Code Review Programme 2018

Consultation paper

Submissions close: 5pm, 6 March 2018

16 January 2018

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1 What you need to know to make a submission

What this consultation paper is about

1.1 This consultation paper presents the Electricity Authority's (Authority) latest set of 'omnibus' changes to the Electricity Industry Participation Code 2010 (Code): the *Code Review Programme 2018*. Consistent with the Authority's statutory objective, the aim of these proposed changes is to promote the efficient operation of the electricity industry for the long-term benefit of consumers. The purpose of this paper is to consult with interested parties on the proposed changes.

1.2 The Authority's previous 'omnibus' Code amendment, the *Code Review Programme 2017*, focused primarily on simplifying language and particular processes in the Code.[1] The changes proposed in this consultation paper focus largely on resolving practical problems created by particular Code provisions that directly impede the efficient operation of the industry. The Authority believes that making the proposed changes would resolve these practical problems, and, as a result, promote the efficient operation of the industry.

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

1.4 Under section 39(3)(a) of the Act, if the Authority is satisfied that a proposed amendment is technical and non-controversial, the Authority need not provide a regulatory statement or consult on the proposed amendment. The Authority considers that four of the 23 proposals in the *Code Review Programme 2018* are technical and non-controversial and has not provided a regulatory statement for them. Although the Authority is not required to consult on the technical and non-controversial changes, it invites comment on all proposals in the *Code Review Programme 2018*.

1.5 For each discrete proposal, the regulatory statement (where required) is included in the relevant table for the proposed amendment in Appendix B.

How to make a submission

1.6 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "Consultation Paper—Code Review Programme 2018" in the subject line.

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

[1] For example, the *Code Review Programme 2017* sought to simplify the Code's processes and requirements for making information available. For further reference, the Authority's decision paper on the *Code Review Programme 2017* is available at: https://www.ea.govt.nz/development/work-programme/operational-efficiencies/code-review-programme/development/decision-and-reasons-paper/.

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Level 7, ASB Bank Tower
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1.8 Please note the Authority wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published

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

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

1.9 If you indicate that we should not publish part of your submission, we will discuss with you before deciding whether to not publish that part of your submission.

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

When to make a submission

1.11 Please deliver your submissions by **5pm** on Tuesday **6 March 2018**.

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

2 Code Review Programme 2018

This is the third Code Review Programme

2.1 The *Code Review Programme 2018* is the third Code Review Programme and latest set of ‘omnibus’ changes the Authority proposes to make to the Code.

2.2 Ordinarily, Code change proposals have a single theme. These ‘omnibus’ proposals allow the Authority to make a number of relatively small amendments, each with a different theme, all at once.

2.3 The Authority considers that the ‘omnibus’ approach allows it to use its resources efficiently, and that the Code will benefit from improvements that might not otherwise have been possible.

2.4 A new feature of this *Code Review Programme 2018* is a standalone proposal to correct minor typographical errors in the Code. These errors include outdated cross-references, incorrect headings, terms that are in bold but should not be, and other minor drafting errors. The proposal to correct the errors is reference number 2018-23 as shown in the list of topics in the table below.

The proposals are set out in Appendix B

2.5 The 23 Code change proposals are set out in Appendix B. Because each proposal is discrete from the others, the Authority has described and analysed each one separately. This means the format of this consultation paper is different from the consultation papers the Authority usually publishes.

2.6 For each proposal, there is a problem definition, a proposed solution (including proposed Code drafting), and an assessment against the Authority's statutory objective, section 32(1) of the Act, and the Authority's Code amendment principles. Apart from the four proposals the Authority considers are technical and non-controversial, each proposal also includes a regulatory statement.

2.7 The Code change proposals are described in Appendix B. Each table has a unique reference number in its top row.

2.8 Most proposed amendments address a discrete issue, but in some places changes intersect or overlap. Because each proposal stands on its own, some may proceed while others may not. Showing the draft changes separately allows submitters to assess how each proposed amendment would affect Code obligations.

2.9 The table below shows the list of topics addressed by each proposed amendment.

Table 1: List of proposed amendments

Reference number	Topic	Page
2018-01	Clarifying requirement to update registry metering records	10
2018-02	Timeframe for distributors to give written notice of ICP decommissioning	13
2018-03	Clarifying the scope of an appeal under clause 8.36	16
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2018-17	Removing the defined term “customer” from Part 1	80
2018-18	Update to security forms under Schedules 14A.2 to 14A.	95

3 Regulatory Statements for the proposed amendment

3.1 As noted above, this consultation paper differs in format from the consultation papers the Authority usually publishes. For each proposed amendment that requires a regulatory statement, the regulatory statement is included in the relevant table for the proposed amendment in Appendix B.

3.2 The primary economic benefit described in the regulatory statements is a reduction in transaction costs across the industry, which is a productive efficiency benefit. Having said this, by improving the clarity and operation of the Code, the proposed amendments could also deliver dynamic efficiency benefits. A clear, predictable and up-to-date set of industry rules is good regulatory practice, and can facilitate increased participation in the electricity markets. This in turn might be expected to facilitate all three limbs of the Authority's statutory objective, and provide both static and dynamic efficiency benefits to the economy.[2]

3.3 When assessing the quantitative benefits and costs of proposed Code amendments, the Authority typically uses a real discount rate of 6% with sensitivities of plus or minus 2%. For the *Code Review Programme 2018*, the Authority has used a point estimate of the discount rate, for ease of analysis. To minimise the risk of overstating the net benefit of a proposed Code amendment, the Authority used a real discount rate of 8%.

[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, the costs of production equal the minimum amount necessary to produce the output. A productive efficiency loss results if the costs of production are higher than this, because the additional resources used could instead be deployed productively elsewhere in the economy. Dynamic efficiency is achieved by firms having appropriate (efficient) incentives to innovate and invest in new products and services over time. This increases their productivity, including through developing new processes and business models, and lowers the relative cost of products and services over time.

Appendix A Format for submissions

A.1 Please complete the table below for each proposed amendment on which you wish to submit. Please include the reference number from the first row of the table in Appendix B).

Reference	2018 -
Question 1: Do you agree with the Authority's problem definition? If not, why not?	
Question 2: Do you agree with the Authority's proposed solution? If not, why not?	
Question 3: Do you have any comments on the Authority's proposed Code drafting?	
Question 4: Do you agree with the objectives of the proposed amendment? If not, why not?	

Question 5: Do you agree the benefits of the proposed amendment outweigh its costs? If not, why not?
Question 6: Do you agree the proposed amendment is preferable to the other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Appendix B Proposed amendments

2018-01 Clarifying requirement to update registry metering records

Reference number(s)	2018-01 Clarifying requirement to update registry metering records
Problem definition	Clause 3 of Schedule 11.4 requires a metering equipment provider (MEP) to advise the registry manager of the registry metering records, or any change to the registry metering records, for a metering installation for which it is responsible, no later than 10 business days following: a) the electrical connection of an ICP that is not also an NSP b) any subsequent change in any matter covered by the metering records. The policy intent of clause 3 of Schedule 11.4 is that, where an MEP has an arrangement with a trader at an ICP that is not also an NSP, the MEP must advise the registry manager of the records for all metering installations for which the MEP is responsible at the ICP. This helps to minimise the amount of unaccounted for electricity in submission information provided to the reconciliation manager. However, this policy intent is not reflected in the clause's current wording. An MEP responsible for two or more metering installations at an ICP that is not also an NSP only has to advise the registry manager of the registry metering records for one of the metering installations. This gap in the drafting of clause 3 of Schedule 11.4 means it is possible that some registry metering records could end up missing for ICPs. This could result in participants submitting inaccurate metering volumes to the reconciliation manager, which leads to inaccurate invoicing of traders and inaccurate customer invoicing.
Proposal	The Authority proposes to amend clause 3 of Schedule 11.4 to clearly state that, where an MEP has an arrangement with a trader at an ICP that is not also an NSP, the MEP must advise the registry manager of the registry metering records, or any change to the registry metering records, for all metering installations for which the MEP is responsible at that ICP.
Proposed Code amendment	**Schedule 11.4, clause 3 Metering equipment provider to advise registry manager of changes to registry metering records** ~~A~~If a **metering equipment provider** has an arrangement with a **trader** at an **ICP** that is not also an **NSP**, the **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~~an~~ **ICP**

	~~that is not also an NSP~~: (b) any subsequent change ~~in any matter covered by~~ to the **metering installation's metering records**.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective and section 32(1)(c) of the Act because it would contribute to the efficient operation of the electricity industry. Clarifying the requirements under clause 3 of Schedule 11.4 in the manner proposed would help facilitate accurate registry metering records. This in turn would facilitate accurate reconciliation, and accurate invoicing of traders and customers. To a smaller degree, the proposed amendment may also promote competition in the electricity industry. This is because facilitating accurate registry metering records better enables traders to undertake customer switching in a timely manner. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to promote accurate registry metering records, which in turn promotes accurate reconciliation, and accurate invoicing of traders and customers.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the proposed Code amendment should place no additional costs on industry participants. This is because the proposal reflects current industry practice, which is that an MEP advises the registry manager of the registry metering records for

	each metering installation the MEP is responsible for at an ICP. *Benefits* The proposed amendment's primary benefit is a much lower possibility that, in future, an MEP will not advise the registry manager of the registry metering records for all metering installations the MEP is responsible for at an ICP that is not an NSP. As outlined above, this would facilitate the submission of accurate metering volumes to the reconciliation manager, which in turn would facilitate accurate invoicing of traders and accurate customer invoicing. If the Authority did not amend the Code as proposed, some reconciliation participants could, in the future, start providing incomplete submission information by ICP. This would be expected to result in higher volumes of unaccounted for electricity, the cost of which would be shared amongst all traders operating in the same balancing area. Additionally, consumers would be invoiced for an amount of electricity that differed from that which they consumed by a greater quantity than under the proposed Code amendment. The marginal value that consumers placed on the electricity they purchased would not be as close to the cost of producing that electricity as it could be. This would be a market inefficiency. Facilitating accurate registry metering records also helps enable traders to undertake customer switching in a timely manner. This may facilitate retail competition in the electricity industry, i.e. the first limb of the Authority's objective. It would also be expected to reduce traders' transaction costs in the switching process, which would further the third limb of the Authority's objective. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.

2018-02 Timeframe for distributors to give written notice of ICP decommissioning

Reference number(s)	2018-02 Timeframe for distributors to give written notice of ICP decommissioning
Problem definition	Clause 8 of Schedule 11.1 of the Code requires a distributor to give written notice to the registry manager if ICP information (which the distributor has provided to the registry manager under clause 7 of Schedule 11.1) changes. Under clause 7(1)(k) of Schedule 11.1, this includes updating the status of the ICP if it has been decommissioned under clause 20 of Schedule 11.1. Under clause 8(2)(b) of Schedule 11.1, a distributor has 3 business days after decommissioning an ICP on its network to give written notice to the registry manager of the decommissioning. However, distributors are sometimes unable to comply with this timeframe, because it is not consistent with the longer timeframe (5 business days) that the trader has under clause 10(2) of Schedule 11.1 to advise the registry manager that an ICP is ready for decommissioning. One example of when this issue arises is when an ICP is made inactive and then decommissioned on the same day. The distributor whose network the ICP is on cannot give notice to the registry manager of the ICP's decommissioning until the ICP's status in the registry is "inactive". If the trader responsible for the ICP takes 4 or 5 business days to update the ICP's status to "inactive", the distributor cannot meet the 3-business day timeframe for giving notice of the ICP's decommissioning to the registry manager.
Proposal	The Authority proposes to amend the Code to require a distributor to give the registry manager written notice of having decommissioned an ICP by the later of: • 3 business days after the registry manager has advised the distributor that an ICP is ready for decommissioning • 3 business days after the distributor has decommissioned the ICP.[1]
Proposed Code amendment	**8 Distributors to change ICP information provided to registry manager** (1) If information about an **ICP** provided to the **registry manager** in accordance with clause 7 changes, the **distributor** in whose **network** the **ICP** is located must give written notice to the **registry manager** of the change. (2) The **distributor** must give the notice— (a) in the case of a change to the information referred to in clause

[1] This second scenario is to accommodate instances where an ICP is ready for decommissioning for some time before the distributor decommissions it.

	7(1)(b) (other than a change that is the result of the **commissioning** or **decommissioning** of an **NSP**), no later than 8 **business days** after the change takes effect~~; and~~: (ab) in the case of **decommissioning** an **ICP**, by the later of: (i) 3 **business days** after the **registry manager** has advised the **distributor** under clause 11.29 that the **ICP** is ready to be **decommissioned**; and (ii) 3 **business days** after the **distributor** has **decommissioned** the **ICP** (b) in every other case, no later than 3 **business days** after the change takes effect.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed 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. The proposed amendment would: • make a distributor's timeframe for giving the registry manager notice of an ICP's decommissioning compatible with the timeframe a trader has to give the registry manager notice of making the ICP inactive • remove unnecessary compliance costs for distributors in reporting breaches of clause 8 of Schedule 11.1, and for the Authority in processing such breaches. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	Some of the costs and benefits of the proposed Code amendment can be quantified, but it has not been practicable to quantify others. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the	The objective of the proposal is to resolve a problem in the Code

proposed amendment	where a distributor breaches the Code due to a trader's actions that comply with the Code.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the proposed amendment would place no additional costs on industry participants because it does not put any additional obligations on distributors, traders, or other participants. *Benefits* The primary benefit of the proposed amendment would be to reduce compliance costs for distributors and the Authority. These costs include those arising from the Code compliance process, and discussions between Authority staff and auditors on breaches of clause 8 of Schedule 11.1 identified in audit reports. The Authority estimates the cost that it and distributors[2] would save in aggregate is approximately $600-$850 per annum.[3] This equates to a present value benefit of approximately $5,000-$7,500.[4] *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed amendment that would meet the objective of the proposal.

[2] Including the cost of time spent by auditors.
[3] This relates to time saved for staff from distributors, auditors and the Authority.
[4] Assuming one Code breach per year for the next 15 years, in the absence of the proposed Code amendment being made, and using a real discount rate of 8%.

2018-03 Clarifying the scope of an appeal under clause 8.36

Reference number(s)	2018-03 Clarifying the scope of an appeal under clause 8.36
Problem definition	Clause 8.36(1) contains erroneous drafting. It allows participants to "…appeal a decision of…an asset owner in relation to an application for dispensation or equivalence arrangements on the grounds set out in clause 8.36(3)". However, such an appeal is impossible, because asset owners have no decision-making powers under the Code in relation to applications for dispensations or equivalence arrangements. When the former Electricity Governance Rules (EGRs) were first being drafted, it was proposed that a participant would be able to appeal a decision of an asset owner that certain information in an application for an equivalence arrangement or a dispensation was confidential. This ground for appeal ended up not being included in the EGRs, but the words "or an asset owner" were never deleted from what is now clause 8.36(1) of the Code. Clause 8.36(1) is therefore misleading in this respect, and could potentially create unnecessary cost and confusion for participants trying to understand their appeal rights under this provision.
Proposal	The Authority proposes to remove the wording "or an asset owner" from clause 8.36(1) to align it with clause 8.36(2) to (5), which refers only to a decision made by the system operator.
Proposed Code amendment	**8.36 Appeal against decisions** (1) A **participant** may **appeal** a decision of the **system operator** ~~or an asset owner~~ in relation to an application for **dispensation** or **equivalence arrangements** on the grounds set out in subclause (3).
Grounds for not consulting	The Authority is satisfied the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will have no effect on current practice. Rather, the proposed amendment would remove the possibility of any confusion, caused by inaccurate language in the Code.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by making it easier for participants to understand and follow clause 8.36(1) of the Code. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.

Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an error in the Code, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

2018-04 Clarifying when losing trader must respond to switch move request

Reference number(s)	2018-04 Clarifying when losing trader must respond to switch move request
Problem definition	Under clause 10(1) of Schedule 11.3, after receiving notice of a switch request from the registry manager under clause 22(a) of Schedule 11.3, the trader recorded in the registry as being responsible for the ICP (the "losing trader") must: • complete the switch using the event date the gaining trader proposes; • acknowledge the switch request to the registry manager, but determine a different event date; or • request the switch be withdrawn. If the losing trader determines a different event date, the losing trader must still complete the switch, but with the event date being that determined by the losing trader. Currently, if the losing trader determines a different event date under clause 10(1)(b) of Schedule 11.3, clause 10(2) of Schedule 11.3 does not explicitly specify a timeframe by which the losing trader must complete the switch. The policy intent of clause 10(2) of Schedule 11.3 is that the losing trader should complete the switch in the same timeframe as it would under clause 10(1)(a) of Schedule 11.3. That is, the trader should complete the switch within 5 business days of receiving notice of the switch request from the registry manager under clause 22(a) of Schedule 11.3.
Proposal	The Authority proposes to amend clause 10(2) of Schedule 11.3 of the Code to deliver the policy intent described immediately above. That is, if the losing trader determines a different event date to that proposed by the gaining trader for a switch move request, the losing trader must complete the switch within 5 business days of receiving notice of the switch request from the registry manager.
Proposed Code amendment	**Schedule 11.3** … **10 Losing trader response to switch move request** (1) After receiving notice of a switch request from the **registry manager** under clause 22(a), the **trader** that is recorded in the **registry** as being responsible for the **ICP** (the "losing **trader**") must, no later than 5 **business days** after receiving the notice,— (a) if the losing **trader** accepts the **event date** proposed by the gaining **trader**, complete the switch by providing to the **registry manager**— (i) *[Revoked]*

	(ia) confirmation of the **event date**; and (ib) a valid switch response code approved by the **Authority**; and (ii) final information in accordance with clause 11; or (b) if the losing **trader** does not accept the **event date** proposed by the gaining **trader**, acknowledge the switch request to the **registry manager** and determine a different **event date** that— (i) is not earlier than the gaining **trader's** proposed **event date**; and (ii) is not later than 10 **business days** after the date the losing **trader** receives the notice: or (c) request that the switch be withdrawn in accordance with clause 17. (2) If the losing **trader** determines a different **event date** under subclause (1)(b), the losing **trader** must<u>, no later than 5 **business days** after receiving the notice referred to in subclause (1),</u> also complete the switch by providing to the **registry manager** the information described in subclause (1)(a), but in that case the **event date** is the **event date** determined by the losing **trader**.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. This is because the proposed amendment would, for a switch move request where the losing trader determines a different event date to that proposed by the gaining trader, set a timeframe for the losing trader to complete the switch. Such a timeframe would reduce the likelihood of: • disputes between traders • unnecessary transaction costs for the losing trader and customer, caused by uncertainty as to when the losing trader will complete the switch, or delays completing the switch. The proposed Code amendment would also facilitate competition in the electricity industry. This is because clarifying the obligations in the manner proposed will help to minimise customer switch times. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied that the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and

	the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2, because it is expected to: • result in participants operating more efficiently, and incurring lower costs in complying with the Code • facilitate timely customer switching.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, the Authority has undertaken a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to facilitate efficient customer switching by clarifying the time by which the losing trader (after determining a different switch event date to that proposed by the gaining trader) must complete a switch following a switch move request.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit. *Costs* The Authority expects that implementing the proposed Code amendment would have no costs, because it reflects current industry practice. That is, if the losing trader determines a different switch event date for a switch move request, the losing trader completes the switch within 5 business days of receiving notice of the switch move request. *Benefits* The proposed amendment is expected to reduce the likelihood of the gaining trader (in particular) and customer incurring unnecessary transaction costs following a switch move request. These costs might arise if the gaining trader expected the switch to occur within 5 business days, but the losing trader took longer. An example of these transaction costs would be additional time spent by the gaining trader liaising with the customer over a delay to the switch. The proposed amendment would also reduce the likelihood of disputes between traders during the switch move process, because of the losing trader delaying the completion of the switch. This represents another form of transaction cost. Lastly, the proposed amendment should facilitate competition in the industry by placing downward pressure on the timeframe for a losing trader to switch an ICP following a switch move request. This encourages customers to switch, and retailers to compete for

	customers. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.

2018-05 Block dispatch agreement notification

Reference number(s)	2018-05 Block dispatch agreement notification
Problem definition	Clause 13.60(2)(a) provides that if a generator and the system operator enter into a block dispatch agreement, the generator must give written notice to the clearing manager and the system operator of having entered into that agreement. As the system operator is one of the parties to such an agreement, there is no need for the generator to give the system operator written notice of the agreement it has just reached with the system operator. Clause 13.60(3) puts a similarly unnecessary obligation on a generator by requiring it to give written notice to the system operator when there is a change to the block dispatch agreement it has with the system operator. Both of these obligations create transaction costs for a generator without delivering any clear benefits.
Proposal	The Authority proposes to amend clause 13.60(2)(a) and (3) to remove the requirement for a generator to give written notice to the system operator when: • the generator reaches a block dispatch agreement with the system operator • there is a change to an existing block dispatch agreement.
Proposed Code amendment	**13.60 Block dispatch may occur** (1) A **generator** and the **system operator** may agree to treat a group of **generating stations** as a **block dispatch group**. (2) If an agreement for block dispatch has been reached, the following procedures apply: (a) the **generator** must give written notice to ~~the **system operator** and~~ the **clearing manager** of the agreement, at least 5 **business days** before the agreement takes effect, specifying— ... (3) The **generator** must give written notice to ~~the **system operator** and~~ the **clearing manager** of any change to an agreement for **block dispatch** made under this clause or clause 13.61 at least 5 **business days** before the change takes effect.
Grounds for not consulting	The Authority is satisfied that, under section 39(3)(a) of the Act, the nature of the amendment is technical and non-controversial. This is because the amendment will not change the fact that the system operator receives notice of a block dispatch agreement, or an amendment to an existing agreement, because the system operator

	is a party to such an agreement.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective and section 32(1)(c) of the Act because it would contribute to the efficient operation of the electricity industry. It would do this by revoking the requirement for a generator to give written notice to the system operator under clause 13.60(2)(a) and (3) which, for the reason outlined above, is unnecessary and hence inefficient. The proposed amendment is expected to have no effect on competition or reliability.
Assessment against Code amendment principles	The Authority is satisfied the Code proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The proposed amendment is expected to impose no costs on participants. The Authority expects that the proposed amendment would result in a quantifiable benefit of less than $1,000.[1] This relates to a saving in system operator staff time. System operator staff would no longer receive from generators, and then file, written notices of block dispatch agreements. On average, there are two such notices each year. The Authority believes the proposed amendment would deliver negligible benefit to generators with block dispatch generating stations. The only benefit to them would come from no longer advising the system operator of a block dispatch agreement under clause 13.60. However, the incremental cost of advising the system operator in addition to the clearing manager is very small, meaning the proposal's benefit to them is negligible.

[1] Using a discount period of 15 years and a real discount rate of 8%.

2018-06 Amending or rescinding an approved shorter post-default exit period

<table>
<tr><td>Reference number(s)</td><td>2018-06 Amending or rescinding an approved shorter post-default exit period</td></tr>
<tr><td>Problem definition</td><td>The amount of prudential security that the clearing manager requires from a participant under the Code is determined in part by the participant's post-default exit period under clause 14A.22(4) of the Code.

If the participant defaults to the clearing manager, the participant's post-default exit period is the period during which the participant must cover its electricity purchases with its prudential security while exiting the wholesale electricity market.

Under clause 14A.22(4), a participant's post-default exit period is as follows, unless the Authority has approved a shorter period elected by the participant:

a) for a retailer, 18 trading days:
b) for a direct purchaser, 7 trading days:
c) for a participant that is not a retailer or a direct purchaser, 7 trading days.

There are two problems with how clause 14A.22(4) currently provides for the Authority to approve a shorter post-default exit period than those set out in paragraphs a) to c) above:[1]

• It is foreseeable that, after the Authority approves a shorter post-default exit period for a participant, the participant's circumstances change such that the criteria against which the Authority approved a shorter period are no longer met. As a result, the participant may have a lower level of prudential security than that which best promotes the efficient operation of the electricity market. This problem is compounded by the Code not requiring:
    o a participant with a shorter post-default exit period to immediately advise the Authority when such a change in circumstances may have occurred
    o the clearing manager to immediately advise the Authority if the clearing manager becomes aware that such a change in circumstances for a participant may have occurred.

• The clause's wording "elected by the participant" does not convey the Authority's desired policy intent, which is that a participant <u>requests</u> that the Authority approve a shorter post-default exit period than that set out in paragraphs a) to c) above.</td></tr>
</table>

[1] The criteria against which the Authority assesses and determines a participant's request to approve a shorter post-default exit period under clause 14A.22(4) are outlined at: https://www.ea.govt.nz/operations/market-operation-service-providers/clearing-manager/prudential-security/.

