry consistency to ensure the compensation factor is applied accurately, by always making it the responsibility of the trader. The suggestion to apply the factor at first download would actually create inconsistency, as there would be different entities responsible depending on the type of metering. Applying the factor at first download for AMI meters would be the MEP's responsibility, for traditional commercial and industrial (C&I) meters the responsibility would be on the data administrator as an agent of the trader, and for legacy metering that is manually read the responsibility would be on the meter reader as an agent of the trader.

The amendment will contribute primarily to the efficient operation of the electricity industry

12.9 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) 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.

12.10 The Code amendment will come into force on 1 February 2021.

The Code amendment

12.11 The Code amendment is as follows:

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**.

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 Table 1 of Schedule~~ Part~~ 11.4.

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**
…				
The following details for each **metering component** in the **metering installation** for each **ICP** …				
19	**registry compensation factor**	the mathematical product of all **compensation factors**~~,~~ that ~~which in the case of a complex **compensation factor**, must be obtained from **equipment provider**~~ the **trader** must apply to transform the **raw meter data** into **volume information**	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.**

13 Proposal 012: Monitoring of Event Logs

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

13.1 We have decided to amend clause 8 of Schedule 10.6 and clause 17 of Schedule 15.2 to clarify participants' existing obligations under the Code regarding responsibility for monitoring event logs.

13.2 In short, the MEP is responsible for reviewing event logs for events that may affect the integrity of the metering installation (eg covers removed, loose connections, time synchronisation errors), investigating and remediating issues found, and informing the reconciliation participant where appropriate.

13.3 The reconciliation participant is responsible for reviewing event logs for events that may affect the accuracy of the metering data and for investigating and remediating any event that the MEP is not investigating, to ensure they use the correct data for submitting electricity volumes to the reconciliation manager.

13.4 This is the proposal we consulted on with a minor drafting change to reflect a participant's submission and other very minor drafting changes for clarity.

We have decided to revise the proposal following submitters' feedback

Submitter's view

13.5 Metrix agrees with the allocation of responsibility and would like to see the trader responsibilities altered to indicate that the trader should not necessarily have to refer to the full event log; in the event where MEPs pass relevant events to the retailer, this should be sufficient.

13.6 They suggest that the wording under Schedule 15.2 Clause 17 (4)(f) refers to the "event log OR relevant events passed through by the MEP in accordance with Schedule 10.6 Clause 8 (5A)".

Our decision

13.7 We have decided to make a change to the proposed drafting of clause 17 of Schedule 15.2 to reflect the trader's responsibility as suggested.

13.8 We agree that an MEP may review the event logs and pass on the relevant notifications to the reconciliation participant. However, the responsibility remains with the reconciliation participant to check the event log. If the MEP does this on the reconciliation participant's behalf and passes relevant events on, then this is part of the contracted service and the MEP is acting as an agent.

13.9 We agree that clause 17 of Schedule 15.2 needs to take account of events passed through by the MEP, but this should be the trigger for initiating action by the reconciliation participant, not a replacement for the checking of event logs.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

13.10 Contact believes that distributors should be included in the proposal so they are obligated to respond to power quality events that are identified by the meter logs.

Our decision

13.11 Power quality issues are between the distributors and retailers, and managed by the use of system agreement and electricity safety regulations. We consider this out of scope of the proposed change. The Authority welcomes any new proposed Code amendments that might address issues outside of these existing areas of responsibility.

Submitter's view

13.12 One submitter believes the sole responsibility for ensuring event logs are addressed should be with the reconciliation participant, as they are best placed to decide if investigation and remediation is required. They assert that investigating event log indications of malfunctioning or tampering will increase costs to MEPs.

13.13 Another submitter proposed the opposite; retailers are not equipped to review event logs for the data they receive and all responsibilities should sit with the MEPs.

Our decision

13.14 MEPs have the responsibility to provide accurate metering. Reconciliation participants have the responsibility to submit accurate data to the reconciliation manager. Both of these require appropriate review of situations which may affect each respective entity's ability to comply with its responsibility.

13.15 Additionally, the policy intent behind the wording is the same as before the proposed changes – which only clarify the responsibility, and do not add additional ones. MEPs and retailers alike both have responsibilities under the existing Code to address issues relevant to their responsibility raised by the event log to ensure metering installations are accurate and that this accurate data is then passed on to reconcile the market.

The amendment will promote the efficient operation of the electricity industry

13.16 The Code amendment will promote the efficient operation of the electricity industry by making it easier for MEPs and reconciliation participants to understand their respective obligations to review metering event logs.

13.17 The Code amendment will come into force on 1 February 2021.

The Code amendment

13.18 The Code amendment is 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 evidence of an 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~~5) A **reconciliation participant** must, if it finds an event that could have affected the integrity of the **metering data** or an event is reported to it under clause 8(5A)(d) of Schedule 10.6,~~—~~

(a) investigate and remediate the event if the **metering equipment provider** responsible for the **metering installation** ~~does not have responsibility~~ is not responsible 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**.

14 Proposal 013: Raw Meter Data Output Tests

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

14.1 We have decided 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 for each phase for category 1 metering installations, and at least 10 amps primary current for each phase for category 2.

(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 increment by at least one number or mark 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 a load that is at least double the load of the first test. We have modified the Code drafting to include the words "at least" as we realised the proposed wording would mean the ATH is technically in breach if the second load was not exactly twice the first load.

14.2 This is the proposal we consulted on, with minor modifications to account for technical problems raised by submitters.

We have decided to revise the proposal following submitters' feedback

Submitter's view

14.3 One submitter suggested a different figure than 5% should apply for current transformer (CT) metered installations, where the percentage should relate to the primary CT rating, not the meter rating. The submitter also requested the drafting clarify if the load is per phase or split across all phases.

Our decision

14.4 We agree with this suggestion and have revised the Code wording to include appropriate provisions for each category. 10 amps on category 2 is enough to prove that the meter is actually working, where 5%, while technically possible, is impractical in the field.

14.5 We have also clarified that the load must be applied to each phase. Splitting the load across all phases may reduce the load to the point where the time taken to perform is not practical and the test results are not a good indication that the metering installation is performing as expected.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

14.6 One submitter disagreed with the solution as the way their metering is programmed has the potential to increase their costs. They assert forcing the technicians doing the raw meter data output test in the proposed manner (ie waiting for the least significant digit to increment) would mean it would take an additional 30 minutes to perform tests on site, since the smallest increment for their meters is 1kW, and test loads are 2kW.

Our decision

14.7 Clause 9 of Schedule 10.7 contains minimum standards for some, but not all, of the tests required by Table 3 of Schedule 10.1. To comply with the 'register advance' test (column 15 of Tables 3 and 4 of Schedule 10.1), the ATH must already be waiting for the register to advance. Therefore there should be no incremental costs to the MEP of including a register advance requirement in the minimum requirements for the 'raw meter data output' test. When complying with this proposed requirement the ATH will have completed the 'register advance' test in addition to the 'raw meter data output' test, and so a separate 'register advance' test will not be required (although the ATH may complete an additional test if they want to). For new meters, the MEP has the option to program the meter's register with decimal places, or to program the meter with a register to use for testing to reduce the time (and cost) needed to certify the metering installation.

Submitter's view

14.8 Some submitters believe the current industry practice is well understood, and that additional specificity around methodology or decimal places is unnecessary.

Our decision

14.9 We have been advised that there are at least two different methods of applying this test, and the clause can be interpreted in such a way that both are compliant. The proposal is to clarify the clause so that the minimum standard is clear. The Code does not prevent an ATH from applying a test to a higher standard.

14.10 Additionally, the Authority notes that decimal places in all register types (including pointer, cyclo and LCD) have been in use in the industry for many years without issue. It is an MEPs choice to use them or not. As noted above, any ATH must also perform the "register advance" test, which also requires incrementing the least significant digit to prove the register display is still connected to the metrology and hasn't been damaged in transit or during the installation process.

Other considerations from submissions

Submitter's view

14.11 One submitter requested more information on why we are requiring two test points for Ferraris disc meters.

Our comments

14.12 A common type of fault (when faults occur) with the disc/axle/bearing is to have a friction applied to the spinning assembly (through several different means, eg tight bearings or bent shaft, or interference with the disc). This fault allows the disc to spin but the applied friction prevents the disc speed increasing at the higher load. If an issue prevents spinning at the first test point then the meter is obviously faulty and the second test is not necessary.

Submitter's view

14.13 Some submitters requested additional clarity on the test parameters as they currently stand, and what the reasoning was behind the proposed parameters. One submitter requested clarification that 9(1)(c) relates to NHH metering installations, and whether the 5% load specified in the proposal needs to be on all phases or balanced. Another submitter suggesting a narrower ammeter accuracy range might be more appropriate for this test.

Our comments

14.14 This clause has always applied to all metering, both HHR and NHH. The chapeau (lead-in) of clause 9(1) clearly states the clause applies to the tests performed under Table 3 (selected component methodology) and Table 4 (fully calibrated methodology) of Schedule 10.1. As noted in paragraph 14.7 above and 14.17 below, clause 9 of Schedule 10.7 describes the minimum standard for some, but not all, of the tests required in Tables 3 and 4. We are not proposing to change that application. However, the test methods listed are a minimum, and often an ATH will perform tests at a higher standard than the minimum, especially for fully calibrated, as the raw meter data output test is incorporated as part of the calibration testing rather than being performed as a separate test.

