Code Review Programme number 4 - September 2019

Consultation paper

Submissions close: 5pm, 5 November 2019

24 September 2019

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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 number 4 - September 2019*. 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 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.

1.3 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. Appendix C is a table of proposed changes that the Authority is satisfied are technical and non-controversial. 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 number 4 - September 2019*.

1.4 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

1.5 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 number 4 - September 2019" in the subject line.

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

Postal address	Physical address
Submissions Electricity Authority PO Box 10041 Wellington 6143	Submissions Electricity Authority Level 7, Harbour Tower 2 Hunter Street Wellington

1.7 The Authority will publish all submissions it receives. If you consider that we should not publish any part of your submission, please:

(a) indicate which part we should not publish

(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).

1.8 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.9 However, please note that all submissions we receive, including any parts of submissions that we do not publish, can be requested under the Official Information Act 1982 (OIA). This means we would be required to release parts of submissions that we did not publish unless good reason existed under the OIA to withhold it. We would normally consult with you before deciding whether to release parts of submissions that you considered we should not publish.

When to make a submission

1.10 Please deliver your submissions by **5pm** on **Tuesday 5 November 2019**.

1.11 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 number 4 – September 2019

This is the fourth Code Review Programme

2.1 The *Code Review Programme number 4 - September 2019* is the fourth Code Review Programme and the 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 This *Code Review Programme number 4 - September 2019* also includes a standalone proposal to correct minor typographical errors in the Code. These errors include outdated cross-references, incorrect headings, incorrectly bolded terms, and other minor drafting errors. The proposal to correct the errors is found in Appendix C.

The proposals are set out in Appendix B

2.5 The 13 Code change proposals are set out in Appendix B and each table has a unique reference number in its top row. 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 proposals the Authority considers are technical and non-controversial, each proposal also includes a regulatory statement.

2.7 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.

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

Table 1: List of proposed amendments

Reference number	Topic	Page
2019-01	Revised timeframe for distributors to change price category code information in the registry	11
2019-02	Returning retail market share transparency at GXPs to its former level	15

Reference number	Topic	Page
2019-03	Requirement to provide complete and accurate information under Part 8	20
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2019-12	Removing provision for supply shortage declarations to trigger payments under the Customer Compensation Scheme	80
2019-13	Broadening the definitions of Generating Unit and Intermittent Generating Station	86

Source: Electricity Authority

3 Regulatory Statement for the proposed amendments

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.[1]

3.3 A second key benefit described in the regulatory statements is an improvement in the accuracy of information in the electricity industry. This is expected to deliver competition, reliability and efficiency benefits, thereby promoting the three limbs of the Authority's statutory objective

3.4 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 number 4 - September 2019, 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%.

[1] 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	2019 -
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

2019-01 Revised timeframe for distributors to change price category code information in the registry

Reference number(s)	2019-01 Revised timeframe for distributors to change price category code information in the registry
Problem definition	<u>Problem 1</u> If the price category code for an installation control point (ICP) changes, then under clause 8(1) and 8(2)(b) of Schedule 11.1 of the Code, the distributor in whose network the ICP is located must give the registry manager written notice of the change (using the registry) no later than three business days after the change takes effect. Despite this requirement, in practice a distributor may receive a request from a trader to backdate a change to a price category code by more than three business days. For example, a customer may advise their trader that they have been a low user of electricity at their ICP since they moved into the premises a couple of months earlier. Should the distributor agree with the proposed backdated change to the price category code, the distributor would breach clause 8(2)(b) of Schedule 11.1 by giving the registry manager notice of the change. This is because more than three business days would have passed since the change took effect. Conversely, the distributor would breach clause 11.2 and clause 8(1) of Schedule 11.1, if it chose not to give the registry manager notice of the change. This is because the information held in the registry for the ICP would be inaccurate. In both scenarios, the distributor would be in breach of the Code. This is not a desirable regulatory outcome. <u>Problem 2</u> The price category code may be changed after an ICP switches between traders. However, currently, if the ICP switch is subsequently withdrawn, the losing trader that receives the ICP back is not notified of the change to the price category code. The losing trader will then apply the wrong distribution charges to the customer's invoice, resulting in the need for the trader to subsequently correct the customer's invoice. This is an unnecessary transaction cost.
Proposal	<u>Problem 1</u> To address Problem 1, the Authority proposes to insert a new clause 8(2)(aa) in Schedule 11.1 of the Code. The new clause would allow a distributor to backdate a change to a price category code provided under clause 7(1)(g) of Schedule 11.1, if the distributor and the trader responsible for the ICP agreed to a date. <u>Problem 2</u>

	To address Problem 2, the Authority proposes the registry be changed so that it generates a notification to a losing trader when: a) a trader ICP switch is withdrawn b) the registry's information for the ICP differs from the registry's information for the ICP at the time the switch withdrawal request is made. We consider a Code amendment to require the registry manager to fulfil this obligation is unnecessary. The obligation can be accommodated under the service provider agreement between the Authority and the registry service provider. We have included this proposed change to the registry alongside the Code amendment proposal, so that participants have the opportunity to comment on both matters under the same process.
Proposed Code amendment	**Schedule 11.1** … **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 (aa) in the case of a change to the information provided under clause 7(1)(g) that is intended to take effect from a date earlier than the date on which the **distributor** and the **trader** responsible for the **ICP** agree on the change, no later than 3 **business days** after the **distributor** and the **trader** responsible for the **ICP** agree the date on which 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 (i) 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 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 improve the accuracy of the ICP information held in the registry. This would facilitate accurate invoicing of traders and consumers. The proposed Code amendment is expected to have little or no effect on competition or reliability.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as described below.
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 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 improve the accuracy of ICP information held by the registry, thereby improving the accuracy of invoicing of traders 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 Code amendment would place little additional cost on industry participants. The Authority expects the incremental cost for a participant to update the registry to correct price category codes would be small. The Authority knows some distributors already incur this cost, although other distributors may not, in order to avoid breaching the Code. There may be a small cost of approximately $1,250 – $1,500,[1] to change a report prepared by the registry manager that uses price category code information.

[1] Based on an estimate provided by the registry manager.

	Benefits The main benefit of the proposed Code amendment is that it would facilitate accurate information in the registry. This, in turn, would facilitate accurate invoicing of traders and consumers. If the Code were to not be amended, consumers would face a greater likelihood of being invoiced an incorrect distribution charge. 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. Another benefit of the proposed Code amendment would be reduced auditing and compliance costs. These reduced costs would relate to identifying and processing alleged breaches of the Code by distributors who backdate price category code changes in the registry outside the three business day timeframe currently permitted by the Code. The Authority estimates there would be a potential cost of approximately $200 per year if an auditor were to allege that a distributor had breached the Code, by backdating a price category code outside three business days.[2] Currently, approximately half of grid-connected distributors regularly backdate price category codes outside three business days. If we assume 14 alleged breaches of the Code each year, for the next 15 years, in relation to this backdating of price category codes, the present value benefit of removing this compliance cost would be approximately $24,000.[3] *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code 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 objectives of the proposed Code amendment.

2 This relates to staff time, for the auditor and the distributor.

3 Using a real discount rate of 8 %.

2019-02 Returning retail market share transparency at GXPs to its former level

Reference number(s)	2019-02 Returning retail market share transparency at GXPs to its former level
Problem definition	The Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011 (DSBF Code amendment) came into force in mid-2012. As a result of the DSBF Code amendment, purchasers in the wholesale electricity market *no longer must submit bids* for a grid exit point (GXP) that the Authority has determined to be a "*conforming GXP*". A conforming GXP is a GXP for which the system operator is better able to predict demand using a central forecast instead of purchasers' bids. A GXP where a purchaser *must submit bids* is known as a "*non-conforming GXP*". The Authority has determined that there are 215 conforming GXPs and 13 non-conforming GXPs, meaning purchasers no longer submit bids for almost 95% of GXPs. Under clause 13.55(1), the WITS manager must, within 24 hours of the end of each day, make available on WITS and at no cost on a publicly accessible approved system, all final bids, final offers, and final reserve offers received for the trading periods of the previous trading day. Prior to the DSBF Code amendment, a retailer was able to estimate its market share at a GXP, by looking at the published bids for that GXP. Retailers could place some reliance on the accuracy of these bids, because the Code required a bid to represent that purchaser's reasonable endeavours to predict the quantity of electricity that purchaser would demand at the GXP for the relevant trading period.[1] Following the DSBF Code amendment, a retailer is able to estimate its market share using this approach for only the 13 non-conforming GXPs. No longer having this market share information available is inefficient. The primary problem is that, for any one of the 215 conforming GXPs, a retailer is more likely to under- or over-hedge its financial exposure to a transmission constraint because they can't accurately estimate their market share.
Proposal	The Authority proposes requiring the reconciliation manager to provide more granular information in the report it provides to the Authority and all participants on the difference between: a) electricity supplied, as reported by retailers; and b) submission information submitted by retailers. This proposal would require an amendment to clause 27(b) of Schedule 15.4.

[1] Refer to the version of clause 13.13 of the Code that existed prior to the DSBF Code amendment. (https://www.ea.govt.nz/code-and-compliance/the-code/historical-versions-of-the-code/historical-versions-of-the-code/)

	The proposal would provide for retailers to have a similar level of transparency of retail market shares to that which existed prior to the DSBF Code amendment coming into force.
Proposed Code amendment	**Schedule 15.4** **Reconciliation procedures** ... **27 Surveillance reports** The **reconciliation manager** must make the following reports available to the **Authority** and all **participants**: ... (b) reports by **retailers** ~~for each **balancing area**~~ of the variation between **electricity supplied** as reported by **retailers** (in accordance with clause 17) and **submission information** submitted for reconciliation by **retailers**, specified for each— (i) **point of connection** to the **grid**; and (ii) **NSP identifier**; and (iii) **balancing area**: …
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. The proposed amendment would do this by enabling retailers to more accurately hedge their transmission risk at GXPs. The proposed amendment may also have a minor, positive effect on competition, if currently retailers, on average, tend to over-hedge their transmission risk at GXPs in the absence of market share information. If this were the case, then the proposed amendment would mean retailers would face a lower cost to serve customers at a GXP, which should have a positive influence 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, as described below.
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 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 proposed Code amendment is to restore the transparency of retailers' market shares at all GXPs to the level that existed prior to the DSBF Code amendment coming into force, so that participants can identify basis risk and pivotal positions.
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 proposed Code amendment would require the reconciliation manager to prepare an amended GR-130 file ("Report electricity supplied/submitted comparison"). The amended file would contain data aggregated by network supply point (NSP), in addition to balancing area (the status quo). The Authority estimates the cost of this system change would be approximately $15,000 – $19,000.[2] The Authority would also need to make some minor updates to guideline documents. The Authority estimates the incremental cost to do this would be under $500. Under the proposed amendment, retailers might need to change IT systems, and/or processes and procedures, if they wanted to use the NSP-level information in the amended GR-130 file. However, the proposed Code amendment *would not compel* retailers to use this information. Presumably, a retailer that used the NSP-level information would do so because the benefit outweighed the cost of any systems or process changes. Therefore, the Authority does not consider it necessary, or appropriate, to include an estimate of the cost for retailers to use the information in the amended GR-130 file. *Benefits* The primary benefit of the proposed Code amendment is to improve the productive efficiency of the electricity market,[3] by enabling retailers to more accurately calculate the hedging they need to cover the risk of a transmission constraint. The Authority notes this benefit closely aligns with a key benefit underpinning the most recent increase in the number of financial transmission right (FTR) hubs,

[2] This is based on an estimate from the reconciliation manager.

[3] As noted in section 3 of this consultation paper, productive efficiency is achieved when products and services that consumers desire are produced at minimum cost to the economy.

	which was to reduce hedging costs for participants managing within-island basis risk.[4] [5] The proposed amendment would also deliver an economic benefit if currently, in the absence of market share information, retailers are over-hedging their transmission risk at GXPs. Under the proposal, these retailers would face a lower cost to serve customers at a GXP. This would promote retail competition, which delivers both static and dynamic efficiency benefits to the economy.[6] *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code amendment would outweigh the costs. It is likely that retailers' cost savings would be greater than the cost of changing the reconciliation system.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has identified one alternative means of achieving the objectives of the proposal. This alternative would be to require the reconciliation manager to provide an amended GR-050 file ("Report summary of actual reconciled traded kWhs") to traders, as well as distributors. The GR-050 file shows monthly settlement volumes (as opposed to submission volumes) at an NSP. In other words, the GR-050 file shows the actual market share of each trader at an NSP, for the month. The Authority estimates the cost of this system change for the reconciliation manager would be similar to the cost for the amending the GR-130 file (ie, approximately \$15,000 – \$20,000). Currently, under clause 26(a) of Schedule 15.4, the reconciliation manager provides the information in this file only to distributors. The file that each distributor receives contains information only in relation to each trader trading on the distributor's network. The Code could be amended to require the reconciliation manager to provide monthly and *half-hourly* settlement volumes at the NSP to the distributor at the NSP and all traders at the NSP. However, traders may consider their settlement volumes to be commercially sensitive information. At the time the file is provided,

4 See the FTR manager's cost benefit analysis for adding three additional FTR hubs in 2018, available at: www.ftr.co.nz/documents/10179/97733/FTR+Additional+Hubs+-+CBA_v0_9.docx/e34475ad-2c2a-33c8-a9a5-cda5a8cff434.

5 Within-island basis risk is the commercial risk associated with unpredictable variations in the difference between electricity spot prices at two market pricing nodes within the same island. Transmission constraints can cause these unpredictable variations. See:
- *Within-island basis risk: proposed approach*, available at www.ea.govt.nz/dmsdocument/15230
- *Within-island basis risk: Characterising the risk*, available at: www.ea.govt.nz/dmsdocument/14051.

6 See section 3 of this consultation paper.

	there would mostly likely be little difference between actual retail positions and the end-of-month retail positions shown in the file.[7] Therefore, the Authority considers the proposal to be preferable to the alternative.

[7] Under clause 24 of Schedule 15.4, the reconciliation manager must provide the information contained in the GR-050 file by 1600 hours on the seventh business day of each reconciliation period (month).

2019-03 Requirement to provide complete and accurate information under Part 8

Reference number(s)	2019-03 Requirement to provide complete and accurate information under Part 8
Problem definition	Under clause 8.1A(1) of the Code, a participant must take all practicable steps to ensure that information it provides to the extended reserve manager under Part 8 is— a) complete and accurate b) not misleading or deceptive c) not likely to mislead or deceive. A participant must also provide revised information to the extended reserve manager as soon as practicable if the participant subsequently becomes aware that information provided to the extended reserve manager previously under Part 8 is— a) incomplete; b) inaccurate; c) misleading or deceptive; or d) likely to mislead or deceive. The provision of complete and accurate information from one participant to another is fundamental to competitive, **reliable** and operationally efficient electricity markets. It enables industry participants to make well-informed decisions on matters such as: a) how much electricity to use or produce b) when to invest in equipment or devices that use, produce, or convey electricity. There is a problem with the current obligation under clause 8.1A because the obligation only applies to information a participant provides to the extended reserve manager. It does not apply to other information that participants must provide under Part 8. This means a participant is not explicitly required to provide complete and accurate information to another person under Part 8, except to the extended reserve manager.
Proposal	The Authority proposes to address the problem identified above, by expanding the scope of clause 8.1A of the Code so that it applies to all information a participant provides to any person under Part 8.
Proposed Code amendment	**8.1A Requirement to provide complete and accurate information** (1) A **participant** must take all practicable steps to ensure that information that the **participant** is required to provide to any person ~~it provides to the **extended reserve manager**~~ under this Part is— (a) complete and accurate; and

	(b) not misleading or deceptive; and (c) not likely to mislead or deceive. (2) If a **participant** provides information to any person ~~**the extended reserve manager**~~ under this Part, and subsequently becomes aware that the information is incomplete, inaccurate, misleading or deceptive, or likely to mislead or deceive, the **participant** must provide revised information as soon as practicable. (3) For the purpose of this clause, information provided by an **asset owner** to the **extended reserve manager** is deemed to be accurate if it complies with a data specification published by the **extended reserve manager**.
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) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would also promote reliability. The proposed Code amendment would promote efficiency and reliability by lowering the risk of an adverse event on the power system. The proposed Code amendment is expected to have little or no effect on competition.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it addresses an identified efficiency gain, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It has not been practicable to quantify the costs and benefits of the proposed Code amendment. Hence, a qualitative 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 facilitate complete and accurate information in the electricity industry.
Evaluation of the	The Authority considers the proposed Code amendment would have

costs and benefits of the proposed amendment	a positive net benefit, for the reasons set out below. *Costs* We believe the incremental cost of the proposed Code amendment would be small. This is because we consider that, typically, participants currently act in a reasonable and responsible manner when it comes to providing information under Part 8, which includes: 1) a provider of erroneous information informing the recipient of the error 2) the information provider correcting the error and resubmitting the information to the recipient 3) the recipient checking the resubmitted information and advising the provider if the information is correct. We expect that participants are likely to only have to make minor updates to procedures—to note that it is a Code requirement to provide accurate information under all clauses in Part 8. *Benefits* We expect the proposed Code amendment's main benefit would be to lower slightly the probability of incorrect information being provided under Part 8, which in turn would lower slightly the risk of an adverse event on the power system. Part 8 deals with common quality. Consumers place a very high value on avoiding power outages, particularly unplanned outages (measured in the thousands, and in some instances tens of thousands, of dollars). An instance of incorrect information resulting in an under-frequency event could have economic costs measured in the millions of dollars.[1] Due to common quality issues having a relatively high impact on consumers, we consider that even a minor decrease in the risk of an adverse event on the power system would offer a benefit greater than the proposed amendment's identified cost. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	We considered whether the Fair Trading Act 1986 and the general law of negligence (particularly the duty of care and the consequences of breaching it) might apply to circumstances where a participant provided potentially misleading, or misleading, information. However, we considered it was unclear how both the Fair Trading Act and the law of negligence might apply in the context of providing information under the Code. Therefore, we do not think

[1] For example, the system operator may receive incorrect information from a generator about the under-frequency performance of its generating plant. This could lead to the system operator underestimating reserve requirements and an increased risk of system failure during under-frequency events.

	that relying on the Fair Trading Act and the general law of negligence would best achieve the objective of this proposed Code amendment. The Authority has not identified any other means of achieving the objectives of the proposed amendment.