Proposal	The Authority proposes to amend the Code to: a) require a participant with a shorter post-default exit period to advise the Authority immediately if the participant's circumstances change such that the criteria against which the Authority approved a shorter period may no longer be met b) require the clearing manager to advise the Authority immediately if the clearing manager becomes aware that the circumstances of a participant for whom the Authority has approved a shorter post-default exit period have changed such that the criteria against which the Authority approved a shorter period may no longer be met c) provide that, if the Authority considers there has been a change in the circumstances of a participant for whom it has approved a shorter post-default exit period, the Authority may: • amend the participant's post-default exit period; or • rescind its approval of a shorter post-default exit period d) provide that if the Authority amends or rescinds its approval of a participant's shorter post-default exit period under clause 14A.22(4), the Authority must: • give the participant at least 1 month's notice in writing before the rescission or amendment comes into effect • advise the participant of the reasons for rescinding or amending the approval e) change the wording in clause 14A.22(4) from "elected by the participant" to "requested by the participant", to reflect that approving the shorter period is at the Authority's discretion.
Proposed Code amendment	**14A.22 Clearing manager to keep register of specified time periods** ... (4) The post-default exit period for a **participant** is as follows, unless the **Authority** has approved a shorter period <u>requested </u>~~elected~~ by the **participant**: (a) for a **retailer**, 18 **trading days**: (b) for a **direct purchaser**, 7 **trading days**: (c) for a **participant** that is not a **retailer** or a **direct purchaser**, 7 **trading days**. ... <u>(8) If the **Authority** has approved a shorter post-default exit period for a **participant**, the **participant** must immediately advise the **Authority** if the **participant's** circumstances change such that the criteria against which the **Authority** approved the shorter post-default exit period may no longer be met.</u>

	<u>(9) If the **Authority** has approved a shorter post-default exit period for a **participant**, the **clearing manager** must immediately advise the **Authority** if the **clearing manager** becomes aware that the **participant's** circumstances have changed such that the criteria against which the **Authority** approved the shorter post-default exit period may no longer be met.</u> <u>(10) If the **Authority** considers a **participant's** circumstances have changed such that the criteria against which the **Authority** approved the **participant** having a shorter post-default exit period are no longer met, the **Authority** may—</u> <u>(a) amend the **participant's** post-default exit period; or</u> <u>(b) rescind its approval of the shorter post-default exit period for the **participant**.</u> <u>(11) If the **Authority** amends or rescinds its approval of a **participant's** shorter post-default exit period, the **Authority** must—</u> <u>(a) give the **participant** at least 1 month's notice in writing before the amendment or the rescission comes into effect; and</u> <u>(b) advise the **participant** of the reasons for rescinding or amending the approval.</u>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute primarily to the efficient operation of the electricity industry. The proposed amendment would do this by reducing the risk of a shortfall in prudential security provided by purchasers in the wholesale electricity market. The proposed amendment is expected to have little or no effect on competition. On the supply side, the relative benefit to generators from a lower risk of a shortfall in prudential security should, in large part, be similar across generators, since any settlement shortfall is pro-rated across generators. On the demand side, it is difficult to say whether a retailer that is putting up less prudential security than it should is using the additional working capital to compete harder to win consumers. Therefore, it is difficult to say that the proposed amendment would have an effect on retail competition. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1:	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and

Lawfulness.	the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, the Authority has undertaken a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to contribute to the efficient operation of the electricity industry by enabling the Authority to amend a participant's post-default exit period (or rescind its approval of a shorter post-default exit period) if the participant's circumstances change.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed amendment would have a positive net benefit. *Costs* The Authority expects the proposed amendment could create relatively minor costs, arising primarily from: 1) participants advising the Authority if their circumstances change such that the criteria against which the Authority approved a shorter exit period may no longer be met 2) the clearing manager advising the Authority if it becomes aware that a participant's circumstances have changed such that the criteria against which the Authority approved a shorter exit period may no longer be met 3) the Authority reconsidering its approval, including liaising with the relevant participant and with the clearing manager 4) the Authority advising relevant parties of its decision (and reasons) to amend or rescind its approval of a shorter post-default exit period. Based on its experience, the Authority anticipates the above process will occur infrequently – perhaps once per year. The Authority estimates this would cost it and the relevant participant approximately $2,400 per annum,[2] which equates to a present value of approximately $20,500 (assuming a 15-year discount period and a real discount rate of 8%).

[2] Relating primarily to staff time and costs.

	Benefits The primary benefit of the proposed amendment is that it would reduce the risk of a shortfall in prudential security provided by purchasers in the wholesale electricity market. In a competitive market, generators would be expected to remove any risk premium attached to this risk from their offers into the market. It is extremely difficult, if not impossible, to quantify this benefit. However, even a small fraction of a percentage saving in generators' offers would deliver greater savings than the estimated cost of the proposal. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment would outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	*Alternative: Approving shorter post-default exit periods for a fixed term instead of an indefinite term* An alternative means of achieving the proposal's objective would be for the Authority to approve shorter post-default exit periods for fixed terms, rather than approving them for indefinite terms. Each participant would need to re-apply to the Authority before the fixed term expired, if they wanted to retain a shorter post-default exit period. The fixed term could be prescribed in the Code, or set at the Authority's discretion when approving a request for a shorter post-default exit period under clause 14A.22(4). *Costs* A regular assessment of a shorter post-default exit period would cost more than assessments undertaken on an "as needed" basis under the proposal. Participants and the Authority would incur a cost regardless of whether or not the participant's circumstances had changed. This would impose unnecessary transaction costs on participants and the Authority. *Benefits* The main benefit of the alternative arrangement would be the obligation on participants to regularly report to the Authority on their circumstances. This would help keep their post-default exit period in a more prominent position in the participant's consciousness than would perhaps be the case under the proposal. *Evaluation* The Authority believes the net benefit of the alternative would be lower than the proposal's net benefit, because of the alternative's higher costs. If the Authority adopted the proposal, the Authority could also regularly communicate (eg, annually) with participants, reminding

	them of their obligations under clause 14A.22. This would be expected to achieve most, if not all, of the benefit of the alternative, while still delivering the reduced costs from the proposal's "as needed" effect.

2018-07 Clarifying Code requirements for ICP information relating to chargeable capacity

Reference number(s)	2018-07 Clarifying Code requirements for ICP information relating to chargeable capacity
Problem definition	Clause 7(1) of Schedule 11.1 requires a distributor to provide certain information to the registry manager for each ICP on the distributor's network. Under clause 7(1)(g) of Schedule 11.1, this information includes the price category code assigned to an ICP. If the price category code requires a value for the capacity of the ICP, then under clause 7(1)(h) of Schedule 11.1, the distributor must also provide the registry manager with the chargeable capacity of the ICP, as follows: • if the chargeable capacity cannot be determined before electricity is traded at the ICP, a placeholder chargeable capacity: • if the capacity value can be determined from the metering information, no chargeable capacity: • in any other case, the actual chargeable capacity. Many distributors calculate monthly values for the chargeable capacity of some ICPs on their networks. These distributors use an ICP's metering information for a calendar month to calculate the ICP's chargeable capacity for that month. Some distributors also use an ICP's metering information for a calendar year to calculate an annual value for the ICP's chargeable capacity. The policy intent of clause 7(1)(h)(ii) of Schedule 11.1 is that a distributor must leave the chargeable capacity field in the registry empty *only if* the chargeable capacity at an ICP is calculated from metering information collected for a calendar month.[1] However, a distributor that calculates annual chargeable capacity values using metering information could interpret clause 7(1)(h)(ii) of Schedule 11.1 to mean the distributor must not populate these values in the chargeable capacity field in the registry. Some distributors have adopted this interpretation, and mistakenly left an ICP's chargeable capacity field empty instead of populating it with an annual chargeable capacity value. This has proven to be a problem for some traders, who know the intended meaning of clause 7(1)(h)(ii) of Schedule 11.1. These traders see an empty chargeable capacity field for an ICP in the registry and assume that a monthly capacity charge applies, when in

[1] In the Code, "billing period" means a period of 1 calendar month.

	fact an annual capacity charge applies. This has resulted in traders: • incorrectly charging the customer at the ICP; or • erroneously pricing a quote to supply a potential customer at the ICP.
Proposal	The Authority proposes to amend clause 7(1)(h) of Schedule 11.1 of the Code to clarify that a distributor must leave the chargeable capacity field empty *only if* the chargeable capacity at an ICP is calculated from metering information collected *for a billing period*.[2]
Proposed Code amendment	**Schedule 11.1** … **7 Distributors to provide ICP information to registry** (1) A **distributor** must, for each **ICP** on the **distributor's network**, provide the following information to the **registry manager**: … (g) the **price category** code assigned to the **ICP**, which may be a placeholder **price category** code only if the **distributor** is unable to assign the actual **price category** code because the capacity or **volume information** required to assign the actual **price category** code cannot be determined before **electricity** is traded at the **ICP**: (h) if the **price category** code assigned under paragraph (g) requires a value for the capacity of the **ICP**, the **chargeable capacity** of the **ICP**, as follows: (i) if the **chargeable capacity** cannot be determined before **electricity** is traded at the **ICP**, a placeholder **chargeable capacity**: (ii) if the capacity value can be determined for a **billing period** from the **metering information** collected for that **billing period**, no **chargeable capacity**: (iii) in any other case, the actual **chargeable capacity**: …
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by: • clarifying clause 7(1)(h)(ii) of Schedule 11.1, which would mean distributors populated chargeable capacity values in the registry according to the policy intent of that clause

[2] Adopting the Code's terminology for a calendar month.

	• reducing the number of billing errors resulting from traders misinterpreting empty chargeable capacity fields in the registry. The proposed Code amendment may also facilitate competition in the electricity industry by reducing the cost that some traders face in gaining customers. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, the Authority has carried out a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposed Code amendment is to make clause 7(1)(h) of Schedule 11.1 clearer as to when a distributor must leave empty the chargeable capacity field for an ICP in the registry.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed amendment would have a positive net benefit. *Costs* The Authority considers that implementing the proposed Code amendment would have negligible costs. The Authority expects there would be no additional cost for a distributor that currently populates the registry with an annual capacity charge calculated using metering information. In fact, there may be a reduced cost—see the discussion below under 'Benefits'. If it adopted the proposed Code amendment, the Authority would prepare an accompanying information memorandum that explained the use of chargeable capacity fields in the registry. The

	memorandum would assist distributors implement the proposed Code amendment. The Authority expects the costs of preparing the memorandum would be negligible. *Benefits* The primary benefit of the proposed Code amendment is that distributors should populate chargeable capacity values in the registry according to the policy intent of clause 7(1)(h) of Schedule 11.1. This would reduce the likelihood of traders misinterpreting empty chargeable capacity fields in the registry, which would correspondingly reduce the number of billing errors from traders. This would reduce traders' costs of supplying customers, since they would not have to re-invoice customers as frequently. This would be a productive efficiency benefit. A further productive efficiency benefit might arise from a subset of distributors facing lower operational costs. These are the distributors that currently do not populate the registry with an annual capacity charge calculated using metering information. Under the proposed Code amendment, these distributors would no longer need to provide each trader on their respective networks with a file containing the annual capacity charge values. Instead, the distributor would upload a single file to the registry, which updated all relevant ICP identifiers. Traders would receive notice of changes to the capacity charges for their ICPs via the registry change notification process. The proposed Code amendment may also facilitate competition in the electricity industry. Clarifying clause 7(1)(h) of Schedule 11.1 in the proposed manner will improve the accuracy of ICP information in the registry. Therefore, a retailer would: • find it easier to prepare a price plan for a prospective customer that accurately reflects the prospective customer's consumption • face a lower probability of making a billing error when gaining a new customer. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.

2018-08 Amending the timeframe for the clearing manager to calculate constrained off/on amounts

Reference number(s)	2018-08 Amending the timeframe for the clearing manager to calculate constrained off/on amounts
Problem definition	Constrained off compensation and constrained on compensation form part of the monthly settlement of the New Zealand electricity market. The clearing manager uses information from the pricing manager, reconciliation manager, and system operator to calculate constrained off amounts and constrained on amounts. The Code specifies timeframes within which the clearing manager must calculate these amounts. The timeframe in clause 13.197 for calculating constrained off amounts is absolute: the clearing manager must calculate constrained off amounts by 1600 hours on the 8th business day each month. Under clause 13.206, the clearing manager also must calculate constrained on amounts by 1600 hours on the 8th business day each month, unless final prices are late. This means the clearing manager will be in breach of the Code if: • there is a delay in the clearing manager receiving information required to calculate constrained off amounts (eg, final prices, reconciliation information), which results in the clearing manager calculating the constrained off amounts late • there is a delay in the clearing manager receiving information (other than final prices) required to calculate constrained on amounts, which results in the clearing manager calculating the constrained on amounts late. This is inconsistent with the timeframes for the clearing manager to advise participants of amounts owing to/from the clearing manager under clause 14.18 of the Code. Under clause 14.18(2), the clearing manager must advise participants of amounts payable to/from the clearing manager by the 9th business day of the month. However, if there is a delay in the clearing manager receiving information required to determine these amounts, the clearing manager does not breach the Code if it advises participants of the amounts payable after the 9th business day. The Authority considers the clearing manager should not breach the Code if it cannot calculate constrained off/on amounts by the 8th business day of the month because of a delay in receiving the information required to calculate the amounts.
Proposal	The Authority proposes to amend the Code so that, if the clearing manager receives the required information late, the clearing

	manager must calculate and make available constrained off amounts and constrained on amounts by 1600 hours on the business day after the clearing manager receives the information. This proposal would make clauses 13.197 and 13.206 consistent with clause 14.18. The proposed amendments to clauses 13.197 and 13.206 would not affect the timing of the settlement process, which is governed by clause 14.18.
Proposed Code amendment	**13.197 Timeframe for calculating~~Calculation of~~ constrained off amounts** ~~By 1600 hours on the 8th **business day** of e~~Each **billing period**, the **clearing manager** must calculate **constrained off amounts** for the previous **billing period** in accordance with clauses 13.194 to 13.196— (a) by 1600 hours on the 8th **business day** of the **billing period** after the previous **billing period**; but (b) if the **clearing manager** has not received the information required for it to calculate **constrained off amounts** by the time specified in paragraph (a), by 1600 hours on the 1st **business day** after the **clearing manager** receives the required information. **13.206 Timeframe for calculating constrained on amounts** Each **billing period**, t~~T~~he **clearing manager** must calculate **constrained on amounts** for the previous **billing period** in accordance with clauses 13.204 and 13.205— (a) by 1600 hours on the 8th **business day** of~~ each~~ the **billing period** ~~for the previous **billing period** in accordance with clauses 13.204 and 13.205~~after the previous **billing period**; ~~or~~but (b) if the **clearing manager** has not received the information required for it to calculate **constrained on amounts** by the time specified in paragraph (a), by 1600 hours on the 1st **business day** after the **clearing manager** receives the required information ~~(b) if **final prices** for any **trading period** in the relevant **billing period** are delayed and only made available on **WITS** later than 1600 hours on the 6th **business day** of the month following the relevant **billing period**; 1 **business day** after all **final prices** for the **billing period** are made available on **WITS**~~.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objective because it would contribute to the efficient operation of the electricity industry. It would do this by avoiding situations where the Code imposes unnecessary compliance costs on the clearing manager and Authority, in particular. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.

	The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The Authority has carried out a quantitative assessment of the proposal's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to resolve a problem in the Code where the clearing manager breaches the Code due to factors over which it has no control.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the proposed amendment would not place additional costs on industry participants, because it would not necessitate changes to their processes or systems. *Benefits* The primary benefit of the proposed amendment is to reduce compliance costs for the clearing manager and Authority where the clearing manager cannot calculate constrained off/on amounts by the 8th business day of the month because of a delay in receiving the information required to calculate the amounts. Based on actual breaches of clauses 13.206 and 13.208 of the Code, the Authority estimates the cost it and the clearing manager would together incur per breach is $350-$450.[1] There has been, on average, less than one breach per year since 2011. This equates to a present value benefit of approximately $2,000-$3,750.[2]

[1] This relates to staff time.
[2] Assuming one breach per year for the next 15 years, in the absence of the proposed Code amendment being made, and using a real discount rate of 8%.

	Net benefit Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

2018-09 Calculation of switching event dates

Reference number(s)	2018-09 Calculation of switching event dates
Problem definition	Clause 3(a)(i)(A) of Schedule 11.3 requires a trader that loses responsibility for an ICP (losing trader) to establish a switch event date for that ICP. Clause 4(1) of Schedule 11.3 requires the losing trader to establish the event date within a certain timeframe. Under clause 4(1)(a) of Schedule 11.3, each event date must not be more than 10 business days after the date on which the losing trader receives notice from the registry manager of information about the switch request. Under clause 4(1)(b) of Schedule 11.3, in any 12 month period, at least 50% of the event dates a losing trader establishes must be no more than 5 business days after the losing trader receives the registry manager's notice. Clause 4(2) of Schedule 11.3 qualifies the timeframes under subclause (1). Clause 4(2) requires the losing trader to disregard, in determining whether it has complied with subclause (1), every event date it establishes for a customer who, at the time the event date is established, has been a customer of the losing trader for less than 2 months. As currently worded, clause 4(2) applies to subclauses (1)(a) and (1)(b). This means the Code does not set any timeframe for an event date, if the customer for whom the event date is established has been a customer of the losing trader for less than 2 months. This is inconsistent with the Authority's policy intent for clauses 3 and 4 of Schedule 11.3, in two ways. First, clause 4(2) should refer to the event date for an "ICP" rather than for a "customer". This is because event dates apply to ICP switching, not customer switching. A retailer may lose a customer at an ICP through a move out, but gain a customer at the same ICP through the subsequent move-in. In this example, no switch occurs under Part 11, although the retailer has lost and gained a customer. Second, the policy intent was for the qualification in clause 4(2) to apply only to subclause (1)(b). That is, there should be a maximum timeframe of 10 business days on all event dates for ICP switching, not just switches where the trader had responsibility for the ICP for two months or more prior to the ICP being switched away from the trader. Clause 4 of Schedule 11.3 needs amending so that it accurately reflects this policy intent. Additionally, the wording in clause 4(2) describing when the 2-month timeframe applies ("at the time that the event date is established") is not as clear as it could be. It should be clear from this wording that

	the 2-month timeframe applies from the event date.
Proposal	The Authority proposes to amend clause 4 of Schedule 11.3 so that subclause (2): • applies only to subclause (1)(b). This would mean the 10-business day timeframe under clause 4(1)(a) of Schedule 11.3 would apply to a losing trader when it switched any ICP, including those for which it had been responsible for less than 2 months • states that the 2-month timeframe applies from the event date • refers to the event date for an "ICP" rather than for a "customer".
Proposed Code amendment	**Schedule 11.3 Switching** ... **4 Event dates** (1) The losing **trader** must establish **event dates** so that— (a) no **event date** is more than 10 **business days** after the date on which the losing **trader** receives notice from the **registry manager** in accordance with clause 22(a); and (b) in any 12 month period at least 50% of the **event dates** established by the losing **trader** are no more than 5 **business days** after the date on which the losing **trader** receives notice from the **registry manager** in accordance with clause 22(a). (2) ~~When establishing an **event date** under~~ For the purpose of determining whether it complies with subclause (1)(b)~~this clause~~, the losing **trader** must disregard the~~every~~ **event date** ~~established by the **losing trader**~~it establishes for ~~a~~every **ICP** for which ~~**customer** who~~, at the~~ time that the~~ **event date**~~ is established~~, ~~has been a **customer** of~~ the losing **trader** was responsible for less than 2 months.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory 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) clarifying the Code, which makes it easier for participants to understand and meet their obligations b) ensuring the Code sets a maximum timeframe of 10 business days from the date of switch notification for a losing trader to switch an ICP. The proposed amendment may also have a positive effect on competition, by mandating a maximum switching timeframe for all ICPs. Any such effect is expected to be small, since traders already comply with the intended 10-business day timeframe.

	The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it corrects an erroneous clause in the Code that: • means there is no maximum timeframe for switching ICPs for which the losing trader had been responsible for less than 2 months • refers to "customer" rather than "ICP".
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposed Code amendment is to contribute to the efficient operation of the electricity industry by clarifying the Code and ensuring it sets a maximum timeframe for switching ICPs.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed amendment would have a positive net benefit. *Costs* The Authority expects that implementing the proposed amendment would have no costs. Traders currently comply with clause 4 of Schedule 11.3 as if clause 4(2) applied only to clause 4(1)(b), and as if "customer" meant "ICP". Amending clause 4(2) of Schedule 11.3 to clarify that the 2 month timeframe applies as at the event date, may require procedures to be updated. However, the Authority anticipates this cost would be less than the benefit from making the clause unambiguous in this regard. *Benefits* Under the current arrangements, a losing trader would not breach the Code if it disregarded clauses 4(1)(a) and 4(1)(b) of Schedule 11.3 when switching an ICP for which the losing trader had been responsible for less than 2 months. A losing trader disregarding

	these clauses in this manner could create considerable inconvenience for the customer and the gaining trader, and materially increase the transaction cost of the ICP switch. The proposed Code amendment's purpose is to prevent this cost arising in the future. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

2018-10 Requirement to have an arrangement with a customer or embedded generator at an ICP before commencing the switch process

Reference number(s)	2018-10 Requirement to have an arrangement with a customer or embedded generator at an ICP before commencing the switch process

Problem definition	Schedule 11.3 of the Code prescribes three different processes for switching ICPs.
	
	The policy intent of Schedule 11.3 is that:
	
	• before a trader commences switching an ICP, the trader must have an arrangement with:
	    ○ a customer at the ICP that results in the customer purchasing, or agreeing to purchase, electricity from the trader, or
	    ○ any embedded generator at the ICP
	• a trader must use one of the three processes for switching ICPs (depending on the circumstances) prescribed in Schedule 11.3.
	
	However, the current wording of Schedule 11.3 does not properly give effect to this policy intent.
	
	The Code does not prevent one of the switch processes in Schedule 11.3 applying when a trader has no arrangement with a customer or an embedded generator at an ICP. That is, a trader would not breach the Code if the trader switched an ICP using one of the switch processes in Schedule 11.3, without first having in place an arrangement with the customer or embedded generator at the ICP.
	
	In addition, the Code does not make it clear that a trader <u>must</u> use one of the three switch processes in Schedule 11.3 to switch an ICP. Practically speaking, a trader would have difficulty trying to switch an ICP using a process other than those prescribed in Schedule 11.3. However, clarifying the Code would remove any doubt about this matter.

Proposal	The Authority proposes to amend the Code so that it clearly states that: • a trader must have an arrangement with a customer or embedded generator at an ICP before the trader commences switching the ICP • a trader must use one of the three processes prescribed in Schedule 11.3 for switching ICPs.
Proposed Code amendment	Schedule 11.3 Switching ... **1A <u>Application</u>~~Overview~~ of Schedule** <u>(1)</u> This Schedule prescribes 3 processes for switching **ICPs** as

follows:

(a) a standard switch process that applies in the circumstances described in clause 1(1):

(b) a switch move process that applies in the circumstances described in clause 8(1):

(c) a gaining **trader** switch process that applies in the circumstances described in clause 13(1).

(2) If a **trader** proposes switching an **ICP**, the **trader** must use one of the switch processes set out in this Schedule.

1 Standard switch process for ICPs

(1) A standard switch process applies only when a **trader** (the "gaining" **trader**) has an arrangement with a **customer** or **embedded generator** to commence trading **electricity** with the **customer** or **embedded generator** at, or to otherwise assume responsibility under clause 11.18(1) for, an **ICP** at which another **trader** (the "losing **trader**") trades **electricity**, and the gaining **trader** switch process under clauses 13 to 16 does not apply.

…

8 Switch move process for ICPs

(1) A switch process applies only when a trader (the "gaining" trader) has an arrangement with a **customer** or **embedded generator** to commence trading **electricity** with the **customer** or **embedded generator** at, or to otherwise assume responsibility under clause 11.18(1) for, an **ICP** for which no **trader** has an agreement to trade **electricity** and the gaining **trader** switch process under clauses 13 to 16 does not apply.

…

13 Gaining trader switch processe~~s~~

(1) A gaining **trader** switch process applies only when a **trader** (the "gaining" **trader**) has an arrangement with a **customer** or **embedded generator** to—

(a) trade **electricity** through—

(i) a **half-hour metering installation** (not being a **category 1 metering installation** or a **category 2 metering installation**) at an **ICP** with a submission type of **half hour** in the **registry** and an AMI flag of "N" at which another **trader** (the "losing **trader**") trades **electricity** through a **half-hour metering installation** with the same submission type and AMI flag; or

(ii) a **half-hour metering installation** at an **ICP** with a submission type of **half hour** in the **registry** and an AMI flag of "N" at which another **trader** (the "losing **trader**") trades **electricity** through a non

	half-hour metering installation with the **customer** or **embedded generator** with a submission type of non **half hour** in the **registry** and an AMI flag of "N"; or (iii) a non **half-hour metering installation** at an **ICP** at which another **trader** (the "losing **trader**") trades **electricity** through a **half-hour metering installation** with an AMI flag of "N" with the **customer** or **embedded generator**; or (b) assume responsibility under clause 11.18(1) for an **ICP** described in paragraph (a). …
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(2)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by reducing the possibility of a trader creating unnecessary costs in the switching process by: a) commencing an ICP switch without having an arrangement with a customer or embedded generator at the ICP b) commencing an ICP switch using a process other than one of those specified in Schedule 11.3. The proposed amendment is expected to have little or no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objectives of the proposal are: • to prevent a trader switching an ICP when the trader has no arrangement with a customer or an embedded generator at the ICP

	• to make traders use the switching processes in Schedule 11.3 when switching an ICP.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the cost of the proposed amendment to be $0. The proposal should place no additional costs on industry participants, because it reflects current industry practice. Currently, a trader only switches an ICP using one of the switch processes set out in Schedule 11.3 of the Code, and if the trader has an arrangement with a customer or embedded generator at the ICP. *Benefits* The proposed Code amendment's primary benefit is to lessen the possibility of: • traders commencing an ICP switch without having an arrangement with a customer or embedded generator at the ICP • traders attempting to use a switch process other than one of the three processes specified in Schedule 11.3. The proposed amendment would make it easier for traders to understand their Code obligations in relation to the three switch processes in Schedule 11.3. It would reduce the possibility of traders incurring unnecessary costs – primarily transaction costs – from having to stop, and withdraw, a switch. The proposal would also lessen the possibility of customers incurring unnecessary costs in order to remain with a trader they had been erroneously switched from (eg, transaction costs associated with liaising with the trader as part of the process of switching back to the trader). Lastly, the proposed amendment should reduce the Authority's costs related to liaising with, and educating, participants about the switch processes in Schedule 11.3. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed amendment.

2018-11 Providing submission information to the reconciliation manager

Reference number(s)	2018-11 Providing submission information to the reconciliation manager
Problem definition	There are two issues relating to clause 8 of Schedule 15.3 of the Code: 1) The current drafting of clause 8 of Schedule 15.3 means the definition of 'submission information' is circular in nature. Clause 1(1) of the Code defines 'submission information' to mean volume information aggregated in accordance with clause 8 of Schedule 15.3. However, clause 8 of Schedule 15.3 describes how <u>submission information</u> must be aggregated, rather than how volume information must be aggregated. To address the circularity in the definition of 'submission information', clause 8 of Schedule 15.3 should refer to volume information being aggregated and submitted to the reconciliation manager, rather than submission information. 2) Clause 8(g) of Schedule 15.3 requires each reconciliation participant to provide submission information to the reconciliation manager aggregated to the following level: a) trading period, if the ICP is half hour metered b) consumption period or day, for all other ICPs. However, this is problematic because a single ICP can have half hour and non-half hour metering installations, and unmetered load. In such circumstances, the Code does not clearly require the reconciliation participant for the ICP to provide the reconciliation manager with submission information aggregated to: a) trading period for any half hour metering installations at the ICP for which the reconciliation participant wants to submit half hour submission information b) consumption period, or day, for: i) any non half hour metering installations or unmetered load at the ICP ii) any half hour metering installations at the ICP for which the reconciliation participant wants to submit non half hour submission information. This issue also arises under clause 2(1)(b) of Schedule 15.3. Under this clause, if a reconciliation participant must prepare certain submission information, then this must comprise the following for certain ICPs for which there is a category 1 metering installation or a category 2 metering installation: a) half hour volume information for the ICP; **<u>or</u>** b) non half hour volume information calculated under clauses 4 to 6

	of Schedule 15.3 (as applicable) for the ICP. It is important that reconciliation participants provide submission information to the reconciliation manager for all electricity conveyed at an ICP, so as to facilitate accurate reconciliation and invoicing.
Proposal	The Authority proposes to amend the Code as follows: 1) amend clause 2(1)(b) of Schedule 15.3 to require submission information for all category 1 metering installations or category 2 metering installations at an ICP, rather than allowing the reconciliation participant to choose whether to provide either half hour or non half hour volume information in situations where there is both 2) amend clause 8 of Schedule 15.3 to: a) describe the information to be submitted to the reconciliation manager in terms of aggregated volume information b) clarify that the clause requires a reconciliation participant to provide the reconciliation manager with submission information aggregated by: i) trading period for half hour metering installations at the ICP for which the reconciliation participant wants to submit half hour submission information ii) consumption period, or day, for: (A) any non half hour metering installations or unmetered load at the ICP (B) any half hour metering installations at the ICP for which the reconciliation participant wants to submit non half hour submission information.
Proposed Code amendment	**Schedule 15.3 Calculation and provision of submission information** ... **2 Reconciliation participants to prepare information** (1) If a **reconciliation participant** is required to prepare **submission information** for an **NSP** for the relevant **consumption period** in accordance with this Code, the **submission information** must comprise the following: … (b) for each **ICP** about which information is provided under clause 11.7(2) for which there is a **category 1 metering installation** or **category 2 metering installation**, each of the following— (i) any **half hour volume information** for the **ICP**:~~; or~~ (ii) any non **half hour volume information** calculated under clauses 4 to 6 (as applicable) for the **ICP**: ...