14.15 With regard to the load and ammeter accuracy, the intent of the test is to ensure that there has been no damage to the metering components in transit or during installation and that the overall functionality of the metering installation (including wiring) is working as designed, without having to be to the accuracy level of a calibration test. The test should apply per phase, not balanced across phases. 5% is already quite a low level of current, and if that was balanced across the phases, the amount of current in each phase would be too low to make the test useful.

Our observation

14.16 Submissions indicate some participants are unclear that clause 9 only adds additional specificity to the tests required in Tables 3 and 4 of Schedule 10.1.

Our comments

14.17 Tables 3 and 4 of Schedule 10.1 list the tests that must be performed on a metering installation to ensure metering is working effectively. Clause 9 of Schedule 10.7 is intended to add additional detail to specify the minimum testing conditions for <u>some</u> of the required tests. For these tests, the Authority is aware of some methods that will not achieve a desired level of confidence in the metering installation's accuracy. Where a required test is not explained in detail in clause 9, the Authority is currently satisfied that the various testing methods currently employed by ATHs are satisfactory.

14.18 We note again that these tests have always been required per Tables 3 and 4 of Schedule 10.1, and that clause 9 of Schedule 10.7 only adds additional detail of the minimum requirements for some tests. A raw meter data output test has always been required, to prove the meter hasn't been damaged in transit and the installation works as designed. A register advance test has also always been required, and so adding a requirement to increment the least significant digit as part of the raw meter data output test is not adding a new obligation.

14.19 When it is efficient to do so, the Authority tends towards an outcome-based approach, without being too prescriptive of methodology, unless we have received advice that a certain method may not achieve the desired outcomes in some situations. The metering installation is the foundation that the market reconciliation data is built on and ensuring accuracy is critical to the integrity of the market.

The amendment will promote the efficient operation of the electricity industry

14.20 The Code amendment will promote 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.

14.21 The Code amendment will come into force on 1 February 2021.

The Code amendment

14.22 The Code amendment is as follows:

Schedule 10.7

…

9 Certification tests

(1) An **ATH**, when carrying out a test set out in Table 3 or Table 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–

(~~i~~ai) applying a ~~measured increase in load and measuring – that~~ load on each phase that is—

(A)~~is~~ greater than 5% of the **meter's** maximum rated current for a **category 1 metering installation**; or

(B) 10 amps on each phase for a **category 2 metering installation**; and

(~~i~~bii) 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

(~~i~~ciii) ensuring that the change in the **meter** register that occurs under subclause (~~i~~bii)(A) or subclause (~~i~~bii)(B) is at least "1" in the least significant digit, or one mark if the least significant digit does not have numerical markings~~, of the **meter** register~~; and

(~~i~~div) if the **meter** is a Ferraris disc **meter**, undertaking two **raw meter data** output tests ~~where~~ in which the second test must have a load applied to the **meter** that is at least double the load applied to the **meter** in the test carried out in accordance with subclause (c)(i) and measuring:

(~~i~~A) the increment of the sum of the **meter** registers; or

(~~ii~~B) the accumulation of pulses resulting from the increase in load:

15 Proposal 014: HHR Certification and Interrogation Cycles

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

15.1 We have decided to amend the Code 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:

(a) the increment of the accumulating meter registers, to

(b) the sum of the half-hour metering raw meter data for the same period.

15.2 We will also amend clause 20 of Schedule 10.7 to state that a half-hour metering installation's certification is automatically cancelled if a MEP:

(a) does not read each meter within the meter's maximum interrogation cycle; or

(b) reads each meter within the meter's maximum interrogation cycle but—

(i) does not perform a comparison check; or

(ii) 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 and the MEP cannot remedy this within 3 business days.

15.3 We have also made some changes to the drafting of clause 20 of Schedule 10.7 to remove duplication and make the intent clearer.

15.4 This is the proposal we consulted on, with the drafting in clause 20(1)(j) edited for clarity, and the addition of three business days to resolve any comparison check failures.

We have decided to revise the proposal following submitters' feedback

Submitter's view

15.5 Most submitters are concerned about the automatic and immediate cancellation of certification proposed if the data comparison fails (either is not performed or is performed and the difference between accumulating and half hour registers is too great).

Our decision

15.6 We have decided to modify the Code wording to allow MEP's three business days to investigate and remediate metering which fails the difference check specified in clause 8(9) of Schedule 10.6.

15.7 We consider three business days appropriate. The validation required exists to ensure the accumulating registers and interval registers match. If they do not match then investigation is urgently required to identify why. Until this is done, the data cannot be relied upon as it is unclear which data stream (interval or accumulating) is inaccurate. We expect instances of meters failing this check to be rare, but because of the importance of reliable data, investigation is reasonably urgent. The data cannot be used by the retailer in these instances, because it is not certified HHR data until it has passed this check. If the issue is with the data (or the comms network) this should be reasonably quick to remedy, but if the meter is faulty three business days is sufficient to arrange repair or replacement.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

Metrix is also concerned with certification being cancelled if the installation fails the check by more than 1kWh. Metrix note this can be breached for valid reasons such as precision and slight timing differences between the scalar [accumulating] and interval registers.

Our decision

15.8 The validation required by this clause exists to ensure the accumulating registers and interval registers match. To allow for greater differences would render this check ineffectual. The Authority considers that a slight timing difference should not result in a difference over one kilowatt hour. If it does, the timing difference should be eliminated and the check re-performed.

Submitter's view

15.9 Some submitters requested more prescriptive clauses to allow participants to address non-communicating meters before certification is cancelled.

Our decision

15.10 The Authority acknowledges that in some situations, mains power (and power to the meter) may be shut off for legitimate reasons, such as vacancy of some kind. Where the maximum interrogation cycle is short, this increases the chance that a site would not regain power in time to retain HHR certification.

15.11 However, MEPs have the option of extending the interrogation cycle to the maximum allowed by clause 8(2) of Schedule 10.6. As some submitters have pointed out, data is not lost when the site is powered down; the meter would resume recording consumption as soon as power is restored. Setting a longer interrogation cycle would be a prudent move in vacant sites or holiday homes where the installation is less likely to retain power during its vacancy.

15.12 Additionally, the very end of an interrogation cycle should not be the first indication of trouble at a meter. MEPs can receive data from an installation on a more regular basis, and should communication issues arise, use the time remaining until the end of the interrogation cycle to address communications issues.

Other considerations from submissions

Submitter's view

15.13 Submitters requested clarification on what happens when HHR certification is cancelled under the proposed Code.

Our decision

15.14 Proposal 25 is intended to provide that a site can be certified for HHR and NHH concurrently. It is the Authority's intention that if HHR certification is cancelled under the provisions of this clause, that if NHH functionality is still functioning correctly, the NHH certification would remain.

The amendment will promote the efficient operation of the electricity industry

15.15 The Code amendment will promote the efficient operation of the electricity industry 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.

15.16 The Code amendment will come into force on 1 February 2021.

The Code amendment

15.17 The Code amendment is as follows:

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:

…

(f) if under clause 6(2) the **metering installation** has been determined to be a lower category, ~~under clause 6~~ and—~~the maximum current conveyed through the **metering installation** at any time exceeds the current rating of its **metering installation** category as ser out in Table 1 of Schedule 10.1~~

(i) the **metering equipment provider** has not received, in any month, the report referred to in clause 6(2A)(a); or

(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

(iii) the **metering equipment provider** has not received, in any month, the report referred to in clause 6(2A)(b); or

(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:

…

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

(i) fails to comply with clause 8(2)(b) of Schedule 10.6 ~~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~~ fails to comply with clause 8(9) of Schedule 10.6; or

(iii) performs the comparison in clause 8(9) of Schedule 10.6 but—

(A) the difference between the sum of the **half hour metering raw meter data** and the increment of the **metering installation's** accumulating **meter** registers is greater than 1kWh; and

(B) the **metering equipment provider** has failed to remediate the issue causing the difference and provide the correct data within three **business days**.

(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~~ any one 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**.

16 Proposal 015: Comparative Recertification

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

16.1 We have decided to amend clause 12 of Schedule 10.7 to ensure clarity around when comparative certification may be used by MEPs to recertify a metering installation.

16.2 None of the changes alter any of the Code obligations as they currently exist.

16.3 The purpose of selected component certification is to allow the certification of a metering installation without having to recertify current transformers (CTs) that have already expired or will expire before the next planned metering installation expiry date. Recertifying CTs requires a shutdown to either change the CTs or recalibrate the existing CTs.

16.4 Comparative recertification is used to reduce both the costs of certifying the CTs and the adverse customer effects, but this is balanced against the potential risks of performing the certification tests at only one load point. To reduce the risks, comparative recertification is only permitted on Category 2 metering installations, and the meter and data storage device(s) must be newly certified and remain certified throughout the duration of the new certification period.

16.5 This is the proposal we consulted on, with minor drafting changes.

We have decided to revise the proposal following submitters' feedback

Submitter's view

16.6 Metrix noted that the proposed wording in clause 12(2)(b) implies that the only way a meter can be certified is as part of the comparative recertification process, and therefore cannot be certified in their test lab prior to installation.

Our decision

16.7 We have amended the wording in 12(2)(b).

16.8 We agree the originally proposed wording could be interpreted differently to our intent. The revised amendment makes explicit the requirement for the meter and data storage devices to be newly certified and remain so for the entire metering installation certification period desired.