2019-04 Improving the event of default provisions

Reference number(s)	2019-04 Improving the event of default provisions
Problem definition	Schedule 11.5 of the Code sets out the process that the Authority and each participant must comply with when the Authority is satisfied that a trader has committed an event of default under paragraph (a), (b), (f), or (h) of clause 14.41(1). Based on our experience with an event of default in 2018, the Authority considers there are some improvements that could be made to: a) the description of an event of default under paragraph (f) of clause 14.41(1) b) the process set out in Schedule 11.5. <u>Problem 1</u> Under clause 14.41(1)(f) an event of default can be triggered by a participant threatening to stop or suspend payment of that participant's debts (excluding its security or settlement payments). The ability for an event of default to be triggered by a threat to stop or suspend payment is unecessary and creates uncertainty in the default process. Identifying a threat is subjective. For example, comments taken out of context, or from staff that might not have authority over payments, could trigger an unnecesary event of default. The Authority considers that an event of default should be triggered by the failure to pay debt when it is due, not the perception that such an event may occur in the future. We note this approach would be consistent with the approach in clause 14.41(1)(a) and (b), in respect of participants' security and settlement payments. <u>Problem 2</u> The event of default in 2018 showed that the current process for a trader event of default can result in unnecessary errors in: a) reconciliation and settlement of the wholesale electricity market b) consumer invoicing. Currently, under clause 3 of Schedule 11.5, the Authority may require certain information from the registry and from distributors on whose network(s) the defaulting trader trades electricity. However, there is no mechanism for the Authority to obtain meter readings if the defaulting trader cannot or will not obtain meter readings.

It may be necessary for the Authority to obtain meter readings and associated information (eg, ICP identifiers and meter serial numbers) from the MEP(s) responsible for the ICPs the defaulting trader trades at, in instances where the defaulting trader cannot, or will not, provide suitable meter readings. This is to ensure the meter readings and associated information are available for market settlement and consumer invoicing. In the absence of any requirement for the MEP(s) used by the defaulting trader to provide meter readings and associated information to the Authority, errors are more likely in reconciliation, market settlement and consumer invoicing.

<u>Problem 3</u>

The event of default in 2018 has also shown that the current process for a trader event of default imposes unnecessary transaction costs on participants, the Authority, and possibly consumers.

Currently, clause 4 of Schedule 11.5 applies when:

a) 7 days have elapsed since the Authority notified the defaulting trader of the need to remedy the event of default

b) the Authority considers the defaulting trader—

    i) has not remedied the event of default or agreed with the Authority to resolve the event of default

    ii) has one or more customer contracts in place or is still recorded in the registry as being responsible for one or more ICPs.

In this situation, the Authority must, after notifying the defaulting trader, attempt to advise the defaulting trader's customers of the event of default and that—

a) the customer should switch to another trader within a specified timeframe

b) the Authority may assign the customer to another trader if the customer does not switch within the specified timeframe.

The requirement for the Authority to attempt to communicate with the defaulting trader's customers can impose unncessary transaction costs on the Authority and possibly on the defaulting trader's customers. It may be unnecessary for the Authority to attempt this communication—for example, because the defaulting trader has already communicated the required information to its customers. Or the Authority may want to delay sending this communication—for example, because the defaulting trader is in the process of finalising the sale of its customer base to one or more other traders.

<u>Problem 4</u>

Part of the policy intent of the trader default provisions in the Code is to prevent a defaulting trader's liabilities increasing during the trader default process.

Under clause 4B of Schedule 11.5, the Authority may only give written notice to the registry manager to not complete certain ICP switching activities if the Authority has already given written notice to the defaulting trader under clause 4 of Schedule 11.5. The Authority can not give notice to the defaulting trader under clause 4 for at least 7 days after giving notice of the default. This means that, for seven days, a defaulting trader can gain new customers, and request the withdrawal of switches involving existing customers leaving the defaulting trader, before the Authority can prevent this via the registry.

This unnecessarily increases the risk of the defaulting trader's liabilities growing during the trader default process.

<u>Problem 5</u>

Currently, clause 5(8) of Schedule 11.5 is not as clear as it could be in stating how the Authority can specify the recipient trader to whom the Authority may:

a) in accordance with the contract under which a customer purchases electricity from the defaulting trader, assign the rights and obligations of the defaulting trader under the contract

b) assign an ICP for which the defaulting trader is recorded in the registry as being responsible.

This makes it unnecessarily difficult for the Authority and participants to understand and comply with their obligations under the Code.

<u>Problem 6</u>

Currently, clause 7 of Schedule 11.5 is not as clear as it could be in describing the registry manager's obligations around processing ICP switches involving a defaulting trader. In particular, the clause is unclear about the following:

a) that it is referring to ICP switches that are in progress as well as ICP switches that have not yet been initiated

b) the treatment of switch withdrawal requests involving the defaulting trader

c) that the registry manager is to act only as directed by the Authority in relation to processing ICP switches involving a defaulting trader.

This lack of clarity has the following potential drawbacks:

a) it could prevent a customer of the defaulting trader from voluntarily switching to a trader of the customer's choosing

b) it could add unnecessary transaction costs to the trader default process by leading to traders disputing an Authority directive for the registry manager to—

    i) cancel an ICP switch to the defaulting trader

	ii) complete or cancel a switch withdrawal request involving the defaulting trader c) it could result in traders receiving, without the traders' prior knowledge, customers of the defaulting trader.[1] This could adversely affect the switching experience for the customers and impose costs on the traders—for example, a trader may be unable to trade at a customer's ICP.
Proposal	<u>Problem 1</u> To address problem 1, the Authority proposes to amend clause 14.41(1)(f) of the Code to remove the ability for an event of default to be triggered by a participant threatening to stop or suspend payment of its debts. <u>Problem 2</u> To address problem 2, the Authority proposes to amend clause 3 of Schedule 11.5 to require the MEP(s) of a defaulting trader to provide metering-related information (eg, meter readings, ICP identifiers and meter serial numbers) to the Authority, if requested by the Authority. <u>Problem 3</u> To address problem 3, the Authority proposes to amend clause 4 of Schedule 11.5 to enable the Authority to not communicate with a defaulting trader's customers if there is good reason not to. We also propose to amend clause 4 of Schedule 11.5 to make it clearer that: a) clause 4 of Schedule 11.5 applies if at least seven days have elapsed since the Authority gave notice to the defaulting trader under clause 2(1) of Schedule 11.5 b) the Authority can provide to a defaulting trader's customers, any information the Authority considers appropriate, which may or may not include the information currently required to be provided. <u>Problem 4</u> To address problem 4, the Authority proposes to amend clause 4B of Schedule 11.5 to enable the Authority to direct the registry manager to not process certain ICP switching activities if the Authority has given written notice to the defaulting trader under clause 2 of Schedule 11.5, rather than waiting for the notice under clause 4. We also propose to amend clause 4B of Schedule 11.5 to clarify that the applicable switch withdrawal request is for an ICP switching away from the defaulting trader. <u>Problem 5</u> To address problem 5, the Authority proposes to amend clause 5 of

1 If the registry manager processed the switching of ICPs away from the defaulting trader to one or more other traders prior to the Authority communicating this to the other trader(s).

<table>
<tr><td></td><td>Schedule 11.5 to clearly state that the Authority can determine the recipient trader via:
a) exercising the Authority's discretion; or
b) a tender or other competive process.
<u>Problem 6</u>
To address problem 6, the Authority proposes to amend clause 7 of Schedule 11.5 to clarify that, when directed to do so by the Authority, the registry manager must:
a) complete an initiated ICP switch away from a defaulting trader
b) initiate and complete an ICP switch away from a defaulting trader
c) cancel an ICP switch to a defaulting trader
d) complete a switch withdrawal request for an ICP that is being switched to a defaulting trader (so that the ICP remains with the other (non-defaulting) trader)
e) cancel a switch withdrawal request for an ICP that is being switched away from the defaulting trader (so that the ICP switches to the other (non-defaulting) trader).</td></tr>
<tr><td>Proposed Code amendment</td><td>Schedule 11.5 Process for trader event of default
…
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 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
(b) if the defaulting trader does not comply with the requirements set out in paragraph (a) within 7 days of the notice, clause 4 will apply.
(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.</td></tr>
</table>

(3) The defaulting **trader** must provide the information requested by the **Authority** under subclause (2) within the time specified by the **Authority**.

3 Authority may require distributor, ~~and~~ registry manager, and metering equipment provider 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, specified in the notice, about the defaulting **trader's** customers ~~specified in the notice (if the **distributor** holds the information)~~, within the period specified in the notice.

(2) If the **distributor** holds the information, the **distributor** must provide the information ~~requested by~~ to the **Authority** ~~under subclause (1)~~ within the time specified by the **Authority**.

(3) The **Authority** may, by notice in writing to the **registry manager**, require the **registry manager** to provide to the **Authority** the information, specified in the notice, about **ICPs** for which the defaulting **trader** is recorded in the **registry** as being responsible, within the period specified in the notice.

(4) If the **registry manager** holds the information, ~~T~~the **registry manager** must provide the information ~~requested by~~ to the **Authority** ~~under subclause (3)~~ within the time specified by the **Authority**.

(5) The **Authority** may, by notice in writing to a **metering equipment provider** who is recorded in the **registry** as the **metering equipment provider** for an **ICP** for which the defaulting **trader** is responsible, require the **metering equipment provider** to provide to the **Authority** the information, specified in the notice, about the defaulting **trader's ICPs**, within the period specified in the notice.

(6) If the **metering equipment provider** holds the information, the **metering equipment provider** must provide the information to the **Authority** within the time specified by the **Authority**.

4 Failure by defaulting trader to remedy event of default

(1) This clause applies if—

(a) 7 days or more 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 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) unless the Authority considers there is good reason not to, attempt to advise customers of the defaulting **trader** that the defaulting **trader** has committed an **event of default** and one or more of the following:— ~~(i) the defaulting **trader** has committed an **event of default**; and~~ (ii) the 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 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's contract with the defaulting **trader** to another **trader** under clause 5: (iv) any other information the **Authority** considers appropriate. **4A Trader to provide information about NSPs and ICPs at which it cannot trade** (1) If the **Authority** gives written notice to a **trader** under clause 4, the **Authority** must give written notice to each **trader** (except the defaulting **trader**) that it must provide the information specified in subclause (2) to the **registry manager** by no later than 1600 on the **business day** following the day on which the notice under this subclause was given. (2) The information that a **trader** must provide to the **registry manager** is— (a) the **NSPs** at which the **trader** cannot trade because it does not have an arrangement with the relevant **distributor** on whose network the **NSPs** are located to trade at the **NSP**; and (b) the **ICPs** at which the **trader** cannot trade for any of the following reasons: (i) the type of each **meter** at the **ICPs** (for example,

half hour, non **half hour**, or prepay):

(ii) the **price category code** assigned to the **ICPs**:

(iii) the **metering installation** category of the **metering installation** at the **ICPs**:

(iv) the **installation type** code assigned to the **ICPs**; and

(c) the reasons, being 1 or more reasons specified in paragraph (a) and (b), for the **trader** being unable to trade at the **NSPs** or **ICPs**.

(3) A **trader** must comply with a notice given to it under subclause (1).

4B Authority may direct registry manager not to process ~~take~~ certain ICP switching activities ~~actions~~

(1) If the **Authority** gives written notice to a **trader** under clause ~~4~~2, the **Authority** may, by written notice to the **registry manager**, direct the **registry manager** not to—

(a) process the initiation or completion of ~~complete~~ the switch of any **ICP** to the defaulting **trader**; or

(b) ~~accept a request from the defaulting **trader** to withdraw~~ process ~~-~~a switch withdrawal request under clauses 17 and 18 of Schedule 11.3 if processing the switch withdrawal request would mean the defaulting **trader** retained responsibility for the **ICP** to which the switch withdrawal request applies.

(2) If the **Authority** gives written notice under subclause (1), the **registry manager** must comply with the notice ~~not—~~

~~(a) complete the switch of any **ICP** to the defaulting **trader**; or~~

~~(b) accept a request from the defaulting **trader** to withdraw a switch under clauses 17 and 18 of Schedule 11.3~~.

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),—

(a) 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

(b) the defaulting **trader** continues to have 1 or more contracts under which a 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 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

(b) assign an **ICP** to a recipient **trader** and direct the **registry manager** to amend the record in the **registry** so that the recipient **trader** is recorded as being responsible for the **ICP**; and

(c) specify the recipient **trader** to whom the rights and obligations under the contract or the **ICP** will be assigned.

(2A) When determining an assignment under subclause (2), the **Authority** may do 1 or both of the following:

(a) exercise its discretion to determine the recipient **trader**:

(b) undertake a tender or other competitive process to determine the recipient **trader.**

(3) The **Authority** must, by notice in writing to each recipient **trader**, direct the recipient **trader** to accept an assignment under subclause (2).

(4) Before the **Authority** gives notice to a recipient **trader** under subclause (3), the **Authority** may decide not to assign rights and obligations of the defaulting **trader** under a contract or an **ICP** to a recipient **trader** if the recipient **trader** satisfies the **Authority** that the assignment would pose a serious threat to the financial viability of the recipient **trader**.

(5) A recipient **trader** must comply with a direction given to it under subclause (3).

(6) The **registry manager** must comply with a direction given to it under subclause (2).

(7) Before the **Authority** exercises its right to assign rights and obligations or an **ICP** under subclause (2), the **Authority** must, if the **Authority** considers it is practicable, consult with the defaulting **trader** as to the need for the notice.

~~(8) Nothing in this clause prevents the **Authority** from deciding to give a notice under subclause (3) to 1 or more recipient **traders** by undertaking a tender or other competitive process.~~

…

7 Authority may direct ~~R~~registry manager ~~may complete~~ to process certain ICP switching activities ~~without required information~~

(1) If the **Authority** gives written notice to a defaulting **trader** under clause 2, the **Authority** may, by written notice to the **registry manager**, ~~may complete the switch of any **ICP** for which the defaulting **trader** is recorded in the **registry** as being responsible~~ even if the defaulting **trader** has not complied with its obligations under Schedule 11.3, direct the **registry manager** to—

(a) initiate and complete the switch of an **ICP** away from the defaulting **trader**; or

(b) process the initiation or completion of the switch of an **ICP** away from the defaulting **trader**; or

(c) cancel the switch of an **ICP** to the defaulting **trader**; or

(d) process the completion of a switch withdrawal request under clauses 17 and 18 of Schedule 11.3 for an **ICP** that is being switched to the defaulting **trader**; or

(e) cancel a switch withdrawal request made under clauses 17 and 18 of Schedule 11.3 for an **ICP** that is being switched away from the defaulting **trader**.

(2) The **registry manager** must, as soon as possible, comply with a direction given by the **Authority** in a written notice.