	8 Provision of submission information to reconciliation manager (1) For each **half hour metering installation** for which it is responsible, a **reconciliation participant** must provide **volume information** to the **reconciliation manager** for each **trading period**— (a) aggregated to the levels in subclause (3); and (b) with a submission type of **half hour** or non **half hour**. (2) For each non **half hour metering installation** or **unmetered load** for which it is responsible, a **reconciliation participant** must provide **volume information** to the **reconciliation manager** for each **consumption period** or day— (a) aggregated to the levels in subclause (3); and (b) with a submission type of non **half hour**. (3) Under subclauses (1) and (2), e~~E~~ach **reconciliation participant** must provide ~~**submission**~~**volume information** to the **reconciliation manager** aggregated to the following levels: (a) **NSP** code: (b) **reconciliation type**: (c) **profile**: (d) **loss category** code: (e) flow direction: (f) dedicated **NSP**~~;~~ ~~(g) **trading period** for **half hour metered ICPs** and **consumption period** or day for all other **ICPs**~~.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by: a) making it easier for participants to understand and meet their Code obligations, which reduces their costs of transacting in the electricity market b) improving the accuracy of submission information through the capture of each ICP's half hour and non-half hour metering information, which leads to more accurate reconciliation and more accurate invoicing of participants and consumers. The proposed amendment is expected to have little, if any, effect on competition, and no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.

Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it addresses a regulatory failure that could lead to a market inefficiency, and which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, the Authority has undertaken a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The primary objective of the proposed Code amendment is to improve the accuracy of submission information, thereby improving the accuracy of reconciliation and invoicing of participants and consumers. A secondary objective is to make it easier for participants to understand and meet their Code obligations.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the proposed amendment would place no additional costs on industry participants. This is because the proposal reflects what the Authority understands to be current industry practice. *Benefits* The primary benefit of the proposed amendment is that it would clarify that reconciliation participants are to provide submission information for all electricity conveyed at an ICP. The provision of accurate data to the reconciliation manager facilitates accurate reconciliation and accurate invoicing of participants and consumers. If the Authority did not amend the Code as proposed, some reconciliation participants could, in the future, start providing incomplete submission information by ICP. This would be expected to result in higher volumes of unaccounted-for-energy, the cost of which would be shared amongst all traders operating in the same balancing area. Without the proposed amendment, consumers could be invoiced for an amount of electricity that differed from that which they consumed by a greater quantity than under the proposed Code amendment. The marginal value that consumers placed on the electricity they purchased would not be as close to the cost of producing that

	electricity as it could be. This would be a market inefficiency. Amending clause 8 of Schedule 15.3 to explicitly link submission information to volume information is also beneficial. This is because the amendment makes it easier for reconciliation participants to understand and comply with their obligations under this provision, which reduces their transaction costs. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority considered moving the content of clause 8 of Schedule 15.3 into the definition of ‘submission information’ in Part 1 of the Code. However, the Authority concluded that the Code would be easier to interpret under the proposed amendment rather than this alternative. The Authority has not identified an alternative means of achieving the objective of the second part of the proposed amendment (the aggregation of submission information to metering installation level rather than ICP level).

2018-12 Removing repeated obligations to report Code breaches and to publish these reports

Reference number(s)	2018-12 Removing repeated obligations to report Code breaches and to publish these reports
Problem definition	The Authority has identified the following issues with the compliance reporting arrangements in the Code: • there is some duplication in the compliance reporting obligations on the pricing manager, clearing manager, and reconciliation manager • the obligation on the Authority to publish alleged breaches by the pricing manager, clearing manager and reconciliation manager appears to be unnecessary. *Summary of existing compliance reporting arrangements* (see also the table at Attachment 1) Regulation 7 of the Electricity Industry (Enforcement) Regulations 2010 (Enforcement Regulations) requires a participant, and therefore a market operation service provider (MOSP), to report to the Authority as soon as practicable if it reasonably believes that it or another participant has breached a common quality or security provision in Part 7, 8, 9, 13 or 17 of the Code. Regulation 8 of the Enforcement Regulations requires a participant, and therefore a MOSP, to report to the Authority an alleged breach of the Code by another participant as soon as possible. Although regulations 7 and 8 do not require them to do so, MOSPs typically self-report to the Authority any of their Code breaches that do not relate to common quality or security, as soon as practicable. Clause 3.14 of the Code requires each MOSP to prepare a written report for the Authority each month. This report must include details of circumstances in which the MOSP has failed, or may have failed, to comply with its obligations under the Code or under Part 2 or Subpart 1 of Part 4 of the Act. Clause 13.213 of the Code requires the pricing manager to provide a written report to the Authority each day. Amongst other things, this report must specify any situation where the pricing manager believes, on reasonable grounds, that it or another participant has breached the Code, giving details. Clause 14.68 of the Code requires the clearing manager to report to the Authority in writing each month. This report must include information on any situations where the clearing manager believes, on reasonable grounds, that it or another participant has breached the Code in the previous calendar month. Clause 15.30 of the Code requires the reconciliation manager to provide a written report to the Authority detailing the number and

	details of any alleged breach of the Code that the reconciliation manager is aware of. The reconciliation manager must provide the report as soon as possible and by no later than 1300 hours on the 2nd business day after providing reconciliation information for a consumption period under clauses 15.21 and 15.22.
	
	Considering all of these compliance reporting obligations together:
	
	• The pricing manager must:
	  o self-report alleged Code breaches to the Authority each day and each month
	  o report to the Authority any alleged Code breaches by other participants as soon as possible and each day.
	• The clearing manager must:
	  o self-report alleged Code breaches to the Authority each month
	  o report to the Authority any alleged Code breaches by other participants as soon as possible and each month.
	• The reconciliation manager must:
	  o self-report alleged Code breaches to the Authority each month
	  o report to the Authority any alleged Code breaches by other participants as soon as possible, and each month.
	• The FTR manager, registry manager, and WITS manager must:
	  o self-report alleged Code breaches to the Authority each month
	  o report to the Authority any alleged Code breaches by other participants as soon as possible.
	• The system operator and extended reserve manager must:
	  o self-report alleged Code breaches to the Authority as soon as practicable (since alleged breaches by the system operator and extended reserve provider relate to common quality or security), and each month
	  o report to the Authority any alleged Code breaches by other participants as soon as possible and each month.
	
	Clauses 13.214, 14.69, and 15.33 require the Authority to publish alleged Code breaches reported by, respectively, the pricing manager, clearing manager, and reconciliation manager, under clauses 13.213, 14.68 and 15.30.
	
	Clauses 13.214 and 14.69 require the Authority to publish the alleged breaches by the pricing manager and clearing manager by the 15th business day of each calendar month. Clause 15.33 requires the Authority to publish the alleged breaches by the reconciliation

	manager by 1630 hours on the 2nd business day after the Authority receives the reconciliation manager's report under clause 15.30.<ins>*There is some duplication and inconsistency in compliance reporting obligations*</ins> There is some duplication in the compliance reporting obligations on the pricing manager, clearing manager, and reconciliation manager. The obligation under clauses 13.213, 14.68, and 15.30 for the pricing manager, clearing manager and reconciliation manager, respectively, to report alleged Code breaches by other participants largely duplicates the compliance reporting requirement under regulation 8 of the Enforcement Regulations. The main difference between the compliance reporting obligations in the Code and the obligation under regulation 8 in the Enforcement Regulations relates to when the reporting must occur. The three MOSPs have more time to report under the Code than they do under regulation 8. The obligation under clause 3.14 for the pricing manager, clearing manager, and reconciliation manager to self-report alleged Code breaches largely duplicates the compliance reporting obligations on these MOSPs under clauses 13.213, 14.68, and 15.30, respectively. The main difference between the compliance reporting obligations under clause 3.14 and those under clauses 13.213 and 15.30 also relates to when the reporting must occur. The pricing manager and reconciliation manager have more time to report under clause 3.14 than they do under clauses 13.213 and 15.30. There is no material difference between the clearing manager's compliance reporting obligations under clauses 3.14 and 14.68, which both require a monthly report. There is also some inconsistency in the compliance reporting obligations on MOSPs. The pricing manager must report alleged Code breaches on a daily basis, while the other two MOSPs must report on a monthly basis. The pricing manager, clearing manager, and reconciliation manager must report alleged breaches by other participants as soon as possible, and then again on a monthly basis. <ins>*Publishing alleged breaches by the pricing manager, clearing manager, and reconciliation manager appears unnecessary*</ins> The obligation under clauses 13.214, 14.69 and 15.33 for the Authority to publish alleged Code breaches by, respectively, the pricing manager, clearing manager and reconciliation manager appears to be unnecessary. This is because the Authority publishes all alleged Code breaches by market participants as part of the Authority's compliance process. This includes naming the pricing manager, clearing manager and reconciliation manager when any of these MOSPs have allegedly breached the Code. The Authority

targets publication of alleged Code breaches within a month of the Authority's Compliance Committee considering them. The Compliance Committee considers the majority of alleged Code breaches within 4 months of the alleged breach occurring.

The Authority therefore expects that the transparency and accountability of each of the three MOSPs should not be adversely affected by removing clauses 13.214, 14.69 and 15.33.

The key issue is whether, compared with the more frequent publication of alleged breaches by the three MOSPs under clauses 13.214, 14.69 and 15.33, relying on the publication of alleged breaches under the compliance process would hinder the efficient operation of the electricity market.

The Authority considers the less frequent publication of alleged breaches under the Authority's compliance process would not hinder the efficient operation of the market.

In reaching this conclusion, the Authority looked at the number of times the 2016 and 2017 monthly reports containing alleged breaches by the three MOSPs were downloaded outside the Authority:[1]

Table 1: Downloads of compliance reports

	Monthly service provider compliance report	Reconciliation manager monthly breach report	Reconciliation manager monthly breach report – wash-ups
0 downloads	38% of reports	81% of reports	42.5% of reports
1 download	29% of reports	14% of reports	47.5% of reports
2 downloads	14% of reports	5% of reports	5% of reports
3 downloads	9.5% of reports	0% of reports	5% of reports
4 downloads	0% of reports	0% of reports	0% of reports
5 downloads	9.5% of reports	0% of reports	0% of reports

Table 1 shows:

- the report published by the Authority each month showing alleged breaches reported by all MOSPs (except the reconciliation manager) is downloaded infrequently
- the reconciliation manager's monthly compliance report is downloaded even more infrequently than the report the Authority publishes.

Table 2 shows the length of time between the publication and first

[1] Please note the Authority's systems did not track document downloads from 1 January–25 February 2016 and from 2-16 June 2016, totalling approximately 10 weeks. This means the number of downloads in the tables may slightly understate the actual number of downloads.

download (outside the Authority) of each monthly report from the Authority's website.

Approximately half of the reports published by the Authority are first downloaded within a month of publication. However, nearly 40% of these reports are never downloaded.

In contrast, more than 80% of the reconciliation manager's monthly breach reports are never downloaded, as are over 40% of the reconciliation manager's monthly breach reports for wash-ups.

Table 2: Downloads of compliance reports

Length of time until first download of a report	Monthly service provider compliance report	Reconciliation manager monthly breach report	Reconciliation manager monthly breach report – wash-ups
0<1 months	52% of reports	14% of reports	24% of reports
1<3 months	0% of reports	0% of reports	9.5% of reports
3<6 months	0% of reports	0% of reports	9.5% of reports
6<12 months	10% of reports	5% of reports	14% of reports
Not downloaded	38% of reports	81% of reports	43% of reports

The information shown in the tables indicates that participants and other stakeholders may place little importance on:

- the timing and frequency of publication of the reports
- the content of the reports.

Participants and other stakeholders may place little importance on the content of the reports because:

- in relation to the reconciliation manager's compliance report, participants receive sufficient information under the reconciliation procedures in Schedule 15.4 of the Code to verify their reconciliation information, and they therefore do not need to know whether there has been an alleged breach by the reconciliation manager
- in relation to the Authority's monthly report on alleged breaches by all MOSPs, the overwhelming majority of alleged breaches have little or no effect on the electricity market.

<u>Publishing alleged breaches before the Authority considers them may have adverse reputational effects</u>

Publishing alleged Code breaches under clauses 13.214, 14.69, and 15.33 before the Authority's Compliance Committee has considered the breaches may imply a higher level of non-compliance in the electricity industry than is actually the case. Removing the publication requirement under these clauses, and publishing the alleged breaches after the Compliance Committee has considered

	them (under the compliance process), would reduce the potential for non-compliance to be overstated. *<u>Clause 13.213 duplicates other reporting of provisional prices and pricing errors</u>* The obligation under clause 13.213(1)(a) for the pricing manager to provide the Authority with a daily written report specifying any provisional prices effectively duplicates obligations on the pricing manager under clauses 13.149(2) and 13.150(2). Under clauses 13.149(2)(a) and 13.150(2)(a), the pricing manager must give written notice to any persons that request notice of a provisional price situation. The pricing manager informs the Authority of provisional price situations under these clauses as well as via the daily reports. It is timelier for the Authority to receive written notice of provisional prices in the manner specified in clauses 13.149(2)(a) and 13.150(2)(a) than to wait for the daily report. Similarly, the obligation under clause 13.213(1)(b), for the pricing manager to provide the Authority with a written report specifying any pricing errors claimed, duplicates the obligation on the pricing manager to give written notice of a pricing error claim under clause 13.173(c). Revoking clause 13.213(1)(a) and (b) would remove this duplication.
Proposal	The Authority proposes to: • insert a new clause 3.14A to require MOSPs to self-report to the Authority any alleged Code breaches as soon as practicable after becoming aware of them • amend clauses 13.149 and 13.150 to: o require the pricing manager to give written notice to the Authority under clauses 13.149(2)(a) and 13.150(2)(a) of any provisional price situation (thereby removing the need for clauses 13.149(2)(c), 13.150(2)(c), and 13.213(1)(a)) o revoke clauses 13.149(2)(c) and 13.150(2)(c) • amend clause 14.68 to: o remove the clearing manager's Code breach reporting requirements under clause 14.68(3)(a) to (d), which largely duplicate the requirements of the existing clause 3.14 (and the proposed new clause 3.14A) o shift the requirement under clause 14.68(3)(c)(iii) to report on delays in advising a participant of an amount owing under clause 14.18 (which clause 3.14 does not duplicate) to new clause 14.68(3)(f) • amend clause 15.31 to remove the reference to the reconciliation manager's report provided under clause 15.30

	• revoke clauses 13.213, 13.214, 14.69, 15.30 and 15.33.
Proposed Code amendment	**3.14A Market operation service providers must self-report breaches to Authority** (1) If a **market operation service provider** believes on reasonable grounds that it has breached a provision of this Code, the **market operation service provider** must report the alleged breach to the **Authority** in writing as soon as practicable after the **market operation service provider** becomes aware of the alleged breach. (2) The written report must specify— (a) the provision of this Code allegedly breached; and (b) the date and time the alleged breach occurred; and (c) the circumstances relating to the alleged breach, including any **participants** the **market operation service provider** believes the alleged breach affected. … **13.149 Pricing manager to make provisional prices and provisional reserve prices available if revised data and notice not given regarding provisional price~~pricing~~ situation arising on business day** (1) This clause applies if— (a) a notice of a **provisional price situation** is given on a **business day**; and (b) a **participant** that is listed in clause 13.147(1)— (i) does not comply with the timeframes specified in clause 13.146(3); or (ii) does not comply with the timeframes specified in clause 13.147(3). (2) If this clause applies, the **pricing manager** must— (a) by 1200 hours on that day, give to the **system operator**, relevant **grid owner**, the **Authority**, and any persons that request notice, written notice of the **provisional price situation** and each **trading period** affected; and (b) by 1200 hours on that day, make **provisional prices** and **provisional reserve prices** available on **WITS**~~; and~~ ~~(c) by 0900 hours on the following day, inform the **Authority** of the **provisional price situation** in the daily report submitted under clause 13.213~~. **13.150 Pricing manager to make provisional prices and provisional reserve prices available if revised data and notice not given regarding provisional price situation arising on day other than business day** (1) This clause applies if— (a) a notice of a **provisional price situation** is given on day other than a

business day; and

(b) a **participant** that is listed in clause 13.147(1)—

(i) does not comply with the timeframes specified in clause 13.146(3); or

(ii) does not comply with the timeframes specified in clause 13.147(3).

(2) If this clause applies, the **pricing manager** must—

(a) by 1000 hours on the day that the notice of a **provisional price situation** was given, give to the **system operator**, relevant **grid owner**, the **Authority**, and any persons that request notice, written notice of the **provisional price situation** and each **trading period** affected; and

(b) by 1000 hours on that day, make **provisional prices** and **provisional reserve prices** available on **WITS**~~; and~~

~~(c) by 0900 hours on the following day inform the **Authority** of the **provisional price situation** in the daily report submitted under clause 13.213~~.

…

~~**13.213 Daily reports**~~

~~(1) On each **trading day** the **pricing manager** must provide the **Authority** with a written report for the **trading periods** beginning at 0700 hours on the previous **trading day** and ending with the **trading period** beginning at 0630 hours on the **trading day** the report is due to be given, specifying—~~

~~(a) any **provisional prices** made available on **WITS**; and~~

~~(b) any **pricing errors** claimed; and~~

~~(c) any situation where the **pricing manager** believes, on reasonable grounds, that it or another **participant** has breached this Code.~~

~~(2) In relation to each alleged breach the report must give details of—~~

~~(a) occasions when prices were or will be made available on **WITS** late and whether the delay was caused by the **pricing manager**; and~~

~~(b) the time at which the alleged breach took place; and~~

~~(c) the nature of the alleged breach, including details of the person alleged to be in breach and any **generator** or **purchaser** believed to be affected by the alleged breach; and~~

~~(d) the reason for the alleged breach, if the **pricing manager** is aware of the reason.~~

~~**13.214 Authority to publish pricing manager reports**~~

~~(1) By the 15th **business day** of each calendar month, the **Authority** must **publish** the sections of the reports of the **pricing manager** given in the previous calendar month under clause 13.213 that relate to any alleged breaches of this Code by the **pricing manager**~~.

	(2) *[Revoked]*~~.~~ … **14.68 Monthly divergence reports to be prepared by clearing manager** (1) The **clearing manager** must report to the **Authority** in writing under this clause. (2) The **clearing manager** must give the report to the **Authority**— (a) on the 10th **business day** of each calendar month; or (b) if exceptional circumstances prevent the **clearing manager** from providing the report by that day, as soon as reasonably practicable after that day. (3) The report must include— ~~(a) information on any situations where the **clearing manager** believes, on reasonable grounds, that the **clearing manager**, or another **participant**, has breached this Code in the previous calendar month; and~~ ~~(b) the date and time at which each alleged breach took place; and~~ ~~(c) the nature of each alleged breach, including—~~ ~~(i) details of the person alleged to be in breach; and~~ ~~(ii) any **participants** believed to be affected by the alleged breach; and~~ ~~(iii) in the case of a delay in advising a **participant** of an amount owing under clause 14.18, the part of the process that was delayed; and~~ ~~(d) the reason for the alleged breach occurring if the **clearing manager** is aware of the reason; and~~ (e) situations in which information about an amount owing was or will be issued late and whether or not the delay was caused by the **clearing manager**; and (f) if there is a delay in the **clearing manager** advising a **participant** of an amount owing under clause 14.18, the part of the process that was delayed. ~~**14.69 Authority to publish clearing manager reports**~~ ~~(1) By the 15th **business day** of each calendar month, the **Authority** must **publish** the sections of the report, received in the previous calendar month from the **clearing manager** in accordance with clause 14.68, that relate to any breaches of this Code by the **clearing manager**.~~ … ~~**15.30 Alleged Code breaches reported by the reconciliation manager**~~ ~~(1) As soon as possible and by no later than 1300 hours on the 2nd **business day** after the **reconciliation manager** provided **reconciliation information** for a **consumption period** in accordance with clauses 15.21 and 15.22, the **reconciliation manager** must provide a written report to the **Authority**~~

	~~detailing the number and details of any alleged breach of this Code that the **reconciliation manager** is aware of.~~ ~~(2) The report must include the matters set out below, and information about any situations when the **reconciliation manager** allegedly breached this Code, or, in the opinion of the **reconciliation manager**, a **reconciliation participant** allegedly breached this Code:~~ ~~(a) the time and, if appropriate, the **consumption period**, during which the alleged breach took place:~~ ~~(b) the nature of the alleged breach, including, in the case of late **submission information** or information in a form that compromises the **reconciliation information**, the **reconciliation participant** allegedly responsible for the information:~~ ~~(c) the reason for the alleged breach including, in the case of late **submission information** or information in a form that compromises the **reconciliation information**, the reason for the delay or the inadequate form, if the **reconciliation manager** is aware of the reason.~~ **15.31 Right to information concerning reconciliation manager's actions** (1) A **reconciliation participant** may, by notice in writing to the **reconciliation manager**, request further information related to any alleged breach of this Code— (a) ~~situation set out in~~by the **reconciliation manager**: (b) in respect of this Part, by a **reconciliation participant**, if the alleged breach~~manager's report provided in accordance with clause 15.30 that~~ has materially affected the **reconciliation participant** requesting the information. … ~~**15.33 The Authority publishes reports**~~ ~~By 1630 hours on the 2nd **business day** following the day on which the **Authority** receives the report of the **reconciliation manager** in accordance with clause 15.30, the **Authority** must **publish** the sections of the report that relate to an alleged breach of this Code by the **reconciliation manager** (if any).~~
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed 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. Streamlining the process for the pricing manager, clearing manager and reconciliation manager to report alleged breaches of the Code to the Authority would reduce their operational costs as well as those of the Authority. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment against Code	The Authority is satisfied the proposed Code amendment is

amendment principles	consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it is expected to result in participants operating more efficiently and incurring lower costs complying with the Code.
Principle 3: Quantitative Assessment	Some of the costs and benefits of the proposed Code amendment can be quantified, but it has not been practicable to quantify others. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to reduce unnecessary compliance costs in the electricity market.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the proposed amendment would place no additional costs on industry participants. Participants do not appear to rely on, or use, the compliance reporting that the proposed changes would discontinue or amalgamate with other reporting. The proposed amendment is unlikely to adversely affect the efficient operation of the market because the information contained in the discontinued or amalgamated compliance reports will still be made publicly available. This retains the current level of transparency related to alleged breaches by the MOSPs. *Benefits* The primary benefit of the proposed amendment is a reduction in compliance costs for the pricing manager, reconciliation manager, clearing manager, and the Authority, in relation to compliance reporting. The Authority estimates the cost that it and the three MOSPs would save in aggregate is approximately \$2,900-\$4,300 per annum.[2] This equates to a present value benefit of approximately \$25,000-\$37,000.[3] The proposed amendment would also remove the risk of the three MOSPs breaching unnecessary compliance reporting obligations in

[2] This relates to staff time.
[3] Assuming one breach per year for the next 15 years, in the absence of the Authority making the proposed Code amendment, and using a real discount rate of 8%.

	the Code. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified any alternatives to the proposed amendment that would meet the objective of the proposal.

Attachment 1 – Table of MOSP compliance reporting obligations under the Enforcement Regulations and the Code

Obligation and timing	MOSP							
	Clearing manager (CM)	Extended reserve manager	FTR manager	Pricing manager (PM)	Reconciliation manager (RM)	Registry manager	System operator	WITS manager
Reg 7 (Enforcement Regulations): self-report common quality/ security breaches – *as soon as possible*		✔					✔	
Reg 8 (Enforcement Regulations): alleged breaches by another participant – *as soon as possible*	✔	✔	✔	✔	✔	✔	✔	✔
Clause 3.14 (the Code): self-report instances of non-compliance – *monthly*	✔	✔	✔	✔	✔	✔	✔	✔
Clause 13.213 (the Code): PM reports breaches by it or other participant – *daily*				✔				
Clause 14.68 (the Code): CM reports breaches by it or other participant – *monthly*	✔							
Clause 15.30 (the Code): RM reports any breaches it is aware of – *by 2nd business day after providing reconciliation information for each consumption period*					✔			

2018-13 Timeframe for completing switch event meter reading disputes

Reference number(s)	2018-13 Timeframe for completing switch event meter reading disputes
Problem definition	Clauses 6A and 12(3) of Schedule 11.3 of the Code permit a gaining trader to dispute a switch event meter reading for a period of four months after the switch event date. However, in practice, this four-month timeframe for disputing a switch event meter reading can shorten, or disappear entirely, if a switch event date is backdated to correct an error in the registry metering records. This is inconsistent with the policy intent of these clauses, which is to give a gaining trader four months after completing a switch to dispute the switch event meter reading.
Proposal	The Authority proposes to amend the Code to state that the four-month timeframe for disputing a switch event meter reading starts from the date the registry manager gives the gaining trader information about the switch completion under clause 22(d) of Schedule 11.3. This proposal would ensure the current four-month timeframe does not shorten, or disappear entirely, if a switch event date is back-dated to correct an error in the registry metering records.
Proposed Code amendment	**Schedule 11.3 Switching** ... **6A Gaining trader disputes reading** (1) If a gaining **trader** disputes a **switch event meter reading** under clause 6(1)(b), the **gaining trader** must, no later than 4 months after the **registry manager** gives the gaining **trader** written notice under clause 22(d) of having received information about the switch completion~~**event date**~~, provide to the losing **trader** a revised **switch event meter reading** supported by 2 **validated meter readings**. ... **12 Gaining trader may change switch event meter reading** ... (3) If the gaining **trader** disputes a **switch event meter reading** under subclause (2)(b), the gaining **trader** must, no later than 4 months after the **registry manager** gives the gaining **trader** written notice under clause 22(d) of having received information about the switch completion~~actual **event date**~~, provide to the losing **trader** a changed **validated meter reading** or a **permanent estimate** supported by 2 **validated meter readings**, and the losing **trader** must either,— (a) no later than 5 **business days** after receiving the **switch event meter reading** from the gaining **trader**, the losing **trader**, if it does

	not accept the **switch event meter reading**, must advise the gaining **trader** (giving all relevant details), and the losing **trader** and the gaining **trader** must use reasonable endeavours to resolve the dispute in accordance with the disputes procedure contained in clause 15.29 (with all necessary amendments); or (b) if the losing **trader** advises its acceptance of the **switch event meter reading** received from the gaining **trader**, or does not provide any response, the losing **trader** must use the **switch event meter reading** supplied by the gaining **trader**. ...
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it promotes the efficient operation of the electricity industry. The proposed Code amendment does this by giving effect to the underlying policy intent of clauses 6A and 12 of Schedule 11.3: ensuring that a gaining trader has four months to dispute and correct a switch event meter reading, even if the switch is backdated. This enables more accurate reconciliation and invoicing of participants and consumers. The proposed amendment is expected to have little or no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2. This is because the Authority expects it to reduce the number of incorrect meter readings provided to the reconciliation manager. This in turn enables accurate reconciliation and invoicing of participants and consumers.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits and costs of the proposed amendment. Accordingly, the Authority has not undertaken a quantitative analysis. Please refer to the qualitative cost-benefit analysis under the Regulatory Statement below.
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to reduce the number of incorrect meter readings provided to the reconciliation manager by ensuring that a gaining trader has a full four months to dispute and correct a switch event meter reading. This in turn would improve the accuracy of reconciliation and invoicing of participants and consumers.

Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects the proposed amendment would place little or no additional costs on industry participants. Traders and metering equipment providers already incur costs liaising with each other over incorrect meter readings extending back in time by more than four months. The Authority therefore expects the incremental cost of providing revised metering readings to the reconciliation manager would be small or negligible. *Benefits* The primary benefit of the proposed amendment is that it would reduce the number of incorrect meter readings provided to the reconciliation manager, and used in consumer invoicing. This in turn enables more accurate reconciliation and invoicing of participants and consumers. If the Authority did not amend the Code to address this problem, some consumers might be invoiced for an amount of electricity that differed from that which they consumed by a greater quantity than under the proposed Code amendment. The marginal value that consumers placed on the electricity they purchased would not be as close to the cost of producing that electricity as it could be. This would be a market inefficiency. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

2018-14 Clarifying requirement for distributors to give written notice of change to network supply point identifier

Reference number(s)	2018-14 Clarifying requirement for distributors to give written notice of change to network supply point identifier
Problem definition	Clause 8 of Schedule 11.1 of the Code requires a distributor to give written notice to the registry manager if there is a change to the ICP information the distributor has provided to the registry manager under clause 7 of Schedule 11.1. This includes a change to the network supply point (NSP) identifier of the NSP to which an ICP is usually connected. Despite this requirement, under clause 8(3) of Schedule 11.1, a distributor need not give written notice of a change to the NSP identifier if the change applies for fewer than 14 days.[1] The reason for this is to avoid imposing an unnecessary administrative cost on distributors when an NSP change is temporary. The policy intent of subclauses (2) and (4) of clause 8 of Schedule 11.1 is that a distributor must give written notice to the registry manager of an NSP identifier change that applies for more than 14 days, including the date of the change. Subclause (4) states that when giving notice of a change to the NSP identifier, the timeframe for giving notice to the registry manager applies as if the change had taken effect on the 15th day after the change actually occurred. The combined effect of these subclauses is that the distributor must give notice to the registry manager: • by the 3rd business day after 15 days have elapsed since the date of the change, if the change is the result of the commissioning or decommissioning of an NSP • by the 8th business day after 15 days have elapsed since the date of the change, if the change is *not* the result of the commissioning or decommissioning of an NSP. However, the drafting of clause 8(4) of Schedule 11.1 is not as clear as it could be. Distributors have interpreted the clause to mean the date they must advise the registry manager is the date that is 15 calendar days after the actual date of the change to the NSP identifier. This is incorrect. Distributors should give written notice to the registry manager of the actual date of change. Under their current interpretation, distributors are providing inaccurate data to the registry manager. It would also be clearer for distributors if the timeframes in this

[1] Where "days" means "calendar days".

	clause were either in "days" or "business days", but not in both.
Proposal	The Authority proposes to amend clause 8(4) of Schedule 11.1, to make it clear that distributors must always give written notice to the registry manager of the actual date of a change to an ICP's NSP identifier. The Authority also proposes to further simplify clause 8(3) and (4) by converting the timeframes that currently use "days" to "business days". The Authority considers that, if a change to an ICP's NSP identifier applies for 10 business days or more, distributors should have a maximum of 13 business days to give written notice to the registry manager of the change. Currently, the distributor would have up to 18 business days to give notice of the change.[2]
Proposed Code amendment	**8 Distributors to change ICP information provided to registry manager** (1) If information about an **ICP** provided to the **registry manager** in accordance with clause 7 changes, the **distributor** in whose **network** the **ICP** is located must give written notice to the **registry manager** of the change. (2) The **distributor** must give the notice— (a) in the case of a change to the information referred to in clause 7(1)(b) (other than a change that is the result of the **commissioning** or **decommissioning** of an **NSP**), no later than 8 **business days** after the change takes effect; and (b) in every other case, no later than 3 **business days** after the change takes effect. (3) A **distributor** is not required to give written notice of a change of information provided in accordance with clause 7(1)(b) if the change ~~is~~applies for less than ~~14 days~~10 **business days**. (4) If a change of information provided in accordance with clause 7(1)(b) ~~is~~applies for ~~more than 14 days~~10 **business days** or more, the **distributor** must— (a) give the notice under subclause (1~~2~~) no later than 13 **business days**~~applies as if the change had taken effect on the 15th day~~ after the change takes effect; and (b) include in the notice the date the change occurred.
Assessment of propose Code amendment against the Authority's	The proposed amendment is consistent with the Authority's objective and section 32(1)(c) of the Act because it would

[2] A distributor has 18 business days in instances where 14 calendar days translate to 10 business days. A distributor would have fewer than 18 business days over holiday periods, such as Christmas/New Year and Easter.

objective and section 32(1) of the Act	contribute to the efficient operation of the electricity industry. It would do this by: a) making it easier for distributors to understand and meet their Code obligations, which reduces their costs of transacting in the electricity market b) improving the accuracy of ICP information in the registry. To a lesser degree, the proposed amendment may also promote competition in the electricity industry. This is because facilitating accurate ICP information in the registry better enables traders to undertake customer switching in a timely manner. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it is expected to improve the accuracy of ICP identifier information in the registry, and allow participants to operate more efficiently and incur lower costs in complying with the Code.
Principle 3: Quantitative Assessment	The estimated costs of the proposed Code amendment can be quantified. However, it has not been practicable to quantify the benefits. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The primary objective of the proposed Code amendment is to make it easier for distributors to understand their Code obligations, thereby facilitating accurate ICP information in the registry.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the proposed amendment should not place additional costs on industry participants – specifically, distributors. If a change to an ICP's NSP identifier applies for 10 business days or more, a distributor should not need a further 8 business days after a period of 10 business days, to give written notice to the registry manager. Following the initial 10-business day period, a

	distributor should be able to give written notice to the registry manager within 3 business days, consistent with the obligation on distributors to give written notice of changes to other ICP information. *Benefits* The primary benefit of the proposed amendment is to make it easier for distributors to understand their Code obligations. The Authority anticipates the compliance costs a distributor would face in relation to clause 8 of Schedule 11.1 of the Code would be less than the cost the distributor faces now. Making it easier for distributors to understand their obligation to advise the registry manager of the actual date of a change to an ICP's NSP identifier would facilitate more accurate ICP information in the registry. Specifically, an ICP will be correctly assigned to the NSP to which it is usually connected. A secondary benefit of the proposal, stemming from more accurate ICP information, would be the reduced likelihood of the reconciliation manager reconciling consumption volumes at an ICP in the wrong balancing area. This in turn would reduce the amount of unaccounted-for-electricity in balancing areas, which would enable more accurate invoicing of traders and more accurate customer invoicing. Improving the accuracy of customer invoicing brings the marginal value that consumers place on the electricity they purchase closer to the cost of producing the electricity consumed. Improving the accuracy of customer invoicing therefore improves the electricity market's efficiency. Improving the accuracy of ICP information in the registry also enables traders to conduct customer switching in a more timely manner. This may facilitate retail competition in the electricity industry, which would further the first limb of the Authority's objective. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has identified one alternative means of achieving the objective of this proposal: requiring a distributor to give written notice to the registry of all changes to an NSP identifier (regardless of the duration of the change) to the registry manager. However, this would impose transaction costs on distributors that would be materially greater than the identified benefits.

	Therefore, the Authority has rejected this alternative.

2018-15 Clarifying clauses 19, 21, and 22 of Schedule 15.2

Reference number(s)	2018-15 Clarifying clauses 19, 21, and 22 of Schedule 15.2
Problem definition	Clauses 19 and 22 of Schedule 15.2 have the same heading: “Correction of meter readings”. The content of clause 22 develops on the requirements in clause 19, and does not need to be a separate clause. It is also unclear from the current wording of clause 19 that the obligations in this clause apply to reconciliation participants. Also, in clauses 21(4)(c) and 22(2)(d), the meaning of the term “operator identifier” is not as clear as it could be. “Operator identifier” is intended to refer to an identifier for the person in the reconciliation participant who corrects or alters data. It is not an identifier for the reconciliation participant.
Proposal	The Authority proposes to amend the Code to: • clarify the intent of clause 19 of Schedule 15.2 (including that the obligations shifted from clause 22(1) and (2) apply to reconciliation participants) • shift clause 22(1) and (2) to new clause 19(4) and (5) of Schedule 15.2 • clarify the meaning of clause 21(4)(c) of Schedule 15.2 • revoke clause 22 of Schedule 15.2.
Proposed Code amendment	**19 Correction of meter readings** (1) If a **reconciliation participant** detects errors ~~are detected during the~~while validating~~validation of~~ non **half hour meter readings**, the **reconciliation participant** must~~1 of the following must be undertaken~~: (a) confirm~~ation of~~ the original **meter reading** by carrying out another **meter reading**~~:~~; and (b) if the confirmed original **meter reading** is erroneous, replace~~ment of~~ the original **meter reading** with~~by~~ another **meter reading** (even if the replacement **meter reading** ~~may be~~is at a different date)~~:~~. (1A~~c~~) ~~if~~If a **reconciliation participant** detects errors while validating non **half hour meter readings**, but the **reconciliation participant** cannot confirm the original **meter reading** or replace it with ~~cannot be confirmed or replaced by~~ a **meter reading** from another **interrogation**, the **reconciliation participant** must: (a) ~~an **estimated reading** may be~~ substitute~~d if~~ the original **meter reading** with an **estimated reading** that is marked as an estimate; and (b) ~~it is~~ subsequently replace~~d~~ the **estimated reading** in

accordance with clause 4(2).

(2) If a **reconciliation participant** detects errors ~~are detected during the~~ while validating~~validation of~~ **half-hour meter readings**, the **reconciliation participant** must correct~~,~~ the **meter readings** ~~must be corrected~~ as follows:

(a) if the relevant **metering installation** has a check **meter** or **data storage device** ~~is installed at the **metering installation**~~, substitute the original **meter reading** with data from the check **meter** or **data storage device** ~~may be substituted:~~; or

(b) ~~in the absence of any~~ if the relevant **metering installation** does not have a check **meter** or **data storage device**, ~~data may be~~ substitute~~d~~ the original **meter reading** with data from another period ~~if~~ provided—

(i) the total of all substituted intervals matches the total consumption recorded on a **meter**, if available;~~,~~ and

(ii) the **reconciliation participant** considers the pattern of consumption ~~is considered~~ to be materially similar to the period in error.

(3) A **reconciliation participant** may use ~~**E**~~**error compensation** and **loss compensation** ~~may be carried out~~ as part of the process of determining accurate data. Whatever methodology is used, the **reconciliation participant** must document the compensation process ~~must be documented~~ and ~~must~~ comply with audit trail requirements set out in this Code.

(4) In correcting a **meter reading** in accordance with this clause, a **reconciliation participant** must not overwrite the **raw meter data**. If the **raw meter data** and the **meter readings** are the same, the **reconciliation participant** must use the processing or data correction application to:

(a) make an automatic secure backup of the affected data; and

(b) archive the affected data.

(5) If a **reconciliation participant** corrects or alters data, the **reconciliation participant** must generate and archive a journal that contains the following information:

(a) the date of the correction or alteration; and

(b) the time of the correction or alteration; and

(c) the operator identifier for the person within the **reconciliation participant** who made the correction or alteration; and

(d) the **half-hour meter reading** data or the non **half-hour meter reading** data corrected or altered, and the total difference in volume of such corrected or altered data; and

(e) the technique used to arrive at the corrected data; and

(f) the reason for the correction or alteration.

…

21 Audit trails

(1) Each **reconciliation participant** must ensure that a complete audit trail exists for all data gathering, validation and processing functions of the **reconciliation participant**.

(2) The audit trail must—

(a) include details of information—

(i) provided to and received from the **registry manager**; and

(ii) provided to and received from the **reconciliation manager**; and

(iii) provided and received from other **reconciliation participants** and their agents; and

(b) cover all **raw meter data** and any changes to the **raw meter data** archived under clause 18.

(3) Logs of communications and processing activities must form part of the audit trail, including if automated processes are in operation.

(4) Logs must be printed and filed as hard copy or maintained as data files, in a secure form, along with other archived information, and must include (at a minimum) the following:

(a) an activity identifier~~:~~; and

(b) the date and time of the activity~~:~~; and

(c) the operator identifier for the person within the **reconciliation participant** who performed the activity.

(5) A **reconciliation participant** must collect all relevant data used by the **reconciliation participant** to determine **profile** data, including external control equipment operation logs, and archive that data in accordance with clause 18.

~~**22 Correction of meter readings**~~

~~(1) In correcting a **meter reading** in accordance with clause 19, the **raw meter data** must not be overwritten. If the **raw meter data** and the **meter readings** are the same, an automatic secure backup of the affected data must be made and archived by the processing or data correction application.~~

~~(2) If data is corrected or altered, the **reconciliation participant** correcting or altering the data must generate and archive a journal that contains the following information:~~

~~(a) the date of the correction or alteration:~~

~~(b) the time of the correction or alteration:~~

	~~(c) the operator identifier of the **reconciliation participant**:~~ ~~(d) the **half-hour meter reading** data or the **non half-hour meter reading** data corrected or altered, and the total difference in volume of such corrected or altered data:~~ ~~(e) the technique used to arrive at the corrected data:~~ ~~(f) the reason for the correction or alteration.~~
Grounds for not consulting	The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed amendment is consistent with the Authority's objective, and with section 32(1)(c) of the Act, because it will contribute to the efficient operation of the electricity industry. Merging clauses 19 and 22 of Schedule 15.2, and simplifying or clarifying the wording of clauses 19 and 21 in the manner proposed, will simplify the Code and make it easier for reconciliation participants to understand their obligations. This promotes the efficient operation of the electricity industry.
Assessment against Code amendment principles	The Authority is satisfied the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32 of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The amendment is consistent with principle 2 in that it addresses a problem in the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

2018-16 Switching ICPs with category 3 or higher metering installations that have advanced metering infrastructure components

Reference number(s)	2018-16 Switching ICPs with category 3 or higher metering installations that have advanced metering infrastructure (AMI) components
Problem definition	The purpose of the ICP switching process set out in clauses 13 to 16 of Schedule 11.3 of the Code ("gaining trader switch process") is to provide for the switching of ICPs metered using half-hour metering installations that are category 3 and above. Currently, the gaining trader switch process does not provide for the switching of an ICP with one or more metering installations that are category 3 and above, if any of the metering installations have AMI components. The reason for this is historical. When the gaining trader switch process was designed, AMI components were not used in metering installations that were category 3 and above. This is no longer the case. AMI components are now used in category 3 and above metering installations. This trend is expected to continue. It is possible to switch ICPs that have category 3 and above metering installations with AMI components using a manual workaround process. However, this is more time-consuming and less cost-effective than an automated process would be, and it is not governed by the Code. It would therefore be simpler to amend the gaining trader switch process in clauses 13 to 16 of Schedule 11.3 should so it applies to all ICPs with a metering installation of category 3 or above, regardless of whether the metering installation has AMI components. The Authority also considers that the wording of clause 13(1)(a) of Schedule 11.3 could be clearer in describing when this provision applies.
Proposal	The Authority proposes to amend the Code: • so the gaining trader switch process in clauses 13 to 16 of Schedule 11.3 applies to all ICPs with a metering installation of category 3 or above, regardless of whether the metering installation has AMI components • to clarify the drafting of clause 13(1)(a) of Schedule 11.3.
Proposed Code amendment	**13 Gaining trader switch processes** (1) A gaining **trader** switch process applies when a **trader** (the "gaining **trader**") has an arrangement with a **customer** or **embedded generator** to— (a) trade **electricity** ~~through—~~<u>with the **customer** or **embedded**</u>

generator at an **ICP** at which another **trader** (the “losing **trader**”) trades **electricity** with the **customer** or **embedded generator**, and one of subparagraphs (i) to (iii) applies—

(i) at the **ICP**, the gaining **trader** will trade **electricity** through a **half-hour metering installation** that is~~(not being~~ a category 3 or higher ~~**category 1**~~ **metering installation**~~ or a **category 2 metering installation**) at an **ICP** with a submission type of **half hour** in the **registry** and an AMI flag of "N" at which another **trader** (the "losing **trader**") trades **electricity** through a **half-hour metering installation** with the same submission type and AMI flag~~; or

(ii) at the **ICP**—

(A) the gaining **trader** will trade **electricity** through a **half-hour metering installation**, ~~at an~~ and in the **registry** the **ICP** ~~with~~will have a submission type of **half hour** ~~in the **registry**~~ and an AMI flag of "N"; and

(B) ~~at which another **trader** (~~the ~~"~~losing **trader**~~")~~ trades **electricity** through a non **half-hour metering installation**, ~~with the **customer** or **embedded generator** with~~ and in the **registry** the **ICP** has a submission type of non **half hour** ~~in the **registry**~~ and an AMI flag of "N"; or

(iii) at the **ICP**—

(A) the gaining **trader** will trade **electricity** through a non **half-hour metering installation**, ~~at an~~ and the **ICP** will have a submission type of non **half hour** in the **registry**; and

(B) ~~at which another **trader** (~~the ~~"~~losing **trader**~~")~~ trades **electricity** through a **half-hour metering installation**, and in the **registry** the **ICP** has a submission type of **half hour** and ~~with~~ an AMI flag of "N" ~~with the customer or embedded generator~~; or

(b) assume responsibility under clause 11.18(1) for an **ICP** described in subparagraphs (a)(i) to (iii).

…

Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and with section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. This is because the proposed amendment would remove the need for a gaining trader and the registry manager to undertake a manual process each time a trader switched an ICP with a category 3 and above metering installation with AMI components. The proposed amendment may promote competition in the provision of metering and related services, by encouraging greater uptake of AMI components in metering installations that are category 3 and above. The proposed amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The estimated costs and benefits of the proposed Code amendment can be quantified. Therefore, the Authority has undertaken a quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposed Code amendment is to improve the efficiency of the switching process for ICPs that have category 3 or above metering installations with AMI components.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the proposed amendment would cost $1,000-$3,000 to implement. This cost would be to amend the registry's functionality and to update the registry's functional specification. *Benefits* The primary benefit of the proposed Code amendment is to remove

	the need for traders and the registry manager to use a manual workaround process when switching an ICP that has category 3 or above metering installations with AMI components. The Authority estimates the cost that a trader and the registry manager together currently incur per switch is $150-$225.[1] There are currently approximately two of these switches per year, but the Authority believes this number will increase materially over time as the number of category 3 metering installations with AMI components increases. The Authority has allowed for the annual number to increase by 25 % per year over 15 years, reaching 57 switches after 15 years. This equates to a present value benefit of approximately $40,000-$60,000.[2] A secondary benefit of the proposed Code amendment is that it may promote competition in the provision of metering and related services. The proposal might encourage greater uptake of AMI components in metering installations that are category 3 and above, thereby promoting competition between providers of AMI and non-AMI metering components. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

[1] This relates to staff time.
[2] Using a real discount rate of 8% per annum.

2018-17 Removing the defined term “customer” from Part 1

Reference number(s)	2018-17 Removing the defined term “customer” from Part 1
Problem definition	The term “customer” is defined twice in the Code – in Part 1 and in Schedule 12.4 (the Transmission Pricing Methodology). The term is also used in some places in the Code without any intention that either of these definitions applies. This makes the use of the term “customer” unnecessarily confusing for readers of the Code. For example, the definition of “customer” in Part 1 conflicts with the meaning of “customer” in the definition of “distributed unmetered load” in Part 1. This is because “distributed unmetered load” means unmetered load with a single profile supplied to a single customer across more than 1 point of connection. By contrast, “customer” means a person who purchases, or has agreed to purchase, electricity from a retailer at a specific ICP.[1] The Authority also considers that it is unhelpful to give commonplace terms like ‘customer’ a defined meaning—particularly when the defined meaning closely reflects the ordinary meaning of the term. This is inefficient, and reduces the clarity and readability of the Code by forcing those interpreting the Code to check the Part 1 definitions of terms that need not be defined.
Proposal	The Authority proposes to remove the defined term “customer” from Part 1 of the Code and to let it take its ordinary meaning throughout the Code, except in Schedule 12.4. The Authority considers it appropriate to retain the defined meaning of “customer” in Schedule 12.4, since any changes to this meaning are more appropriately considered as part of the Authority’s review of transmission pricing.
Proposed Code amendment	**Part 1** ~~**customer** means a person who purchases, or has agreed to purchase, **electricity** from a **retailer** at a specific **ICP**~~ **distributed unmetered load** means **unmetered load** with a single **profile** supplied to a single customer~~**customer**~~ across more than 1 **point of connection** **electricity supplied** means, for any particular period, the information relating to the quantities of **electricity** supplied by **retailers** across

[1] Under clause 1.1 of the Code, an ICP means a point of connection.

points of connection to **consumers**, sourced directly from the **retailer's** financial records, including quantities—

(a) that are metered or unmetered; and

(b) supplied through normal <u>customer</u>~~**customer**~~ supply and billing arrangements; and

…

ICP means an installation control point being 1 of the following:

(a) a **point of connection** at which a <u>customer</u>~~**customer**~~ installation is connected to a **network** other than the **grid**:

…

loss of communication means a sustained disruption of communications between the **system operator** and 1 or more **dispatch** <u>customers</u>~~**customers**~~ such that operation of the **grid** is affected or is likely to be affected

1.3 Special definition of "related"

For the purposes of this Code a person (the "first person") is deemed to be related to another person (the "second person") if the first person is related to the second person by reason of any domestic or **business** relationship (other than because the second person is a <u>customer</u>~~**customer**~~ of the first person), such that the first person can reasonably be expected to have influence over the second person's judgment in trading or investment matters, or to be consulted by the second person before any such judgment is formed, and if the first person is deemed to be so connected, the second person is also deemed to be related to the first person. No person is deemed to be related to any other person if either person is a shareholding minister as that term is defined in section 2 of the State-Owned Enterprises Act 1986 or any other New Zealand legislation, provided that person is acting in his or her capacity as a shareholding minister.

Part 9

9.20 Retailer must have customer compensation scheme

…

(3) A **retailer's customer compensation scheme** may cover a <u>customer</u>~~**customer**~~ who is not a **qualifying customer**.

9.21 Qualifying customers

(1) A **retailer's qualifying customer** is a person who, as at the end of the last day of a **public conservation period**,—

  (a) is a <u>customer</u>~~**customer**~~ of the **retailer**; and

…

(4) To avoid doubt,—

…

(b) a **retailer's qualifying customers** includes a customer~~**customer**~~ who switched,—

(i) to the **retailer** from another **retailer** on or before the last day of a **public conservation period**, including during that **public conservation period**; or

(ii) from the **retailer** to another **retailer** between the last day of a **public conservation period** and the date on which the **retailer** pays compensation under the **customer compensation scheme**.

9.28 Publishing description of additional customer compensation schemes

A **retailer** who has 1 or more **additional customer compensation schemes** must—

(a) **publish** and keep **published** a description of its **additional customer compensation schemes**; and

(b) on request from a customer~~**customer**~~, provide a written description of the **additional customer compensation schemes**.

Part 11

11.1 Contents of this Part

This Part—

...

(b) prescribes a process for switching customers~~**customers**~~ and **embedded generators** between **traders**; and

11.15 Process for customer or embedded generator switching

(1) This clause applies if a **trader** ("the gaining **trader**") has an arrangement with a customer~~**customer**~~ or **embedded generator** to—

(a) commence trading **electricity** with the customer~~**customer**~~ or **embedded generator** at an **ICP** at which another **trader** ("the losing **trader**") trades **electricity** with the customer~~**customer**~~ or **embedded generator**; or

(b) assume responsibility under clause 11.18(1) for such an **ICP**.

...

11.15AB Switch saving protection

…

(2) If the protected **trader** enters into an arrangement with a customer~~**customer**~~ of another **trader** (the "losing **trader**") to commence trading **electricity** with the customer~~**customer**~~, the losing **trader** must comply with subclause (4).

(3) If a **trader** enters into an arrangement with a customer~~**customer**~~ of a protected **trader** to commence trading **electricity** with the customer~~**customer**~~, the protected **trader** must comply with subclause (4).

(4) A losing **trader** referred to in subclause (2) or a protected **trader** referred to in subclause (3) must not, by any means, initiate contact with the customer~~**customer**~~ to attempt to persuade the customer~~**customer**~~ to terminate the arrangement referred to in subclause (2) or subclause (3) (as the case may be) during the period specified in subclause (5), including by—

(a) making a counter-offer to the customer~~**customer**~~; or

(b) offering an enticement to the customer~~**customer**~~.