16.9 This is further supported by the wording in 12(2A) which further clarifies that this method exists so that a metering installation with expired CTs can be recertified as a whole.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

16.10 One submitter would like to see category 3 metering installations included in the comparative recertification method. They believe it will alleviate non-compliances where an outage date for recertification is not achievable with the customer.

Our decision

16.11 The Authority has decided not to make changes to the proposal in response to this, as it is out of scope of the proposal. It is unlikely the Authority would consider this as a future change, as the potential effects of inaccuracies are magnified in higher category metering.

Expiry dates are always available and participants must actively manage their Code requirements, including those which need to be coordinated with the customer.

Submitter's view

16.12 Trustpower advised we should make it clearer that CTs can be recertified regardless of their current CT certification.

Our decision

16.13 Comparative recertification does **not** recertify the CTs, comparative recertification only recertifies the metering installation. The metering installation must successfully pass the required tests and the meter and data storage device must have current component certification to be certified, but under comparative certification, the CTs remain expired.

16.14 ATHs may only use comparative certification if the expiry date for a CT is prior to the expiry date of the meter and other devices in the installation (including already expired CTs), and therefore prior to the metering installation expiry date. If all components' expiry dates are at or later than the planned date of expiry of the metering installation, then the selected component or fully calibrated certification methods must be used.

16.15 The only way to certify CTs as components is to use the provisions of clause 2 of Schedule 10.8.

The amendment will promote the efficient operation of the electricity industry

16.16 The Code amendment will promote the efficient operation of the electricity industry by:

(a) making it easier for participants to understand the testing requirements for category 2 metering installations, and

(b) helping ensure that metering installations are not inadvertently certified incorrectly.

16.17 The Code amendment will come into force on 1 February 2021.

The Code amendment

16.18 The Code amendment is as follows:

Schedule 10.7

…

12 Comparative recertification

(1) This clause only applies when an **ATH** uses the **comparative recertification** method.

(1A) ~~An **ATH** may use the **comparative recertification** method to **recertify** only a **category 2 metering installation**.~~ The **comparative recertification** method may only be used to recertify a **category 2 metering installation**.

(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** is ~~has been~~ **certified** at the date of the recertification in accordance with Schedule 10.8 ~~as part of the **comparative recertification** method~~:

(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.

17 Proposal 016 - 016: Error Calculations at Certification

We have decided not to proceed with the proposal

17.1 For problem 1:

(a) We have decided to take no further action to create a simplified process for error calculations, on advice from the Chief Metrologist 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.

17.2 For problem 2:

(a) We have decided **not** to amend clause 22(1)(a) of Schedule 10.7 as initially proposed, which was to specify that an ATH must take account of:

(i) the estimated load profile at the ICP over the next 12 months

(ii) the estimated power factor of the load at the ICP over the next 12 months.

(b) 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.

(c) We will consider an interim proposal in the future to change clause 22(1)(a) another way, to specify different tests that will reduce non-compliance with the current clause. However, the changes we are considering as a result of feedback are too far removed from our original proposal to implement without further consultation.

(d) We will also consider assembling a technical group to discuss the issue further and formulate a complete proposed solution.

Submitters raised issues with the proposal we wish to consider further

Submitters' views

17.3 Several submitters do not believe the changes we had proposed for problem 2 are practicable. They are concerned primarily that either:

(a) the data will not be available

(b) if the data is available, it adds unnecessary complexity to the certification process that does not produce an appropriate benefit.

17.4 One submitter considered there was no evidence that metering installations are inaccurate under the current requirements.

Our decision

17.5 We considered changing proposed clauses (ii) and (iii) to allow for different tests based on the estimated maximum and minimum expected load amounts and power factors. However, we believe this change, while it may be an acceptable interim solution, is too different from the original proposal to implement without additional consultation.

We intend to consider this matter in a future project

17.6 As we consider this issue still requires remediation, we will review the interim solution discussed and reconsult at an appropriate time if required. We will also consider the establishment of a technical group to permanently solve the issues with non-compliance.

18 Proposal 017: Application of Error Compensation

We have decided to implement the proposal without change

18.1 We have decided to amend clause 24 of Schedule 10.7 to clarify that compensation factors can only be applied to metering installations in specific circumstances, and that only external compensation factors are to be advised to reconciliation participants and the registry manager.

18.2 This is the proposal we consulted on.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

18.3 Submitters were in broad agreement of the Authority's assessment of the issue, and the proposed solution.

Our decision

18.4 The Authority is implementing the proposal as consulted.

Other considerations from submissions

Submitter's view

18.5 Meridian would like to understand the extent to which data inaccuracies may have arisen as an outcome of this ongoing issue, and what remedial actions may be required as a result.

Our decision

18.6 The Authority does not have an industry-wide picture of the scope of incorrect compensation factors. It is assessed in audits, and as part of other checks done by retailers and MEPs. If a retailer finds that a compensation factor is incorrectly recorded in the registry, they may allege a breach against the MEP.

The amendment will promote the efficient operation of the electricity industry

18.7 The Code amendment will promote the efficient operation of the electricity industry by making it easier for participants to know when they can and cannot apply compensation factors to a metering installation. This should remove the possibility of participants applying a compensation factor to metering installations when it is inappropriate to do so.

18.8 The Code amendment will come into force on 1 February 2021.

The Code amendment

18.9 The Code amendment is as follows:

Schedule 10.7

…

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.

19 Proposal 018: Certification Validity Periods

We have decided to implement the proposal without change

19.1 We have decided to:

(a) remove the reference to “electromechanical” from clause 27(4) of Schedule 10.7, so that the clause applies equally to all meter types

(b) require an ATH that determines a certification validity period for a meter that is shorter than the maximum validity period shown in Table 1 of Schedule 10.1 to note in the meter certification report the reason for the shorter validity period

(c) make changes to move information regarding the statistical sampling process to a single location for ease of use

(d) combine the information in Table 2 of Schedule 10.1 with the information in Table 1 to improve readability.

19.2 This is the proposal we consulted on, with minor drafting changes for clarity. We note that the proposal had an error in the wording of clause 1(1)(d) of Schedule 10.8, extracted from the current Code, which stated “…produces a meter calibration report”. The word “calibration” should have read “certification” as this is the current wording of the Code (which is not part of the proposed changes). We have corrected the wording in this decision paper.

19.3 We have removed proposed changes to clause 45 of Schedule 10.7, as the redrafting of that clause is also relevant to problem 2 of proposal 22. These changes are now contained in proposal 22.

We have decided to make no changes to the proposal in response to some feedback

Submitter’s view

19.4 Accucal suggests that the shelf life should be based on calibration instead of certification, as certification depends on calibration.

Our decision

19.5 The Authority considers this change to be out of scope of the original proposal. The proposal as stated will standardise the shelf life approach between meter types and provide consistency within the industry. We recommend Accucal proposes a future Code change if it considers shelf life would be better tied to calibration.

Submitter’s view

19.6 Transpower suggests amending Table 1 of Schedule 10.1 to clarify that maximum meter certification validity periods should not exceed the metering installation’s certification validity period.

Our decision

19.7 As clause 27 of Schedule 10.7 already specifies this limit on the meters contained within an installation, we will not make further amendments to the table at this time. We believe these requirements are sufficiently clear.

Submitter's view

19.8 Submitters had differing opinions on what an appropriate shelf life might be. One submitter considers there should be no shelf life on electronic meters, since there is no evidence of failure. The submitter further asserts that as meters are checked on installation, this can serve as proof that the meters are appropriately accurate. Other submitters recommend shelf lives based on a meter's normal validity period, or on an unspecified "more appropriate" duration between calibration and certification.

Our decision

19.9 We have received advice from the Chief Metrologist that electronic componentry is liable to fail and drift over time like any other component. Further, the Code does not specify storage and handling standards, so extended storage, especially in poor conditions, can have detrimental effects on the components. We consider it best practice to bring electronic meters in line with electromechanical meters to provide reasonable assurance around accuracy over time, and a standardised period, which will make it easy for participants to comply.

19.10 Installation tests for the selected component certification method are not accuracy tests. They are intended to give a general indication the metering installation is working as designed.

Submitter's view

19.11 Trustpower requested the Code be changed to specify that a meter certification report be created "on request" as calibration reports are not included in full in meter certification reports.

Our decision

19.12 The Authority considers current industry practice of including a reference to the meter calibration report within the meter certification report acceptable, so long as that calibration report is also provided when the meter certification report is requested. We did not propose to change current industry practice or the majority of what is provided within the meter certification report – with the exception of now requiring a reason if a meter is certified for a period shorter than the maximum allowable. Any change would be out of scope of this proposal and would need to be consulted on. If Trustpower (or any other participant) thinks the Code needs amendment to clarify the requirement then a Code amendment request should be submitted.

19.13 We agree both the meter certification report and the meter calibration report can and should be provided, on request, by the MEP. However, we disagree that auditors are the only parties who are interested in the certification report. Consumers and retailers are among the other parties entitled to request and receive these reports to verify meter certification.

The amendment will promote the efficient operation of the electricity industry

19.14 The Code amendment will promote the efficient operation of the electricity industry 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.

19.15 The Code amendment will come into force on 1 February 2021.

The Code amendment

19.16 The Code amendment is as follows:

Also refer to attached Table 1 of Schedule 10.1 and Table 2 of Schedule 10.1.