…

Part 14 Clearing and settlement

…

14.41 Definition of an event of default

(1) Each of the following events constitutes an event of default:

(a) failure of a **participant** to provide security for the minimum amount required in accordance with clause 14A.6:

(b) a **settlement default**:

(c) any action taken for, or with a view to, the declaration of a **participant** that is required to comply with Part 14A as a corporation at risk under the Corporations (Investigation and Management) Act 1989:

(d) appointment of a statutory manager in respect of **participant** that is required to comply with Part 14A under the Corporations (Investigation and Management) Act 1989 (or a recommendation or submission is made by a person to the Financial Markets Authority supporting such an appointment):

(e) appointment of a person under section 19 of the Corporations (Investigation and Management) Act 1989 to investigate the affairs or run the **business** of a **participant**

	that is required to comply with Part 14A: (f) if a **participant** that is required to comply with Part 14A is (or admits that it is or is deemed under any applicable law to be) unable to pay its debts as they fall due or is otherwise insolvent, or stops or suspends, ~~or threatens to stop or suspend,~~ or a moratorium is declared on, payment of its indebtedness generally, or makes or commences negotiations or takes any other steps with a view to making any assignment or composition with, or for the benefit of, its creditors, or any other arrangement for the rescheduling of its indebtedness or otherwise with a view to avoiding, or in expectation of its inability to pay, its debts: (g) a holder of a security interest or other encumbrancer taking possession of, or a receiver, manager, receiver and manager, liquidator, provisional liquidator, trustee, statutory or official manager or inspector, administrator or similar officer being appointed in respect of the whole or any part of the assets of a **participant** that is required to comply with Part 14A or if the **participant** requests that such an appointment be made: (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 or customers purchasing **electricity** from the **trader** on the **distributor's local network** or **embedded network**; and (ii) there are no unresolved disputes between the **trader** and the **distributor** in relation to the termination; and (iii) the **distributor** has not been able to remedy the situation in a reasonable time; and (iv) the **distributor** gives notice to the **Authority** that this subclause applies. (2) If a **distributor**, having given notice under subclause (1)(h)(iv), considers that an **event of default** no longer exists, the **distributor** must advise the **Authority** that it considers that the **event of default** has been remedied.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry by: a) lowering the risk of an unnecessary default being triggered b) reducing instances of unnecessary errors in reconciliation,

	settlement, and consumer invoicing c) reducing transaction costs associated with a trader event of default. The proposed amendment is expected to have no effect on the reliable supply of electricity.
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 identified efficiency gains, which require a Code amendment to resolve.
Principle 3: Quantitative Assessment	Some of the costs and benefits of the proposed Code amendment can be quantified. However, it has not been practicable to quantify all of the costs and 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 reduce electricity market operational costs by: a) lowering the risk of an unnecessary default being triggered b) reducing instances of unnecessary errors in reconciliation, settlement, and consumer invoicing c) reducing transaction costs associated with a trader event of default.
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 main cost of the proposed amendment to address Problem 1 would be a slight increase in the risk of shortfall in energy payments to generators due to triggering an event of defualt later. In a workably competitive market, increasing the risk of a shortfall in energy payments to generators, by triggering an event of default later, would at the margin, be expected to reduce the cost faced by traders when participating in the electricity market (since a trader

	would face a marginally lower risk of default). We do not consider it is possible to quantify this cost. The Authority expects the main cost of the proposed Code amendment to address Problem 2 would be the cost incurred by the Authority: a) to receive, from the MEP(s) responsible for the ICPs at which the defaulting trader trades, files containing meter reads for the days on which ICPs switch to the trader(s) gaining the defaulting trader's customers b) to provide meter read files to the trader(s) gaining the defaulting trader's customers. We consider the MEP(s) providing the Authority with meter read files would face negligible incremental costs, if they were to use their standard processes to provide the Authority with meter read files. Therefore, for the purposes of this CBA, we assume all meter reads would be provided to the Authority via the electricity information exchange protocol (EIEP) hub. We also assume the MEP(s) would be undertaking daily meter reads of the ICPs for which the defaulting trader is responsible, meaning there would be no incremental cost associated with the MEP(s) obtaining meter reads for the days on which these ICPs switch to the gaining trader(s). We consider traders gaining the defaulting trader's customers would also face negligible incremental costs, because: a) they would be receiving the meter reads via the EIEP hub b) they would be under no compulsion to use the meter reads for switching, reconcilation, settlement and consumer invoicing purposes—they would be free to use the meter reads based on what best suits their business needs. We estimate the incremental cost associated with the Authority receiving, storing and forwarding switch meter reads, for ICPs that a defaulting trader trades at, would be approximately $1,500 – $2,000 for each trader default that requires meter reads to be obtained for the days on which an ICP is switched away from the defaulting trader. This cost covers: a) IT systems development b) staff time for the Authority, MEPs and gaining traders, relating to liaison over the meter read files. The Authority considers any costs associated with addressing Problems 3, 4, 5 and 6 would be negligible. We believe the proposed solutions to these problems would not require any changes to systems, processes and procedures by affected parties. *Benefits* The Authority considers the proposed Code amendment would have several main benefits.

	Firstly, removing the ability for an event of default to be triggered by a threat will decrease the costs faced by the Authority and associated participant when validating the threat. This effort is likely to be wasted, as by the time a threat of non-payment of a debt has been validated it is likely payment will have been due. Secondly, providing gaining traders with meter reads for the days on which the defaulting trader's customers are switched away, would promote accurate reconciliation, settlement and customer invoicing. More accurate customer invoicing would be expected to mean fewer customer complaints associated with the transfer to the gaining trader(s). Thirdly, ensuring that the trader default process results in no ICPs remaining the responsibility of a defaulting trader would also promote accurate reconciliation, settlement, and customer invoicing. Fourthly, providing the Authority with discretion over when to communicate with customers of the defaulting trader, and what information to provide the customers, would remove unnecessary transaction costs. The Authority estimates these would range from thousands of dollars to tens of thousands of dollars, depending on the size of the defaulting trader. Avoided costs would include advertising, stationery, postage and/or courier. Fifthly, removing the need to initiate and/or complete ICP switches to a defaulting trader and then assign these ICPs to another (non-defaulting) trader would reduce market transaction costs. The final main benefit of the proposed Code amendment would be to clarify the Code. This would reduce the time and effort spent by participants understanding the Code in order to meet their Code obligations, and the Authority liaising with participants over Code obligations. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code amendment outweigh the costs. In relation to Problem 1, on balance, we expect that providing for an event of default to be triggered later would lower traders' risk of an unnceessary default being triggered. This is because an event of default would occur only if a trader took action that resulted in non-payment occuring.
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.

2019-05 Issues with the definition and use of Historical Estimates

<table>
<tr><td>Reference number(s)</td><td>2019-05 Issues with the definition and use of Historical Estimates</td></tr>
<tr><td>Problem definition</td><td>Clause 1.1(1) of the Code defines “historical estimate” to mean—

in relation to non half hour metered ICPs,[1] 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:
(d) the difference between a validated meter reading and a permanent estimate.

Clause 4 of Schedule 15.3 sets out the methodology for preparing an historical estimate of volume information for an ICP, when the relevant seasonal adjustment shape is available.

Clause 5 of Schedule 15.3 says that when a seasonal adjustment shape is not available, a reconciliation participant must follow the same methodology for preparing an historical estimate set out in clause 4 of Schedule 15.3, but with daily quantities prorated as determined by the reconciliation participant —

a) using its own methodology; or
b) on a flat shape basis.

<u>Problem 1</u>

Neither clause 4 nor clause 5 of Schedule 15.3 explicitly provides for a reconciliation participant to use a profile approved by the Authority when preparing an historical estimate. Although this right could be inferred in clause 5 (because a reconciliation participant could choose a profile approved by the Authority as its own methodology), it would only be possible when a seasonal adjustment shape was not available.

A number of reconciliation participants prepare historical estimates of volume information using profiles we have approved (eg, telecommunication cabinet load), instead of a seasonal adjustment shape.[2] Currently, these participants are in breach of the Code because of the drafting of the Code.

<u>Problem 2</u></td></tr>
</table>

1 Installation control points.

2 An information paper containing the list of approved profiles is available on the Authority’s website at https://www.ea.govt.nz/dmsdocument/8563-approved-profiles.

	The current definition of "historical estimate" does not include historical estimates calculated under clause 5 of Schedule 15.3. The definition of "historical estimate" requires an historical estimate of volume information to use the seasonal adjustment shape or any other profile approved by the Authority for the purpose of apportioning volume information to part or full consumption periods. In contrast, historical estimates of volume information calculated under clause 5 of Schedule 15.3 do not use the seasonal adjustment shape or any other profile approved by the Authority for the purpose of apportioning volume information to part or full consumption periods. Currently, clause 6 of Schedule 15.3 says a forward estimate may be used only for a period for which an historical estimate, as defined under clause 1.1(1), cannot be calculated. This means a reconciliation participant can, when allocating volume information from a non half hour metering installation to a consumption period, choose between the following options when the relevant seasonal adjustment shape is not available: a) using an "historical estimate" calculated under clause 5 of Schedule 15.3, but not being an historical estimate of the type defined under clause 1.1(1); or b) using a forward estimate, in accordance with clause 6 of Schedule 15.3. Being able to use a forward estimate in this manner is inconsistent with the policy intent of clause 6 of Schedule 15.3. The policy intent of this clause is that a reconciliation participant may use a forward estimate only if the participant cannot calculate an historical estimate under either clause 4 or clause 5 of Schedule 15.3. The reason for restricting the use of forward estimates in this manner is to help the Authority and participants to better monitor the quality of volume information.[3] <u>Problem 3</u> Clause 3(1) of Schedule 15.3 says reconciliation participants must, for each ICP that has a non half hour metering installation, allocate volume information derived from validated meter readings, estimated readings or permanent estimates, to consumption periods using the techniques described in "this" clause to create historical estimates and forward estimates. However, clause 3 of Schedule 15.3 does not set out the techniques that reconcilation participants are to use to create historical estimates and forward estimates. These techniques are described in clauses 4, 5, 6, and 7 of Schedule 15.3.

[3] This policy intent is set out on page 62 of the *Report of the Electricity Commission Reconciliation Project Team*, December 2004, available at https://www.ea.govt.nz/dmsdocument/5383-annex-1-final-report-from-commission-reconciliation-project-team.

	The reference to “this clause” in clause 3 of Schedule 15.3 was inserted when the Code was established in 2010. It stems from when clauses 3 to 7 of Schedule 15.3 together formed a single clause in Schedule J3 of the Electricity Governance Rules 2003.
Proposal	Problem 1 To address problem 1, the Authority proposes to: a) insert a new clause 4A of Schedule 15.3 that expressly allows a reconciliation participant to use a profile approved by the Authority, instead of the seasonal adjustment shape b) amend clause 10 of Schedule 15.3 to refer to the new clause 4A. Problem 2 To address problem 2, the Authority proposes to: a) amend the definition of ‘historical estimate’ to clarify that its meaning includes an historical estimate prepared in accordance with clause 5 of Schedule 15.3 b) amend clause 10 of Schedule 15.3 to refer to clauses 4, 4A, and 5 of Schedule 15.3 (thereby ensuring the most accurate historical estimate input data is used in volume information provided to the reconciliation manager, consistent with the current definition of historical estimate). Problem 3 To address problem 3, the Authority proposes to amend clause 3(1) of Schedule 15.3 to refer to the techniques described in clauses 4 to 7 of Schedule 15.3 for creating historical estimates and forward estimates.
Proposed Code amendment	**Part 1** **1.1 Interpretation** (1) … **historical estimate** means, in relation to non **half hour** metered **ICPs**, **volume information** (in kWh)— (a) ~~,~~apportioned to part or full **consumption periods** after having applied— (i) the **seasonal adjustment shape**;~~,~~ or (ii) any other **profile** that has, from time to time, been approved by the **Authority** for this purpose;~~,~~ ~~applied,~~ or (iii) any other **profile** permitted under clause 5 of Schedule 15.3; and

(b) being 1 of the following:

~~(a)~~(i) the difference between 2 **validated** actual **meter readings**:

~~(b)~~(ii) the difference between 2 **permanent estimates**:

~~(c)~~(iii) any relevant **unmetered load**:

~~(d)~~(iv) the difference between a **validated meter reading** and a **permanent estimate**.

Part 15

Schedule 15.3

…

3 Historical estimates and forward estimates

(1) Each **reconciliation participant** must, for each **ICP** that has a non **half hour metering installation**, allocate **volume information** derived from **validated meter readings**, **estimated readings** or **permanent estimates**, to **consumption periods** using the techniques described in ~~this~~ clauses 4 to 7 to create **historical estimates** and **forward estimates**.

(2) Each estimate that is a **forward estimate** or an **historical estimate**, must be clearly identified as such.

(3) If a **validated meter reading** is not available for the purpose of clauses 4, 4A, and 5, a **permanent estimate** may be used in place of a **validated meter reading**.

4 Historical estimates with seasonal adjustment

The methodology that must be used by each **reconciliation participant** to prepare an **historical estimate** of **volume information** for each **ICP** when the relevant **seasonal adjustment shape** is available and the **reconciliation participant** is not using an approved **profile** in accordance with clause 4A, is as follows:

(a) if the period between any 2 consecutive **validated meter readings** encompasses an entire **consumption period**, an **historical estimate** must be prepared in accordance with the following formula:

$$HE_{ICP} = kWh_p \times A / B$$

where

HE_{ICP} is the quantity of **electricity** allocated to a **consumption period** for an **ICP**

	kWh_P is the difference in kWh between the last **validated meter reading** before the **consumption period** and the 1st **validated meter reading** after the **consumption period** A is the sum of the **seasonal adjustment shape** values for the **consumption period** B is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_P as published by the **reconciliation manager**: (b) if the period between any 2 consecutive **validated meter readings** encompasses the 1st part of a **consumption period** and the period between the 2nd **validated meter reading** and the subsequent **validated meter reading** encompasses the rest of that **consumption period**, an **historical estimate** must be prepared in accordance with the following formula: $$HE_{ICP} = kWh_{P1} \times A_1 / B_1 + kWh_{P2} \times A_2 / B_2$$ where HE_{ICP} is the quantity of **electricity** allocated to a **consumption period** for an **ICP** kWh_{P1} is the difference in kWh between the last **validated meter reading** before the **consumption period** and the **validated meter reading** during the **consumption period** A_1 is the sum of the **seasonal adjustment shape** values for the relevant days in the 1st part of the **consumption period** B_1 is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_{P1} kWh_{P2} is the difference in kWh between the first **validated meter reading** during the **consumption period** and the 1st **validated meter reading** after the **consumption period** A_2 is the sum of the **seasonal adjustment shape** values for the relevant days in the latter part of the **consumption period** B_2 is the sum of the **seasonal adjustment shape**

values for the same time period as is covered by kWh_{P2}.

4A Historical estimates using approved profile

If the **Authority** has approved a **profile** for the purpose of apportioning **volume information** (in kWh) to part or full **consumption periods**, a **reconciliation participant**—

(a) may use the **profile** despite the relevant **seasonal adjustment shape** being available; and

(b) if it uses the **profile**, must otherwise prepare the **historical estimate** in accordance with the methodology in clause 4.

5 Historical estimates without seasonal adjustment

If a **seasonal adjustment shape** is not available, either due to timing (for the provision of **submission information** by the 4th **business day** of each **reconciliation period**) or for any other reason, and the **reconciliation participant** is not using an approved **profile** under clause 4A, the methodology for preparing an **historical estimate** of **volume information** for each **ICP** must be the same as in clause 4, except that the relevant quantities kWh_{Px} must be prorated as determined by the **reconciliation participant** using its own methodology or on a flat shape basis using the relevant number of days that are—

(a) within the **consumption period**; and

(b) within the period covered by kWh_{Px}.

…

10 Reporting requirements

(1) By 1600 hours on the 13th **business day** of each **reconciliation period**, each **reconciliation participant** must report to the **reconciliation manager** the proportion of **historical estimates** prepared under clauses 4 or 4A, per **NSP** contained within its non **half hour submission information**.

(2) By 1200 hours on the last **business day** of each **reconciliation period**, the **reconciliation manager** must provide to the **Authority** a report of the proportion of **historical estimates** prepared under clause 4 or clause 4A, per **NSP**~~,~~ and per **reconciliation participant**, being used to create non **half hour consumption information** in respect of each **consumption period** being reconciled, and the **Authority** must publish the information.