…

11.15AC Trader may communicate with customers for certain purposes

Clause 11.15AB(4) does not prohibit a **trader** from—

(a) contacting a customer~~**customer**~~ to advise the customer~~**customer**~~ of any termination fees that the customer~~**customer**~~ is required to pay as a result of the customer~~**customer**~~ ceasing to trade with the **trader**; or

(b) contacting a customer~~**customer**~~ regarding administrative matters, including—

(i) any fees the customer~~**customer**~~ owes the **trader**:

(ii) the customer’s~~**customer's**~~ final meter reading:

(iii) how the **trader** will return any keys it holds on the customer’s~~**customer's**~~ behalf:

(iv) the effect of the customer~~**customer**~~ ceasing to buy **electricity** from the **trader** on other contracts between the customer~~**customer**~~ and the **trader**, for example, for the supply of gas; or

(c) providing a factual response to a question asked by a customer~~**customer**~~; or

(d) making a counter-offer or offering an enticement to a customer~~**customer**~~ who has invited the **trader** to attempt to persuade the customer~~**customer**~~ to terminate the arrangement referred to in clause 11.15AB(2) or (3); or

(e) offering an enticement to a customer~~**customer**~~ as part of a general marketing campaign.

11.15B Trader contracts with customers to permit assignment by Authority

(1) Each **trader** must at all times ensure that the terms of each contract under which a customer~~**customer**~~ of the **trader** purchases **electricity** from the **trader** permit—

…

(b) the terms of the assigned contract to be amended on such an assignment to—

(i) the standard terms that the recipient **trader** would normally have offered to the customer~~**customer**~~ immediately before the **event of default** occurred; or

(ii) such other terms that are more advantageous to the customer~~**customer**~~ than the standard terms, as the recipient **trader** and the **Authority** agree; and

(c) the terms of the assigned contract to be amended on such an assignment to include a minimum term in respect of which the customer~~**customer**~~ must pay an amount for cancelling the contract before the expiry of the minimum term; and

(d) the **trader** to provide information about the customer~~**customer**~~ to the **Authority** and for the **Authority** to provide the information to another **trader** if required under Schedule 11.5; and

…

11.16 Trader to ensure arrangements for line function services and metering

Before providing the **registry manager** with information in accordance with clause 11.7(2) or clause 11.18(4), a **trader** must—

(a) ensure that it, or its customer~~**customer**~~, has made any necessary arrangements for the provision of **line function services** in relation to the **ICP**; and

…

11.31 Customer and embedded generator queries

(1) If a **trader** receives a request from a customer~~**customer**~~ of the **trader** or a person authorised by a customer~~**customer**~~ of the **trader** for the customer's~~**customer's**~~ **ICP identifier**, the **trader** must provide that information no later than 3 **business days** after receiving the request.

(2) If a **distributor** receives a request from a customer**~~customer~~** or **embedded generator** whose **ICP** is connected to the **distributor's network** for the customer's**~~customer~~** or **embedded generator's ICP identifier**, or a person authorised by such a customer**~~customer~~** or **embedded generator**, the **distributor** must provide that information no later than 3 **business days** after receiving the request.

Schedule 11.1

7 Distributors to provide ICP information to registry manager

(1) A **distributor** must, for each **ICP** on the **distributor's network**, provide the following information to the **registry manager**:

…

(j) the **participant identifier** of the first **trader** who has entered into an arrangement with a customer**~~customer~~** or an **embedded generator** to sell or purchase **electricity** at the **ICP** (only if the information is provided by the first **trader**):

…

9 Traders to provide ICP information to registry manager

(1) Each **trader** must provide the following information to the **registry manager** for each **ICP** for which it is recorded in the **registry** as having responsibility:

…

(k) except as provided in subclause (1A), the relevant business classification code applicable to the customer**~~customer~~** at the **ICP**, in accordance with business classification codes **published** by the **Authority**.

…

17 "Active" status

…

(2) Before an **ICP** is given the "Active" status, the **trader** must ensure that—

(a) the **ICP** has only 1 customer**~~customer~~**, **embedded generator**, or **direct purchaser**; and

…

Schedule 11.3

1 Standard switch process for ICPs

(1) A standard switch process applies when a **trader** (the "gaining

	trader") has an arrangement with a customer~~**customer**~~ or **embedded generator** to commence trading **electricity** with the customer~~**customer**~~ or **embedded generator** at, or to otherwise assume responsibility under clause 11.18(1) for, an **ICP** at which another **trader** (the "losing **trader**") trades **electricity**, and the gaining **trader** switch process under clauses 13 to 16 does not apply. … (2) If subpart 2 of Part 4A of the Fair Trading Act 1986 applies to an arrangement described in subclause (1),— (a) the gaining **trader** must identify the period within which the customer~~**customer**~~ or **embedded generator** may cancel the arrangement in accordance with section 36M of the Fair Trading Act 1986; and … **2 Gaining trader advises registry manager of standard switch request** (1) For each **ICP** to which a switch relates, the gaining **trader** must advise the **registry manager** of the switch no later than 2 **business days** after the arrangement to trade **electricity** with the customer~~**customer**~~ or the **embedded generator** comes into effect. … **6 Traders must use same reading** … (2) Despite subclause (1), subclause (3) applies if— … (b) the gaining **trader** will trade **electricity** at the **ICP** through a **metering installation** with a submission type of **half hour** in the **registry**, as a result of the gaining **trader's** arrangement to trade **electricity** with the customer~~**customer**~~ or the **embedded generator**; and … **8 Switch move process for ICPs** (1) A switch move process applies when a **trader** (the "gaining **trader**") has an arrangement with a customer~~**customer**~~ or **embedded generator** to commence trading **electricity** with the customer~~**customer**~~ or **embedded generator** at, or to otherwise assume responsibility under clause 11.18(1) for, an **ICP** for which no **trader** has an agreement to trade **electricity** and the gaining **trader** switch process under clauses 13 to 16 does not apply.

	(1A) This clause and clauses 9 to 12 apply to a switch move process. (2) If subpart 2 of Part 4A of the Fair Trading Act 1986 applies to an arrangement described in subclause (1)— (a) the gaining **trader** must identify the period within which the customer~~**customer**~~ or **embedded generator** may cancel the arrangement in accordance with section 36M of the Fair Trading Act 1986; and … **9 Gaining trader informs registry manager of switch request** (1) For each **ICP** to which a switch relates, the gaining **trader** must advise the **registry manager** of the switch request no later than 2 **business days** after the arrangement to trade **electricity** with the customer~~**customer**~~ or the **embedded generator** comes into effect. … **12 Gaining trader may change switch event meter reading** … (2A) Despite subclauses (1) and (2), subclause (2B) applies if— … (b) the gaining **trader** will trade **electricity** at the **ICP** through a **metering installation** with a submission type of **half hour** in the **registry**, as a result of the gaining **trader's** arrangement with the customer~~**customer**~~ or **embedded generator**; and … **13 Gaining trader switch processes** (1) A gaining **trader** switch process applies when a **trader** (the "gaining **trader**") has an arrangement with a customer~~**customer**~~ or **embedded generator** to— (a) trade **electricity** through— … (ii) a **half-hour metering installation** at an **ICP** with a submission type of **half hour** in the **registry** and an AMI flag of "N" at which another **trader** (the "losing **trader**") trades **electricity** through a non **half-hour metering installation** with the customer~~**customer**~~ or **embedded generator** with a submission type of non **half hour** in the **registry** and an AMI flag of "N"; or (iii) a non **half-hour metering installation** at an **ICP** at which another **trader** (the "losing **trader**") trades

electricity through a **half-hour metering installation** with an AMI flag of "N" with the customer~~**customer**~~ or **embedded generator**; or

(b) assume responsibility under clause 11.18(1) for an **ICP** described in paragraph (a).

…

(2) If subpart 2 of Part 4A of the Fair Trading Act 1986 applies to an arrangement described in subclause (1)—

(a) the gaining **trader** must identify the period within which the customer~~**customer**~~ or **embedded generator** may cancel the arrangement in accordance with section 36M of the Fair Trading Act 1986; and

(b) for the purpose of this Schedule, the arrangement is deemed to come into effect on the day after the expiry of the period.

14 Gaining trader informs registry manager of switch request

(1) For each **ICP** to which a switch relates, the gaining **trader** must advise the **registry manager** of the switch request no later than 3 **business days** after the arrangement to trade **electricity** with the customer~~**customer**~~ or the **embedded generator** comes into effect.

…

Schedule 11.5

2 Notice to trader who has committed event of default

(1) If the **Authority** is satisfied that a **trader** ("defaulting **trader**") has committed an **event of default** under paragraph (a) or (b) or (f) or (h) of clause 14.41 the **Authority** must give written notice to the defaulting **trader** that**—**

(a) the defaulting **trader** must—

(i) remedy the **event of default**; or

(ii) assign its rights and obligations under every contract under which a customer~~**customer**~~ of the defaulting **trader** purchases **electricity** from the defaulting **trader** to another **trader**, and assign to another **trader** all **ICPs** for which the defaulting **trader** is recorded in the **registry** as being responsible; and

…

(2) The **Authority** may give written notice to the defaulting **trader** requiring the defaulting **trader** to provide to the **Authority**, within a time specified by the **Authority**, information about the

defaulting **trader's** customers~~**customers**~~.

…

3 Authority may require distributor and registry manager to provide information

(1) The **Authority** may, by notice in writing to a **distributor** on whose **network** a defaulting **trader** trades **electricity**, require the **distributor** to provide to the **Authority** the information about the defaulting **trader's** customers~~**customers**~~ specified in the notice (if the **distributor** holds the information), within the period specified in the notice.

…

4 Failure by defaulting trader to remedy event of default

(1) This clause applies if**—**

(a) 7 days have elapsed since the **Authority** gave notice to the defaulting **trader** under clause 2(1); and

(b) the **Authority** considers that—

(i) the defaulting **trader** has not remedied the **event of default** or, in the case of an **event of default** under clause 14.41(b) in respect of which there is an unresolved invoice dispute under clause 14.25, has not reached an agreement with the **Authority** to resolve the **event of default**; and

(ii) the defaulting **trader** still has 1 or more contracts under which a customer~~**customer**~~ of the defaulting **trader** purchases **electricity** from the defaulting **trader** or is still recorded in the **registry** as being responsible for 1 or more **ICPs**.

(2) The **Authority** must—

(a) give written notice to the defaulting **trader** that the **Authority** considers that this clause applies; and

(b) attempt to advise customers~~**customers**~~ of the defaulting **trader** that—

(i) the defaulting **trader** has committed an **event of default**; and

(ii) the customer~~**customer**~~ should enter into a contract for the purchase of **electricity** with another **trader** by the date that is 14 days after the day on which the **Authority** gave written notice to the defaulting **trader** under clause 2(1); and.

(iii) if the customer~~**customer**~~ fails to enter into a contract with another **trader** by that date, the **Authority** may assign the defaulting **trader's**

	rights and obligations under the customer'~~**customer's**~~ contract with the defaulting **trader** to another **trader** under clause 5. … **5 Authority may assign contracts and ICPs** (1) This clause applies if, by the end of the 17th day after the defaulting **trader** was given notice under clause 2(1),**—** … (b) the defaulting **trader** continues to have 1 or more contracts under which a customer~~**customer**~~ of the defaulting **trader** purchases **electricity** from the defaulting **trader** or the defaulting **trader** is still recorded in the **registry** as being responsible for 1 or more **ICPs**. (2) The **Authority** may— (a) exercise its right under a contract under which a customer~~**customer**~~ purchases **electricity** from the defaulting **trader** to assign the rights and obligations of the defaulting **trader** under the contract to a recipient **trader** in accordance with the contract; and … **6 Authority must provide information to recipient trader** If the **Authority** exercises its right to assign rights and obligations or an **ICP** under clause 5(2), the **Authority** must provide the following information to each recipient **trader**: (a) the number of customer~~**customer**~~ contracts (to the extent that the **Authority** has the information) and **ICPs** assigned to the **trader**; and (b) any information that the **Authority** holds about the customers~~**customers**~~ and **ICPs** assigned to the **trader**. **8 Terms of assigned contract** (1) If the **Authority** exercises its right to assign rights and obligations under clause 5(2), the **Authority** must attempt to advise the customer~~**customer**~~ that the terms of the contract may be amended on assignment. (2) The recipient **trader** must use reasonable endeavours to advise the customer~~**customer**~~ of those terms. **Part 12** **12.43 Net benefits test** … (8) The estimate of **expected unserved energy** in MWh multiplied

	by the value per MWh of that **expected unserved energy** under subclause (1) must be based on— … (b) if **Transpower** and a **designated transmission customer** cannot agree on the amount and value of the **expected unserved energy** under paragraph (a), the **value of expected unserved energy** in clause 4 of Schedule 12.2 and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer~~**customer**~~. **12.117 Permanent removal of interconnection assets from service or permanent grid reconfiguration** … (9) The estimate of **expected unserved energy** in MWh multiplied by the value per MWh of that **expected unserved energy** under subclause (2) must be based on the **value of expected unserved energy** in clause 4 of Schedule 12.2 and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer~~**customer**~~**.** … **12.141 Consideration of the likely effects of planned outages** … (3) … (d) the estimate of **expected unserved energy** in MWh multiplied by the value per MWh of that **expected unserved energy** under subclause (2) must— (i) in the case of **connection assets**, be based on— … (B) if **Transpower** and a **designated transmission customer** cannot agree on the amount and value of the **expected unserved energy** under subsubparagraph (A), the **value of expected unserved energy** in clause 4 of Schedule 12.2 and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer~~**customer**~~; and (ii) in the case of **interconnection assets**, be based on— …

	(B) **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer~~**customer**~~. … **Part 14** **14.41 Definition of an event of default** (1) Each of the following events constitutes an **event of default**: … (h) termination of a **trader's use-of-system agreement** with a **distributor** because of a serious financial breach if— (i) the **trader** continues to have a customer~~**customer**~~ or customers~~**customers**~~ purchasing **electricity** from the **trader** on the **distributor's local network** or **embedded network**; and … **Part 14A** **14A.17 Participants subject to prudential requirements must provide information to clearing manager** … (3) Each **participant** that is required to comply with prudential requirements under this Part must provide the following information to the **clearing manager** immediately upon the **participant** becoming aware of the situation: (a) if the **participant** is a **purchaser**, any significant change to that **purchaser's business**, including a merger or acquisition, loss or gain of a customer~~**customer**~~, or sale or purchase of assets, that could significantly affect the quantity of **electricity** purchased or generated by the **participant** in its capacity as a **purchaser** or **generator**: …
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed amendment would simplify the Code, which would make it easier for participants to understand and meet their obligations. This 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. The proposed amendment is expected to have no effect on competition or reliability of supply.
Assessment	The Authority is satisfied the proposed Code amendment is

against Code amendment principles	consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2. This is because the proposed amendment is expected to result in participants incurring lower costs in interpreting and complying with the Code.
Principle 3: Quantitative Assessment	The estimated cost of the proposed Code amendment can be readily quantified, but it has not been practicable to quantify benefits. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to simplify the Code by removing an unnecessary (and potentially confusing) definition in Part 1. This will make it easier for participants to understand the Code and comply with it.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority does not expect the proposed amendment to place costs on industry participants. The proposal does not change industry participants' obligations under the Code. Under the proposal, the Authority has clarified several Code provisions to ensure the reference to "customer" means "electricity customer", per the current definition of "customer" in Part 1 of the Code. Therefore, the Authority expects there to be no additional cost on participants seeking to understand the Code clauses that contain "customer". *Benefits* The primary benefit of the proposed Code amendment is to make it easier for participants to understand and comply with their Code obligations. In particular, participants would no longer need to consider whether a reference to "customer" should take its defined meaning. Participants

	would instead know that a reference to "customer" simply meant the Code was referring to an electricity customer. The proposed amendment also lessens the probability of the Code being internally inconsistent, from the defined meaning of "customer" being used incorrectly. Making it easier for participants to understand and comply with the Code lowers the cost of participating in the electricity industry, which represents a productive economic efficiency benefit. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

2018-018 Update to security forms under Schedules 14A.2 to 14A.5

Reference number(s)	2018-18 Update to security forms under Schedules 14A.2 to 14A.5
Problem definition	Schedules 14A.2 to 14A.5 of the Code set out the following forms for participants that incur financial obligations under the Code: • guarantee given by a bank • guarantee given by another person • letter of credit • surety bond. Under clauses 3(3) and 4(2) of Schedule 14A.1, if the Code requires a participant to give one of these forms, it must be on the terms in the applicable form under Schedules 14A.2 to 14A.5, or as otherwise approved by the Authority. There are a number of improvements that could be made to the forms under Schedules 14A.2 to 14A.5 to make them more user-friendly and administratively efficient. In particular: a) The current forms (apart from the form in Schedule 14A.5) have signature blocks that specify how they are to be signed and witnessed. Banks and others that use the forms have signing arrangements (delegated authorities and powers of attorney) that are inconsistent with those provided for in the forms. This can create uncertainty about whether a form has been properly executed. b) Similarly, there are variables in the current forms that users must complete, but frequently overlook. This has meant signed forms have had to be returned to participants to be completed and re-signed. c) The numbering, language and clarity of the forms could also be improved.
Proposal	The Authority proposes amending the forms to resolve the problems described in paragraphs a) to c) above, without changing the purpose or effect of the obligations or level of security in the current forms. Specifically, the Authority proposes: a) removing the requirements from the forms in Schedules 14A.2, 14A.3, and 14A.4 that specify how the forms are to be executed b) removing the variables that users currently have to complete, but which are not needed c) simplifying the numbering and updating the forms' wording to make the forms clearer and more consistent with each other.

Proposed Code amendment

Schedule 14A.2
Guarantee

To: [Clearing manager] (the "Clearing Manager")
[address]

Attention: [name]

Dear Sir/Madam

1. [Bank] (~~"~~the "Bank") refers to each ~~and every~~ obligation ~~pursuant to the Electricity Industry Participation Code 2010 ("the Code")~~ of [Participant] (~~"~~the "Principal") to pay amounts the Principal, now or at any time, owes to, and is invoiced by, ~~you~~the Clearing Manager (whether as principal or agent) together with default interest, if any, in relation to such amounts (~~"~~the "Obligations") ~~pursuant to~~under the Electricity Industry Participation Code 2010 (the "Code").

2. The Bank unconditionally guarantees to pay the ~~payment to you~~Clearing Manager on demand ~~of~~ an amount specified in each such demand provided that—

    (a) [the ~~aggregate~~Bank's liability ~~of the Bank~~under this guarantee will not exceed $[~~$~~amount determined from time to time by the ~~clearing manager~~Clearing Manager calculated in accordance with clause 14A.5 of the Code] (the “Maximum Amount”); and]

    [Note: Bank to elect either this paragraph or the following paragraph].

    (a) [the ~~aggregate~~Bank's liability ~~of the Bank~~under this guarantee ~~in respect of which this guarantee is in effect~~will not exceed the Maximum Amount as defined below—

        (i) The sum of the amounts calculated for all trading periods to which this guarantee applies in any period to which a demand under this guarantee relates in accordance with the following formula:

$$A*B$$

where

	A. is [X] MWh B. is the final price for the trading period at the [specify] [grid injection point/grid exit point/reference point]; and (ii) For the purposes of ~~subparagraph~~paragraph 2(a)(i), this guarantee applies to every trading period within any period to which a demand under this guarantee relates as follows: A. From the ~~[~~"Starting Date"~~]~~, being the later of— 1. the start of the period; and 2. [~~DATE~~date]; and B. Until the "Final Date", being the earlier of— 1. the end of the period; and 2. the Final Date as notified to the ~~clearing manager~~Clearing Manager under paragraph 2(a)(iii); and 3. [~~DATE~~date]; and (iii) ~~Notwithstanding~~Despite anything in this guarantee or in the Code, the Bank may give the ~~clearing manager~~Clearing Manager notice of the Final Date for the purposes of paragraph 2(a)(ii)B. The Final Date is the later of the date specified in the notice or ~~2~~two business days after the date on which the ~~clearing manager~~Clearing Manager receives the notice; and] (b) ~~your~~the Clearing Manager's demand is made in writing and is signed by or purported to be signed by an authorised signatory; and (c) a certificate signed by or purported to be signed by ~~your~~the Clearing Manager's authorised signatory and certifying that the Principal has failed, in whole or in part, to fulfil the Obligations accompanies ~~your~~the demand, ~~which~~such certificate will be conclusive proof of such failure. 3. ~~This~~The Bank's liability under this guarantee will not be

affected, discharged, or diminished by any act~~ or~~, omission, or matter, which~~ would~~, but for this provision, ~~have exonerated~~would have affected, discharged, or diminished a guarantor's liability, but would not have affected~~ or~~, discharged, or diminished the Bank's liability had it been a principal debtor.

4. Subject to paragraph 5 below, this guarantee will continue in force until the date at which the Principal ~~has ceased~~ceases to be bound by the Code and has discharged its obligations to ~~you~~the Clearing Manager under the Code, at which time ~~you~~the Clearing Manager will return this guarantee to the Bank.

5. [Despite anything else in this guarantee, the Bank may at any time pay ~~you~~the Clearing Manager the Maximum Amount less any amount or amounts the Bank may previously have paid under this guarantee or such lesser sum as ~~you~~the Clearing Manager may require. -Upon payment of that sum, ~~the liability of the Bank under~~this guarantee ~~will cease~~shall be cancelled and ~~determine~~the Bank shall have no further liability.]

[Note: Bank to elect either this paragraph or the following paragraph as a method of cancellation.]

5. [~~Despite anything else in this guarantee, the~~The Bank may cancel this guarantee ~~as to subsequent liability ~~by giving ~~ninety~~90 days' notice in writing to ~~[clearing manager]; however~~the Clearing Manager. Following cancellation of this guarantee, the Bank ~~will remain~~remains liable ~~with respect to the~~for any Obligations ~~that relate to the period prior to~~incurred before the effective date of ~~the ninety (90) days' notice~~cancellation, but shall not be liable for any Obligations incurred after that date.]

6. This guarantee may be assigned by you without the Bank's consent. -It will bind the successors and assigns of the Bank~~, as well as any entity with which the Bank may amalgamate~~.

7. This guarantee is governed by ~~and interpreted in all respects in accordance with ~~New Zealand law and the parties irrevocably submit to the non-exclusive jurisdiction of the courts of New Zealand.

[insert execution block for Bank]

~~EXECUTED for and on behalf)~~
~~of [BANK])~~
~~by its Attorneys)~~

	~~………………………………)~~ ~~[Print Names]) Signature(s)~~ ~~………………………………………………~~ ~~in the presence of:~~ ~~………………………………………………~~ ~~Signature~~ ~~………………………………………………~~ ~~Full Name~~ ~~………………………………………………~~ ~~Address~~ ~~………………………………………………~~ ~~Occupation~~ ~~………………………………………………~~ ~~Signature(s)~~ **Schedule 14A.3** **Deed of guarantee and indemnity** DATED BY 8. [Guarantor] (the "Guarantor") IN FAVOUR OF 9. [Clearing manager] (the "Beneficiary") 1. **Guarantee and indemnity** 1.1 ~~1.~~ The Guarantor— (a) unconditionally and irrevocably guarantees to the Beneficiary the due performance and observance by [Participant] (~~"~~the "Debtor") of each ~~and every~~ obligation the Debtor may now or ~~hereafter~~in the future have to the Beneficiary to pay amounts it owes to, and is invoiced by, the Beneficiary (whether as principal or agent) together with default interest, if any, in relation to such amounts (~~"~~the "Obligations") ~~pursuant to~~under the Electricity Industry Participation Code 2010 (~~"~~the "Code")~~ and promises to pay to the Beneficiary on demand all amounts now or hereafter owing, due or payable by the Debtor to the Beneficiary in respect of the Obligations~~; and

(b) ~~agrees as a primary obligation to indemnify~~indemnifies the Beneficiary ~~from time to time on demand from and~~ against any loss incurred by the Beneficiary as a result of any failure by the Debtor to fulfil the Obligations. This indemnity shall apply to any of the Obligations ~~being void, voidable~~(or ~~unenforceable for any reason, whether or not known to the Beneficiary, the~~ any amount ~~of such loss being the amount that the Beneficiary~~ which, if recoverable, would ~~otherwise~~ have ~~been entitled to recover from the Debtor. 2. This Deed~~ formed part of the Obligations) which is ~~to~~not or may not be ~~security in respect of each~~enforceable, recoverable, or recovered for any reason; and

(c) shall pay the Obligations (and ~~every one of the Obligations but, nevertheless, the~~any other amounts owing under this Deed) on demand.

1.2 The total amount payable by the Guarantor under this Deed must not exceed ~~the aggregate of~~ $[~~$~~amount determined from time to time by the ~~clearing manager~~Clearing Manager calculated in accordance with clause 14A.5 of the Code] (the "Maximum Amount") and any sums payable under clauses 1~~(~~.3~~)~~ and 9 of this Deed.

1.3 ~~3.~~ If any moneys payable by the Guarantor under this Deed are not paid on demand, the Guarantor must pay to the Beneficiary interest on such unpaid moneys (both before and after ~~judgement~~judgment) at the rate determined in accordance with clause 1~~(~~.4~~)~~ of this Deed from the date of demand to the date of their actual receipt by the Beneficiary calculated on a daily basis and capitalised as the Beneficiary will determine.

1.4 ~~4.~~ The ~~rate at which~~interest ~~must~~rate will be ~~calculated is the aggregate of~~ 5% per annum plus the then prevailing settlement bid rate for 90 day bills displayed on Reuters Screen BKBM at 10:45am on the date of demand or, if for any reason that rate is not displayed, the rate determined by the Beneficiary to be the nearest practicable equivalent.

2. Preservation of rights

2.1 ~~1.~~ The obligations of the Guarantor and the rights, powers and remedies conferred on the Beneficiary under this Deed are in addition to, and not in substitution for, any other security or guarantee that the Beneficiary may at any time hold in respect of the Obligations ~~or any of them~~ and may be enforced without the Beneficiary first having recourse to any such security and without the Beneficiary first taking steps or proceedings against the Debtor.