NB: Table 1 is also amended under Proposals 007 and 022. The changes shown here are only those from this proposal. We will amalgamate the changes from the three proposals in the final Code amendment.

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

(ab) if the group meets the **recertification** requirements of this Part use the appropriate maximum validity period set out in Table 5 of AS/NZS 1284 as the **certification** validity period for each **metering installation** in the group; and

…

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.

NB: clause 45 is also extensively amended under Proposal 022. The changes shown here are only those from this proposal. We will amalgamate the changes from the two proposals in the final Code amendment.

…

Schedule 10.8

…

1 Meter certification requirements

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

…

(d) it produces a **meter certification 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 categories of **metering installations** in which the **meter** may be used ~~class of~~ ~~**meter**~~.

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~~

20 Proposal 019: Measuring Transformers and Burdens

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

20.1 To address problem 1, the Authority will:

(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.

20.2 To address problem 2A, the Authority will 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. We have made a minor drafting change to address the fact that nameplate ratings may only contain the upper bound for the burden limits of the measuring transformer.

20.3 To address problem 2B, the Authority will amend clauses 28(4)(a)(i), 31(7) of Schedule 10.7, and 2 and 3 of Schedule 10.8 to:

(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.

20.4 To address problem 3A, the Authority will 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.

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

20.6 To address problem 4A, the Authority will 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.

20.7 To address problem 4B, the Authority will 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.

20.8 These are the proposals we consulted on, with one minor change to the proposed wording of the solution for 2A, clause 2(1)(e) of Schedule 10.8, and drafting changes for clarity.

Proposal 1

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.9 Submitters did not have comments on proposal 1.

Our decision

20.10 This is a minor change to make Code requirements easier to follow and we will implement the change as proposed.

Proposal 2A

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.11 Submitters did not have comments on proposal 2A.

Our decision

20.12 This is a minor change to correct an incorrect reference and we will implement the change as proposed.

Proposal 2B

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.13 One submitter supported proposal 2B, other submitters did not have comments on proposal 2B.

Our decision

20.14 We will implement the changes largely as proposed with a minor change to the drafting. Since nameplate ratings usually contain only an upper bound of burden range, the certifying ATH may need to use another source to obtain the lower bound. The drafting now reflects this. We have made some other minor changes for clarity.

Proposal 3A

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.15 Accucal are unsure why the provisions proposed in clause 31 of Schedule 10.7 (Problem 3A) only apply to measuring transformers with a primary voltage of >1kV and why lower voltage sites, which would be less risky to certify the same way, cannot be included in this proposal.

20.16 FCLM raised that the risk of burden resistors failing on low voltage installations is the same as on high voltage, and that we should have extended our focus to include those sites under 1kV.

Our decision

20.17 We have decided to implement the original change as proposed. It is best to operate measuring transformers within the manufacturer's stated burden range, and this is the Authority's primary preferred solution. Where this cannot be done using existing metering components then the measuring transformers should be replaced so that the metering installation will now operate within the new measuring transformer's stated burden range or for burdening resistors to be installed to increase the burden to be within the existing measuring transformer's stated burden range.

20.18 However, the Authority understands that in some cases for higher voltage metering, these options may be very cost-prohibitive to the consumer and the risk of damage from a failed burden resistor is much higher than for a low voltage measuring transformer. Therefore the alternative of a class A ATH certifying that the measuring transformer is accurate at a burden lower than the manufacturer's specification is reasonable. We consider that this solution adequately balances the risk of higher voltage measuring transformers failing, accuracy, and cost.

20.19 For lower voltage, less complex installations, the cost of replacing the measuring transformers with ones of the appropriate specification does not outweigh the benefits of a metering installation certified to operate within the manufacturer's specifications.

20.20 For reference, the Authority calculated the cost to install burdening resistors based on the cost provided to us for a set of resistors ($30), plus the cost of labour given a technician will already be on site (to recertify the metering installation), and that the installation of resistors would typically take about 15 minutes at most (1/4hr at $80/hr labour).

Proposal 3B

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.21 One submitter asserts a class B test house can confirm accuracy at in-service burden levels, which it does when it tests an installation.

Our decision

20.22 We have decided not to change the proposal in response to this submission. Class B test houses are not required to comply with ISO 17025. The best way to minimise the effects of any testing errors on higher voltage metering is to comply with this standard, which provide a high level of control around the way these tests are performed. The Authority considers the risk to the market too high to allow Class B ATHs who are not required to work to this standard to calibrate higher voltage measuring transformers. For lower voltage metering installations, as stated in our decision to proposal 3A above, we require these metering installations to operate within the manufacturer's specification

Proposal 4A

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.23 Accucal commented that problem 4A needs to clarify that comparative certification can only be used for category 2 sites.

Our decision

20.24 The Authority will implement the change as proposed and notes that the request to clarify that comparative certification can only be used on Category 2 metering sites is included in

Proposal 015 of this decision paper. Please refer to that decision for our response to this issue.

Industry forum attendees view

20.25 During the industry forums held on 9 October 2018 to discuss this project, several attendees requested the Authority clarify the burden requirements when using the comparative recertification method.

Our response

20.26 Comparative recertification is one of the certification methods permitted to certify a category 2 metering installation under Schedule 10.7. The specific requirements are contained in clause 12 of Schedule 10.7. Burdening requirements are contained in clause 31 of Schedule 10.7.

20.27 Clause 12 does not contain an exemption from the other requirements in Schedule 10.7. When using the method in clause 12 (as when using the other the permitted methods contained in clauses 11, 13, or 16) all other appropriate requirements of Part 10 must be complied with, including the requirements for burdening measuring transformers.

Proposal 4B

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

20.28 Submitters did not have comments on proposal 4B.

Our decision

20.29 We will implement the changes as proposed.

The amendment will promote the efficient operation of the electricity industry

20.30 The Code amendment will promote the efficient operation of the electricity industry by:

(a) 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.

(b) The proposal would also remove an impossible obligation on ATHs to certify measuring transformers in a test laboratory.

20.31 The Code amendment will come into force on 1 February 2021.

The Code amendment

20.32 The Code amendment is as follows:

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 or the **comparative recertification** method, ensure that the **ATH** ~~uses the **measuring transformer's** actual accuracy (rather than class accuracy) when calculating~~ calculates the maximum permitted error in accordance with clause 22 ~~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** incorporating ~~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~~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 upper limit of the range specified 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.~~; and

(~~a~~b) 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

(c~~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~~.

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 range, including highest and lowest values, that the in-service burden must ~~fall between~~ be within to ensure the **measuring transformer** remains accurate, by using one or more 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 set out in Table 5 of Schedule 10.1 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 range, including highest and lowest values, that the in-service burden must ~~fall between~~ be within; 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.

21 Proposal 020: Alternative Certification for POC to the Grid

We have decided to implement an amended form of the proposal

21.1 The Authority's original proposal was 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.

21.2 We have amended that proposal taking into account feedback that alternate certification is an important tool for the grid owner to maintain certification compliance in situations where it unexpectedly cannot access measuring transformers during planned outages.

We have decided to revise the proposal following submitters' feedback

Submitter's view

21.3 Transpower's submission explained that alternate certification is a valuable method for it to use to recertify grid-level metering when unexpected access issues arise with regards to planned outages. They consider the incremental time to recertify does not compromise measurement accuracy in the interim. Additionally, were this not an avenue available to them, additional costs to both Transpower and the Authority could be incurred due to the breach or exemption process.

Our decision

21.4 The Authority is comfortable with Transpower's use of alternate certification in the situation it described and has revised the Code drafting to ensure Transpower is able to continue this practice. However, alternate certification has its limits. It is only to be used in accordance with all of the following provisions, as stated in the Code:

(a) where there are genuine access issues (ie not for convenience)

(b) used only once with a set of measuring transformers

(c) up to a maximum of 2 years certification

(d) the ATH must be satisfied the measuring transformers will be accurate through due enquiry

(e) in the case of ICPs which are not NSPs, when the MEP has updated the certification in the registry

21.5 The Authority also expects that the ATH will have appropriate documentation to justify the use of alternate certification for audit purposes.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

21.6 The other submitter on this proposal agreed with the original proposal.

The amendment will promote the efficient operation of the electricity industry

21.7 The Code amendment will promote the efficient operation of the electricity industry by clarifying the Code to ensure that alternative certification is only used in appropriate circumstances.

21.8 The Code amendment will come into force on 1 February 2021.

The Code amendment

21.9 The Code amendment is as follows:

Schedule 10.7

…

32 Alternative certification requirements for metering installation incorporating measuring transformer

(1) ~~For an **ICP** that is not also an **NSP**, A~~~~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) in the case of an **ICP** that is not an **NSP**, the **metering equipment provider** has updated the **metering installation's certification** in the **registry**.

…

22 Proposal 021: Obsolete Sticker Removal

We have decided to implement the proposal without change

22.1 We have decided to amend clause 41 of Schedule 10.7 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.

22.2 This is the proposal we consulted on.

22.3 Note that the numbering in the final drafting may be slightly altered with the changes related to proposal 023 of this decision paper.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

22.4 All three submitters were in support of the proposal without changes. One submitter raised that any scraping off of old stickers should be done carefully to avoid damaging components. Another submitter noted that statistically sampled certifications will not have sticker replacements and this Code change will not address the stated problem of untrained persons misreading old stickers.

Our decision

22.5 The Authority acknowledges that this will not resolve this issue in cases of statistical sampling. We also note that ATHs should be cautious about not unduly damaging equipment as a matter of course.