	(3) The proportion of **submission information** per **retailer** per **NSP** that is comprised of **historical estimates** <u>prepared under clause 4 or clause 4A</u> must, unless **exceptional circumstances** exist, be— (a) at least 80% for revised data provided at the month 3 revision; and (b) at least 90% for revised data provided at the month 7 revision; and (c) 100% for revised data provided at the month 14 revision.
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. The proposed amendment would improve the efficient operation of the electricity industry by clarifying the Code requirements relating to the use of historical estimates and forward estimates, for example by encouraging the use of historical estimates over forward estimates. This would make the Code easier to understand and reducing participants', and the Authority's, compliance costs. The proposed Code amendment is expected to have little or no effect on competition and the reliable supply of electricity.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as described below.
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 problem with the Code, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The costs of the proposed Code amendment can be readily quantified. However, it has not been practicable to quantify all of 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 clarify the Code requirements to ensure reconciliation participants use historical estimates over forward estimates, to reduce electricity market transaction costs.
Evaluation of the costs and benefits of the proposed	The Authority considers the proposed amendment would have a positive net benefit.

amendment	*Costs* We expect there would be no incremental costs imposed on participants. This is because the proposed Code amendment would align the Code with industry practice. *Benefits* A benefit of the proposed Code amendment is to avoid unnecessary compliance costs. These costs arise from participants allegedly breaching the Code, by using a profile approved by the Authority when preparing an historical estimate. The Authority estimates there would be a potential cost of approximately $250 per year if an auditor were to allege that a reconciliation participant had breached the Code, by using an approved profile instead of the seasonal adjustment shape.[4] Currently, three participants use an approved profile instead of the seasonal adjustment shape. If we assume three alleged breaches of the Code each year, for the next 15 years, in relation to this use of approved profiles, the present value benefit of removing this compliance cost would be approximately $6,500.[5] A further benefit of the proposed amendment would be better ensuring reconciliation participants use historical estimates over forward estimates. This would improve the quality of volume information, thereby promoting accurate clearing and settlement of the wholesale electricity market. A final key benefit of the proposed 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) of transacting in the electricity market, which would be a productive economic efficiency benefit. *Net benefit* Based on the analysis above, the Authority is satisfied the benefits of the proposed amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

4 This relates to staff time, for the auditor, the reconciliation participant, and the Authority.

5 Using a real discount rate of 8%.

2019-06 Clarifying definition of Point of Connection

Reference number(s)	2019-06 Clarifying definition of Point of Connection
Problem definition	Part 1 of the Code defines “point of connection” to mean— *a point at which **electricity** may flow into or out of a **network** and, for the purposes of **Technical Code** A of Schedule 8.3, means a **grid injection point** or a **grid exit point**.* It has been put to the Authority that this definition means a three-phase metering installation is, in fact, three points of connection. A participant contends that each phase of a three phase metering installation is a separate “point” of connection between load and/or generation, and the network to which the load and/or generation is connected. The Authority disagrees with this interpretation—we consider it to be too narrow. The definition of “point of connection” does not prevent multiple phases being connected at the same point at which the electrical arrangements internal to load and/or generation connect to the electrical arrangements of a network. The definition does not specify what form that connection may or may not take. We consider it problematic that the definition can be interpreted in the manner put to us. It means the Code is not as clear and easy to understand as it could be.
Proposal	To address this problem, the Authority proposes to amend the definition of “point of connection” to explicitly state that a point of connection can have multiple phases or conductors, with load in either direction. The intent is that the meaning of “point of connection” includes the entire connection for an ICP, regardless of how many individual phases or wires are needed for the connection.
Proposed Code amendment	**Part 1** **1.1 Interpretation** (1) … **point of connection** means— (a) a point at which **electricity** may flow, via one or more phases or conductors— (i) into or out of a **network**; or (ii) both into and out of a **network** at the same time; and~~,~~ (b) for the purposes of **Technical Code** A of Schedule 8.3, means a **grid injection point** or a **grid exit point**

Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry by clarifying the Code requirements relating to a point of connection. This would make the Code easier to understand and would reduce participants', and the Authority's, compliance costs. The proposed Code amendment is expected to have little or no effect on competition and the reliable supply of electricity.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as set out below.
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 problem with the Code, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The costs, and some of the benefits, of the proposed Code amendment can be quantified. However, it has not been practicable to quantify all of 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 clarify the Code requirements relating to a point of connection, to reduce electricity market transaction costs.
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 no additional costs on participants. This is because current industry practice is aligned with the proposed amendment. *Benefits* The primary benefit of the proposed amendment is to clarify the Code. This would reduce the time and effort spent by: a) participants understanding the Code in order to meet their Code obligations b) the Authority informing participants about their Code

	obligations c) the Authority and participants addressing matters related to participants' compliance with their Code obligations. Based on its experience over the past few years, the Authority estimates it and participants might avoid thousands of dollars in compliance-related costs under the Code amendment proposal.[1] *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

1 Primarily in legal fees and staff time.

2019-07 Clarifying definitions of Block Security Constraint and Station Security Constraint

Reference number(s)	2019-07 Clarifying definitions of Block Security Constraint and Station Security Constraint
Problem definition	The definitions of “block security constraint” and “station security constraint” in Part 1 of the Code are not as clear as they could be. This makes the Code harder to understand and comply with than is necessary. The Code defines “block security constraint” and “station security constraint” as follows: ***block security constraint*** *means any of the following:* *(a) a constraint applied by the* ***system operator*** *to a* ***generating unit*** *or* ***generating station*** *to provide* ***voltage support*** *or* ***frequency keeping*** *as determined in accordance with Part 8* *(b) a limitation in the offered capacity of a* ***grid owner’s network*** *to convey* ***electricity*** *between* ***generating stations*** *constituting a* ***block dispatch group*** *(c) a limitation in the offered capacity of a* ***grid owner’s network*** *to convey* ***electricity*** *between* ***generating stations*** *constituting a* ***block dispatch group*** *and a* ***grid owner’s network***— *and, in paragraphs (b) and (c), such a limitation in the offered capacity being the offered capacity of a* ***grid owner’s network*** *or a* ***grid system security constraint*** *as determined by the* ***system operator*** *in accordance with Part 8* ***station security constraint*** *means any of the following:* *(a) a constraint applied by the* ***system operator*** *to a* ***generating unit*** *to provide* ***voltage support*** *or frequency reserve capacity as determined in accordance with Part 8:* *(b) a limitation in the offered capacity of a* ***grid owner’s*** *network to convey* ***electricity*** *between* ***generating units*** *constituting a* ***station dispatch group****:* *(c) a limitation in the offered capacity of a* ***grid owner’s network*** *to convey* ***electricity*** *between* ***generating units*** *constituting a* ***station dispatch group*** *and a* ***grid owner’s network***— *and, if in paragraphs (b) and (c) above, the limitation in the offered capacity is either the offered capacity of a* ***grid owner’s network*** *or a* ***grid system security*** *limit, as determined by the* ***system operator*** *in accordance with Part 8*

	<u>Problem 1</u> The policy intent of paragraph (a) in each definition is that a security constraint applied by the system operator can be the result of the need for voltage support or frequency keeping. Paragraph (a) of the definition of block security constraint clearly expresses this policy intent by using the words “voltage support or frequency keeping”. However, paragraph (a) of the definition of station security constraint does not express this policy intent as clearly, because it uses the words “voltage support or frequency reserve capacity”. <u>Problem 2</u> The references to “Part 8” in the definitions of block security constraint and station security constraint were inserted when the Code was made in 2010. Previously, under the Electricity Governance Rules 2003 (EGRs), the references were to Part C of the EGRs. When the Code was first drafted, most of Part C of the EGRs was placed in Part 8. However, the system operator’s principal performance obligations (PPOs) were placed in Part 7. The system operator’s first PPO is relevant to paragraph (a) in each of the definitions of block security constraint and station security constraint.[1] By not referring to Part 7 of the Code, and thereby not referencing the system operator’s first PPO, the definitions of “block security constraint” and “station security constraint” do not adequately provide for a system security constraint to limit grid capacity. <u>Problem 3</u> As currently drafted, the definitions of block security constraint and station security constraint each say that a limitation in the offered capacity of a grid owner’s network is either: a) the offered capacity of the grid owner’s network; or b) a grid system security constraint / limit, as determined by the system operator. The current drafting makes the two definitions unnecessarily hard to understand and comply with. For example, “network” is defined in Part 1 of the Code to mean “the grid, a local network or an embedded network”. Therefore, the definitions of block security constraint and station security constraint could be interpreted as applying to a network other than the grid, in

[1] Under its first PPO, the system operator must dispatch assets made available in a manner that avoids cascade failure of assets, resulting in a loss of electricity to consumers, arising from—

a) a frequency or voltage excursion; or

b) a supply and demand imbalance.

	instances where a grid owner owns a local network and/or embedded network.[2] Another example is the use of "offered capacity" in paragraphs (b) and (c) of the definitions of block security constraint and station security constraint. This could be interpreted as requiring the system operator to ask a grid owner to revise the grid owner's offered network capacity if the system operator were to determine a grid system security constraint. A third example is the use of "grid system security constraint" in the definition of "block security constraint" and ""grid system security limit" in the definition of "station security constraint". The term "constraint" is defined in Part 1 of the Code, whereas "limit" takes its ordinary meaning.
Proposal	<u>Problem 1</u> To address problem 1, the Authority proposes to replace the words "frequency reserve capacity" with the words "frequency keeping" in the definition of "station security constraint". <u>Problem 2</u> To address problem 2, the Authority proposes to insert references to Part 7 of the Code in the definitions of "block security constraint" and "station security constraint". <u>Problem 3</u> To address problem 3, the Authority proposes to amend the definitions of "block security constraint" and "station security constraint", to clarify: a) that each definition refers to a limitation in the capacity of the grid b) that a limitation in the capacity of the grid can arise because of— i) a limitation in the offered capacity of the grid; or ii) a grid system security constraint c) to replace the words "grid system security limit" in the definition of "station security constraint" with the words "grid system security constraint", which is consistent with the definition of "block security constraint". The term "constraint" is more appropriate than "limit", because it is defined in Part 1 of the Code to mean "a limitation in the capacity of the grid to convey electricity caused by limitations in capability of available assets forming the grid or limitations in the performance of the integrated power system".

2 For example, the local network owner, Westpower, is also a grid owner because it owns some of the West Coast transmission network that forms part of the grid.

	The Authority also proposes making minor drafting changes to both definitions, to replace the first reference (in each definition) to “constraint” with “limitation”. The term ‘constraint’ is a defined term, but the definition does not apply in these situations.
Proposed Code amendment	**Part 1** **1.1 Interpretation** (1) … **block security constraint** means any of the following: (a) a ~~constraint~~ limitation applied by the **system operator** to a **generating unit** or **generating station** to provide **voltage support** or **frequency keeping** as determined in accordance with Parts 7 and 8: (b) a limitation in capacity that: (i) is a limitation in the ~~offered~~ capacity of ~~a **grid owner’s network**~~ the **grid** to convey **electricity** between either: (A) **generating stations** constituting a **block dispatch group**; or (B) ~~a limitation in the offered capacity of a **grid owner’s network** to convey **electricity** between~~ **generating stations** constituting a **block dispatch group** and ~~a **grid owner’s network**~~ the **grid**;~~—~~ and~~,~~ (ii) ~~in paragraphs (b) and (c), such~~ arises because of either— (A) a limitation in the ~~offered capacity being the~~ offered capacity of ~~a **grid owner’s network**~~ the **grid**; or (B) a **grid system security constraint** as determined by the **system operator** in accordance with Parts 7 and 8 … **station security constraint** means any of the following: (a) a ~~constraint~~ limitation applied by the **system operator** to a **generating unit** to provide **voltage support** or ~~frequency~~ ~~reserve capacity~~ **frequency keeping** as determined in accordance with Parts 7 and 8: (b) a limitation in capacity that: (i) is a limitation in the ~~offered~~ capacity of ~~a **grid owner’s**~~ ~~network~~ the **grid** to convey **electricity**

	between either— (A) **generating units** constituting a **station dispatch group**; or (B) ~~a limitation in the offered capacity of a~~ ~~**grid owner's network**~~ ~~to convey~~ ~~**electricity**~~ ~~between~~ **generating units** constituting a **station dispatch group** and ~~a~~ ~~**grid owner's network**~~ the **grid**;— and~~,~~ (ii) ~~if in paragraphs (b) and (c) above, the~~ arises because of either: (A) a limitation in the ~~offered capacity is either the~~ offered capacity of ~~a~~ ~~**grid owner's network**~~ the **grid**; or (B) a **grid system security** ~~limit~~ **constraint**, as determined by the **system operator** in accordance with Parts 7 and 8 …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry by clarifying the Code requirements relating to block security constraints and station security constraints, thereby making the Code easier to understand and reducing compliance costs. The proposed Code amendment would also promote the reliable supply of electricity to the extent that it reduced the possibility of a misunderstanding over whether a block security constraint or station security constraint should be applied. The proposed amendment is expected to have no effect on competition.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as described below.
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 problem with the Code, which requires a Code amendment to resolve.

Principle 3: Quantitative Assessment	It has not been practicable to quantify the costs and benefits of the proposed Code amendment. Hence, a qualitative 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 clarify the Code requirements relating to block dispatch constraints and station dispatch constraints, to reduce electricity market transaction costs.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* We expect the proposed amendment would place no additional costs on industry participants. If it did, these would be negligible—perhaps some minor updating of procedures by the grid owner and/or system operator. *Benefits* The primary benefit of the proposed amendment is to clarify the Code. This would reduce the time and effort spent by participants (primarily the grid owner, system operator and generators) understanding the Code in order to meet their Code obligations. Similarly, improving clarity would reduce time and effort for the Authority to enforce compliance with Code obligations using the security constraint definitions. *Net benefit* Based on the above assessment, the Authority is satisfied the benefits of the proposed Code 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 objectives of the proposed Code amendment.

2019-08 Clarifying manner of providing final audit report and compliance plan

<table>
<tr><td>**Reference number(s)**</td><td>2019-08 Clarifying manner of providing final audit report and compliance plan</td></tr>
<tr><td>**Problem definition**</td><td><u>Problem 1</u>

Clause 16A.13 of the Code—

a) sets out when a participant must give a final audit report to the Authority
b) requires a participant to submit a compliance plan to the Authority when it gives a final audit report to the Authority (provided the audit report identifies breaches or potential breaches of the Code)
c) requires each compliance plan and audit report to be in the form prescribed by the Authority
d) requires that each compliance plan specify:
i) the actions the participant intends to take to address any breaches or potential breaches of the Code identified in the audit report
ii) the timeframes within which the participant intends to complete those actions.

However, clause 16A.13 does not specify that a final audit report and compliance plan must be given to the Authority in the prescribed manner—via the audit portal. This raises the possibility that some participants may not use the audit portal. This would mean the Authority would incur unnecessary administration costs.

<u>Problem 2</u>

The policy intent of clause 16A.13(3) is that the participant must provide a final audit report to the Authority in the form prescribed by the Authority. However, this clause refers to “audit report” rather than “final audit report”, and does not specify to whom the obligation applies. This duplicates the requirement of clause 16A.12(1)(a).</td></tr>
<tr><td>**Proposal**</td><td><u>Problem 1</u>

To address problem 1, the Authority proposes to amend clause 16A.13(3) of the Code to clarify that a participant must provide a final audit report and compliance plan to the Authority in the manner prescribed by the Authority.