2.2 ~~2. Neither the obligations of the Guarantor under this Deed nor~~The Guarantor's liability and the rights, powers, and remedies conferred ~~in respect of the Guarantor upon~~ on the Beneficiary ~~by~~ under this Deed ~~or by law may~~ will not be affected, discharged~~, impaired~~ or diminished by (and the Guarantor waives notice of) any act, omission or matter which, but for this clause 2.2, would have affected, discharged or diminished the Guarantor's liability to the Beneficiary or the Beneficiaries rights, powers and remedies with respect to the Guarantor or would have otherwise ~~affected by anything that might operate to discharge, impair, or otherwise affect the same,~~ provided a defence to the Guarantor (in each case, in whole or in part), including—

(a) the insolvency, liquidation, or dissolution of the Debtor or any other person, the appointment of any receiver, manager, ~~receiver and manager,~~ inspector, trustee, statutory manager, or other similar person in respect of the Debtor or any other person, or any change in the Debtor’s status, function, control, or ownership; and

(b) any of the Obligations, or the obligations of any person under any security or guarantee held in relation to any of the Obligations, being or becoming in whole or in part void, voidable, defective, illegal, invalid, or unenforceable in any respect or ranking after any other security; and

(c) any time, credit or other indulgence or other concession being granted or agreed to be granted by the Beneficiary to, or any composition or other arrangement made with or accepted from, the Debtor in respect of any of the Obligations or the obligations of any person under any security or guarantee held in relation to the same; and

(d) any variation of the terms of any of the Obligations or of any security or guarantee (including under this ~~guarantee~~Deed) held in relation to the same; and

(e) any failure to realise or fully realise the value of, or any release, discharge, exchange, or substitution of, any security or guarantee held in relation to any of the Obligations~~:~~; and

(f) any failure (whether intentional or not) to take, fully take or perfect any security now or ~~hereafter~~in the future

	agreed to be taken by the Beneficiary in relation to any of the Obligations; and (g) any other act, event or omission that, but for this clause 2~~(~~.2~~)~~, would or might operate or discharge, impair, or otherwise affect any of the obligations of the Guarantor under this Deed or any of the rights, powers, or remedies conferred upon the Beneficiary by the rules or by law. 2.3 ~~3.~~ If any payment to the Beneficiary under this Deed is avoided by law, the Guarantor's obligation to ~~have made such~~ make the payment will ~~be deemed~~ not ~~to have been~~ be affected ~~or~~, discharged, or diminished, and the Guarantor must on demand indemnify the Beneficiary against all costs sustained or incurred by the Beneficiary as a result of it being required for any reason to refund all or part of any amount received or recovered by it in respect of such payment and must in any event pay to the Beneficiary on demand the amount so refunded by it. The Beneficiary and the Guarantor will, in any such case, be deemed to be restored to the position in which each would have been and will be entitled to exercise the rights they respectively would have had if that payment had not been made. ~~4. The Beneficiary is not obliged before exercising any of the rights, powers, or remedies conferred upon it in respect of the Guarantor by law to make any demand on the Debtor, take any action or obtain judgement in any court against the Debtor, make or file any claim or prove in any liquidation of the Debtor, or enforce or seek to enforce any security or guarantee taken in respect of the Obligations.~~ 2.4 ~~5.~~ After a demand has been made by the Beneficiary under this Deed, and so long as the Guarantor is under any actual or contingent liability under this Deed, the Guarantor must not— (a) exercise in respect of any amount paid by the Guarantor under this Deed any right of subrogation or any other right or remedy that the Guarantor may have in respect of such amount paid; or (b) except with the Beneficiary's consent in writing, claim or receive payment of any other moneys for the time being due to the Guarantor by the Debtor or exercise any other right or remedy that the Guarantor may have in respect of

the same; or

(c) unless so required by the Beneficiary, prove in the liquidation of the Debtor in competition with the Beneficiary for any moneys owing to the Guarantor by the Debtor on any account.

Any moneys obtained by the Guarantor from the Debtor with such consent or as so required or in breach of this clause must, in each case, be held by the Guarantor upon trust to pay such moneys to the Beneficiary in or towards discharge of the Guarantor's obligations under this Deed.

2.5 Any moneys received by the Beneficiary that may be applied in or towards discharge of any of the obligations of the Guarantor under this Deed must be regarded as a payment in gross so that, in the event of the liquidation of the Guarantor, the Beneficiary may prove in the liquidation for the whole of such moneys.

3. **Representations and warranties**

The Guarantor represents that—

(a) it is duly incorporated and validly existing under the laws of ~~[New Zealand]~~ the jurisdiction in which it was incorporated, capable of suing and being sued and has the power to enter into and perform this Deed, and has taken all necessary corporate action to authorise it to enter into, execute, deliver, and perform its obligations under this Deed; and

(b) its entry into, execution, delivery, and performance of this Deed will not contravene any law or regulation to which the Guarantor is subject or any provision of its constitutional documents and all things (including the obtaining of consents) requisite for such entry, execution, delivery, and performance have been taken, fulfilled, and done, and are in full force and effect; and

(c) no obligation of the Guarantor under this Deed is secured by, and the execution, delivery and performance of this Deed will not result in the existence of, or oblige it to create, any mortgage, charge, pledge, lien or other encumbrance over any of its present or future revenues or assets; and

(d) the execution, delivery of and performance of the Guarantor's obligations under this Deed will not cause the Guarantor to be in breach of or in default under any agreement binding on the Guarantor or any of its assets and no material litigation or administrative proceeding

	before~~, by or of~~ any court or governmental authority is pending or (so far as the Guarantor knows) threatened against the Guarantor or any of its assets which, if decided against the Guarantor, would have a material adverse effect on the ability of the Guarantor to meet any or all of the obligations ~~hereunder~~in this Deed. 4. **Payments** All payments to be made by the Guarantor to the Beneficiary under this Deed must be made without set-off or counterclaim and without any deduction or withholding. If the Guarantor is obliged by law to make any deduction or withholding from any such payment, the amount due from the Guarantor in respect of such payment will be increased to the extent necessary to ensure that, after the making of such deduction or withholding, the Beneficiary receives a net amount equal to the amount the ~~Bank~~Beneficiary would have received had no such deduction or withholding been required to be made. 5. **Continuing security** This Deed will be a continuing security to the Beneficiary in respect of each ~~and every one of the Obligations~~ Obligation and must not be (or be construed so as to be) discharged by any intermediate discharge or payment of or on account of the Obligations or any settlement of accounts between the Beneficiary and the Debtor or anyone else. 6. **~~Termination~~Cancellation** [~~1.~~ Despite anything else in this Deed, the Guarantor may at any time pay to ~~you~~ the Beneficiary the Maximum Amount less any amount or amounts the Guarantor may previously have paid under this Deed or such lesser sum as ~~you~~ the Beneficiary may require. Upon payment of that sum, ~~the liability of~~ this Guarantee shall be cancelled and the Guarantor ~~under this Deed will cease and determine~~ shall have no further liability.] [Note: Guarantor to elect either this clause or the following clause as a method of cancellation.] [~~1. Despite anything else in this Deed the~~ The Guarantor may cancel this Deed ~~as to subsequent liability~~ by giving ~~ninety (~~90~~)~~ days' notice in writing to ~~[Clearing manager]; however~~ the Beneficiary. Following cancellation of this Guarantee, the Guarantor ~~will remain~~ remains liable ~~with respect to the~~ for any

	Obligations ~~that relate to the period prior to~~ incurred before the effective date of ~~the ninety (90) days' notice~~ cancellation but shall not be liable for any Obligations incurred after that date.] 7. **Assignment** This Deed may be assigned by the Beneficiary without the Guarantor's consent. It will bind the successors and assigns of the Guarantor~~, as well as any entity with which the Guarantor may amalgamate~~. 8. **Notices** 8.1 ~~1.~~ Any demand ~~to be~~ made on the Guarantor by the Beneficiary under this Deed ~~may~~ must be ~~made~~ in writing and delivered to the ~~address set out below~~ registered office of the Guarantor or to any other address in New Zealand from time to time notified ~~under clause 8(2). The Guarantor's address, as at the date of this Deed is: [address]~~ by the Guarantor to the Beneficiary in writing. 8.2 ~~2.~~ The Guarantor must immediately notify the Beneficiary of any change in the above address. 9. **Costs and expenses** The Guarantor ~~must on demand indemnify and hold harmless~~ indemnifies the Beneficiary ~~from and against~~ for all costs and expenses (including legal fees and any taxes or duties) incurred by the Beneficiary in the enforcement and protection of its rights under this Deed. 10. **Governing law** This Deed is governed by~~, and construed in accordance with~~ New Zealand law, and the Guarantor irrevocably submits to the non-exclusive jurisdiction of the courts of New Zealand. [insert execution block for Guarantor] ~~EXECUTED for and on behalf)~~ ~~of [Guarantor])~~ ~~in the presence of:)~~ ~~………………………………~~ ~~………………………………~~ ~~Director Director/Secretary~~ ~~………………………………………~~ ~~Signature~~ ~~………………………………………~~ ~~Full Name~~

	~~………………………………………~~ ~~Address~~ ~~………………………………………~~ ~~Occupation~~ ~~Note I: If two directors sign, no witness is necessary. If a director and secretary sign, both signatories are to be witnessed. If the director and secretary are not signing together, a separate witness will be necessary for each signature.~~ ~~Note II: If the Guarantor is incorporated outside of New Zealand, insert an appropriate execution clause for the country of incorporation.~~ **Schedule 14A.4** **Letter of credit** To: [Clearing manager] (the "Clearing Manager") [address] Attention:[name] Dear Sir/Madam IRREVOCABLE TRANSFERABLE STANDBY LETTER OF CREDIT NO. [number] DATED [date] We, [Bank] ("the "Bank") issue ~~our~~ in favour of the Beneficiary this irrevocable transferable standby letter of credit ("the "Letter of Credit") as follows: ~~IRREVOCABLE TRANSFERABLE STANDBY LETTER OF CREDIT NO. [number] DATED [date]~~ The Account Party: [Participant] ("the "Account Party") ~~Beneficiary: [Clearing manager] ("the~~ Beneficiary~~")~~: The Clearing Manager (the "Beneficiary") Issued in Connection With: -Each ~~and every~~ obligation ~~("the Obligations")~~ of the Account Party to pay the amounts it, now or at any time, owes to, and is invoiced by, the Beneficiary (whether as principal or agent) together with default interest, if any, in relation to such amounts (the "Obligations") under the Electricity Industry Participation Code 2010 ("the "Code").

Maximum Amount: $[insert amount]~~.~~ (the "Maximum Amount").

Expiry: This Letter of Credit expires on the earliest of—

(a) the date at which the Account Party has ceased to be bound by the Code and has discharged its obligations to the Beneficiary under the Code; or

(b) the date of satisfaction of this Letter of Credit in accordance with its terms; or

~~[~~(c) [the date on which the Bank makes payment to the Beneficiary of the Maximum Amount either at its sole discretion or following demand by the Beneficiary under this Letter of Credit in accordance with its terms,]~~,~~

[Note: Bank to elect either this clause or the following clause as a method of cancellation.]

~~[~~(c) [~~ninety (~~90~~)~~ days after notice in writing of cancellation of this Letter of Credit ~~as to subsequent liability~~ has been given ~~to [Clearing manager]; however,~~ by the Bank ~~will remain~~ to the Clearing Manager, provided that the Bank remains liable ~~with respect to the~~ for any Obligations ~~that relate to the period prior to~~ incurred before the effective date of cancellation but shall not be liable for any Obligations incurred after that date,]

(the ~~ninety (90) days' notice~~ "Expiry Date").

Payable at: [Sight or by demand using SWIFT]
Available at: [address]
By ~~Drafts~~ demand on: The Bank.
Enfaced: Drawn under [Bank] Irrevocable Transferable Standby Letter of Credit No. [number] dated [date].
Returnable to: The Bank upon expiry.

The proceeds of this Letter of Credit are transferable by the Beneficiary. A claim may be made under this Letter of Credit by delivering to the address at which this Letter of Credit is expressed to be available, by no later than [time] New Zealand time on or before the Expiry Date, a draft drawn on the Bank (enfaced as specified above) accompanied by—

(a) this Letter of Credit; and

(b) a ~~Certificate purported to be~~ certificate signed by an

	authorised signatory of the Beneficiary in the following form: To [Bank] [date] [Clearing manager] of [address] ("the "Beneficiary") hereby makes claim under the [Bank] Irrevocable Transferable Standby Letter of Credit No. [number] ("the "Letter of Credit"). -Words and expressions defined in the Letter of Credit will have the same meaning in this Certificate. [Participant] ("the "Account Party") has failed, in whole or in part, to fulfil the Obligations. As at the date of this Certificate, the amount owed to the Beneficiary by the Account Party in respect of the Obligations is the sum of $[amount outstanding]. Accordingly, the Beneficiary is entitled to claim and requests payment by [date] of the amount of $[amount claimed] to be credited to account number [Beneficiary's trust account number]. The signatory or signatories is/are authorised by the Beneficiary to make the statements in this Certificate on behalf of the Beneficiary. Signed…………………………………… Authorised Signatory This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (2007 Revision) International Chamber of Commerce Publication No. -600 [and the Supplement to the Uniform Customs and Practice for Documentary Credits for Electronic Presentation 2007], except as otherwise provided in this Letter of Credit. Subject to that, this Letter of Credit will be governed by~~, and construed in accordance with, the laws of~~ New Zealand law, and the parties irrevocably submit to the non-exclusive jurisdiction of the courts of New Zealand. The Bank ~~engages~~agrees with the Beneficiary that drafts drawn under, and in compliance with, this Letter of Credit and~~, in aggregate,~~ up to the Maximum Amount will be paid on presentation in the manner provided in this Letter of Credit.

	[insert execution clause for Bank] ~~EXECUTED for and on behalf)~~ ~~of [BANK])~~ ~~by its Attorneys)~~ ~~………………………………)~~ ~~[Print Names]) Signature(s)~~ ~~……………………………………………~~ ~~in the presence of:~~ ~~…………………………………………~~ ~~Signature~~ ~~……………………………………………~~ ~~Full Name~~ ~~……………………………………………~~ ~~Address~~ ~~……………………………………………~~ ~~Occupation~~ **Schedule 14A.5** **Surety bond** To: [Clearing manager] (the "Clearing Manager") [address] From: [Surety] (the "Surety") [address] Bond Number: [number] ~~We, [Participant] as Principal, and [name of Surety], as Surety, are held and firmly bound to [Clearing manager], a corporation organised and existing under the laws of New Zealand, its successors and assigns, in the amount of [amount in words] New Zealand dollars (NZ$), lawful money of New Zealand for the payment of which the Principal and Surety, their heirs, executors, administrators, successors and assigns are jointly and severally bound.~~ ~~RECITALS~~ 1. [Participant] (the "Principal") has obligations ~~pursuant to~~under the Electricity Industry Participation Code 2010 (the "Code") to pay the ~~[~~Clearing ~~manager~~ Manager amounts invoiced to ~~it~~the Principal by the ~~[~~Clearing ~~manager]~~ Manager ("Obligations").

2. ~~The~~On written demand by the Clearing Manager, the Surety agrees to ~~deliver payment~~ pay to the ~~[~~Clearing ~~manager]~~ Manager any outstanding amounts invoiced to the Principal (together with any default interest payable in respect of those invoiced amounts~~) forthwith upon receipt of written demand for payment issued by a purported authorised representative of [Clearing manager]~~. Such written ~~demands~~demand must be delivered to the Surety at its above address and certify that the Principal has failed, in whole or in part, to fulfil the Obligations.

3. The ~~Surety is~~Surety's total liability under this Bond shall not ~~liable for a larger~~ exceed $[insert maximum amount] ("Maximum Amount").

4. [The Surety may at any time pay to the ~~[~~Clearing ~~manager]~~ Manager the ~~amount of this Bond~~ Maximum Amount less any amount or amounts the Surety may previously have paid under this Bond or such lesser sum as the ~~[~~Clearing ~~manager]~~ Manager may require. -Upon payment of that sum, ~~the liability of the Surety under~~ this Bond will ~~cease~~ be cancelled and ~~determine~~ the Surety shall have no further liability.]

[Note: Surety to elect either this proviso or the following proviso as a method of cancellation.]

4. [~~This Bond may be cancelled by the~~ The Surety ~~as to subsequent liability~~ may cancel this Bond by giving ~~ninety (~~90~~)~~ days' written notice ~~in writing~~ to ~~[~~the Clearing ~~manager] However~~ Manager. Following cancellation of this Bond, the Surety remains liable ~~with respect to the Principal's~~ for any Obligations ~~that relate to the period prior to~~ incurred before the effective date of ~~the ninety (90) days' notice~~ cancellation but shall not be liable for any Obligations incurred after that date.]

5. This Bond is not affected, discharged, or diminished by any act or omission that would, but for this provision, have ~~exonerated~~ released a surety but would not have affected~~ or~~, discharged, or diminished the Surety's liability had it been a principal debtor.

~~This Bond is governed by, and interpreted according to, the laws of New Zealand, and the Principal and the Surety agree to submit to the non-exclusive jurisdiction of the courts of New Zealand.~~

6. This Bond may be transferred or assigned by the ~~[~~Clearing ~~manager]~~ Manager without the Surety's consent.

	7. Upon cancellation, the Bond will be returned to the Surety. ~~EXECUTION CLAUSE~~ 8. This Bond is governed by New Zealand law, and the Surety agrees to submit to the non-exclusive jurisdiction of the courts of New Zealand. [insert execution clause for Surety]
Grounds for not consulting	The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment will not change the purpose or effect of the obligations or level of security in the current forms.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed amendment is consistent with the Authority's objective, and with 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 security forms under Schedules 14A.2 to 14A.5 easier to understand and use, which reduces participants' transaction costs in putting security arrangements in place under the Code. The amendment would have no effect on competition or reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32 of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	The Authority has undertaken a partial quantitative assessment of the costs and benefits of the proposed Code amendment. The Authority expects the proposed amendment to impose no costs on participants. The Authority expects the proposed amendment to deliver a benefit by reducing participants' transaction costs in putting security arrangements in place under the Code. This expected benefit stems from making the security forms under Schedules 14A.2 to 14A.5 easier for participants to understand and use.

2018-19 Making volume information permanent

Reference number(s)	2018-19 Making volume information permanent
Problem definition	**<u>Problem 1</u>** Under clause 4(2) of Schedule 15.2, the relevant reconciliation participant must, at the earliest opportunity and by no later than the month 14 revision cycle, replace any volume information created using estimated readings, with volume information created using validated meter readings or permanent estimates. Sometimes the relevant reconciliation participant cannot replace an estimated reading with a validated meter reading by the month 14 revision cycle. The metering installation(s) at the ICP may have been rendered inoperable or destroyed (eg, in a fire). Alternatively, access to manually read metering installation(s) may not be permitted for a time period longer than 14 months (eg, following an earthquake). In such circumstances, clause 4(3) of Schedule 15.2 provides for a reconciliation participant to use a permanent estimate in place of a validated meter reading. However, clause 4(2) of Schedule 15.2 currently also provides that a reconciliation participant can use a permanent estimate to create volume information, regardless of whether the participant is able to get a validated meter reading. This does not align with the policy intent. A reconciliation participant is meant to use reasonable endeavours to get a validated meter reading in time to create volume information for the month 14 revision cycle. It is only if the reconciliation participant cannot obtain a validated meter reading using reasonable endeavours, that it should use a permanent estimate. **<u>Problem 2</u>** The definition of 'permanent estimate' states that it must be calculated from validated meter readings. However, clause 4 of Schedule 15.2 provides that the reconciliation participant should use a permanent estimate if it cannot obtain a validated meter reading. A reconciliation participant will therefore breach clause 4 of Schedule 15.2 if it cannot obtain a validated meter reading for those of its ICPs with no validated meter reading in the past 14 months. Based on experience, the Authority estimates this occurs for approximately 0.5% of ICPs in New Zealand (ie, approximately 10,000 ICPs). As a result, each year the Authority is notified of approximately 10 reconciliation participants breaching clause 4(2) of Schedule 15.2, because the reconciliation participant has been unable to obtain sufficient validated meter readings to calculate permanent

	estimates. **<u>Related problems</u>** In identifying the two problems above, the Authority has identified a problem with the definition of "historical estimate" in Part 1 of the Code. The definition does not cater for instances where a participant cannot get a second validated meter reading for a metering installation, and must instead use a permanent estimate. The Authority also considers clarifying the wording of clause 4 of Schedule 15.2 would assist in delivering the policy intent described in Problem 1 above.
Proposal	The Authority proposes to amend the Code as follows: • amend the definition of "permanent estimate" in Part 1 to permit, in certain circumstances, a reconciliation participant to replace volume information created using estimated readings with volume information created using the reconciliation participant's best estimates of validated meter readings • amend the definition of "historical estimate" in Part 1 to clarify that an historical estimate includes volume information that is the difference between a validated meter reading and a permanent estimate • clarify the drafting of clause 4 of Schedule 15.2, without altering participants' obligations.
Proposed Code amendment	**Part 1 Preliminary provisions** ... **historical estimate** means, in relation to non **half hour** metered **ICPs**, **volume information** (in kWh), apportioned to part or full **consumption periods** after having the **seasonal adjustment shape**, or any other **profile** that has, from time to time, been approved by the **Authority** for this purpose, applied, being 1 of the following: (a) the difference between 2 **validated** actual **meter readings**: (b) the difference between 2 **permanent estimates**: (c) any relevant **unmetered load**<u>:</u> <u>(d) the difference between a **validated meter reading** and a **permanent estimate**</u> … **permanent estimate** means<u>:</u> <u>(a) </u>a value sourced from an **estimated reading** that has passed the validation process in clauses 16 and 17 of Schedule 15.2 and has been calculated from **validated meter readings**<u>; or</u> <u>(b) if, despite using reasonable endeavours, a **reconciliation participant** cannot replace **volume information** created using **estimated readings** with</u>

	volume information created using **validated meter readings** by the month 14 revision cycle, a value created by the **reconciliation participant** using its best estimates of **validated meter readings** … **Schedule 15.2 Collection of volume information** ... **4 Permanence for the purposes of reconciliation** (1) Only **volume information** created using **validated meter readings**, or if such values are unavailable, **permanent estimates**, has permanence within the reconciliation processes (unless subsequently found to be in error). (2) The relevant **reconciliation participant** must, at the earliest opportunity, and no later than the month 14 revision cycle, replace ~~**V**~~**volume information** created using **estimated readings** ~~must be replaced at the earliest opportunity by the relevant **reconciliation participant**~~ with **volume information** ~~that has been~~ created using **validated meter readings** ~~or **permanent estimates** by no later than the month 14 revision cycle~~. (3) ~~A **permanent estimate** may be used in place of a **validated meter reading** only if a **reconciliation participant**~~If, despite having used reasonable endeavours for at least 12 months, a **reconciliation participant** has been unable to obtain a **validated meter reading**, the **reconciliation participant** must replace **volume information** created using an **estimated reading** with **volume information** created using a **permanent estimate** in place of a **validated meter reading**.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by: • reducing unnecessary compliance costs on reconciliation participants • making the allocation of metered quantities of electricity to traders under the reconciliation process more accurate. The amendment is expected to have little or no effect on competition and no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.

Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 in that it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It has not been practicable to quantify the estimated costs of the proposed Code amendment. However, some of the estimated benefits have been quantified. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to: • resolve a problem in the Code where reconciliation participants breach the Code due to factors over which they have no control • improve the accuracy of metered quantities allocated to traders by the reconciliation manager.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority expects some industry participants may incur additional costs under the proposed Code amendment. This would be to change their processes or systems to apply permanent estimates when they cannot obtain more than one validated meter reading by the month 14 revision cycle. *Benefits* The primary benefit of the proposed Code amendment is to reduce the cost for reconciliation participants to comply with clause 4(2) of Schedule 15.2. A reconciliation participant should obtain two validated meter readings within the first month of a metering installation's life if the reconciliation participant wants to have a low risk of breaching clause 4(2) of Schedule 15.2.[1] A reconciliation participant using remote readings of metering installations might incur a cost for this second read of: • $0, if the participant receives a daily read file from its MEP • an average of $10, if the participant must do a special remote read. A reconciliation participant using a meter reader might incur a cost for this second read of: • an average of $15 for an unscheduled urban read • an average of $30 for an unscheduled remote rural read.

[1] Since this will enable a reconciliation participant to prepare a permanent estimate.

	Currently, approximately 2,000 new ICPs are created each month in New Zealand. There is at least one metering installation at an ICP. This implies that reconciliation participants, in total, currently face a monthly cost of approximately $500–$1,000 in order to have a low risk of breaching clause 4(2) of Schedule 15.2.[2] Reconciliation participants would not have to incur this cost if the proposed Code amendment were to be made. Avoiding this monthly cost of $500–$1,000 equates to a present value benefit of approximately $50,000–$100,000.[3] A further, but much smaller, benefit is the cost that a reconciliation participant and the Authority would otherwise incur each time the reconciliation participant breaches clause 4(2) of Schedule 15.2. Based on actual breaches of clause 4(2) of Schedule 15.2, the Authority estimates the cost it and reconciliation participants would together incur per breach is $75–$150.[4] There are, on average, 10 breaches per year. This equates to a present value benefit of approximately $6,000–$12,000.[5] Another benefit of the proposed amendment is that metered quantities allocated to traders by the reconciliation manager will more accurately reflect actual quantities consumed by traders' customers over the 14 month revision period. That is, there would be a reduced amount of unaccounted-for-electricity over the revision period. In a workably competitive market, this would be expected to result in more economically efficient prices.[6] However, given the relatively small quantities of electricity in question, any such economic benefit is expected to be small. *Net benefit* Based on the above analysis, the Authority considers that, on balance, the benefits of the proposed amendment are likely to outweigh the costs.
Evaluation of alternative means of achieving the objectives of the	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

[2] The Authority estimates the cost to do 2,000 meter readings a month is approximately $850, if the following weightings are applied to the estimated meter reading costs listed above:
$0 – 97 %
$10 – 2 %
$15 – 0.5 %
$30 – 0.5 %.

[3] Assuming a timeframe of 15 years and a real discount rate of 8 %.

[4] This relates to staff time.

[5] Assuming 25 breaches per year for the next 15 years, in the absence of the proposed Code amendment being made, and using a real discount rate of 8 %.