The amendment will promote the efficient operation of the electricity industry

22.6 The Code amendment will promote the efficient operation of the electricity industry 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.

22.7 The Code amendment will come into force on 1 February 2021.

The Code amendment

22.8 The Code amendment is as follows:

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~~9) An **ATH** must, when attaching a **metering installation certification sticker** under subclause (1), remove or obscure any invalid or expired **certification stickers**.

23 Proposal 022 - Inspection Periods Proposal 022: Inspection Periods

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

23.1 We have decided to:

(a) For Problem 1:

(i) clarify that inspections of metering installations must be completed within the maximum timeframe set out in Table 1 of Schedule 10.1

(ii) 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 change the current inspection window to a maximum period.

(b) For Problem 2:

(i) clarify that if an MEP chooses to use statistical sampling for the inspection of its category 1 metering installations, the MEP must ensure that the sample is selected from the entire population of the MEP's category 1 metering installations and an ATH inspects all of the selected metering installations between 1 January and 31 December each year.

(ii) additionally, clarify that 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.

(c) For Problem 3:

(i) The reference to interim certified metering installations in clause 45(1)(a) of Schedule 10.7 will be removed, as the certification for all of these installations has expired and this reference is no longer valid.

23.2 This is the proposal we consulted on, with some changes to the clause drafting for clarity:

(a) amending clause 45(2)(b) of Schedule 10.7 to better support the changes required in Problem 2

(b) removing the reference to interim certification in clause 45(2)(a) of Schedule 10.7.

We have decided to revise the proposal following submitters' feedback

Submitter's view

23.3 In its submission, Northpower commented that the wording of the proposed new clause 45(1)(b)(i) of Schedule 10.7 seemed to obligate participants to include recently certified meters in the sample population.

Our decision

23.4 The submitter appears to have mis-understood the existing Code requirements. Clause 45(2) of Schedule 10.7 sets out how to select the sample. This process removes all meters certified or inspected less than 7 years ago from the list the sample will be chosen from, so they will not be inspected.

23.5 The actual process does not change. The new wording only addresses problem 2 – that the wording was unclear about whether an MEP may spilt their Category 1 metering installations into several populations so they can be inspected/treated separately. This is not permitted in the current Code and we are making that clearer.

23.6 We have made further amendments to the drafting to ensure the obligations of this clause are clear.

The amendment will promote the efficient operation of the electricity industry

23.7 The Code amendment will promote the efficient operation of the electricity industry by:

(a) Clarifying the requirements for inspecting category 1 metering installations to help ensure ATHs undertake inspections appropriately and in a timely manner, thereby better ensuring the ongoing accuracy of the metering installation.

23.8 The Code amendment will come into force on 1 February 2021.

The Code amendment

23.9 The Code amendment is as follows:

23.10 Refer to attached Table 1 of Schedule 10.1.

NB: Table 1 is also amended under Proposals 007 and 018. The changes shown here are only those from this proposal. We will amalgamate the changes from the three proposals in the final Code amendment.

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.~~

(b) if the **metering equipment provider** is responsible for any **category 1 metering installations** that were **certified** more than 84 months ago, the **metering equipment provider** inspects a sample of all **category 1 metering installations**.

(1A) When inspecting a sample of **category 1 metering installations** under subclause (1)(b), the **metering equipment provider** must—

(a) complete the inspections each 12 month calendar year between 1 January and 31 December~~, provided~~; and

~~(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.~~

(b) perform the first inspection in the same calendar year the oldest **metering installation** reaches 84 months since certification.

~~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~~.

(2) A **metering equipment provider** must, for the purposes of subclause (1)(b), select a sample by—

(a) producing a list of all **ICP identifiers** of each **category 1 metering installation** for which it is responsible~~, other than **interim certified metering installations**~~; and

(b) removing from the list of **ICP identifiers**, any **ICP identifier** for a **metering installation** that has been **certified** or inspected in the 84 months prior to 31 December in the year in ~~date on~~ which the list was produced; and

…

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									

24 Proposal 023: Combining Certification Stickers

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

24.1 We have decided to amend clause 41 of Schedule 10.7 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 clause also places conditions of use on the single sticker.

24.2 This is the proposal we consulted on with the removal of proposed subclause 41(7) of Schedule 10.7 as the provision deciding the expiry date was already present in subclause 17(2) of Schedule 10.7. We also made a minor typographical change to the drafting in clause 8 of Schedule 10.8 as it had an error in the original proposal.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

24.3 All three submitters agreed with the proposal with no changes. Intellihub noted that some ATHs will continue to use separate certification stickers for components and installations.

Our decision

24.4 The Authority confirms that the proposed clause does not prohibit ATHs from continuing with current practice and using separate stickers for components and installations, should they wish to do so. The proposal allows the additional practice of using a single sticker for both, under the appropriate circumstances as described in the Code text.

The amendment will promote the efficient operation of the electricity industry

24.5 The Code amendment will promote the efficient operation of the electricity industry by lowering the cost of certifying metering components and metering installations.

24.6 The Code amendment will come into force on 1 February 2021.

The Code amendment

24.7 The Code amendment is as follows:

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**.

…

<u>(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**</u>

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~~7) The combined sticker under subclause (~~6~~5) 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~~8) 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~~7).

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 it certifies the **metering installation** that 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 ~~and attach it to the **metering installation** in accordance with clause 41 of Schedule 10.7.

25 Proposal 024: NSP Decommissioning Timeframes

We have decided to implement the proposal without change

25.1 We have decided to amend clause 25 of Schedule 11.1 to:

(a) 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) require the relevant participant to advise the reconciliation manager, as soon as practicable, of a change to the scheduled date on which an NSP is to be created or decommissioned.

25.2 This is the proposal we consulted on.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

25.3 There was only one submitter on this proposal, and they agreed with the proposal, with no modifications or comments.

The amendment will promote the efficient operation of the electricity industry

25.4 The Code amendment will promote the efficient operation of the electricity industry by:

(a) helping 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.

25.5 The Code amendment will come into force on 1 February 2021.

The Code amendment

25.6 The Code amendment is as follows:

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**.

…

(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.

(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.

26 Proposal 025: MEP updates of HHR/NHH and AMI flags

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

26.1 We have decided to amend several clauses to clarify the Code provisions for MEP updates to the HHR/NHH and AMI flags within the registry as follows:

(a) Amend clause 10 of Schedule 10.4 to require an ATH, when preparing a metering installation certification report, to specify:

(i) all possible services access interfaces for a metering installation

(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.

(c) Amend clause 8 of Schedule 10.6 to require the metering equipment provider to:

(i) restore communications and download raw meter data by the earlier of:

(i) (A) the number of full days that equate to 25% of the maximum interrogation cycle for the metering installation; and

(ii) (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.

(d) 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".

(e) 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.

(f) 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.

(g) 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, when an ATH has certified the metering installation as being half hour <u>and</u> non half hour.

(h) 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.

26.2 This is the proposal we consulted on with two additions for clarity:

(a) The introductory words in clause 36(4) of Schedule 10.7 need to make it clear that the maximum interrogation cycle applies for each services access interface

(b) The reference in clause 2(3)(d) of Schedule 10.7 to a maximum interrogation "cycle" needs to be plural – a design report should include a maximum interrogation cycle for each permissible services access interfaces.

We have decided against making a change suggested by a submitter

Submitter's view

26.3 Contact raised in its submission that in the memo "Expectation on use of the AMI flag in the registry, and determining if an AMI meter is non-communicating"[3] the Authority advised that it would include the timeframes for investigating communication issues in a future proposed Code amendment. Contact was concerned these timeframes were not included in this consultation.

Our decision

26.4 The Authority has considered the information in the memo, and decided against proposing firm timeframes. Using a percentage of the maximum interrogation cycle as originally proposed permits the MEP to ensure the timing of its investigations is aligned to the risk of data loss. Meters with larger data storage (and therefore a higher maximum interrogation cycle) can take longer to investigate than would be the case if a set number of days timeframe is used, as any set number of days would need to be the shortest time to ensure the meters with the least data storage are investigated before data is lost. This ensures communication problems are addressed and allows data to be retrieved and sent to the trader before it is lost from the meter.

Submitters' view

26.5 Some submitters have different views on how an AMI, NHH, or HHR flag change should work. From the wording of the submissions these appear to be based on incorrect assumptions regarding the purpose of the flags or when an MEP is actually required to make changes.

26.6 Some participants were concerned the proposed changes would be imposing additional, unnecessary costs on the industry in the form of investigations.

26.7 Genesis said it remains unclear why there appears to be a link between the ability of a meter to communicate remotely and the resolution of data it is certified to record, and explained several theoretical scenarios where these flags might not go hand-in-hand.

26.8 Contact said that the proposed new clause 8(11) of Schedule 10.6 implies that MEPs can choose whether to investigate or not but incorrectly interpreted clause 8(10) to mean they had to investigate and found this obligation unclear.

Our decision

26.9 Genesis' interpretation of the flags is correct – that is, it is possible to have a metering installation that is certified NHH and is also AMI; likewise a HHR non-AMI site is possible. The two flags are independent of one another.

26.10 The proposed new clause 8(10) of Schedule 10.6 provides a choice when the meter data does not download as part of an electronic interrogation – the MEP may either investigate per clause 8(10)(a) or immediately update the flag to advise the installation is no longer AMI per clause 8(10)(b).