<u>Problem 2</u>

To address problem 2, the Authority proposes to amend clause 16A.13(3) to clarify that the participant must provide a *final* audit report to the Authority in the form prescribed by the Authority.</td></tr>
<tr><td>**Proposed Code amendment**</td><td>**Part 16A**

16A.13 Participants to give final audit report and compliance plan to the Authority

(1) A **participant** must give the final **audit** report to the **Authority**</td></tr>
</table>

	no later than the date by which the **audit** is due to be completed. (2) Each **participant** must submit a compliance plan to the **Authority** when it gives a final **audit** report to the **Authority** under subclause (1). (3) Each **participant** must provide the compliance plan and final **audit** report ~~must~~ — (a) ~~be~~ in the **prescribed form**; and (b) in the manner specified by the **Authority**. (4) Each compliance plan must specify— (a) the actions that the **participant** intends to take to address any breaches or potential breaches of this Code identified in the **audit** report; and (b) the time frames within which the **participant** intends to complete those actions. (5) Subclause (2) does not apply if the relevant final **audit** report in relation to a **participant** identifies no breaches or potential breaches of this Code.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry by clarifying the Code requirements relating to the manner in which final audit reports and compliance plans are provided to the Authority. This would reduce the overall cost of administering an audit. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles as discussed below.
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 problem with the Code, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The costs, and some of the benefits, of the proposed Code amendment can be quantified. However, it has not been practicable to quantify all of 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 clarify that participants must provide final audit reports and compliance plans to the Authority in the manner specified by the Authority, to reduce electricity market transaction costs.
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 will place very little, if any, additional costs on participants. This is because almost all participants currently provide final audit reports and compliance plans to the Authority via the audit portal. Also, even if a participant does not currently use the audit portal, they will still incur costs in submitting the audit report, by whatever alternative means are used. *Benefits* The primary benefit of the proposed amendment is avoiding the possibility that some participants may not use the audit portal. This would mean the Authority would incur unnecessary administration costs. The Authority estimates it would avoid approximately \$1,000 – \$5,000 in costs over the next 15 years,[1] under the Code amendment proposal. This is based on an average of 1 – 2 participants not using the portal over this period. A second, minor, benefit of the proposed Code amendment is to clarify the Code. This reduces the time and effort spent by: a) participants understanding the Code in order to meet their Code obligations b) the Authority liaising with participants over their Code obligations. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

1 These costs would relate to staff time.

2019-09 Clarifying use of "electricity supplied" in clause 15.8

Reference number(s)	2019-09 Clarifying use of "electricity supplied" in clause 15.8
Problem definition	Under clause 15.8 of the Code, each retailer and direct purchaser (excluding direct consumers) must provide the reconciliation manager with the total monthly quantity of electricity supplied for each half hourly metered ICP for which the retailer or direct purchaser provided submission information to the reconciliation manager, including— a) submission information for the immediately preceding consumption period b) revised submission information, provided in accordance with clause 15.4(2). The reconciliation manager uses the information provided under clause 15.8 to: a) report to each retailer / direct purchaser their monthly totals for half hourly metered ICPs for which submission information has not been received within the time required by the Code[1] b) report all half hourly metered ICPs that have switched retailer and direct purchaser in the previous two months and for which consumption has changed by a percentage determined by the Authority (currently 10%).[2] The Authority has identified that the words "electricity supplied" in clause 15.8 are not conveying the policy intent of this clause. Part 1 of the Code defines "electricity supplied" as follows: ***electricity supplied** means, for any particular period, the information relating to the quantities of **electricity** supplied by **retailers** across **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 customer supply and billing arrangements; and* *(c) supplied under sponsorship arrangements; and* *(d) supplied under any other arrangement* <u>Problem 1</u> This term does not apply to direct purchasers, who are defined to be consumers that purchase, or agree to purchase, electricity directly

1 Refer to clause 25(d) of Schedule 15.4, and to GR-090 in the reconciliation manager functional specification available at https://www.ea.govt.nz/operations/market-operation-service-providers/reconciliation-manager/.

2 Refer to clause 25(f) of Schedule 15.4, and to GR-110 in the reconciliation manager functional specification available at https://www.ea.govt.nz/operations/market-operation-service-providers/reconciliation-manager/.

	from the clearing manager for their own consumption at a point of connection.[3] <u>Problem 2</u> The purpose of clause 15.8 is to help identify half hourly metered ICPs for which: a) submission information has not been provided to the reconciliation manager; or b) submission volumes have changed following a switch to another retailer. Sourcing the information to be provided under clause 15.8 from retailers' / direct purchasers' financial records does not enable the purpose of clause 15.8 to be met, because as-billed volumes do not always align with volumes sourced from metering data.[4]
Proposal	To address the problems identified above, the Authority proposes to amend clause 15.8 of the Code to clarify that a retailer or direct purchaser (excluding direct consumers) must provide the reconciliation manager with a file containing monthly totals of metered, not billed, consumption data by individual half hourly metered ICP.
Proposed Code amendment	**15.8 Retailer and direct purchaser half hourly metered ICPs monthly kWh information** <u>Using relevant **volume information**, each</u> ~~Each~~ **retailer** and **direct purchaser** (excluding **direct consumers**) must deliver to the **reconciliation manager** the ~~**retailer's** or **direct purchaser's**~~ total monthly quantity of **electricity** ~~**supplied** for~~ <u>consumed at</u> each **half hourly** metered **ICP** for which the **retailer** or **direct purchaser** has provided **submission information** to the **reconciliation manager**, including— (a) **submission information** for the immediately preceding **consumption period**, by 1600 hours on the 4th **business day** of each **reconciliation period**; and (b) revised **submission information** provided in accordance with clause 15.4(2), by 1600 hours on the 13th **business day** of each **reconciliation period**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry by clarifying the policy intent of clause 15.8. This would reduce retailers' and direct purchasers' costs of

3 Refer to clause 1.1(1) of the Code.

4 In other words, the volumes a retailer / direct purchaser invoiced its customers in a given month will not always align with the customers' consumption during that month.

	understanding and complying with the Code. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as set out below.
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 problem with the Code, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	The costs, and some of the benefits, of the proposed Code amendment can be quantified. However, it has not been practicable to quantify all of 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 reduce electricity market transaction costs by clarifying the policy intent of clause 15.8.
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 would place no additional cost on industry participants. This is because current industry practice is aligned with the proposed amendment. *Benefits* The primary benefit of the proposed amendment is to clarify the policy intent of clause 15.8. This reduces the time and effort spent by: a) participants understanding the Code in order to meet their Code obligations b) the Authority informing participants about their Code obligations c) the Authority and participants addressing matters related to participants' compliance with their Code obligations. Based on its experience over the past 5 years, the Authority estimates the reduction in auditing and compliance costs associated with the current drafting of clause 15.8 over the next 15 years might

	be $35,000 – $85,000. This is based on avoiding, each year, 20 – 25 instances of an auditor alleging that a trader had breached clause 15.8. We estimate each such incidence would have an economic cost in the range of approximately $200 – $400.[5] *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code 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 objectives of the proposed Code amendment.

5 This relates to staff time for the auditor and the trader.

2019-10 Improving the process for converting secondary networks

Reference number(s)	2019-10 Improving the process for converting secondary networks
Problem definition	In its review of secondary networks, the Retail Advisory Group identified some operational efficiency problems associated with: a) Converting an embedded network to another type of secondary network b) Converting a network extension to another type of secondary network.[1] Under the Authority's Switch Process Review, the Authority is considering operational efficiency problems associated with the process by which a secondary network is converted to another type of secondary network. However, the outcomes from the Review may be a couple of years away. Three of the problems identified by the Retail Advisory Group can be addressed relatively easily and quickly. Therefore, we propose addressing these three problems under this 2019 Code Review Programme, rather than including them in the Switch Process Review. Including these three problems in this Code Review Programme will not impose material additional costs on participants. This is because there is little likelihood of the Switch Process Review materially changing the requirements proposed under the 2019 Code Review Programme. <u>Problem 1</u> The Code requires that, before an embedded network or network extension can be converted to another type of secondary network, each retailer trading on the embedded network or the network extension must: a) consent to the secondary network's ICP identifiers having their status in the registry changed to 'Decommissioned', for the conversion of an embedded network or network extension to a customer network b) consent to the transfer of ICP identifiers in the registry, for the conversion of:

[1] Refer to:

a) The Retail Advisory Group's 2015 discussion paper entitled 'Review of secondary networks: Issues and options paper', available on the Authority's website at https://www.ea.govt.nz/dmsdocument/19321-review-of-secondary-networks-issues-and-options-paper.

b) The Retail Advisory Group's 2017 report to the Authority entitled 'Review of secondary networks: Report', available on the Authority's website at https://www.ea.govt.nz/dmsdocument/22147-rag-report-review-of-secondary-networks.

	i) an embedded network to a network extension ii) a network extension to an embedded network.[2] However, currently, the Code does not specify a timeframe for obtaining retailers’ consent to converting an embedded network or network extension to another type of secondary network. Also, the Code does not prohibit a retailer from unreasonably withholding or delaying its agreement to the network conversion. The Authority is aware that some conversions to, or from, an embedded network have been delayed by retailers refusing to agree to them. As a result of the current design of the Code, the following inefficiencies can arise: a) a retailer feels compelled (eg, for reputational reasons) to consent to a network conversion with a timeframe that causes the retailer to breach contracts it has in place (eg, with consumers or MEPs on the embedded network / network extension) b) a retailer may unreasonably delay or withhold giving its consent to the network conversion, even though its customers on the embedded network / network extension agree to the conversion. This could impose costs on the secondary network owner and/or other retailers, as well as on consumers. Problem 2 When an embedded network is converted to a customer network, amongst other things:[3] a) all of the embedded network’s ICP identifiers must have their status in the registry changed to ‘Decommissioned’ b) the network supply point (NSP) identifier for the NSP between the embedded network and its parent network must have its status in the registry changed to ‘Decommissioned’.[4] The efficient operation of the electricity market can be adversely affected (eg, in particular, the accuracy of the reconciliation process), if the NSP identifier is recorded in the registry as ‘Decommissioned’ before all of the embedded network’s ICP identifiers have had their status in the registry changed to ‘Decommissioned’. Problem 3 When an embedded network is converted to a network extension, amongst other things:[5]

2 Refer to clauses 5 and 6 of Schedule 11.2 of the Code.

3 For further information, please see the secondary networks guidelines, available on the Authority’s website at: https://www.ea.govt.nz/dmsdocument/6077-guidelines-for-metering-reconciliation-and-registry-arrangements-for-secondary-networks.

4 The NSP identifier will be replaced with an ICP identifier.

5 For further information, please see the secondary networks guidelines, available on the Authority’s website at:

	a) all of the embedded network's ICP identifiers are transferred, in the registry, from the embedded network's NSP identifier to the relevant parent network's NSP identifier b) the NSP identifier for the NSP between the embedded network and its parent network must have its status in the registry changed to 'Decommissioned'. The efficient operation of the electricity market can be adversely affected (eg, in particular, the accuracy of the reconciliation process), if the NSP identifier is recorded in the registry as 'Decommissioned' before all of the embedded network's ICP identifiers are transferred in the registry from the embedded network's NSP identifier to the relevant parent network NSP identifier.
Proposal	<u>Problem 1</u> To address problem 1, the Authority proposes to amend Schedule 11.2 of the Code. Under the proposed amendment, all participants (other than market operation service providers) affected by a proposed conversion of an embedded network or a network extension to another type of secondary network, would have 40 business days to consent to the conversion. The period could be varied from 40 business days, if all affected parties agreed to the alternative period. If a distributor or trader does not reply to a request for consent, the applicant distributor must within that 40 day period: a) check the registry to ensure it is approaching the correct distributor or trader b) make reasonable endeavours to contact the distributor or trader and obtain a response. If, despite the above, the distributor or trader does not provide a response by the end of the 40 day period, the response is deemed to be consent. The 40 business day period would be consistent with the Retail Advisory Group's recommendation to the Authority.[6] It is designed to give retailers sufficient time to: a) assess the requirements of the proposed secondary network b) make any necessary changes to the configuration of their systems c) communicate price changes or contract cessation notices to their customers, in accordance with the notice period(s) set out in the contract with their customers on the secondary network[7]

https://www.ea.govt.nz/dmsdocument/6077-guidelines-for-metering-reconciliation-and-registry-arrangements-for-secondary-networks.

6 Refer to paragraph 7.50 of the Retail Advisory Group's 2017 report to the Authority entitled 'Review of secondary networks: Report'.

7 A common notice period for a price change is 30 days.

	d) amend, as necessary, any arrangements with MEPs in relation to the secondary network. <u>Problem 2</u> To address problem 2, the Authority proposes to amend clause 25 of Schedule 11.1 of the Code. For the conversion of an embedded network to a customer network, an embedded network owner would not be permitted to set a date after which it would be no longer responsible for the embedded network's NSP identifier, *unless*: a) the embedded network owner has changed the status of all of the embedded network's ICP identifiers in the registry to 'Decommissioned'; or b) each ICP on the NSP has been recorded as being connected to a different NSP; or a combination of a) and b), so that each ICP on the NSP is either 'Decommissioned' or transferred. <u>Problem 3</u> To address problem 3, the Authority proposes to amend clause 25(5) of Schedule 11.1 of the Code. For the conversion of an embedded network to a network extension: a) an embedded network owner would not be permitted to end date the embedded network's NSP identifier, *unless* b) the embedded network owner has assigned all of the embedded network's ICP identifiers with an 'Active' or 'Inactive' status in the registry to the relevant parent network NSP identifier.
Proposed Code amendment	**Schedule 11.1 Creation and management of ICPs, ICP identifiers and NSPs** … **25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network** (1) If an **NSP** is to be created or **decommissioned**,— (a) the **participant** specified in subclause (3) in relation to the **NSP** must give written notice to the **reconciliation manager** of the creation or **decommissioning**; and (b) the **reconciliation manager** must give written notice to the **Authority** and affected **reconciliation participants** of the creation or **decommissioning** no later than 1 **business day** after receiving the notice in paragraph (a). (2) If a **distributor** wishes to change the record in the **registry** of an **ICP** that is not recorded as being usually connected to an **NSP** in the **distributor's network**, so that the **ICP** is recorded

as being usually connected to an **NSP** in the **distributor's network** (a "transfer"), the **distributor** must give written notice to the **reconciliation manager**, the **Authority**, and each affected **reconciliation participant** of the transfer.

(3) The notice required by subclause (1) must be given by—

(a) the **grid owner**, if—

(i) the **NSP** is a **point of connection** between the **grid** and a **local network**; or

(ii) if the **NSP** is a **point of connection** between a **generator** and the **grid**; or

(b) the **distributor** for the **local network** who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **local networks**; or

(c) the **embedded network** owner who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **embedded networks**; or

(d) the **distributor** for the **embedded network**, if the **NSP** is a **point of connection** between an **embedded network** and another **network**.

(4) A **distributor** who is required to give written notice of a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2.

(5) An **embedded network** owner must not give written notice of **decommissioning** an **NSP** under subclause (3)(c) or subclause (3)(d) unless—

(a) the **embedded network** owner has changed the status in the **registry** of all **ICPs** recorded as being usually connected to the **NSP** to 'Decommissioned'; or

(b) a **distributor** has changed the record in the **registry** of each **ICP** previously recorded as being usually connected to the **NSP,** and with a status in the **registry** of 'Active' or 'Inactive', to record the **ICP** as being usually connected to an **NSP** in the **distributor's network**; or

(c) a combination of the changes described in paragraphs (a) and (b) has occurred, so that no **ICP** with a status in the **registry** of 'Active' or 'Inactive' is recorded as being connected to the **NSP** that is to be **decommissioned**.

Schedule 11.2 Transfer of ICPs between distributors' networks

…

5 The applicant **distributor** must give the **Authority** confirmation that the applicant **distributor** has received written consent to

	the proposed transfer from— (a) the **distributor** whose **network** is associated with the **NSP** to which the **ICP** is recorded as being connected immediately before the notice, except if the notice relates to the creation of an **embedded network**; and (b) every **trader** who trades **electricity** at any **ICP** nominated at the time of notice as being supplied from the same **NSP** to which the notice relates. 5A For the purposes of clause 5, the **distributor** (under paragraph (a)) or the **trader** (under paragraph (b)) is deemed to have consented to the proposed transfer if the applicant **distributor** has requested in writing the **distributor's** or **trader's** written consent and— (a) the **distributor** or **trader** (as the case may be)— (i) has not provided written consent; and (ii) has not indicated in writing that it refuses to give written consent; and (b) more than 40 **business days** (or such other period as the applicant **distributor** agrees with the **distributor** or **trader**) have passed since the applicant **distributor** requested the **distributor's** or **trader's** written consent (c) during the 40 **business days** (or such other period as the applicant **distributor** agrees with the **distributor** or **trader**) the applicant **distributor** has— (i) checked the **registry** to ensure it has sought consent from the correct **distributor** or **trader**; and (ii) made reasonable endeavours to contact the **distributor** or **trader** and obtain a response. 5B For the purposes of clause 5, the **distributor** (under paragraph (a)) or the **trader** (under paragraph (b)) must not unreasonably withhold consent to the proposed transfer.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry by removing inefficient costs from the process of converting an embedded network or network extension to a different type of secondary network. The amendment would also improve efficiency in the electricity industry by having more accurate information in the registry. The proposed Code amendment is expected to have little or no effect on competition and the reliable supply of electricity.
Assessment	The Authority is satisfied the proposed Code amendment is

against Code amendment principles	consistent with the Code amendment principles, as discussed below.
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 and benefits of the proposed Code amendment. Hence, a qualitative 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 electricity market operational costs by removing inefficiencies from the process for converting embedded networks and network extensions to other secondary network types.
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 may place a relatively small one-off incremental cost on participants. This would be to update processes and/or systems (eg, implementing software changes to ensure an NSP cannot be decommissioned if ICPs associated with it are still recorded in the registry with a status of 'Active' or 'Inactive'). We expect this cost would be relatively small because: a) the proposed amendment makes a relatively minor change to the existing process in the Code for converting secondary networks b) adding validation to the registry is not particularly difficult c) several stakeholders indicated this in their feedback on the Retail Advisory Group's consultation on secondary networks in 2015 d) some participants have indicated this in informal discussions with Authority staff. *Benefits* A key benefit of the proposed Code amendment would be to avoid a number of unnecessary (and therefore inefficient) costs associated with converting a secondary network to another type of secondary

	network: 1) Standardisation of the secondary network conversion process would enable retailers, in particular, but also local network owners, to reduce the number of processes and procedures they have to accommodate secondary network conversions. This is because the retailer / local network owner would not have to accommodate changes to the conversion process, from one conversion to the next. 2) Retailers, and possibly local network owners, would be able to reduce the number of manual workarounds of existing processes. 3) Retailers would be able to avoid costs associated with reversing system configuration changes, if a retailer withheld its consent to a secondary network conversion.[8] 4) Unnecessary delays associated with secondary network conversions, resulting in inconvenience for participants and consumers, would be removed. Another key benefit of the proposed Code amendment would be that it would ensure ICP identifiers were recorded in the registry against the correct network. This in turn would: a) promote accurate reconciliation, wholesale market settlement, and consumer invoicing b) reduce the cost for retailers to serve their customers, because correct information would be on customer invoices, which would enable call centre staff to follow appropriate processes if a customer contacted them. *Net benefit* Based on the above analysis, on balance, the Authority is satisfied the benefits of the proposed Code amendment outweigh the costs.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

8 In some instances, a delay in a retailer giving its consent may have the same effect as the retailer withholding its consent.