[6] There would be an allocative efficiency benefit, with the price charged for supplying a unit of electricity more closely resembling the cost of supplying that unit of electricity.

proposed amendment	

2018-20 Shorter timeframes for gaining metering equipment provider to receive and provide notifications

Reference number(s)	2018-20 Shorter timeframes for gaining metering equipment provider (MEP) to receive and provide notifications
Problem definition	<u>Main problem: the Code's timeframes for a gaining MEP to receive and provide notifications are causing inefficient market outcomes</u> For each ICP for which a trader is recorded in the registry as having responsibility, clause 9(1)(c) of Schedule 11.1 of the Code requires the trader to provide the registry manager with the participant identifier of a gaining MEP for each metering installation at the ICP. Under clause 9(2) of Schedule 11.1, the trader must provide the gaining MEP's participant identifier to the registry manager within 5 business days of commencing trading at the ICP. Under clause 11.18A, the registry manager then has 1 business day to advise the gaining MEP that it is the gaining MEP for each metering installation at the ICP. Within 10 business days of the registry manager advising it under clause 11.18A, the gaining MEP must advise the registry manager under clause 1 of Schedule 11.4 whether the MEP accepts responsibility for each metering installation at the ICP. If the MEP accepts responsibility, the MEP is able to update the ICP's metering records in the registry. Adding these three timeframes together means that a period of up to 16 business days can elapse between when a trader issues a work order to a gaining MEP at an ICP, and when that MEP is able to update the registry metering records for the ICP.[1] During this period a number of events can happen, which, as shown in the scenario below, result in inefficient market outcomes. The text under each of the *italicised* headings of the scenario illustrates a different inefficient market outcome that can arise in the 16-business day period for a gaining MEP at an ICP to receive and provide the relevant notifications. <u>Scenario demonstrating main problem</u> A new (incoming) trader (Trader A) commences trading at a non half hour (NHH) metered ICP. Trader A decides to use a different MEP (MEP B) to the existing MEP (MEP A) that is responsible for the metering installation at the ICP. As outlined above, the Code currently provides for a total period of up to 16 business days between when Trader A commences trading at the ICP, and when MEP B is able to update the ICP's metering records in the registry. During the first 10 business days of this period: • Trader A switches the ICP identifier and arranges for MEP B to

[1] The registry does not permit an MEP to update the registry metering records for an ICP until the MEP advises the registry manager that it accepts responsibility for each metering installation at the ICP.

	install a new half hour metering installation at the ICP on the day of the switch • on Trader A’s request, MEP B installs a half hour metering installation at the ICP on the day of the switch • another trader (Trader B) quotes to win the consumer at the ICP • a third trader (Trader C) also quotes to the consumer at the ICP and wins the consumer from Trader A. Trader C then requests the ICP be switched. *Traders quote to consumers on the basis of out-of-date metering records in the registry* Traders B and C may quote to the consumer at the ICP using the wrong price plan. This is because they prepare their respective quotes based on the registry’s metering records, which show that the ICP has NHH metering, when in fact the ICP has half hour metering. This is an inefficient outcome, since the traders’ prices do not reflect their cost of supply as accurately as they otherwise would.[2] *Traders encounter inconsistencies between the metering records in their switch completion files and out-of-date metering records in the registry* Trader C’s switch may be delayed. The registry will reject a switch completion file if the metering records in the switch completion file do not match the metering records the registry manager holds for the ICP identifier being switched. In our scenario, Trader A sends a switch completion file showing half hour metering at the ICP, which does not match the registry’s NHH metering records. This then requires a manual workaround involving several participants to enable the switch to proceed. Manual workarounds are inefficient, and increase the risk of making errors in the ICP information.[3] *Out-of-date metering records in the registry create unnecessary costs for traders and MEPs in relation to metering equipment* Continuing with the above scenario, Trader C may decide to ask its MEP (MEP C) to install a new half hour metering installation at the ICP, based on the out-of-date NHH metering records in the registry. Once at the site, MEP C will discover that this is unnecessary because MEP B had already installed a half hour metering installation at the ICP on Trader A’s request. This is another inefficient outcome.

[2] Under a slightly different scenario, a retailer may refuse to quote to a consumer, because it only supplies consumers at ICPs with half hour metering.

[3] These manual workarounds are required because, upon receipt of the switch request, the registry manager will have locked the records of the losing trader (Trader B in the above scenario) and its MEP (MEP B in the above scenario) for the ICP. If MEP B has made changes to the metering installation at the ICP, MEP B will not be able to update the ICP’s metering records in the registry.

	The 16 business-day period creates unnecessary compliance costs for MEPs Lastly, MEP A may breach the Code through no fault of its own. Under clause 3 of Schedule 11.4, an MEP has 10 business days to advise the registry manager of any change to the metering records of a metering installation for which the MEP is responsible. If MEP B installed the new half hour metering installation at the ICP early in the 16-business day period, MEP A would be likely to breach clause 3 of Schedule 11.4 by not updating the ICP's metering records within the 10-business day deadline. This would also be an inefficient outcome, resulting in unnecessary compliance costs for MEP A. <u>Related problem 1: Trader starts trading electricity at new ICP for which there is no MEP</u> Another situation that can cause some of the inefficient market outcomes outlined in the main problem above, is when the first trader at a new ICP commences trading electricity at the ICP when there is no MEP recorded in the registry as being responsible for the ICP. Under clause 11.18(5), unless a trader trades only unmetered load at an ICP, the trader is not permitted to trade at the ICP until an MEP is recorded in the registry as being responsible for each metering installation at the ICP. Some traders do not comply with clause 11.18(5), citing clause 9(2) of Schedule 11.1 as the reason for their non-compliance.[4] This non-compliance can create some of the inefficient outcomes described above—in particular, manual workarounds to effect ICP switching. <u>Related problem 2: MEP does not advise the registry manager when declining to be MEP for ICP</u> Another situation that can cause one of the inefficient market outcomes outlined in the main problem above is when an MEP declines to accept responsibility for a metering installation at an ICP, but does not advise the registry manager, and as a consequence, the registry manager does not advise the trader that nominated the MEP. In such circumstances, a trader at a new ICP may think the MEP has installed metering at the ICP, only to find out several days later that this is not the case. Similarly, an incoming trader at an existing ICP may request an MEP to change the metering at the ICP, only to find out days later that this has not happened. This can delay ICP switching, or result in traders placing consumers

[4] As noted in the description of the main problem, under clause 9(2) of Schedule 11.1, a trader has 5 business days from commencing trading at an ICP to provide the gaining MEP's participant identifier to the registry manager.

	on less favourable price plans than what they should be on. <u>Related problem 3: The Code requires a gaining MEP to enter into an arrangement with a trader, when this may not be necessary</u> In looking at the problems described above, the Authority has identified that clause 1 of Schedule 11.4 requires a gaining MEP to enter into an arrangement with the trader if the MEP intends to accept responsibility for each metering installation for the ICP. This is unnecessary if the gaining MEP already has an arrangement with the trader.
Proposal	To address the problems identified above, the Authority proposes to amend the Code as follows: a) Insert a new subclause (6) into clause 11.18 to make clause 11.18(5) subject to proposed new clause 9(2A) of Schedule 11.1, and make a consequential change to the drafting of clause 11.18(5). b) Insert a new clause 9(2A) in Schedule 11.1, requiring traders to provide the registry manager with the participant identifier of the MEP at an ICP on or before the day the trader asks the MEP to install metering components, or a metering installation, at the ICP. c) Amend clause 1 of Schedule 11.4 to: i. reduce, from 10 business days to 5 business days, the timeframe for a gaining MEP to advise the registry manager that the gaining MEP accepts responsibility for each metering installation for an ICP ii. require a gaining MEP to <u>have</u> an arrangement with a trader rather than to <u>enter into</u> an arrangement with a trader, which would accommodate situations where: a. the gaining MEP already has an arrangement with the trader b. the gaining MEP does not yet have an arrangement with the trader iii. require an MEP to advise the registry manager, in the prescribed form, if the MEP declines to accept responsibility for each metering installation at an ICP (the wording of clause 1(b) means that this is currently only optional). The Authority also proposes to change the registry's functionality. This system change would enable an MEP to update an ICP's metering records once a trader advises the registry manager that the trader wants the MEP to be responsible for each metering installation at the ICP. The registry will revoke the MEP's ability to update the ICP's metering records if the MEP subsequently declines to be the MEP for each metering installation at the ICP.

Proposed Code amendment	**11.18 Trader responsibility for ICP** (1) If a **trader** is recorded in the **registry** as accepting responsibility for an **ICP** that is not also an **NSP**, the **trader** is responsible for all obligations in this Part that— (a) apply to **traders**; and (b) relate to an **ICP** that is not also an **NSP**. ... (4) A **trader** who is responsible for an **ICP**, other than an **ICP** at which there is only **unmetered load**, must ensure that a **metering equipment provider** is recorded in the registry as being responsible for each **metering installation** for the **ICP**. (5) The **trader** must not trade at an **ICP** if a **metering equipment provider** is not recorded in the **registry** as being responsible for each **metering installation** for the **ICP**~~,~~ **unless**— (a) the **trader** trades only **unmetered load** at the **ICP**; or (b) the **trader** has complied with clause 9(2A) of Schedule 11.1**.** … **Schedule 11.1** … **9 Traders to provide ICP information to registry manager** (1) Each **trader** must provide the following information to the **registry manager** for each **ICP** for which it is recorded in the **registry** as having responsibility: (a) the **participant identifier** of the **trader**: (b) the **profile** code of each **profile** at that **ICP** approved by the **Authority** in accordance with clause 13 of Schedule 15.5: (c) the **participant identifier** of the **metering equipment provider** for each **category 1 metering installation**, or higher category **metering installation**, for the **ICP**: (d) *[Revoked]* (e) *[Revoked]* (ea) the type of **submission information** that the **trader** will provide to the **reconciliation manager** for the **ICP**: (f) if the settlement type UNM is assigned to the **ICP**— (i) if the load is profiled through an engineering **profile** in accordance with **profile class** 2.1, the code ENG; or (ii) in all other cases, the daily average **unmetered load** in kWh at the **ICP**: (g) the type and capacity of the **unmetered load** at the **ICP** (if

any):

(h) *[Revoked]*

(i) *[Revoked]*

(j) the status of the **ICP** determined in accordance with clauses 12 to 20.

(k) except as provided in subclause (1A), the relevant business classification code applicable to the **customer** at the **ICP**, in accordance with business classification codes **published** by the **Authority**.

(1A) A **trader** must not provide the information specified in subclause (1)(k) if—

(a) the **ICP** exists for the purpose of reconciling **embedded network** residual load; or

(b) the **ICP** has "Distributor" status as specified in clause 16.

(2) The **trader** must provide the **registry manager** with the information specified in subclause (1)(a) and (b), and~~to~~ subclause (1)(d) to (j), ~~to the **registry manager**~~ no later than 5 **business days** after the **trader** commences trading at the **ICP** to which the information relates.

(2A) The **trader** must provide the **registry manager** with the information specified in subclause (1)(c)—

(a) on or before the day—

(i) the **trader** asks the **metering equipment provider** to which the information in subclause (1)(c) relates to install a **metering component** or a **metering installation** at the **ICP**; or

(ii) the **metering equipment provider** assumes responsibility for the **ICP**; or

(b) in all other situations, no later than 5 **business days** after the **trader** commences trading at the **ICP.**

(3) The **trader** must provide the information specified in subclause (1)(k) to the **registry manager** no later than 20 **business days** after the **trader** commences trading at the **ICP** to which the information relates.

Schedule 11.4

…

1 Metering equipment provider receives notice for ICP identifier

(1) As soon as practicable, but in any event, no later than~~**Within**~~ ~~10~~5 **business days** of being advised by the **registry manager** under clause 11.18A, a gaining **metering equipment provider must**,—

(a) ~~**must**~~, if it intends to accept responsibility for each **metering installation** for the **ICP**—

	(i) ~~enter into~~have an arrangement with the **trader**; and (ii) advise the **registry manager** in the **prescribed form** that it accepts responsibility for each **metering installation** for the **ICP** and of the proposed date on which the **metering equipment provider** will assume responsibility for each **metering installation** for the **ICP**; or (b) ~~may,~~ if it intends to decline responsibility for each **metering installation** for the ICP, advise the **registry manager** in the **prescribed form** that it declines to accept responsibility for each **metering installation** for the **ICP**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it promotes the efficient operation of the electricity industry. The proposed amendment would do this by shortening the timeframe during which registry metering records can become out-of-date when there is a gaining MEP at an ICP, causing the problems identified in the problem definition. The Authority also expects the proposed Code amendment would have a positive effect on competition, primarily by lessening the potential for delays in ICP switching due to inaccurate metering records in the registry. The proposed Code amendment is expected to have no effect on reliability of supply.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because the Authority expects that it would deliver a market efficiency gain by facilitating more accurate reconciliation and settlement, and invoicing of consumers.
Principle 3: Quantitative Assessment	Some of the estimated costs and benefits of the proposed Code amendment can be quantified. Therefore, the Authority has undertaken a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory statement	
Objectives of the proposed amendment	The objective of the proposed Code amendment is to improve the efficiency of the Code's process for a gaining MEP to receive and provide notifications.

Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the proposed Code amendment would place a cost on three traders. The traders affected would be those whose business practice is to advise the registry manager of the MEP at an ICP after the MEP has installed and certified a metering installation at the ICP. The Authority estimates the cost for the three affected traders to amend their processes and systems would be $15,000 in total. The Authority considers the proposed Code amendment may also place a cost on three MEPs that do not advise the registry manager if they decline responsibility for metering installations at an ICP. These MEPs would need to change their business processes. The Authority estimates these MEPs might together incur approximately $75,000 for changes to their processes and systems. The proposal also includes a system change for the registry, to enable an MEP to update the metering records for an ICP once a trader advises the registry manager that the trader wants the MEP to be responsible for each metering installation at the ICP. The Authority estimates the cost of this system change would be approximately $500–$1,000. *Benefits* The primary benefit of the proposed Code amendment is to remove, or lessen, the market inefficiencies identified in the problem definition. The Authority estimates traders and MEPs, and occasionally the Authority, the registry manager, and distributors, would together incur approximately $140–$220 in staff time when a manual workaround is used to update metering records in the registry to enable an ICP switch. A manual workaround involves the losing trader agreeing a switch withdrawal with the gaining trader so that the losing trader can advise the registry manager of the participant identifier of the MEP for the metering installation(s) at the relevant ICP. The MEP of the losing trader then needs to accept responsibility for the metering installation(s) at the ICP, and update the metering records. The gaining trader then needs to backdate a new switch for the ICP. There may also be network events that the distributor (whose network the ICP is on) must reverse first, to allow the switch to be withdrawn. The distributor must then remake the network events in the correct sequence after the losing trader and its MEP correct their respective records for the ICP. The Authority estimates at least 500–1,000 instances of these events have occurred each year since 29 August 2013. Taking a

	conservative estimate of 250 such events occurring each year in the absence of the Code amendment proposal, the present value of avoiding this cost is approximately $310,000-$465,000.[5] Improving the accuracy of metering records in the registry would also enable traders to undertake customer switching in a timelier manner. The Authority expects this would facilitate retail competition in the electricity industry, which would further the first limb of the Authority's objective and promote both static and dynamic economic efficiency in the electricity industry. Another benefit of the proposed Code amendment would be to make it easier for traders to understand their Code obligations. This reduces their operational costs, which is a productive efficiency benefit. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment would outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objective of the proposed amendment.

[5] Assuming a 15 year discount period and a real discount rate of 8 %.

2018-21 Decommissioning a metering installation

Reference number(s)	2018-21 Decommissioning a metering installation
Problem definition	Under clause 11.18(3) of the Code, if an ICP is to be decommissioned, the trader responsible for the ICP must: a) arrange for a final interrogation to take place before or on removal of the meter b) advise each MEP responsible for a metering installation at the ICP that the ICP is to be decommissioned. Under clause 11.18B(3), if an ICP is to be decommissioned, the MEP responsible for each metering installation at the ICP must, in summary: a) if the trader responsible for the ICP is also responsible for interrogating the ICP's metering installation(s), advise the trader that the trader must carry out a final interrogation of the metering installation(s); or b) if the MEP is responsible for interrogating the ICP's metering installation(s), arrange for a final interrogation to take place, and provide the raw meter data to the trader recorded in the registry as being responsible for the ICP. These clauses are inconsistent with each other regarding whether it is the trader or the MEP that must arrange for the final interrogation of a metering installation at an ICP that is to be decommissioned. On the one hand, clause 11.18(3) requires the trader responsible for the ICP to arrange for the final interrogation to take place. On the other hand, if it is the MEP that is responsible for interrogating the metering installation, clause 11.18B(3)(b) requires the MEP to arrange for the final interrogation to take place. This inconsistency is the result of a drafting error in clause 11.18B. The reference in this clause to an *ICP* being decommissioned should be a reference to *a metering installation* being decommissioned at an ICP. The policy intent behind clause 11.18B(3) is that an MEP responsible for interrogating a metering installation that is to be decommissioned must arrange for a final interrogation <u>only if</u> the metering installation is being decommissioned but the ICP is **not**. If the ICP is being decommissioned, the trader responsible for the ICP must arrange for a final interrogation of all metering installations at the ICP (as required under clause 11.18(3)(a)). There is also the situation where the MEP responsible for decommissioning a metering installation is not responsible for interrogating the metering installation.[1] The policy intent behind clause 11.18B(3) in this situation is that the MEP responsible for the

[1] The trader, or another MEP, may be responsible for interrogating the metering installation.

	decommissioning must advise the participant responsible for the meter interrogation of when the decommissioning will occur. This is to assist the participant to plan the final interrogation.
Proposal	The Authority proposes to amend the Code as follows, to address these shortcomings in the drafting of clause 11.18B(3): ● move existing clause 11.18B(3) to new clause 10.23A, since decommissioning a metering installation is a matter more appropriately addressed in Part 10 (Metering), than in Part 11 (Registry information management) ● in the new clause 10.23A, explicitly note that an MEP is not to arrange for a final interrogation of a metering installation at an ICP if the ICP is being decommissioned ● include in the new clause 10.23A an obligation on the MEP responsible for decommissioning the metering installation to advise the participant responsible for interrogating the metering installation of when the decommissioning will occur.
Proposed Code amendment	**10.23A Decommissioning of metering installation at ICP** (1) If a **metering installation** at an **ICP** is to be **decommissioned**, but the **ICP** is not being **decommissioned**, the **metering equipment provider** that is responsible for **decommissioning** the **metering installation** must,— (a) if the **metering equipment provider** is responsible for **interrogating** the **metering installation**— (i) arrange for a final **interrogation** to take place before the **metering installation** is **decommissioned**; and (ii) provide the **raw meter data** from the **interrogation** to the **trader** that is recorded in the **registry** as being responsible for the **ICP**; or (b) if another **participant** is responsible for **interrogating** the **metering installation**, advise the other **participant** not less than 3 **business days** before the **decommissioning**— (i) of the time of the **decommissioning**; and (ii) that the **participant** must carry out a final **interrogation**. (2) To avoid doubt, if a **metering installation** at an **ICP** is to be **decommissioned** because the **ICP** is being **decommissioned**— (a) the **metering equipment provider** is not responsible for arranging a final **interrogation** of the **metering installation**; and (b) the **trader** that is recorded in the **registry** as being responsible for the **ICP** must arrange for a final **interrogation** of the **metering installation** under clause 11.18(3).

	11.18B Metering equipment provider responsibility for metering installation for ICP …. ~~(3) If an **ICP** is to be **decommissioned**, the **metering equipment provider** who is responsible for each **metering installation** for the **ICP** must,—~~ ~~(a) if the **trader** is responsible for the **interrogation** of the **metering installation**, prior to the **decommissioning**, advise the **trader**, not less than 3 **business days** prior to the **decommissioning**, that the **trader** must, when the status of the **ICP** is changed to inactive in accordance with clause 19 of Schedule 11.1, as part of the **decommissioning** of the **ICP**, carry out a final **interrogation**; or~~ ~~(b) if the **metering equipment provider** is responsible for the **interrogation** of the **metering installation**, when the status of the **ICP** is changed to inactive in accordance with clause 19 of Schedule 11.1, as part of the **decommissioning** of the **ICP**, arrange for a final **interrogation** to take place and provide the **raw meter data** to the **trader** who is recorded in the **registry** as being responsible for the **ICP**.~~
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it will contribute to the efficient operation of the electricity industry. The proposed Code amendment would make it easier for participants—particularly MEPs and traders—to understand their respective Code obligations in relation to decommissioning metering installations. This would promote the efficient operation of the electricity industry. The proposed Code amendment is not expected to affect competition or reliability of supply in the electricity industry.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2. This is because the proposed amendment is expected to result in participants operating more efficiently and incurring lower costs in interpreting and complying with the Code.

Principle 3: Quantitative Assessment	The estimated cost of the proposed Code amendment can be quantified, but it has not been practicable to quantify the estimated benefit. Hence, the Authority has undertaken a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to contribute to the efficient operation of the electricity industry by clarifying which participant is responsible for the final interrogation of a metering installation when an ICP or metering installation is decommissioned.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposal would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the proposed amendment should place no additional costs on participants. This is because: • requiring MEPs to arrange for final interrogations of metering installations only at active ICPs would align the Code's drafting with current industry practice • the Authority believes that requiring MEPs to advise the participant responsible for interrogating the metering installation of a pending decommission would also be consistent with current industry practice. However, the Authority has not been able to confirm this. *Benefits* The main benefit of the proposed Code amendment is to make it easier for participants to understand and comply with their Code obligations. This would reduce the ongoing costs for participants (especially traders and MEPs) of transacting in the electricity market, which would be a productive economic efficiency benefit. A second benefit of the proposed amendment would be to reduce the likelihood of a participant decommissioning a metering installation without a final interrogation having first occurred. This would facilitate more accurate invoicing of traders and more accurate customer invoicing. Improving the accuracy of customer invoicing brings the marginal value that consumers place on the electricity they purchase closer to the cost of producing the electricity consumed. Improving the accuracy of customer invoicing would therefore improve the electricity market's efficiency. *Net benefit* Based on the above analysis, the Authority is satisfied that the expected benefits of the proposed amendment would outweigh the

	expected costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

2018-22 Clarifying when a reconciliation participant may connect or electrically connect certain points of connection

Reference number(s)	2018-22 Clarifying when a reconciliation participant may connect or electrically connect certain points of connection
Problem definition	The Authority recently amended clauses 10.28 to 10.33A of the Code to clarify participants' obligations in relation to the physical and electrical connection of assets and electrical installations.[1] However, there are four remaining issues with these Code provisions: 1) The Code clearly sets out, for an ICP with metered load (with or without additional unmetered load) and that is not a network supply point (NSP), when participants may connect the ICP (clause 10.31). However, the Code does not provide the same clarity in relation to when participants may: a. temporarily electrically connect an ICP, or authorise an ICP to be temporarily electrically connected (clauses 10.31A and 10.33) b. electrically connect an ICP, or authorise an ICP to be electrically connected (clause 10.33A). Specifically, clauses 10.33 and 10.33A of the Code each refer to "ICP", when the policy intent is that the references should be to "ICP that is not an NSP". 2) Shared unmetered load is unmetered load at a single point of connection that is distributed across more than one ICP. A distributor must follow the process set out in clause 11.14 of the Code when maintaining shared unmetered load. Part 10 of the Code does not clearly place on a distributor an obligation to advise relevant traders when the distributor is intending to connect, temporarily electrically connect, or electrically connect shared unmetered load ICPs. This is inconsistent with the approach adopted under clause 11.14. 3) The Code clearly sets out when a grid owner or distributor may: a. connect an NSP (clauses 10.29 and 10.30 respectively) b. temporarily electrically connect an NSP (clauses 10.29A and

[1] For more details on the recent Code amendment, see para 2.7(c) of the *Code review programme 2017 – Decision and reasons paper*, available at: http://www.ea.govt.nz/development/work-programme/operational-efficiencies/code-review-programme/consultations/.

	10.30A respectively). However, the Code inadvertently does not say when a reconciliation participant may temporarily electrically connect an NSP, or authorise a metering equipment provider to temporarily electrically connect an NSP. Similarly, the Code does not say when a reconciliation participant may electrically connect an NSP, or authorise the electrical connection of an NSP. 4) The Code inadvertently permits a reconciliation participant that is not a trader to electrically connect an ICP. Reconciliation participants that are not traders should not be able to do this. If a reconciliation participant other than a trader electrically connected an ICP, any electricity consumed at the ICP might not be reconciled against a trader. If this occurred, the electricity consumed at the ICP would become unaccounted for electricity, which would be shared across all consumers within the relevant network balancing area. The four issues described above can cause several problems, including: • confusing participants over their Code obligations • a higher risk of unaccounted for electricity, caused by an electrical connection occurring without appropriate authorisation • a higher risk of inadvertent supply failures.
Proposal	The Authority proposes to amend the Code to address the four issues described above, as follows. *Issue 1* The Authority proposes to amend clauses 10.33 and 10.33A so that references to "ICP" become references to "ICP that is not an NSP". *Issue 2* The Authority proposes: a) to amend clause 10.31 to clarify that a distributor can connect an ICP where there is only shared unmetered load at the ICP and the distributor has advised all traders that are to be assigned the unmetered load b) to amend clauses 10.33 and 10.33A to clarify that a reconciliation participant may temporarily electrically connect (or electrically connect) a point of connection, or authorise the temporary electrical connection (or electrical connection) of a point of connection. However, this will only be the case if, for a point of connection that is an ICP with only shared unmetered load, the relevant distributor has advised all traders (that are to be

	assigned the unmetered load) of the distributor's intention to temporarily electrically connect (or electrically connect) the ICP. *Issue 3* The Authority proposes to amend clauses 10.33 and 10.33A to clarify that a reconciliation participant may temporarily electrically connect (or electrically connect) a point of connection, or authorise the temporary electrical connection (or electrical connection) of a point of connection, if: a) for an NSP that is a point of connection to the grid, the grid owner has given its approval b) for an NSP that is not a point of connection to the grid, the relevant distributor has given its approval. *Issue 4* The Authority proposes to amend clauses 10.33 and 10.33A to clarify that a reconciliation participant may temporarily electrically connect (or electrically connect) a point of connection, or authorise the temporary electrical connection (or electrical connection) of a point of connection. However, this will only apply if the reconciliation participant that electrically connects, or authorises the electrical connection of, an ICP that is not an NSP, is the trader recorded in the registry as having reconciliation and switching responsibility for the ICP identifier.
Proposed Code amendment	**10.31 When distributor may connect ICP that is not NSP** (1) Only a **distributor** may connect an **ICP** that is not an **NSP**. (2) Despite subclause (1), a **distributor** must not connect an **ICP** that is not an **NSP** unless— (a) the **trader** trading at the **ICP** has requested the connection; or (b) there is only **shared unmetered load** at the **ICP** and the **distributor** has advised all **traders** that will be assigned the **shared unmetered load**. **10.33 When reconciliation participant may temporarily electrically connect point of connection** (1) A **reconciliation participant** may temporarily **electrically connect** a **point of connection**, or authorise a **metering equipment provider** 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** temporarily

electrically connecting the **point of connection**; or

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

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

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

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

(b) for a **point of connection** that is an **ICP** with **shared unmetered load** only, but which is not an **NSP**, the **distributor** on whose **network** the **ICP** is located has advised all **traders** that are to be assigned the **shared unmetered load** of the **distributor's** intention to temporarily **electrically connect** the **ICP**.

(2) A **reconciliation participant** described in subclause (1)~~(a)~~ may authorise a **metering equipment provider**, with which the **reconciliation participant** 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**.

10.33A When reconciliation participant may electrically connect point of connection

(1) A **reconciliation participant** may **electrically connect** a **point of connection**, or authorise the **electrical 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 electrically connecting** the **point of connection**; or

(ii) the **reconciliation participant** authorising the **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 electrically connecting** the **point of connection**; or

(ii) the **reconciliation participant** authorising the **electrical connection** of the **point of connection**:

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

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

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

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

(b) for a **point of connection** that is an **ICP** with **shared unmetered load** only, but which is not an **NSP**, the **distributor** on whose **network** the **ICP** is located has advised all **traders** that are to be assigned the **shared unmetered load** of the **distributor's** intention to **electrically connect** the **ICP**.