26.11 There is a link between the AMI flag and the services access interface. If AMI = Y, the MEP is responsible for providing the data through their back office, regardless of how the MEP

---

[3] See the link "Memo - AMI flag and investigation of non-communicating meters on the Authority's website - https://www.ea.govt.nz/operations/retail/metering/advanced-metering/

obtains the data. The flag is not intended to set how frequently a trader receives data – this can be set via commercial arrangements between the trader and the MEP.

26.12 The Authority also notes that electronic interrogation does not always mean remote interrogation – an MEP may go to site to retrieve data for an AMI = Y site (for example by a 'drive by' radio link or by plugging a device into the meter's communications port), and then feed the data through the MEP's back office systems for use by the retailer.

26.13 Further, if the HHR flag is set to Y, this only means that the meter is programmed to store interval data and that data is able to be collected, regardless of the collection method and whether the interval data is actually used by the retailer. Likewise, the proposal does not affect certification – if a site is certified to provide both NHH and HHR data, MEPs can move between the designations depending on their capabilities and commercial offerings to traders.

26.14 The Authority considers MEPs have always had the obligation to investigate and remediate faults, regardless of whether a trader has issued a service request.

26.15 This proposal is intended only to describe and clarify the Authority's expectations of the current situation, and place sensible time limits based on the ability to collect all metering data before it is automatically discarded from, or overwritten in, a metering installation's internal memory. The Authority's Switch Process Review project may investigate enhancements to this area, including the possibility of changing the Y/N nature of the flags or introducing new flags.

Submitter's view

26.16 Genesis believes that knowing promptly that an ICP is electrically connected or has resumed communicating is as important as knowing an ICP has lost communications, and suggested that the proposed new clause 3(c) of Schedule 11.4 should be amended to three business days for an MEP to advise the registry.

Our decision

26.17 The Authority agrees, however amending the Code wording from 10 business days to three business days would require additional consultation. We will leave the proposed timeframe of 10 days and will consult further on the three business day timeframe in the future.

We have decided to revise the proposal following submitters' feedback

Submitters' view

26.18 Although some submitters said they disagreed with the Authority's solution, in many cases the explanation of points they disagreed on actually implies general agreement with the Authority's principles and the proposed solution.

26.19 For example, Electric Kiwi said the MEP should be responsible for trying to resolve the communications failure before being allowed to mark the AMI flag as N in the registry. Electric Kiwi believes the proposal favours the MEP and not the customer or trader reliant on HHR data.

Our decision

26.20 Our position requires us to consider all industry circumstances. The Authority agrees with Electric Kiwi that MEPs should endeavour to resolve communications issues where practicable, and provides support for this in the Code. However, the Authority should not force MEPs to maintain remote communications as a service offering if they choose not to as a business decision. Forcing MEPs to ensure that AMI-capable meters are communicating at all costs could heavily outweigh any benefits from receiving this data in certain situations, like metering in remote areas. The proposal sets the minimum requirements for MEPs and does not prevent MEPs and retailers agreeing commercial arrangements that exceed the minimum requirements.

26.21 Further, the Authority does not conflate HHR and AMI. As long as HHR data can be retrieved from the meter before the expiry of the interrogation cycle (regardless of the retrieval communication mechanism), that data can be used for the reconciliation process or billing the customer. More frequent communications may be desirable from a participant's product development standpoint because they have the potential to enable more variety and granular offerings for retailers and their customers, but are not required to accurately settle the market. The Code does not prevent MEPs and retailers agreeing commercial arrangements that exceed the minimum requirements.

26.22 However, due to significant confusion around responsibilities of MEPs to collect the meter data, we have decided to amend clause 8 of Schedule 10.6 to include an additional statement for the avoidance of doubt – if the services access interface is the MEP's back office, the MEP must obtain relevant data within the maximum interrogation cycle. The MEP may use any method to obtain the data, including remote communications. The frequency of availability of the data is a matter for the contractual arrangements between the MEPs and the retailers.

Submitter's view

26.23 Intellihub submitted that the proposal to record (in the metering installation certification report) all relevant services access interfaces applicable to an installation would also impact the maximum interrogation cycle specified in the design report. As a result, the report should include maximum interrogation cycles for each permissible services access interface and installation type.

Our decision

26.24 The Authority agrees and will amend clause 2(3)(d) of Schedule 10.7 so (in instances where there is more than one maximum interrogation cycle) it is clear that the design report must include all possible interrogation cycles for each services access interface.

26.25 We will also amend clause 36(4) of Schedule 10.7 to indicate that it applies separately to each services access interface.

The amendment will promote the efficient operation of and competition in the electricity industry

26.26 The Code amendment will:

(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 restoration of communications between an AMI meter and an MEP's back office

(ii) making the Code easier to understand and comply with.

.

26.27 The Code amendment will come into force on 1 February 2021.

The 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**,—

(a) all ~~the~~ **services access interfaces**; and

(b) the conditions under which each **services access interface** may be used.

…

Schedule 10.6

…

8 Electronic interrogation of metering installation

…

(11) 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~~:—~~

(a) investigate the reasons for the failure, restore communications, and download all of the **raw meter data** as soon as possible but ~~and~~ no later than the time specified in subclause (12); or

(b) in accordance with clause 3(c~~a~~) of Schedule 11.4, update the **registry metering records** to show that the **metering component** is no longer an advanced metering infrastructure device.

(12) If a **metering equipment provider** decides to take the actions specified in subclause (11)(a), the **metering equipment provider** must complete those actions by the earlier of—

(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

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

(13) If the **metering equipment provider** does not complete ~~the~~ investigating~~on~~, restoring~~on~~ ~~of~~ communications, and downloading ~~of~~ all of the **raw meter data** in accordance with subclause (11)(a) within the time specified in subclause (12) or determines at any time during the time period specified in subclause (12) 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~~d) of Schedule 11.4, to show that the **metering component** is no longer an advanced metering infrastructure device.

…

Schedule 10.7

…

2 Design reports for metering installations

…

(3) The **metering equipment provider** must ensure that a design report includes—

(a) a schematic drawing of the **metering installation** for use by an **ATH**; and

(b) details of the configuration scheme that programmable **metering components** are to include; and

(c) confirmation that the configuration scheme has been approved by an **approved test laboratory**; and

(d) for each **services access interface**, the **maximum interrogation cycle** specified in clause 36(4); and

…

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.

…

36 Requirements for metering installation incorporating data storage device

…

(4) The maximum **interrogation** cycle for each **services access interface** for a **metering installation** incorporating a **data storage device** is the shortest of the following periods:

(a) the period of inherent data loss protection for the **metering installation**; and

(b) the period of memory availability given the **data storage device** configuration; and

(c) the longest period in which the accumulated drift of a **data storage device** clock is expected to remain in compliance with the maximum time error set out in Table 1 of clause 2 of Schedule 15.2 for the category of the **metering installation**.

…

Schedule 11.4

…

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

If a **metering equipment provider** has an arrangement with a **trader** at an **ICP** that is not also an **NSP**, the ~~A~~ **metering equipment provider** must advise the **registry manager** of the **registry metering records**, or any change to the **registry metering records**, for ~~a~~ each **metering installation** for which it is responsible at the **ICP**, no later than ~~**10 business** days following:~~—

~~(a) the **electrical connection** of the **metering installation** at the **ICP**~~[4]~~.~~

~~(b) any subsequent change to the **metering installation's metering records.**~~

(~~a~~c) ~~3 **business days** following the most recent unsuccessful **interrogation**,~~ if updating the **registry metering records** in accordance with clause 8(~~10~~11)(b) of Schedule 10.6, 10 **business days** following the most recent unsuccessful **interrogation**; or

(~~b~~d) if updating the **registry metering records** in accordance with clause 8(~~12~~13) of Schedule 10.6, 3 **business days** following—

(i) the expiry of the time period under clause 8(~~11~~12) of Schedule 10.6; or

(ii) the date on which the **metering equipment provider** determines in an investigation under clause 8(~~10~~11)(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~~e) 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 subparagraphs (c~~a~~) and (d~~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**

…

[4] We note clauses 3(a) and 3(b) were amended on 1 November 2018 and the most recent version of the Code appears here.

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**~~**metering equipment provider's back office** ~~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**.

…

27 Proposal 026 - Excluding Non-Market-Related Meter Registers

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

27.1 We have decided 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.

27.2 This is the proposal we consulted on, with one minor correction. We erroneously included row 31 in the original proposal as changing from “required” to “optional” but row 31 is already an optional field. We have corrected the drafting to reflect this.

We have decided to make no changes to the proposal in response to some feedback

Submitters’ views

27.3 Two submitters wished to expand the proposal to include check meters or other types of meter registers, which would allow billing of customers on a configuration different to the network pricing and market settlement.

Our decision

27.4 The Authority considers expanding this definition to be out of scope of this proposal, and has not appropriately consulted on whether other types of metering records should be excluded from the obligation to be recorded in the registry.

27.5 Any participant that believes other types of metering should be excluded from the requirement to be recorded in the registry should put a Code change proposal forward outlining their reasons.

Submitters’ views

27.6 Two submitters suggested that allowing the proposal to continue would reduce transparency for consumers.

Our decision

27.7 The only information that will be excluded from the obligation to be recorded in the registry under this proposal is that which is used for a distributor direct billing a consumer. In these cases, the consumer will have an appropriate communication path to their network company and will have the appropriate tools through their contract with the distributor to ensure they are accurately billed.