2019-11 Clarifying when obligations linked to clause 22 of Schedule 11.3 begin

Reference number(s)	2019-11 Clarifying when obligations linked to clause 22 of Schedule 11.3 begin.
Problem definition	Clause 22 of Schedule 11.3 sets out who the registry manager must provide written notice to, when it receives information under other clauses in Schedule 11.3. The notices provided by the registry manager relate to the process by which consumers switch traders. Upon receipt of a notice from the registry manager under clause 22 of Schedule 11.3, participants must meet various obligations within specified periods.[1] It is therefore important to determine exactly when participants receive a notice from the registry manager under this clause, for the purpose of calculating the period within which they must meet their subsequent Code obligations. It has been the Authority's intention that a participant receives a written notice from the registry manager under clause 22 of Schedule 11.3 when the registry manager makes the written notice available for the participant to collect from the registry.[2] However, the current wording of the relevant clauses makes this intent unclear. As a result, participants and the Authority are incurring unnecessary transaction costs associated with interpreting and complying with these clauses. There is also the potential for switching timeframes to be longer than intended. This can occur when there is a delay between when the registry manager makes a notice under clause 22 of Schedule 11.3 available, and when a participant's system polls the registry's SFTP service for, and downloads, the notice.
Proposal	To make it clear when a participant is considered to have received a notice from the registry manager, the Authority proposes to amend the following clauses in Part 11: a) clause 11.15AB b) clauses 3, 4, 6, 6A, 10, 12, 15, 16, 18, and 22 of Schedule 11.3. The proposed amendments to these clauses clarify that a participant's time-bound obligation begins when the registry manager makes the written notice under clause 22 of Schedule 11.3 available to the participant. We also propose making two minor drafting amendments: a) amend clause 12(3) of Schedule 11.3 to replace the word "changed" with the word "revised", which is much more commonly used in the Code b) amend clause 11.15AB to replace "day on which" with "date

[1] Refer to clause 11.15AB and clauses 3, 4, 6, 6A, 10, 12, 15, 16, and 18 of Schedule 11.3.
[2] Via the participant retrieving the files from the registry's SFTP service.

	on which" to align with the wording used in Schedule 11.3.
Proposed Code amendment	**11.15AB Switch saving protection** (1) This clause applies if a **trader** (the "protected **trader**") has switch saving protection. (2) If the protected **trader** enters into an arrangement with a customer of another **trader** (the "losing **trader**") to commence trading **electricity** with the customer, the losing **trader** must comply with subclause (4). (3) If a **trader** enters into an arrangement with a customer of a protected **trader** to commence trading **electricity** with the 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 to attempt to persuade the 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; or (b) offering an enticement to the customer. (5) The period: (a) starts on the ~~day~~ date on which the **registry manager**, under clause 22(a) of Schedule 11.3, makes ~~the **trader** receives~~ written notice of the switch request ~~under clause 22(a) of Schedule 11.3~~ available to the **trader**;~~,~~ and (b) ends on the **event date** for the switch. **Schedule 11.3 Switching** … **3 Losing trader response to standard switch request** No later than 3 **business days** after the date on which the **registry manager**, under clause 22(a), makes written ~~receiving~~ notice of a switch request ~~from the **registry manager** under clause 22(a)~~ available to the losing **trader**, the losing **trader** must,**—** (a) either— (i) acknowledge the switch request by providing the following information to the **registry manager**: (A) the proposed **event date**; and (B) a valid switch response code approved by the **Authority**; or

(ii) provide the final information specified in clause 5(a) to (c) to complete the switch; or

(b) *[Revoked]*

(c) request that the switch be withdrawn in accordance with clause 17.

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 **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**; 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 **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**.

(2) For the purpose of determining whether it complies with subclause (1)(b), the losing **trader** may disregard every **event date** it has established for an **ICP** for which, ~~when~~ on the date on which the **registry manager**, under clause 22(a), made ~~the losing **trader** received~~ written notice ~~from the **registry manager** under clause 22(a)~~ available to the losing **trader**, the losing **trader** had been responsible for less than 2 months.

…

6 Traders must use same reading

(1) The losing **trader** and the gaining **trader** must both use the same **switch event meter reading** for the **event date** as determined by the following procedure:

(a) if the **switch event meter reading** provided by the losing **trader** differs by less than 200 kWh from a value established by the gaining **trader**, the gaining **trader** must use the losing **trader's switch event meter reading**; or

(b) if the **switch event meter reading** provided by the losing **trader** differs by 200 kWh or more from a value established by the gaining **trader**, the gaining **trader** may dispute the **switch event meter reading**.

(2) Despite subclause (1), subclause (3) applies if—

(a) the losing **trader** trades **electricity** at the **ICP** through a **metering installation** with a submission type of non **half**

hour in the **registry**; and

(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 or the **embedded generator**; and

(c) a **switch event meter reading** provided by the losing **trader** under subclause (1) has not been obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**.

(3) No later than 5 **business days** after the date on which ~~receiving final information from~~ the **registry manager**, under clause 22(d), makes written notice of switch completion information ~~under clause 22(d)~~ available to the gaining **trader**,—

(a) the gaining **trader** may provide the losing **trader** with a **switch event meter reading** obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**; and

(b) the losing **trader** must use that **switch event meter reading.**

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 date on which the **registry manager**, under clause 22(d), ~~gives the gaining **trader**~~ made written notice of switch completion information ~~under clause 22(d)~~ available to the gaining **trader** ~~of having received information about the switch completion~~, provide to the losing **trader** a revised **switch event meter reading** supported by 2 **validated meter readings**.

(2) On receipt of a revised **switch event meter reading** from the gaining **trader** under subclause (1), the losing **trader** must either,—

(a) if the losing **trader** accepts the revised **switch event meter reading**, or does not respond to the gaining **trader**, use the revised **switch event meter reading**; or

(b) if the losing **trader** does not accept the revised **switch event meter reading**, advise the gaining **trader** (giving all relevant details) no later than 5 **business days** after receiving the revised **switch event meter reading**.

…

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~~ The **trader** that is recorded in the **registry** as being responsible for ~~the~~ an **ICP** that is subject to a switch request (the "losing **trader**") must, no later than 5 **business days** after the date on which the **registry manager**, under clause 22(a), makes ~~receiving the~~ written notice of the switch request available to the losing **trader**,— (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 no later than 10 **business days** after the date on which the ~~date~~ **registry manager**, under clause 22(a), made ~~the losing **trader** receives the~~ written notice of the switch request available to the losing **trader**; 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, no later than 10 **business days** after the date on which the **registry manager** made ~~receiving the~~ written notice referred to in subclause (1) available to the losing **trader**, 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**. … **12 Gaining trader may change switch event meter reading** … (2B) No later than 5 **business days** after the date on which ~~receiving final information from~~ the **registry manager**, under clause 22(d), makes written notice ~~under clause 22(d)~~ available to the losing **trader**,— (a) the gaining **trader** may provide the losing **trader** with a

switch event meter reading obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**; and

(b) the losing **trader** must use that **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 date on which the **registry manager**, under clause 22(d), ~~gives~~ made ~~the gaining **trader**~~ written notice of switch completion information ~~under clause 22(d)~~ available to the gaining trader ~~of having received information about the switch completion~~, provide to the losing **trader** a revised ~~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**.

…

15 Losing trader provides information

No later than 3 **business days** after the date on which the **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**, the losing **trader** must—

(a) provide the **registry manager** with a valid switch response code approved by the **Authority**; or

(b) request that the switch be withdrawn in accordance with clause 17.

16 Gaining trader obligations

(1) The gaining **trader** must complete the switch by advising the **registry manager** of the **event date** no later than 3 **business days** after the date on which the **registry manager**, under clause 22(c), makes written notice of ~~receiving~~ a valid switch

	response code ~~from the **registry manager** under clause 22(c)~~ available to the gaining **trader**. (2) If the **ICP** is being **electrically disconnected** or if **metering** equipment is being removed, the gaining **trader** must either— (a) give the losing **trader** or the **metering equipment provider** for the **ICP** an opportunity to **interrogate** the **metering installation** immediately before the **ICP** is **electrically disconnected** or the **metering** equipment is removed; or (b) carry out an **interrogation** and, no later than 5 **business days** after the **metering installation** is **electrically disconnected** or removed, advise the losing **trader** of— (i) the results of the **interrogation**; and (ii) the **metering component** numbers for each data channel in the **metering installation**. … **18 Withdrawing a switch request** If a **trader** requests the withdrawal of a switch under clause 17, the following provisions apply: (a) the **Authority** must determine the valid codes for withdrawing a switch request (“withdrawal advisory codes”): (b) the **Authority** must **publish** the withdrawal advisory codes: (c) for each **ICP**, the **trader** withdrawing the switch request must provide the **registry manager** with the following information: (i) the **participant identifier** of the **trader**; and (ii) the withdrawal advisory code **published** by the **Authority** in accordance with paragraph (b): (d) no later than 5 **business days** after the date on which the **registry manager**, under clause 22(b), makes written ~~receiving~~ notice ~~from the **registry manager** in accordance with clause 22(b)~~ available to the **trader** receiving the withdrawal, the **trader** must advise the **registry manager** that the switch withdrawal request is accepted or rejected. A switch withdrawal request must not become effective until accepted by the **trader** who received the withdrawal: (e) on receipt of a rejection notice from the **registry manager** in accordance with paragraph (d), a **trader** may re-submit a switch withdrawal request for an **ICP** in accordance with paragraph (c). All switch withdrawal

	requests must be resolved no later than 10 **business days** after the date of the initial switch withdrawal request: (f) if a **trader** requests that a switch request be withdrawn and the resolution of that switch withdrawal request results in the switch proceeding, no later than 2 **business days** after the date on which the **registry manager**, under clause 22(b), makes written ~~receiving~~ notice ~~from the **registry manager** in accordance with clause 22(b)~~ available to the losing **trader**, the losing **trader** must comply with clauses 3, 5, 10 and 11 (whichever is appropriate) and the gaining **trader** must comply with clause 16. **22 Registry manager notices** The **registry manager** must provide notice to **participants** required by this Schedule as follows: (a) on receipt of information about a switch request in accordance with clauses 2, 9 and 14, the **registry manager** must ~~give~~ make written notice available to the losing **trader** of the information received: (b) on receipt of information about a withdrawal request in accordance with clauses 18(c) and (d), the **registry** manager must ~~give~~ make written notice available to the other relevant **trader** of the information received: (c) on receipt of information about a switch acknowledgement in accordance with clauses 3(a) and 15, the **registry manager** must make ~~give~~ written notice available to the gaining **trader** of the information received: (d) on receipt of information about a switch completion in accordance with clauses 3(a)(ii), 5, 10 and 16, the **registry manager** must make ~~give~~ written notice available to the gaining **trader**, the losing **trader**, the **metering equipment provider**, and the relevant **distributor** of the information received.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment would improve the efficient operation of the electricity industry, by clarifying when a participant is meant to fulfil an obligation arising from a notice made available by the registry manager under clause 22 of Schedule 11.3. This would reduce the cost to participants of understanding and complying with the Code. The proposed Code amendment may promote competition, to the extent that it results in participants meeting their switching-related

	obligations in a timelier manner. The proposed Code amendment is expected to have no effect on the reliable supply of electricity.
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 problem with the Code, which requires a Code amendment to resolve.
Principle 3: Quantitative Assessment	It has not been practicable to quantify the costs and benefits of the proposed Code amendment. Hence, a qualitative 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 the cost to participants of understanding and complying with the timeframes linked to notices made available by the registry manager under clause 22 of Schedule 11.3.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* We believe the incremental cost of the proposed Code amendment would be negligible. This is because we consider participants should already be polling the registry SFTP service regularly to receive information from the registry manager, such as notifications and acknowledgements. *Benefits* The primary benefit of the proposed amendment is to clarify the Code. This reduces the time and effort spent by: a) participants understanding the Code in order to meet their Code obligations b) the Authority liaising with participants over their Code obligations c) the Authority, auditors, and participants on matters related to participants' compliance with their Code obligations. *Net benefit*

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

2019-12 Removing provision for supply shortage declarations to trigger payments under the Customer Compensation Scheme

<table>
<tr><td>Reference number(s)</td><td>2019-12 Removing provision for supply shortage declarations to trigger payments under the Customer Compensation Scheme</td></tr>
<tr><td>Problem definition</td><td>The customer compensation scheme (CCS) can be triggered by supply shortage declarations

The common understanding of the CCS is that if hydro storage levels fall sufficiently (ie an energy shortage), an official conservation campaign (OCC) is triggered, which requests consumers to save electricity.

During an OCC, retailers must pay CCS payments to consumers.

The mechanism is an incentive on retailers to manage their dry year risk through hedging to avoid unnecessary OCCs.

If the OCC was insufficient and hydro levels continued to drop to the 50% Electricity Risk Curve (ERC), rolling outages would be used (the OCC would still be active during this time).

However, CCS payments can also be triggered by another route.

Clause 9.24(1)(b) of the Code requires CCS payments to be paid during a public conservation period. Part 1 of the Code defines public conservation periods as:
“public conservation period means—
(a) any period during which an official conservation campaign is running:
(b) any period during which a supply shortage declaration is in force for 1 week or more”.

Under clause 9.14 of the Code, the system operator may make a supply shortage declaration:
• for a capacity shortage (insufficient operating capacity, eg, resulting from an outage on the transmission network)
• for an energy shortage (insufficient ‘fuel’ to generate electricity, eg, during a dry period)[1]
• on a regional or national basis.

A supply shortage may be managed with rolling outages.[2]

Therefore the CCS can be triggered by prolonged capacity shortages, even regional ones, without regard to the hydro storage situation.

This does not make sense as the CCS is not designed to incentivise against capacity events – retailers are unable to influence how or when the grid may experience significant outages.</td></tr>
<tr><td>Proposal</td><td>Official conservation campaigns should be the only trigger for</td></tr>
</table>

[1] Refer: https://www.ea.govt.nz/dmsdocument/21364-the-security-of-supply-framework-information-paper
[2] The Code, clauses 9.14 and 9.15

<table>
<tr><td></td><td>**the CCS**

To achieve this, we propose deleting the **public conservation period** defined term in Part 1, and replacing all references to ‘public conservation period’ with ‘official conservation campaign’.

We do not consider the CCS should be used to compensate for forced disconnections caused by rolling outages during prolonged capacity shortages, because the CCS minimum weekly amount is designed to compensate for OCCs.

Our initial assessment is that we also currently do not consider *any* compensation payment is needed in this circumstance. Rolling outages triggered by other causes do not have compensation arrangements, and it is a non-trivial exercise to work out what would be an appropriate methodology (this could be something looked at in future).

We have already flagged to participants that we may propose making this change.[3]</td></tr>
<tr><td>**Proposed Code amendment**</td><td>The proposed Code amendment would be:

Clause 1.1(1):

~~**public conservation period** means—~~

~~(a) any period during which an **official conservation period** is running:~~

~~(b) any period during which a **supply shortage declaration** is in force for 1 week or more~~

Part 9

9.19 Contents of this subpart

This subpart provides a framework under which each **retailer** must have a **customer compensation scheme** for all of the **retailer’s qualifying customers**, including—

(a) a **default customer compensation scheme** that a **retailer** must have; and

(b) **additional customer compensation schemes** that a **retailer** may have; and

(c) determining when an **official conservation campaign** ~~**public conservation period**~~ commences and ends, during which a **retailer** must make payments under its **customer compensation schemes**; and

(d) a process by which the **Authority** can require that a **retailer’s** compliance with this subpart is **audited**.