(2) A **reconciliation participant** 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** arranges for the **certification** of the **metering installation** to be completed within 5 **business days** of the **ICP** being **electrically connected**: (b) may **electrically connect** an **ICP** if the **point of connection** is solely for **unmetered load**. (3) A **reconciliation participant** must not authorise the **electrical connection** of a **point of connection** in any of the following circumstances: (a) a **distributor** has **electrically disconnected** the **point of connection** for safety reasons, and has not subsequently approved the **electrical connection** of the **point of connection**: (b) **electrically connecting** the **point of connection** would breach the Electricity (Safety) Regulations 2010. (4) No **participant** may **electrically connect** a **point of connection**, or authorise the **electrical connection** of a **point of connection**, other than a **reconciliation participant** as described in subclauses (1) to (3).
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would promote the efficient operation of the electricity industry. It would do this by: • making it easier for participants to understand their obligations in relation to the connection, temporary electrical connection, and electrical connection of ICPs and NSPs • lessening the risk of unaccounted for electricity caused by participants electrically connecting ICPs without appropriate authorisation. The proposed Code amendment is also expected to promote the reliable supply of electricity by reducing the possibility of an inadvertent supply failure caused by a participant not fully understanding its Code obligations. The proposed Code amendment is not expected to affect competition in the electricity industry.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.

Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2. This is because the proposed amendment is expected to result in participants operating more efficiently and incurring lower costs interpreting and complying with the Code.
Principle 3: Quantitative Assessment	The estimated cost of the proposed Code amendment can be quantified, but it has not been practicable to quantify benefits. Hence, the Authority has undertaken a partial quantitative assessment of the proposed amendment's costs and benefits (see below).
Regulatory Statement	
Objectives of the proposed amendment	The primary objective of the proposal is to simplify the Code. This will make it easier for participants to understand the Code and comply with it. A secondary objective of the proposal is to reduce the possibility of unaccounted for electricity caused by ICPs being electrically connected without trader authorisation.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposal would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the proposed Code amendment should place little or no additional costs on participants. Amending the Code to resolve the first two issues identified in the problem definition would align the drafting of the Code with current industry practice. The Authority believes that resolving the third issue identified in the problem definition—ensuring that only traders may authorise or perform the permanent electrical connection of an ICP—would also align the Code with current industry practice. However, given the difficulty of identifying ICPs that have not been electrically connected by traders,[2] the Authority has not been able to confirm this. *Benefits* The main benefit of the proposed Code amendment is making it easier for participants to understand and comply with their Code obligations in relation to the electrical connection of ICPs and NSPs.

[2] This type of electrical connection is virtually impossible to trace through electricity market systems.

	This will reduce participants' ongoing costs of transacting in the electricity market, and deliver a productive economic efficiency benefit. A second benefit of the proposed amendment is to reduce the possibility of unaccounted for electricity caused by reconciliation participants that are not traders authorising or performing the permanent electrical connection of ICPs. A third expected benefit of the proposal is the reduced possibility of an inadvertent supply failure caused by a participant not fully understanding its Code obligations. *Net benefit* Based on the above analysis, the Authority is satisfied that the expected benefits of the proposed amendment would outweigh the expected costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

2018-23 Editorial corrections to the Code

Reference number(s)	2018-23 Editorial corrections to the Code
Problem definition	The Code contains a number of typographical errors including outdated cross-references, incorrect headings, terms that are in bold but should not be, and other minor drafting errors. For example: • clauses 11.1(b) and 15.38(1)(a) refer respectively to 'switching customers and embedded generators' and 'performing customer and generator switching'. In both instances the correct reference should be to switching 'ICPs' • in clause 8.36(1), the word 'appeal' is in bold, but 'appeal' is not a defined term in Part 1 of the Code. The same applies to the reference to 'traded' in clause 15.4(1) • in its *Code Review Programme 2017*,[1] the Authority: ○ removed the definition of 'notify' from Part 1 of the Code ○ replaced references in the Code to 'notify', 'notified', and 'notification' with 'give written notice' and equivalent terms. There remain a number of references in the Code to 'notify', 'notified', and 'notification', which, for completeness, should be amended for consistency with the above amendment.
Proposal	The Authority proposes to amend the Code to correct the sorts of typographical errors exemplified above. The proposed amendments are set out below.
Proposed Code amendment	**Part 1** **sub-block dispatch groups** means that grouping of **generating stations** or **generating units** within a **block dispatch group** into subgroups to take account of any **block security constraints** ~~notified by~~ of which the **system operator** gives notice in accordance with clauses 13.61(1) and 13.73(1)(j) **sub-station dispatch group** means a grouping of **generating units** or **generating stations** within a **station dispatch group** into subgroups to take account of any **station security constraints** ~~notified by~~ of which the **system operator** gives notice in accordance with clauses 13.65(1) and 13.75(1)(g) **submission expiry date** means— (a) in the case of a submission on a **draft policy statement**, the date ~~notified by~~ the **Authority** advises in accordance with clause 8.12(2); and (b) in the case of a submission on a **draft procurement plan**, the date ~~notified by~~ the **Authority** advises in accordance with clause 8.44(2); and (c) in the case of a submission on the **transmission agreement**

[1] Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

structure, the date ~~notified by~~ the **Authority** advises in accordance with clause 12.6(3); and

(d) in the case of a submission on the draft **benchmark agreement**, the date ~~notified by~~ the **Authority** advises in accordance with clause 12.32(2); and

(e) in the case of a submission on the draft **grid reliability standards**, the date ~~notified~~**published** by the **Authority** in accordance with clause 12.61(3); and

(f) in the case of a submission on the issues paper, the date ~~notified~~**published** by the Authority in accordance with clause 12.82(1); and

(g) in the case of a submission on the proposed transmission pricing methodology, the date ~~notified~~**published** by the Authority in accordance with clause 12.92(2)

Part 6

Schedule 6.1, clause 6

30 business days to negotiate connection contract if distributed generator ~~notifies~~ gives notice of intention to proceed

(1) If a **distributed generator** whose application under clause 2 is approved gives notice to a **distributor** under clause 5, the **distributor** and the **distributed generator** have 30 **business days**, starting on the date on which the **distributor** receives the notice, during which they must, in good faith, attempt to negotiate a connection contract.

Schedule 6.1, clause 15
Distributed generator must make final application
(1) A **distributed generator** that makes an **initial application** to a **distributor** must make a **final application**, no later than 12 months after receiving information under clauses 12 and 13, if the **distributed generator** wishes to proceed with the application, unless—
(a) the **distributor** and the **distributed generator** agree that a **final application** is not required; and
(b) there are no persons to whom ~~notification is required~~the **distributor** must give written notice under clause 16 at the time that the **distributor** and **distributed generator** agree that a **final application** is not required.

Schedule 6.1, clause 21
30 business days to negotiate connection contract if distributed generator ~~notifies~~gives notice of intention to proceed
(1) If a **distributed generator** whose **final application** is approved gives notice to a **distributor** under clause 20(1), the **distributor** and the **distributed generator** have 30 business days, starting on the date on which the **distributor** receives the notice, during which they must, in good faith, attempt to negotiate a connection contract.

	Schedule 6.1, clause 28 **Distributors must keep records** A **distributor** must maintain records of each application and ~~notification~~ notice received under this Schedule and the resulting outcomes, including records of how long it took to approve or decline the application, and justification for these outcomes, for a minimum of 60 months after the day on which the application was approved or declined. **Part 7** **7.5 Approval of draft security of supply forecasting and information policy and emergency management policy** … (7) When the **Authority publishes** the changes that the **Authority** wishes the **system operator** to make to the relevant draft policy under subclause (6), the **Authority** must ~~notify~~advise the **system operator** and interested parties of the date by which submissions on the changes must be received by the **Authority**. (8) Each submission on the changes to the draft policy must be made in writing to the **Authority** and be received on or before the date ~~specified by~~ the **Authority** advises under subclause (7). The **Authority** must provide a copy of each submission received to the **system operator** and must **publish** the submissions. **Part 8** **Clause 8.25 Other asset owner performance obligations and technical standards** … (5) If the **system operator** reasonably considers it necessary to assist the **system operator** in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**, the **system operator—** … (b) must ~~notify~~advise the **embedded generator** of its requirement at least 20 **business days** in advance of the requirement coming into effect. **8.28 Responsibility for compliance** ... (2) If the **system operator** advises an **asset owner** ~~receives notification~~ under clause 8.27(3), ~~it~~the **asset owner** must co-operate with the **system operator** and use reasonable endeavours to restore compliance as soon as practicable. **8.36 Appeal against decisions** (1) A **participant** may ~~**appeal**~~appeal a decision of the **system operator** or an **asset owner** in relation to an application for **dispensation** or

	equivalence arrangements on the grounds set out in subclause (3). … **8.54 Other provisions relating to alternative ancillary service arrangements** … (2) An **asset owner** who obtains an authorisation of an **alternative ancillary service arrangement** must comply with its obligations under the arrangement. If the **system operator** advises an **asset owner** ~~receives notification~~ under subclause (1), ~~it~~ the **asset owner** must co-operate with the **system operator** and must immediately use reasonable endeavours to restore compliance as soon as possible. **8.60 System operator must investigate causer of under-frequency event** (1) The **system operator** must promptly ~~notify~~ advise the **Authority**, every **generator**, **grid owner** and any other **participant** substantially affected by an **under-frequency event**, that an **under-frequency event** has occurred. **Schedule 8.3, Technical Code C, clause 8** **~~Notification~~Notice of planned outages of primary means of communication** Each **asset owner** must give written notice to the **system operator** of any planned outage of a primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2). **Part 9** **9.20 Retailer must have customer compensation scheme** ... (2) Each of a **retailer's qualifying customers** must be covered by the **retailer's default customer compensation scheme**, unless the **retailer's qualifying customer** has elected to be covered by 1 of the **retailer's additional customer compensation** ~~scheme~~ **schemes** (if any) in accordance with clause 9.27. **Part 10** **10.8 Requirements for information to be recorded, given, produced, or received** … (2) ~~Part 3 of the Electronic Transactions Act 2002~~Subpart 3 of Part 4 of the Contract and Commercial Law Act 2017 does not, because of section ~~14(2)(a)~~218(2)(a) of that Act, apply to this Part. **10.13 Electricity conveyed** (1) A **participant** must use the quantity of **electricity** measured by a **metering installation** for a **point of connection** as the **raw meter data** for the quantity of **electricity** conveyed through the **point of connection**. (2) Subclause (1) does not apply to **electricity** that is— (a) estimated in accordance with this Code; or

(b) supplied by an **embedded generator** who has given notice to the **reconciliation manager** ~~a notification~~ under clause 15.13.

…

(4) Despite subclause (3), a **metering equipment provider** is not required to measure **electricity** conveyed through a **point of connection** if the **electricity** is—
(a) **unmetered load**; or
(b) supplied by an **embedded generator** who has given notice to the **reconciliation manager** ~~a notification~~ under clause 15.13.

10.16 Metering data exchange timing and formats
(1) A **participant** (other than a **market operation service provider**) must, if it is under an obligation to provide **metering data** under this Part, provide the **metering data** to the relevant person—

> (a) in the absence of any timeframe specified in this Code, within a reasonable timeframe specified ~~**notified**~~ by the **Authority**; and
> (b) in the format the **Authority** specifies ~~**notified**~~ to **participants** from time to time ~~by the **Authority**~~.

(2) The **Authority** must provide reasonable notice of any changes to the format the **Authority** specifies ~~**notified**~~ under subclause (1)(b).
(3) Despite subclause (1)(b), a **participant** may provide the **metering data** in an alternative format if it has an arrangement with the recipient to use the alternative format.
(4) Despite subclause (3), the **participant** must be able to comply with any format requirements ~~**notified** by~~ the **Authority** specifies under subclause (1)(b), within 1 **business day** of ceasing to have an arrangement with the recipient under subclause (3).

…

Schedule 10.3, clause 7

~~Notification~~Notice of cancellation, expiry, or revision of scope of ATH approval
(1) The **Authority** must give written notice to all **metering equipment providers** if—
…

Schedule 10.6, clause 8

Electronic interrogation of metering installation

…

(6) The **metering equipment provider** must, when **interrogating** a **metering installation**, ensure that all **raw meter data** downloaded as part of the **interrogation**, and used for submitting information for the purposes of Part 15, is archived—

> …
> (b) in a form that cannot be modified without an ~~**audit**~~audit trail being created; and
> …

(7) A **metering equipment provider** must, when **interrogating** a

metering installation,—

…

(c) ensure that the **interrogation** log forms part of the **interrogation** ~~**audit**~~ audit trail and contains the following as a minimum:

(i) the date of **interrogation**; and

(ii) the time of commencement of **interrogation**; and

(iii) the operator of the **interrogation** system identification (where available); and

(iv) the unique identifier of the **data storage device** being **interrogated**; and

(v) any clock errors outside the range specified in Table 1 of subclause (5); and

(vi) the method of **interrogation**; and

(vii) the identifier of the reading device used for **interrogation** (if applicable).

…

Schedule 10.7, clause 19

Modification of metering installations

…

(3B) In setting a~~A~~ procedure under subclause (3A)(b)(ii), a **metering equipment provider** must ensure that, within 10 **business days** of the replacement occurring, the person carrying out the replacement provides the ~~notification~~ notice and **metering records** for the replaced **control device** and the replacement **control device** to—

...

Schedule 10.7, clause 41

Certification stickers

…

(2) An **ATH** attaching a **metering installation certification sticker** must ensure that it shows—

…

(f) any other information that the **Authority** may, from time to time, ~~**notify**~~ specify by giving reasonable notice.

Part 11

11.1 Contents of this Part

This Part—

(a) provides for the management of information in the **registry**; and

(b) prescribes a process for switching **ICPs** ~~**customers** and **embedded generators**~~ between traders; and

	11.8 Provision of and changes to ICP information and NSP information by participants … (2) The **participant** specified in clause 25(3) of Schedule 11.1 must give the ~~notification~~ notice required by clause 25(1) of Schedule 11.1. … (5) If a **network** owner acquires all or part of an existing **network**, the **network** owner must give the ~~notification~~ notice required by clause 29 of Schedule 11.1. **11.14 Process for maintaining shared unmetered load** ... (3) A **trader** who receives ~~notification~~ written notice under subclause (2) must give written notice to the **distributor** if it wishes to add an **ICP** to or omit an **ICP** from the **ICPs** across which the **unmetered load** is shared. (4) A **distributor** who receives ~~notification~~ written notice under subclause (3) must give written notice to the **registry manager** and each **trader** responsible for any of the **ICPs** across which the **unmetered load** is shared of the addition or omission of the **ICP**. (5) If a **distributor** becomes aware of a change to the capacity of an **ICP** across which the **unmetered load** is shared or that an **ICP** across which the **unmetered load** is shared is decommissioned, it must give written notice to all **traders** who receive ~~notification~~ written notice under subclause (2) of the change or decommissioning as soon as practicable after the change or decommissioning. (6) A **trader** who receives ~~notification~~ written notice under subclause (5) must, as soon as practicable after receiving the ~~notification~~ notice, adjust the **unmetered load** information for each **ICP** for which it is responsible, so that the **unmetered load** is shared equally across each of those **ICPs**. **11.15B Trader contracts with customers to permit assignment by Authority** (2) The terms specified in subclause (1) must— (a) be expressed to be for the benefit of the **Authority** for the purposes of Subpart 1 of Part 2 of the Contract and Commercial Law Act 2017~~the Contracts (Privity) Act 1982~~; and (b) not be able to be amended without the consent of the **Authority**. **11.22 Registry manager must maintain register of information** … (2) The **registry manager** must ensure that a complete ~~**audit**~~ audit trail exists for all information received by it in accordance with this Code.

	11.23 Reports from registry manager By 1600 hours on the 6th **business day** of each **reconciliation period**, the **registry manager** must **publish** a report containing the following information: (a) the number of **ICPs** ~~notified to~~ in the **registry** ~~**manager** and contained on its register~~ at the end of the immediately preceding **consumption period**: ... **11.25 Reports to clearing manager, system operator or reconciliation manager** … (5) The person who requested the report may vary any of the details set out in the request, by giving ~~notification~~ notice to the **registry manager** of the relevant details in writing by no later than 5 **business days** before the last day of the month before the 1st month for which the person requests the variation. **11.27 Reports to Authority** By 1600 hours on the 1st **business day** of each calendar month, the **registry manager** must deliver to the **Authority** a report summarising the number of events ~~that have not been notified to the **registry manager**,~~ of which ~~it~~ the **registry manager** is aware, but has not been advised within the timeframes specified in this Part. **Schedule 11.1, clause 4** **Authority may grant dispensation** The **Authority** may, by ~~notification in writing~~ giving written notice, grant a dispensation from the requirements of clause 3 for an **ICP** that cannot be **electrically disconnected** without **electrically disconnecting** another **ICP**. **Schedule 11.4, clause 1** **Metering equipment provider receives notice for ICP identifier** (1) Within 10 **business days** of being advised by the **registry manager** under clause 11.18A, a **gaining metering equipment provider**,— … (b) may, if it intends to decline responsibility for each **metering installation** for the ~~ICP~~**ICP**, advise the **registry manager** in the **prescribed form** that it declines to accept responsibility for each **metering installation** for the **ICP**. **Schedule 11.4, clause 6** **Correction of errors in registry** … (3) If the **metering equipment provider** finds a discrepancy between the information obtained under subclause (1) and its own records, the **metering equipment provider** must, within 5 **business days** of becoming aware of the discrepancy,—

	… (b) advise the **registry manager** of any necessary changes to the **registry** ~~**manager**~~ **metering records**. **Part 12** **12.6 Review of structure for transmission agreements** … (3) When the **Authority publishes** its proposed structure, the **Authority** must ~~notify~~advise **registered participants** of the date by which submissions on the proposed structure are to be received by the **Authority**. The date must be no earlier than 15 **business days** from the date of **publication** of the proposed structure. **12.22 Authority may initially approve proposed Connection Code or refer back to Transpower** … (2) **Transpower** may, no later than 20 **business days** (or such longer period as the **Authority** may allow) after the **Authority** ~~notifies~~ advises **Transpower** of its decision under subclause (1), consider the **Authority's** concerns and resubmit its proposed **Connection Code** and accompanying explanation and **statement of proposal** for consideration by the **Authority**. **12.32 Authority must consult on draft benchmark agreement** … (2) When the **Authority publishes** a draft **benchmark agreement**, the **Authority** must ~~notify~~ advise **registered participants** of the date (which must not be earlier than 15 **business days** after the date of publication of the draft **benchmark agreement**) by which submissions on the draft **benchmark agreement** must be received by the **Authority**. **12.40 Replacement and enhancement of shared connection assets** (1) If 2 or more **designated transmission customers** are connected to a **point of connection** and **Transpower** has ~~notified~~ advised those **designated transmission customers**, in accordance with the provisions of a **transmission agreement** between **Transpower** and each of the **designated transmission customers**, that a **grid reliability report published** by **Transpower** in accordance with clause 12.76 sets out that the power system is not reasonably expected to meet the **N-1 criterion** at all times over the next 5 years because of a **connection asset** related to that **point of connection**, **Transpower** must— (a) as soon as practicable after ~~notifying~~ advising the **designated transmission customers**, investigate whether the **connection asset** meets the **grid reliability standards**; and … (2) **Transpower** and the **designated transmission customers** ~~notified~~ advised under subclause (1) must attempt in good faith, within 6 months of

the date on which **Transpower** makes its proposals to the **designated transmission customers** under subclause 1(b), or such longer period as the **Authority** may allow, to reach an agreement for an investment or other solution that will have the effect of—

…

12.71 Investment contracts
Transpower may enter into an **investment contract** with implications for **grid reliability standards** only if—

…

(b) **Transpower** ~~notifies~~ advises the **Authority** of the proposed **investment contract**.

Schedule 12.4, clause 34

Adjustments to AMD, AMI, HAMI, SIMI and RCPD and calculation of customer charges

...

(3) If **Transpower**—

(a) is ~~notified~~ advised that **South Island generation** at **a connection location** has been permanently de-rated (including decommissioning) to a specified aggregate rate capacity ("maximum de-rated capacity"); and

…

(4) If not less than 6 months before the start of a **pricing year**, **Transpower**—

(a) is ~~notified~~ advised that the **offtake** and/or **injection** capacity of a **customer's assets** at a **connection location** has been permanently de-rated (including decommissioning); and

…

(12) **Transpower** must adjust a **customer's AMD**, **AMI**, **HAMI**, **SIMI**, or **RCPD** at a **connection location** to minimise the impact of **reverse flow** at the **connection location** if—

…

(b) within 20 **business days** after the **reverse flow** commences at the **connection location**, the **customer** has ~~notified~~ advised **Transpower** that there is **reverse flow** at the **connection location**; and

…

40 Independent Review
(1) The **customer** may, within 60 days of being ~~notified~~ advised of **Transpower's** decision to offer a prudent discount agreement or that no discount will be provided, request a review by an **independent expert** of any or all of the assessments undertaken by **Transpower** for the purposes of that decision.

Part 13

13.34 Changes may be made within 1 hour before trading period

...

(2) If a **grid owner** has sent revised information to the **system operator** under subclause (1) later than 15 minutes before the relevant **trading period**, the **grid owner** must also immediately ~~notify~~ advise the **system operator** of the revised information by telephone or by such other mechanism as may be agreed from time to time in writing between **grid owners** and the **system operator**.

13.35 System operator to confirm receipt of grid owner information

…

(2) The **system operator** must immediately confirm to each **grid owner** receipt of all information received from that **grid owner** under clauses 13.29 to 13.3~~6~~5. The confirmation must also contain a record of the time of receipt.

13.60 Block dispatch may occur

…

(3) The **generator** must give written notice to the **system operator** and the **clearing manager** of any change to an agreement for ~~**block dispatch**~~ block dispatch made under this clause or clause 13.61 at least 5 **business days** before the change takes effect.

13.61 System operator to notify block security constraints

…

(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—

...

(d) receipt of an instruction from the **system operator** in accordance with clause 13.75(1)(f) for the same **block dispatch group** for the applicable **trading period**, and such instruction remains valid for the **trading periods** specified in that instruction.

...

13.65 System operator to give notice of station security constraints

...

(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—

…

(d) receipt of an instruction from the **system operato**r in accordance with clause 13.75(1)(g) for the same **station dispatch group** for the applicable **trading perio**d, and the instruction remains valid for the **trading periods** specified in the instruction.

13.194 Clearing manager to calculate constrained off amounts

(2) For the purposes of clauses 13.192 to 13.201, dispatched quantity must be calculated taking into account**—**

…

(b) for an **offer**, the ramp rate applying to that **constrained off situation** that is specified in the **offer** submitted by that **generator**, or—

(i) for a **block dispatch group** or a **station dispatch group**; or

(ii) for **generating units**, if the **clearing manager** requires the dispatched quantity to be determined on a **grid injection point** basis—

the fastest of the ramp rates applying to that **constrained off situation** that are specified in the **offers** submitted by the **generator** in that **block dispatch group**, that **station dispatch group** or those **~~generation~~ generating units electrically connected** to the relevant **grid injection point** (as the case may be); and

…

13.202 Constrained on situations may occur

(1) Subject to subclause (2), a **constrained on situation** occurs when—

…

(c) an **ancillary service agent** is given a **dispatch instruction** by the **system operator** and the price **offered** by the **ancillary service agent** for the dispatched **instantaneous reserve** in the relevant **trading period** is higher than the **final reserve price** of the dispatched **instantaneous reserve** in the relevant **trading period**~~.~~; or

Part 14

14.4 Sale by generators with point of connection to local network or embedded network

(1) This clause—

…

(b) does not apply to a **generator** in respect of an **embedded generating station** in relation to a **point of connection** for which a ~~notification~~ notice under clause 15.14 is in force.

14.8 Hedge settlement agreement lodgement

...

(6) A **participant** must provide information under subclause (5) in a form ~~prescribed by~~ the **clearing manager** prescribes and ~~notified~~specifies to **participants**.

	Subpart 4 ~~— Notification~~ Notice of amounts owing and payable **14.25 Participant may dispute amount** … (3) The **clearing manager** must advise all **participants** materially affected by the dispute and the **Authority** of the dispute no later than 1 **business day** after ~~the dispute is notified to~~ the **clearing manager** receives notice of the dispute under subclause (1). (4) On receiving a ~~notification~~ advice of a dispute that relates to **volume information** under subclause (3), the **Authority** may direct that no further action be taken in respect of the dispute. **14.27 Dispute about amount may be referred to Rulings Panel** (1) If the dispute is not resolved within 15 **business days** after the date on which ~~the dispute was notified to~~ the **clearing manager** received notice of the dispute under clause 14.25(1), the disputing **participant** or the **clearing manager** may refer the dispute to the **Rulings Panel** for resolution. … **14.28 Correction of information about amount as result of dispute** ... (2) The **reconciliation manager** must correct **volume information** as follows: ... (b) if a revised **seasonal adjustment shape** is not required to be issued in order for the **volume information** to be corrected, each **reconciliation participant** whose **submission information** or **dispatchable load information** is required to be corrected must provide corrected **submission information** or **dispatchable load information** to the **reconciliation manager** no later than 4 **business days** after ~~being notified~~ receiving notice of the resolution of the dispute: ... **Part 14A** **14A.7 Participant may change form of security** The **clearing manager** must release a **participant's** existing security when the **participant** provides a different form of security ~~notified~~ under this clause, if— ... **Part 15** **15.4 Submission information to be delivered for reconciliation** (1) Each **reconciliation participant** must, by 1600 hours on the 4th **business day** of each **reconciliation period**, ensure that **submission information** has been delivered to the **reconciliation manager** for all **NSPs** for which the **reconciliation participant** is recorded in the **registry**

	as having traded ~~traded~~ **electricity** during the **consumption period** immediately before that **reconciliation period**, in accordance with Schedule 15.3. **15.38 Functions requiring certification** (1) Subject to clauses 2A and 2B of Schedule 15.1, a **reconciliation participant** (except an **embedded generator** selling **electricity** directly to another **reconciliation participant**) must obtain and maintain **certification** in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code: (a) maintaining **registry** information and performing **ICP** ~~**customer** and **generator**~~ switching (except if the maintenance of **registry** information is carried out by a **distributor** in accordance with Part 11): … (f) provision of **metering information** to the relevant **grid owner** in accordance with subpart 4 of Part 13. …
Grounds for not consulting	The Authority is satisfied the proposed amendment is technical and non-controversial because it makes editorial corrections to the relevant Code provisions, but does not alter the effects of the relevant provisions.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. It would do this by correcting typographical errors in the Code, which makes it easier for participants to understand and meet their obligations under the Code. The proposed amendment is expected to have no effect on competition or reliability.
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective, and the requirements set out in section 32 of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative	It is not possible to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis is not possible.

Assessment	