27.8 Retailers will be aware of this arrangement because they will have signed a ‘conveyance only’ use of systems agreement with the distributor, and will not be receiving pass-through charges from distributors for their consumers. The retailer will know that for these ICPs a meter register may not appear on the registry.

27.9 Additionally, we are not preventing MEPs from providing metering information in these cases. MEPs may record information used for direct billing if they wish, and use the settlement indicator “N” as noted by one submitter. Because some retailers’ systems are not able to process certain meter registers, making this information optional prevents retailers from choosing instead to displace the incumbent MEPs simply for entering what they are currently obligated to provide, due to the retailer’s own system limitations. To allow retailers to displace in these cases would inhibit competition for MEPs who provide data that the retailer cannot currently process.

27.10 Retailers have the additional option of specifying in their agreements with MEPs that all meter registers are recorded in the registry, if they wish.

Submitter's view

27.11 One submitter agreed but had no further comments.

The amendment will contribute primarily to the efficient operation of the electricity industry

27.12 The Code amendment will promote the efficient operation of the electricity industry by:

(a) 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

(b) removing an unnecessary cost for traders, arising from their billing systems managing the additional metering data recorded in the registry

(c) 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.

27.13 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).

27.14 The Code amendment will come into force on 1 February 2021.

The Code amendment

27.15 The Code amendment is as follows:

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 30~~1~~ 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 30~~1~~ of Table 1 of Schedule 11.4, after the word "Required", the words "(except where clause 7(1A) of this Schedule applies)".

28 Proposal 027 - Meter Resealing by Traders

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

28.1 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 of Schedule 10.7 so it:

(i) permits a distributor to break or remove a seal for bridging/unbridging a load control device (but not a 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. If a distributor breaks or removes a seal, it must then notify the trader and MEP of having done so. The trader must then update the profile code in the registry (refer to clause 10 of Schedule 11.1) if required and the MEP must update the register content code 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 time blocked channel, eg day/night, as this would affect the accuracy of the meter readings and market settlement), and then requires the trader to update the profile code in the registry (refer to clause 10 of Schedule 11.1) if required. The trader must also notify the MEP so the MEP can update the register content code if required.

(iii) permits a trader to break or remove a meter seal in two further situations. First, for electrical disconnection/electrical connection of the load or generation measured by the meter, as a last resort (such as if it is not possible to electrically disconnect/electrically connect at the point of connection). Second, for bridging meters in specified circumstances.

(c) amend clause 19 of Schedule 10.7 so that the certification of a metering component or a metering installation does not automatically cancel if clause 48(1) is complied with.

28.2 To address the second identified problem, the Authority proposes to amend clause 48 of Schedule 10.7 so that an MEP/ATH is not responsible under the Code for any breach related to the metering component if:

(a) another participant has broken a metering component's seal; and

(b) the MEP/ATH can prove the seal was intact when the MEP/ATH last performed work at the metering installation.

28.3 This is the proposal we consulted on, with the removal of 48(1E)(d) of Schedule 10.7, which was included in error, and minor drafting changes for clarity.

We have decided to revise the proposal following submitters' feedback

Submitter's view

28.4 In its submission, FCLM advised that it wouldn't permit a bridged meter to be unbridged and sealed by a retailer.

Our decision

28.5 The Authority agrees, and the insertion of (1E)(d) was a drafting error. This proposed clause will be deleted.

28.6 To clarify, the Authority intends, in the specified circumstances, to allow breaking seals for bridging and unbridging a load control device, and bridging meters by parties that are not the current MEP. It does not intend to allow unbridging of meters by traders. Unbridging a meter (and the accompanying resealing) must always be done by the current MEP to ensure the metering installation, once unbridged, remains accurate and the original certification remains valid.

Submitter's view

28.7 FCLM wanted the proposal to include a notification to the MEP to repair a fault/reseal a relay.

Our decision

28.8 We agree and have added proposed clause 48(1F)(d) of Schedule 10.7 requiring a trader to notify an MEP that a seal was removed under (1D) or (1E) and what work was performed.

Submitter's view

28.9 Unison advised that the proposed wording appears to refer to load control devices and devices controlling time-blocked channels as separate entities, when in reality these may be contained within the same device, and can be separately bridged. For example, a ripple relay may contain two (or more) switches – one (or more) for load control purposes, and the other to operate the day/night registers on the meter. Seals can be broken on the device and the load control switch accessed without affecting the day/night register control switch.

Our decision

28.10 We have revised the wording to take this into account. Also, instead of using the generic term load control device, we will refer to them more accurately as "load control switches" where relevant.

Submitter's view

28.11 Genesis raised a point regarding the register content code on the registry. It could be affected if a load control device is bridged, effectively changing controlled load to uncontrolled load, without a record existing in the registry of this change. Therefore the MEP may need to update the register content code and period of availability in addition to the retailer updating the profile code.

Our decision

28.12 In cases of the MEP doing the work on behalf of the trader, this would not be a problem, as the MEP would know that the change had happened and could update the registry. However, if the MEP is not aware of the change because the change was made by the trader or distributor, the registry could become inaccurate. As such, we have revised the proposed Code wording to ensure that:

(a) the trader or distributor that removes or breaks the seal must notify the MEP that a load control switch has been bridged or unbridged

(b) the MEP must update the register content code on the registry if required as a result of the bridging.

We have decided to make no changes to the proposal in response to some feedback

Submitter's view

28.13 Orion advised that meters can also be bridged to carry out testing on the service mains.

Our decision

28.14 The Authority considers that amending the proposal to allow bridging in this circumstance would be an expansion of scope over the original proposal and would require re-consulting. As such, we propose retaining the current changes as detailed here and may consider expanding the Code to allow for bridging meters for the purposes of testing the service mains in a separate Code amendment project.

Submitter's view

28.15 Intellihub advised that electricians (who are not participants under the Code) sometimes remove seals, and questioned whether requiring only qualified personnel to do this would be enforceable.

Our decision

28.16 Electricians who are removing seals acting under the instruction of the customer are tampering with the metering installation. Traders' contracts with their customers prohibit the customer, or anyone acting on behalf of the customer, interfering with the metering equipment. The trader is still responsible for the actions of their customer, as referenced in clause 10.12.

28.17 Electricians acting under the request of a participant are acting as the participant's agent, and the relevant participant is responsible for their actions.

28.18 The new provisions will be enforceable as the person breaking the seals is required to reseal using a traceable seal. If they do not, then there will be a record of the site visit, and the participant will be in breach of the new provisions.

Other considerations from submissions

Submitter's view

28.19 Meridian believes the Code provisions should be clarified to note that trader obligations do not apply when someone tampers with the metering.

Our view

28.20 The Code is not able to place obligations on consumers, or other parties, only on participants. A participant needs to be responsible for the results of tampering (remediation and submitting corrected volumes). The retailer is the participant with the contractual relationship with the customer and is best placed to manage the risk through that contractual relationship. In cases of tampering, it is the trader's responsibility to enforce any contractual penalties for repair or unmetered usage.

Submitter's view

28.21 Metrix states interference with an MEP's installation should only be performed by suitably qualified personnel who will not cause damage to the installation or its accuracy, and the trader is still responsible for notifying the MEP of any interference.

Our view

28.22 The Authority agrees and notes that the trader is responsible for the relationship with the customer with regards to tampering. The commercial arrangement between the MEP and trader controls how remediation is handled between these parties. If the distributor did work on an installation, then the retailer's use of system agreement could allow the retailer to recover costs.

Submitter's view

28.23 Orion questioned why training, and auditing of training, should be a particular Code and audit requirement.

28.24 Orion also stated that appropriate auditable training may need to be developed to meet this requirement.

Our view

28.25 Metering is the foundation of the market processes and customer invoicing. Currently metering is tightly controlled by the Code, and only done by ATHs who are audited. This proposal allows non-ATHs to legally perform some limited work on an MEP's metering installation. To ensure the metering remains accurate, and the personnel and public remain safe, we are including a requirement that the person doing the work is competent, and there is an assurance process (audit) for this, in the same way there is an assurance process for the ATH.

28.26 The Authority agrees that appropriate training will need to be developed, but we are not the appropriate organisation to develop training for this work. Participants that want to take advantage of these new provisions will need to either develop their own training or buy it in, leaving an opportunity for an appropriate organisation to provide training. These new provisions are not compulsory, so if a participant doesn't want to comply then they can follow the current process of requesting the MEP to perform this work.

The amendment will promote the efficient operation of the electricity industry

28.27 The Code amendment will promote the efficient operation of the electricity industry by removing unnecessary costs, in particular compliance costs, on:

(a) participants that, for valid reasons, are breaking or removing seals at metering installations, or 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 for issues caused by traders, distributors, or consumers.

28.28 The Code amendment will come into force on 1 February 2021.

The Code amendment

28.29 The Code amendment is as follows:

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 **meter** registers; and

(b) each **meter** register is active for a fixed period of time; and

(c) only one **meter** 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 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)~~ 19(3B), or 19(3C):

…

48 Removal or breakage of seals

(1A) ~~Despite clause 10.12, a~~ A **distributor** may interfere with a ~~the~~ **metering installation** without authorisation of the **metering equipment provider** responsible for the **metering installation**, to reset a load control ~~device~~ switch contained within a load control device or bridge or unbridge a load control ~~device~~ switch, if—

(a) the load control ~~device~~ switch 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~~ switch, 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 for ~~on~~ the **distributor**~~'s behalf~~; and

(c) advise the **trader** and **metering equipment provider** responsible for the **ICP** at which the **metering installation** is located if the load control ~~device~~ switch has been bridged or unbridged.