9.21 Qualifying customers

(1) A **retailer’s qualifying customer** is a person who, at any time during an **official conservation campaign** ~~**public**~~</td></tr>
</table>

[3] Decision paper on review of CCS, 3 October 2017 https://www.ea.govt.nz/development/work-programme/risk-management/review-of-the-customer-compensation-scheme-ccs/development/decision-paper-on-review-of-ccs/

~~**conservation period**~~,—

(a) is a customer of the **retailer**; and

(b) has a contract with the **retailer** for the supply of **electricity** in respect of an **ICP** at which—

(i) there is a **category 1 metering installation** or a **category 2 metering installation**; and

(ii) there was consumption, in the 12 months immediately before the start of the **official compensation campaign** ~~**public conservation period**~~, of 3000 kWh or more.

…

(3) For the purposes of subclause (1)(b)(ii), if a **qualifying customer's** consumption at the **ICP** in the 12 months immediately before the start of the **official conservation campaign** ~~**public conservation period**~~ is not available to the **retailer**, the **retailer** must make a reasonable estimate of the consumption.

(4) To avoid doubt, the **retailer** is not required to make payments under a **customer compensation scheme** to a **qualifying customer** at an **ICP** in respect of any period during an **official conservation period** ~~**public conservation period**~~, when—

(a) the premises to which the **ICP** is **electrically connected** are vacant; or

(b) the **ICP** is **electrically disconnected**.

9.22 Requirement to implement customer compensation schemes

(1) A **retailer** must make payments to its **qualifying customers**, in respect of **ICPs** described in clause 9.21(1)(b), under its **customer compensation schemes** during an **official conservation campaign** ~~**public conservation period**~~.

(2) Despite subclause (1), if ~~a **public conservation period** is running because~~ the **system operator** has commenced an **official conservation campaign** under clause 9.23(1), a **retailer** must make payments under its **customer compensation scheme** to its **qualifying customers** only in respect of **ICPs**, as described in clause 9.21(1)(b), in the South Island.

9.24 Requirements of default customer compensation schemes

(1) A **retailer's default customer compensation scheme** must provide for the **retailer**—

(a) during an **official conservation campaign** for the South Island, to pay each of its **qualifying customers** in the South Island at least the minimum weekly amount of compensation determined by the

Authority under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** that the **qualifying customer** is the **retailer's customer**; and

(b) at any other time during an **official conservation campaign** ~~**public conservation period**~~, to pay each of its **qualifying customers** at least the minimum weekly amount of compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** ~~**public conservation period**~~ that the **qualifying customer** is the **retailer's customer**; and

(c) to pay at least the minimum weekly amount, at a pro rata daily rate, for each day of an **official conservation campaign** ~~**public conservation period**~~ that the **qualifying customer** is the **retailer's customer**—

(i) to each of its **qualifying customers** in the South Island or New Zealand (as the case may be), for each of the **qualifying customer's ICPs** described in clause 9.21(1)(b):

(ii) no later than the end of 2 **billing periods** after the last day of an **official conservation campaign** ~~**public conservation period**~~.

9.25 Authority must determine minimum weekly amount

(1) ....

(2) The **Authority** must—

(a) **publish** the minimum weekly amount; and

(b) review the minimum weekly amount—

(i) after each **official conservation campaign** ~~**public conservation period**~~ ends; and

(ii) at least once every 3 years; and

(c) following a review under paragraph (b), ensure that it gives **participants** at least 3 months' notice if it determines a new minimum weekly amount.

9.29 Each retailer must provide certification

…

(3) A **retailer** must provide certifications as follows:

(a) within 7 months of the end of an **official conservation campaign** ~~**public conservation period**~~:

(b) ….

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 promotes the efficient and competitive operation of the electricity industry. We would not expect this amendment to have any significant impact on the reliability of the system. The efficient and competitive benefits would arise because: - CCS payments triggered by regional capacity shortages would be an unjustified, inappropriate, and inefficient penalty for retailers, as this was not a purpose the CCS was designed to incentivise against - removing a confusing term from the Code would improve certainty and clarity for participants, and hence the efficiency of their decision making.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as discussed below.
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 problem with the Code, which requires a Code amendment to resolve. The efficiency gains from this amendment are outlined under 'assessment against Authority's objectives'.
Principle 3: Quantitative Assessment	It has not been practicable to quantify the costs or benefits. Hence, a qualitative 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 proposed amendment are: - reduced potential for inefficient penalties on participants - improved clarity and reduced complexity of the Code - reduced potential for confusion for participants.
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* There are no anticipated costs of the proposed amendment. *Benefits* The benefits of the proposed amendment relate to retailers not having to pay CCS payments in the event of a supply shortage declaration being in force. As mentioned above, this would be at a

	cost to them, and create perverse incentives for their decision making. Benefits also stem from the Code being clearer, with fewer overlapping definitions, and removing the potential for surprises. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code 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 objectives of the proposed amendment.

2019-13 Broadening the definitions of Generating Unit and Intermittent Generating Station

Reference number(s)	2019-13 Broadening the definitions of Generating Unit and Intermittent Generating Station
Problem definition	The Code defines "generating unit" and "intermittent generating station" as follows: ***generating unit*** *means a machine that generates* ***electricity*** ***intermittent generating station*** *means a* ***wind generating station***. The Authority considers these definitions are inhibiting new generating technologies from participating in the electricity spot market and ancillary service markets regulated by the Code. This is contrary to the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. <u>Problem 1 – definition of 'generating unit'</u> "Generating unit" is used extensively in the Code, including: a) as an input to a large number of definitions in Part 1 b) in various obligations on generators and asset owners under Part 8 c) in certain obligations on Transpower under Part 12 d) in the offer arrangements under Part 13 e) in the settlement arrangements under Part 14 f) in the obligation on generators to provide submission information to the reconciliation manager under Part 15. The word "machine" in the definition of "generating unit" may not adequately describe types of generating plant that use sources of energy other than mechanical force to produce electricity. The problem with the definition of "generating unit" is that it creates uncertainty over Code obligations for these types of generating plant. This could reduce the likelihood of investment in these types of generating plant, meaning competitive pressure in the supply side of the electricity industry may be less than it otherwise could be. The Authority has said previously that a battery energy storage system can be treated as a generating unit for the purposes of offering energy under Part 13 of the Code.[1] However, the reference to "machine" in the definition of "generating unit" means there remains the potential for confusion or uncertainty over the Authority's interpretation. <u>Problem 2 – definition of 'intermittent generating station'</u> The Code includes offer arrangements for three generic types of

1 Electricity Authority Market Brief, May 2019, available at https://www.ea.govt.nz/dmsdocument/23484-market-brief-29-may-2018.

	generating stations: a) generating stations that use a power source that is stored or controlled b) generating stations that use variable resources that are not stored or controlled c) generating stations that rely on a co-located industrial process, or are tightly coupled to an industrial process. In relation to the second type of generating station, the Code permits an intermittent generating station to be offered and dispatched in a manner that accounts for the variability of the resource that powers the intermittent generating station. Intermittent generators receive dispatch instructions from the system operator in the same way as other generators. However, intermittent generators are permitted to generate an amount based on their available power source, subject to any system constraints applied though the dispatch process. The problem with the current definition of "intermittent generating station" is that it refers only to a wind generating station, thereby excluding generating stations powered by variable resources other than wind. Examples of these other types of variable resources include solar and wave energy. As with the definition of "generating unit", this could reduce the likelihood of investment in intermittent generation, meaning competitive pressure in the supply side of the electricity industry may be less than it could be.
Proposal	<u>Problem 1</u> To address Problem 1, the Authority proposes to amend the definition of "generating unit", so that it refers to equipment rather than to a machine. <u>Problem 2</u> To address Problem 2, the Authority proposes to amend the definition of "intermittent generating station", so that it refers to generating stations powered by variable resources that are not stored or controlled. <u>Consequential minor amendments</u> The Authority also proposes to make two minor consequential changes to the Code, to accommodate the proposed changes to the definitions of "generating unit" and "intermittent generating station": a) amending the definitions of "bona fide physical reason" and "synchronised" to be consistent with the proposed amendment to "intermittent generating station" b) amending clause 13.18A(3) to be consistent with the proposed amendment to "intermittent generating station". <u>Further amendments</u>

	The Authority is also considering other amendments to the Code to accommodate specific characteristics of new generating technologies. This work is being progressed under the *Participation of new generating technologies in the wholesale market* project.
Proposed Code amendment	**Part 1** **1.1 Interpretation** (1) … **bona fide physical reason** includes,— … (ba) in relation to an **intermittent generator**, a situation in which— (i) ~~wind~~ <u>variable resource</u> conditions prevent the **intermittent generator** from generating at the level expected; or … **generating unit** means ~~a machine that generates **electricity**~~ <u>all equipment functioning together as a single entity to produce **electricity**</u> … **intermittent generating station** means a ~~**wind**~~ **generating station** <u>that relies on the supply of a variable resource—</u> <u>(a) that is not stored; or</u> <u>(b) that is not controlled while the **generating station** is producing **electricity**</u> … **synchronised** means the condition whereby a synchronous ~~machine~~ <u>**generating unit**</u> is **electrically connected** to a **network** and the electrical angular velocity of the ~~**machine**~~ <u>**generating unit**</u> corresponds with the **network** frequency and **synchronise**, **de-synchronise**, **synchronising**, **synchronism** and **synchronisation** have corresponding meanings. Asynchronous **intermittent generating stations** must be treated as being **synchronised** for the purposes of subpart 2 of Part 8 … **Part 13** **13.18A Intermittent generators to submit revised forecast of generation potential every trading period in last 2 hours** … (3) For the purposes of this clause, a resource persistence model means a method for producing a forecast of the **intermittent generator's** generation for a **trading period**, in **MW**, that is derived from the expected availability and capability of

	generating plant forming all or part of the relevant **intermittent generating station**, on the assumption that the ~~wind (or other~~ variable resource~~)~~ conditions at the time at which the forecast is prepared will persist throughout the **trading period** to which the forecast relates. …
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 promotes the efficient operation of the electricity industry. It would do this by making it easier for participants to understand, and to comply with, their obligations. The proposed Code amendment would also promote competition and reliability. Enabling a wider range of intermittent generators to participate in the electricity spot market and ancillary service markets would. a) promote competition in the supply side of the electricity industry b) promote reliability in the electricity industry, through greater diversity of supply amongst generating stations.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, as described below.
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 would address two identified problems with the Code, which require a Code amendment to resolve.
Principle 3: Quantitative Assessment	It has not been practicable to quantify the costs and benefits of the proposed Code amendment. Hence, a qualitative 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 ensure the Code enables new generating technologies to participate in the electricity spot market and ancillary service markets.
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 would place no additional costs on industry participants. *Benefits* The main benefit of the proposed Code amendment is that it would promote competition in the supply side of the electricity industry, by enabling a wider range of generators to participate in the electricity spot market and ancillary service markets. The entry, or threat of entry, of new generators in these markets would be expected to place downward pressure on wholesale electricity prices. Under a workably competitive retail market, this downward pressure would be to the benefit of consumers. Given the value of electricity settled in the spot market each year, even a small downward pressure on wholesale electricity prices would translate into a material benefit for consumers. Another important benefit of the proposed Code amendment would be to promote reliability in the electricity industry, by enabling greater diversity of supply amongst generating stations. This reliability benefit would be reinforced, or enhanced, by having generators with new generating technologies make offers. This would provide the system operator with greater information on the generators' output, which would enable the system operator to better manage system security. A further, much smaller, benefit of the proposed amendment would be to clarify the Code. This would reduce the time and effort required for the following parties to understand the Code in order to meet their (actual/potential) Code obligations: a) participants who have invested in new generating technologies that rely on variable resources that are not stored or controlled b) persons considering investing in new generating technologies that rely on variable resources that are not stored or controlled. Similarly, improving clarity would reduce time and effort for the Authority to enforce compliance with Code obligations using the definitions proposed to be amended. *Net benefit* Based on the above analysis, the Authority is satisfied the benefits of the proposed Code 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 objectives of the proposed Code amendment.

Appendix C Technical and non-controversial proposed amendments

Technical and non-controversial – CRP 2019

	Clause	Issue	Proposed amendment
Part A – proposed amendments to individual clauses			
1.	1.1(1) definition of 'auditor'	The words in sub-paragraph (a)(ii) do not follow from the chapeau in para (a)	**auditor** means,— (a) for the purposes of Parts 10, 11, 15 and 16A,~~ a person —~~ (i) <u>a person</u> approved or appointed by the **Authority** to carry out an **audit**; or (ii) the **Authority**, if the **Authority** carries out an **audit** itself; and ….
2.	Clause 1.1(1) definitions of 'extended reserve manager', 'FTR manager', 'pricing manager' and 'reconciliation manager'	Definitions are not worded consistently Also, the definition of 'extended reserve manager' provides for the situation prior to regulations having been made to establish the role of 'extended reserve manager'. This is no longer needed, as the regulations were made in 2015 (refer Electricity Industry (Participants and Roles) Regulations 2012).	**extended reserve manager** means the **market operation service provider** ~~that is~~ for the time being appointed as ~~the~~ **extended reserve manager** under this Code~~, or if no regulations have been made establishing the **extended reserve manager** as a **market operation service provider**, the **Authority**~~ **FTR manager** means the **market operation service provider** ~~who is~~ for the time being appointed as the FTR manager under this Code **pricing manager** means the **market operation service provider** ~~who is~~ for the time being appointed as pricing manager under this **Code** **reconciliation manager** means the **market operation service provider** ~~who is~~ for the time being appointed as reconciliation manager under this Code

	Clause	Issue	Proposed amendment
3.	1.1(1) definition of ‘good electricity industry practice’	Refers to an “**asset** owner” but "asset owner" is the defined term, so "owner" should be in bold. Also, "network" is a defined term, so it should be in bold too.	**good electricity industry practice** in relation to transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would be reasonably be expected from a skilled and experience **asset** ~~owner~~ <u>**owner**</u> engaged in the management of a transmission ~~network~~ <u>**network**</u> under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission ~~network~~ <u>**network**</u> and the applicable law
4.	1.1(1) definition of ‘historical estimate’	Paragraph (a) refers to "2 **validated** actual **meter readings**", but "validated" isn't a defined term, but ‘validated meter reading’ is	(a) the difference between 2 ~~**validated**~~ actual <u>**validated** **meter readings**</u>:
5.	1.1(1) definition of ‘system operator register’	Definition includes an obligation for the system operator to maintain and publish the register but: (a) it is difficult to find this obligation here (b) it is poor drafting to include an obligation in a definition	**system operator register** means the register kept by the **system operator** for recording **equivalence arrangements**, **dispensations**, and **alternative ancillary service arrangements** in accordance with clause 8 of Schedule 8.1 and clause 4 of Schedule 8.2. ~~The **system operator** must maintain an up to date copy of the **system operator register** and **publish** it and keep it **published**~~ <u>**8.54AA System operator to maintain and publish register**</u> <u>The **system operator** must maintain an up to date copy of the **system operator register** and **publish** it and keep it **published**.</u>
6.	Clause 6.3(2)(da)	Could be read that sub-paragraphs (i) and (ii) are	(2) Each **distributor** must make publicly available, free of

	Clause	Issue	Proposed amendment
		alternatives, rather than both being required	charge, from its office and Internet site,— … (da) a list of all locations on its **distribution network** that the **distributor**— (i) knows to be subject to **export congestion**;~~ or~~ ~~(ii) expects to become subject to **export congestion** within the next 12 months;~~ and <u>(db) a list of all locations on its **distribution network** that the **distributor** expects to become subject to **export congestion** within the next 12 months; and</u> … Consequential amendment in clause 9D of Schedule 6.1: (1) This clause applies……included in the list made publicly available in accordance with clause 6.3(2)(da)<u> or (db)</u>.
7.	Clause 20 of Schedule 6.1	Heading does not accurately reflect content of the clause	**20 Distributed generator must give notice of intention to ~~proceed~~ <u>negotiate</u>**
8.	Clause 21 of Schedule 6.1	Heading does not accurately reflect content of the clause	**21 30 business days to negotiate connection contract if distributed generator gives notice of intention to ~~proceed~~ <u>negotiate</u>**
9.	Clause 1 of Schedule 6.2	Refers to 'clause 6.6 of Part 6 of this Code', but it is not necessary to mention that it is in Part 6 of this Code, because that is obvious from the clause numbering and the context	This Schedule sets out the **regulated terms** that apply to a **distributor** and a **distributed generator** in respect of **distributed generation** that is connected in accordance with clause 6.6 ~~of Part 6 of this Code~~ and Schedule 6.1.