(1C) A **trader** that is advised under subclause (1B)(c) must, if ~~required~~ the **profile** code has changed, 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~~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~~ switch or bridge or unbridge a load control ~~device~~ switch, if the load control ~~device~~ switch does not control a **time block meter channel**.

(1E) ~~Despite clause 10.12, a~~A **trader** may remove or break a seal in a **metering installation** 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 or **generation** 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**.~~

(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 subclause~~s~~ (1D) or ~~and~~ (1E), 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 for ~~on~~ the **trader**~~'s behalf~~; and

(c) if ~~required~~ the **profile** code has changed, advise the **registry manager** of the updated **profile** code for the **ICP** in accordance with clause 10 of Schedule 11.1~~.~~; and

(d) advise the **metering equipment provider** that is responsible for the **metering installation** in which the seal is located, that the seal has been broken and what permitted work has been performed.

(1G) A **metering equipment provider** that has been advised under subclause (1B)(c) or (1F)(d), must advise the **registry manager** of the updated **meter** register content code for the relevant **meter** channel, if required.

(1) ~~Despite clause 10.12, a~~ A **participant** who removes or breaks a seal without authorisation of the **metering equipment provider** responsible for the **metering installation**, other than ~~and not~~ in accordance with subclauses (1A) to (1F), 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**.

…

(8) If a person removes or breaks a seal without authorisation of the **metering equipment provider** responsible for the **metering installation** in which the seal is located, 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 had ~~was~~ not been removed or broken when the **metering equipment provider** or **ATH** last performed work at the **metering installation**.

29 Proposal 028: Meter Bridging

We have decided to implement the proposal with no change to its policy intent, but with revised Code drafting

29.1 We have decided to amend the Code to allow bridging of a meter in exceptional circumstances. This is to ensure that a consumer is not significantly disadvantaged by their premises being electrically disconnected from a distributor's network. This commonly occurs when:

(a) systems or staff are unavailable to send a connection signal to an AMI meter that is remotely disconnected, which then requires an electrician to go to site and connect by bridging the meter

(b) a meter has a fault and it is unsafe to perform a full meter change at that time.

29.2 This is the proposal we consulted on, but with minor changes:

(a) change the notification period from "immediately" to "within 1 business day"

(b) clarify that the advice to affected participants must include the date of any bridging or unbridging

(c) change 10.33B(6)(c) to obligate the trader to notify the MEP within 1 business day of being advised the meter has been bridged, instead of within 1 business day of bridging occurring. This prevents a consequential breach by a trader if an MEP or distributor does not notify the trader within their own Code-mandated timeframe

(d) remove 10.33B(4), which duplicated the obligation in (6)(c).

We have decided to revise the proposal following submitters' feedback

Submitter's view

29.3 Some submitters felt that the meaning of "immediately" referring to when a party must be notified that bridging has occurred was not explicit enough.

Our decision

29.4 We have given consideration to this and have amended the proposed wording of the Code to state "1 business day", instead of "immediately". We recognise that many connections done via bridging are occurring after hours and it may not always be practical (or possible, in some remote areas) to notify affected parties straight away.

Submitter's view

29.5 Genesis suggested in their comments that the advice to the trader should include an event read at the time of reconnection via bridging, and the date and time of unbridging when it occurs.

Our decision

29.6 We have decided to amend the proposal to include advice of the date of bridging and unbridging in any notice to the current trader. However, we have decided against compelling including the time of day or event reading.

29.7 The Authority considers an event reading is unnecessary, as there will have already been a reading taken when the site was originally disconnected. We consider that a time of day is unnecessary because:

(a) If the meter is an AMI or commercial and industrial half hour meter then the current trader will know the time of reconnection when the meter data is next downloaded

(b) If the meter is a non-half hour AMI or legacy meter then the actual time of day is unnecessary as the meter readings for the submission process is deemed to be at midnight. If a trader requires the actual time of reconnection for other purposes then it can make commercial arrangements for this data to be included from whoever is performing the work.

29.8 If a trader who is not the current trader is reconnecting (as a result of a switch in progress) then a commercial agreement to retrieve the reconnection read is a more appropriate solution as the trader will already have a commercial arrangement with a service provider to perform the work. For AMI and commercial and industrial meters, the trader will receive the read when they receive the meter data from the MEP.

Submitter's view

29.9 Several submitters raised that one of the problems with bridging a meter is that the other parties involved may not be aware it has occurred in time to meet any resulting obligations.

Our decision

29.10 We have reviewed the proposal to ensure all parties have time to meet their obligations while limiting effects on reconciliation and settlement. As a result, we amended proposed 10.33B(6)(c) so that a trader has one business day from being advised of meter bridging to notify the responsible MEP that they must reinstate the meter. The original wording required the trader to notify the MEP within one business day of bridging occurring, which in some cases may not be possible as they may not yet have the advice from the distributor and would be at risk of receiving a consequential breach.

We have decided against making a change suggested by a submitter

Submitter's view

29.11 Several submitters were concerned that five business days for the MEP to reinstate the meter may not be a realistic timeline due to customer access issues. Electric Kiwi noted that occasionally bridging occurs, but the trader and MEP are unaware of it, and may not be able to correct the situation within five business days.

29.12 As a result, these submitters asked for consideration for any exceptional circumstances that may cause a meter to be bridged for longer than five business days.

Our decision

29.13 The Authority has decided not to extend the timeline for MEPs to remedy a bridged meter. We note that the longer a site remains bridged, the less accurate any consumption estimate will become. We also recognise that bridging currently occurs industry-wide, despite not being permitted by the Code. These instances usually occur for what could be considered justifiable reasons such as "the consumer at the ICP will likely be without electricity for a period of time that will cause significant disadvantage to the consumer." However, this must be balanced against the potential for significant disadvantage to the market as a whole, and limits must be in place to reduce risk to the market from inaccurate estimation that will have no basis for subsequent revision.

29.14 MEPs responsible for reinstating a meter have other options if a customer who has been bridged prohibits access to correct the situation designed to limit their inconvenience. For example, a customer can be disconnected further upstream of the meter to prevent further consumption.

29.15 In the future, MEPs may decide to provide additional services that naturally limit instances of bridging, such as 24/7 remote reconnections. An MEP may also allege a trader has breached the Code by bridging a meter when it was not necessary to avoid causing "significant disadvantage" to a consumer.

29.16 There is no risk to the MEP of not being able to correct a bridged meter within five business days simply because they did not know about it – the clock only starts once they have received the notice under subclause (6)(c).

Submitter's view

29.17 One submitter would prefer a solution that would encourage MEPs to offer additional connection services when staff or system unavailability prevents a reconnection from occurring. It notes that out of 4 AMI MEPs it currently contract with, only one provides handheld devices that can be used locally to complete the reconnection.

Our decision

29.18 This scale of change is out of scope of the proposed amendment. The Code does not generally endorse one technology over another where there are multiple ways to satisfy Code obligations. We encourage participants to use commercial arrangements to leverage the use of these existing beneficial services to improve customer outcomes.

Other issues considered by the Authority

29.19 The Authority also reviewed the proposal and noted that the proposed 10.33B(4) duplicated the requirements of the proposed 10.33B(6)(c). We have removed the duplication by deleting 10.33B(4) from the proposal and renumbering the remaining subclauses.

The amendment will contribute to the efficient operation, reliability of supply, and increased competition of the electricity industry

29.20 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, determines the unrecorded quantity of electricity. This is expected to reduce unaccounted for electricity, thereby improving the accuracy of wholesale market settlement and customer invoicing.

29.21 The proposed Code amendment may promote competition, by reducing transaction costs faced by retailers and consumers during the switching of electrically disconnected ICPs.

29.22 The proposed Code amendment would promote reliability of supply for consumers by facilitating the timely electrical connection of consumers.

29.23 The Code amendment will come into force on 1 February 2021.

The Code amendment

29.24 The Code amendment is as follows:

Part 10

…

10.33~~B~~C When trader may bridge meter at ICP

(1) Subject to subclause (2), only a **trader** that is responsible for an **ICP** or a **metering equipment provider** 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**).

(2) A **trader** may authorise a~~n~~ **metering equipment provider** or **distributor** under subclause (1)–

(a) generally for all or some of the **ICP**s that the **trader** is responsible for; or

(b) for a specific **ICP** that the **trader** is responsible for.

(3) A **trader** that is responsible for an **ICP**, or an **metering equipment provider** authorised by the **trader** or a **distributor** authorised by the **trader**, may only bridge a **meter** at the **ICP** if–

(a) the **metering equipment provider** responsible for the **meter**, despite best 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~~4) If a **meter** is bridged under subclause (1) by the **metering equipment provider** or **distributor**, the **metering equipment provider** or **distributor** (as the case may be) must ~~immediately~~, within 1 **business day,** advise the **trader** responsible for the **ICP** that ~~bridging a **meter** has occurred~~ the meter is bridged and include the date of bridging in its advice.

(~~6~~5) 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 being advised that the **meter** ~~being~~ is bridged, notify the **metering equipment provider** 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~~6) The **metering equipment provider** receiving the notice under subclause (~~6~~5)(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 10.33~~BC~~, 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.