	Clause	Issue	Proposed amendment
10.	Clause 8.25(2)	Refers to ‘connected **asset owner**’, but ‘connected asset owner’ is a defined term, so ‘connected’ should be in bold	Each **grid owner** and each ~~connected~~ **connected asset owner** must use reasonable endeavours to ensure….
11.	Clause 3 of Schedule 8.1 and clause 1(2) of Schedule 8.2	Inconsistency in drafting style across these two clauses, which should be the same	Clause 3 of Schedule 8.1: No later than 5 **business days** after receiving the application made under ~~in accordance with~~ clause 2, the **system operator** must… Clause 1(2) of Schedule 8.2: No later than 5 **business days** after receiving ~~receipt of~~ the application under subclause (1), the **system operator** must…
12.	Clause 2(1)(a) of Technical Code A, Schedule 8.3	Refers to ‘connected **asset owner**’, but ‘connected asset owner’ is a defined term, so ‘connected’ should be in bold	(a) its assets at **grid exit points** and at **grid injection points**, and, in the case of ~~connected~~ **connected asset owners**, the **assets** of any **embedded generator**…
13.	Clause 3(2) of Technical Code A of Schedule 8.3	References to ‘information’ and ‘law’ should not be in bold as they are not defined terms	(2) ~~**Information**~~ Information about an **asset**, **supply** or **demand** of other **asset owners** must only be disclosed by the **system operator**— … (c) as required by ~~**law**~~ law; or
14.	Clause 5(2) of Technical Code A of Schedule 8.3	Places the obligation to have an excitation and voltage control system on the generator instead of on the generating unit	Each **generator** must ensure that each of its ~~with a~~ **generating units** connected to the **grid** ~~must~~ is equipped with— (a) ~~have~~ an excitation and voltage control system with… (b) in order to meet the **asset owner performance obligations**, ~~ensure that each of its **generating** units is equipped with~~ either— (i) …

	Clause	Issue	Proposed amendment
15.	Clause 5(1A) of Technical Code B of Schedule 8.3	Reference to an instruction having been issued, amended, or revoked is in the passive voice, rather than being clear as to who will have done these things.	(1A) The **system operator** must issue a notice in writing to all **participants** whenever, or as soon as practicable after, under clause 6, the **system operator** has issued, amended, or revoked an **island** wide instruction to **electrically disconnect demand** ~~has been issued amended, or revoked under clause 6~~.
16.	Clause 9(c) of Technical Code B of Schedule 8.3	Very long paragraph that is difficult to read and understand	(c) when either the minimum voltage limit or the maximum voltage limit set out in the table contained in clause 8.22(1) is exceeded at any **point of connection**:~~,~~ (i) **generators** and **ancillary service agents** must use reasonable endeavours to take immediate independent action to return the voltage to, as close as practicable, within such limits~~.~~: (ii) e~~E~~ach **generator** must use reasonable endeavours to **synchronise** and, as necessary, load and adjust all available **generating units** that can assist in restoring the voltage~~.~~: (iii) **a**~~**A**~~**ncillary service agents** must ~~also~~ use reasonable endeavours to **electrically connect** to the **grid** and, as necessary, load all available **reactive capability** resources, that can assist in restoring the voltage~~.~~: (iv) a~~A~~s soon as practicable after taking the ~~such~~ actions described in subparagraphs (i) to (iii),

<table>
<tr><th></th><th>Clause</th><th>Issue</th><th>Proposed amendment</th></tr>
<tr><td></td><td></td><td></td><td>each generator and ancillary service agent must report to the system operator on the action taken to correct voltage:</td></tr>
<tr><td>17.</td><td>Clause 9(f) of Technical Code B of Schedule 8.3</td><td>Paragraph is complicated and difficult to understand</td><td>(f) in the event of a failure at the system operator's operational centre that disables the main dispatch or communication systems, the system operator may temporarily transfer its operational activities to an alternative operational centre<s>,</s> <s>and</s>. If the system operator makes such a transfer, the system operator must:
(i) arrange for communication facilities to transfer to the new location; and
(ii) <s>must</s> give written notice to participants of those arrangements.</td></tr>
<tr><td>18.</td><td>Table A2 of Appendix A of Technical Code C of Schedule 8.3</td><td>There are two rows in the table for 'Special protections scheme status' – they are identical, so only one is needed</td><td>Delete the first occurrence of the item:<table><tr><td><s>Special protection scheme status</s></td><td><s>Enabled /disabled /summer /winter</s></td><td><s>N/A</s></td></tr></table></td></tr>
<tr><td>19.</td><td>Clause 9.24(1)</td><td>Reference to 'customer' should not be in bold as it is not a defined term.</td><td>9.24 Requirements of default customer compensation schemes [1]
(1) A retailer's default customer compensation scheme must provide for the retailer—
(a) during an official conservation campaign for the South Island, to pay each of its qualifying customers in the South Island at least the minimum weekly amount of</td></tr>
</table>

[1] Note that this consultation paper includes other proposed amendments to this clause, but which are not shown here, as the two proposals are independent.

	Clause	Issue	Proposed amendment
			compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** that the **qualifying customer** is the **retailer's** ~~**customer**~~ customer; and (b) at any other time during a **public conservation period**, to pay each of its **qualifying customers** at least the minimum weekly amount of compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **public conservation period** that the **qualifying customer** is the **retailer's** ~~**customer**~~ customer; and (c) to pay at least the minimum weekly amount, at a pro rata daily rate, for each day of a **public conservation period** that the **qualifying customer** is the **retailer's** ~~**customer**~~ customer— ….
20.	Clause 10.7(3)	Reference to 'regulations' should not be in bold as it is not a defined term.	(3) A party listed in subclause (2) may only request access to the **metering installation** for the purposes of exercising the party's rights and performing the party's obligations under this Code or any relevant ~~**regulations**~~ regulations…

	Clause	Issue	Proposed amendment
21.	Clause 10.31B(2)	Cross reference to subclause (1)(b) is incorrect; it should cross-refer to subclause (1)(c).	(2) Despite subclause (1)~~(b)~~(c), the **distributor** need not advise the **traders** of the **distributor's** intention to **electrically connect** the **ICP** if—
22.	Clause 10.50(3) and (6)	References to 'regulations' in subclauses (3) and (6) should not be in bold as it is not a defined term. Also, subclause (3) is worded in the passive voice, but the active voice would be clearer.	(3) If a ~~A~~ complaint ~~may, if it~~ is not resolved under subclause (1), or by determination of the **Authority** under subclause (2), the **Authority** or a **participant** may refer the complaint ~~be referred~~ to the **Rulings Panel** in accordance with subpart 4 of Part 2 of the **Act** and the ~~**regulations**~~ regulations~~, by the **Authority** or a **participant**~~. … (6) A **participant's** obligations in this clause are subject to the **Act** and the ~~**regulations**~~ regulations.
23.	Clauses 1(5),1(7)(c)(ii), 3(2), 3(4)(b), 5(1), and 5(3)(c) of Schedule 10.6	References to 'regulations' should not be in bold as it is not a defined term.	*Clause 1(5) of Schedule 10.6* (5) A party listed in subclause (4) may only request access to the **raw meter data** for the purposes of exercising the party's rights and performing the party's obligations under this Code or any relevant ~~**regulations**~~ regulations… *Clause 1(7)(c)(ii) of Schedule 10.6* (7) The **metering equipment provider** must, when complying with subclause (6), or when providing access to a person under subclause (2), use appropriate procedures to ensure that— … (c) access to **raw meter data** under subclauses (1) to (6) is limited to only the specific **raw meter data**— … (ii) required for the purposes of exercising the party's rights and performing the

	Clause	Issue	Proposed amendment
			party's obligations under this Code, any relevant ~~**regulations**~~ regulations,… *Clause 3(2) of Schedule 10.6* (2) A party listed in subclause (1) may only request physical access to a **metering component** in the **metering installation** for the purposes of exercising the party's rights and performing the party's obligations under this Code or any relevant ~~**regulations**~~ regulations… *Clause 3(4)(b) of Schedule 10.6* (4) In complying with subclause (3), the **metering equipment provider** must use appropriate procedures to ensure that— … (b) physical access to the **metering installation** under subclause (1) is limited to only the physical access required for the purposes of exercising the party's rights and performing the party's obligations under this Code or any relevant ~~**regulations**~~ regulations… *Clause 5(1) of Schedule 10.6* (1) A **gaining metering equipment provider** may request that a **losing metering equipment provider** provide it with access to **metering records** required for the **gaining metering equipment provider** to exercise its rights and perform its obligations under this Code or any relevant ~~**regulations**~~ regulations…

	Clause	Issue	Proposed amendment
			Clause 5(3)(c) of Schedule 10.6 (3) In complying with subclause (2), the **losing metering equipment provider** must use appropriate procedures to ensure that— … (c) it only provides access to the specific **metering records** required for the purposes of the **gaining metering equipment provider** exercising its rights and performing its obligations under this Code or any relevant ~~**regulations**~~ <u>regulations</u>…
24.	Clause 11.15C(1)	Cross reference to paragraphs in clause 14.41 should specify that they are in subclause (1) of that clause.	(1) This clause applies if the **Authority** is satisfied that a **trader** has committed an **event of default** under paragraph (a) or (b) or (f) or (h) of clause 14.41<u>(1)</u>.
25.	Clause 12.84	Clause heading should not include an indefinite article	**12.84 ~~A~~ Transmission pricing methodology**
26.	Clause 12.86	Clause heading should not include a definite article	**12.86 Review by ~~the~~ Authority**
27.	Clause 12.113	Reference to ‘Transpower’ should be in bold as it is a defined term	~~Transpower~~ **<u>Transpower</u>** must design, construct, maintain and operate all **interconnection assets** in accordance with **good electricity industry practice**.
28.	Clause 12.141	Clause heading should not include a definite article	**12.141 Consideration of ~~the~~ likely effects of planned outages**
29.	Clause 13.24	Refers to clause 13.9(b), which has been revoked	Despite clause~~s 13.9(b) and~~ 13.18(1), a generator is not required to submit a revised **offer** in respect of an **automatic control plant** if— …
30.	Clause 13.39	Refers to clause 13.9(b), which has been revoked	…Accordingly, an **ancillary service agent** that is a **generator** does not breach clause~~s 13.9(b) or~~ 13.38(2)(c) if the **offer** quantity under clauses 13.6 to 13.27 and…

	Clause	Issue	Proposed amendment
31.	Clause 13.40	Reference to demand being ‘electrically connected’ should be ‘electrically disconnected’	**Bids** and **reserve offers** of **interruptible load** are inter-related in that **demand electrically ~~connected~~ disconnected** in response to an **under-frequency event** and in accordance with a dispatched **reserve offer** may lower the quantity purchased at that **grid exit point**….
32.	Clause 13.71(1)(b)	Includes a cross-reference to clause 13.19(1)(a)(iii), which has been revoked. Should now refer to clause 13.18A(1)	(b) any revised **offer** from a **generator** submitted in accordance with clause 13.19 (except for revised **offers** submitted by an **intermittent generator** under clause ~~13.19(1)(a)(iii)~~ 13.18A(1); and
33.	Clause 13.196(c)	Reference to "the less" in the definition of 'SOQcofffk' is grammatically incorrect – no article is required before "less".	(c) … SOQcofffk is the **frequency keeping** quantity advised to the **clearing manager** by the **system operator** under clauses 13.76 to 13.80 or the total quantity constrained off for the **generator**, whichever is ~~the~~ less
34.	Clause 13.215(1)	Reference to “further” information is unnecessary, because there is no other reference to any other information	(1) A **generator** or **purchaser** may, by giving written notice to the **pricing** manager, request ~~further~~ information related to— …
35.	Clause 14.4(1)(b)	Cross reference to clause 15.14 is incorrect; should refer to clause 15.13	(1) This clause— (a) applies to each **generator** that has an **embedded generating station**; but (b) does not apply to a **generator** in respect of an **embedded generating station** in relation to a **point of connection** for which a notice under clause ~~15.14~~ 15.13 is in force.

	Clause	Issue	Proposed amendment
36.	Clause 14A.22(6)	Refers to the number of 'business days' set out in subclause (4), but subclause (4) refers to periods of 'trading days', not 'business days'	(6) A **participant** that has a shorter post-default exit period approved by the **Authority** may increase the period to no more than the number of ~~**business**~~ **trading days** set out in subclause (4) by giving 20 **business days'** notice to the **clearing manager**.
37.	15.38(1)(c)(iv)	This clause requires reconciliation participants to obtain and maintain certification to create and manage dispatchable load information. However, reconciliation participants do not have this type of information (it is covered by subclause (1A)(b)(iv) for dispatchable load purchasers).	(c) creating and managing (including validating, estimating, storing, correcting and archiving)— (i) **half hour volume information**; or (ii) non **half hour volume information**; or (iii) **half hour** and non **half hour volume information**.~~; or~~ ~~(iv) **dispatchable load information**:~~
38.	Clause 8(1) of Schedule 15.2	Refers to the reconciliation participant continuously trading an ICP rather than trading "at" an ICP. Inconsistent with wording used in clause 9(1) of Schedule 15.2.	(1) Each **reconciliation participant** must ensure that, at least once every 12 months, a **validated meter reading** is obtained for every **meter** register for non **half hour** metered **ICPs** ~~that~~ at which the **reconciliation participant** trades continuously for each 12 month period…
39.	Definition of "AES_{RI}" in clause 18(1)(b) of Schedule 15.4	Reference to 'electricity supplied' should be in bold because it is a defined term. At present, only 'electricity' is in bold.	AESRi is the sum of the **electricity** ~~supplied~~ **supplied** quantities for the 12 months up to and including the month of the relevant **consumption period**
40.	Part 16A	Part 16A of the Code was added on 1 June 2017. At that time, the transitional provisions were added to Part 17 of the Code, which contains all the transitional provisions for when the Code was first brought into force. However, users of the	**Subpart 8 – Transitional provisions** **16A.27 Metering equipment provider audits** (1) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the

	Clause	Issue	Proposed amendment
		Code find it difficult to locate these Part 16A transitional provisions in Part 17. It therefore seems more helpful to move them into Part 16A of the Code, so that they are easier to locate.	**Authority** has specified a date under clause 1(1)(b) of Schedule 10.5 by which a **metering equipment provider** must ensure that an **audit** is carried out, the **metering equipment provider** must ensure that an **audit** is completed in accordance with this Part by the later of— (a) the date that the **Authority** has specified; or (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force. (2) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the **Authority** has not specified a date under clause 1(1)(b) of Schedule 10.5 by which a **metering equipment provider** must ensure that an **audit** is carried out,— (a) the **Authority** must, no later than 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, specify a date by which the **metering equipment provider** must ensure that an **audit** is carried out in accordance with this Part; and (b) the **metering equipment provider**

	Clause	Issue	Proposed amendment
			must comply with that requirement. (3) Clause 16A.17 applies to a **metering equipment provider** to which subclauses (1) or (2) apply as if the **audit** completed under those subclauses were the initial **audit** required under clause 16A.17(a). **16A.28 ATH audits** (1) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the **Authority** has specified a date under clause 1(4)(c) of Schedule 10.3 by which an **ATH** must ensure that an **audit** is carried out, the **ATH** must ensure that an **audit** is completed in accordance with this Part by the later of— (a) the date that the **Authority** has specified; or (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force. (2) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the **Authority** has not specified a date under clause 1(4)(c) of Schedule 10.3 by which an **ATH** must ensure that an **audit** is carried out,— (a) the **Authority** must, no later than 1 month after the date that the Electricity Industry

	Clause	Issue	Proposed amendment
			Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, specify a date by which the **ATH** must ensure that an **audit** is carried out in accordance with this Part; and (b) the **ATH** must comply with that requirement. (3) Clause 16A.19 applies to an **ATH** to which subclauses (1) or (2) apply as if the **audit** completed under those subclauses were the initial **audit** required under clause 16A.19(a). **16A.29 Distributor audits** (1) If, immediately before the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, a **distributor** was required to arrange for an **audit** to be completed by a date determined in accordance with clause 11.10(1)(b), the **distributor** must ensure that an **audit** is completed in accordance with this Part by the later of— (a) the date determined in accordance with clause 11.10(1)(b); or (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force. (2) Clause 16A.22 applies to a **distributor** to which subclause (1) applies as if the **audit** completed under that subclause were the initial

	Clause	Issue	Proposed amendment
			audit required under clause 16A.22(a). **16A.30 Reconciliation participant audits** (1) If, immediately before the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, a **reconciliation participant** was required to provide a final **audit** report to the **Authority** by a date determined in accordance with clause 11(1) of Schedule 15.1, the **reconciliation participant** must ensure that an **audit** is completed in accordance with this Part by the later of— (a) the date determined in accordance with clause 11(1) of Schedule 15.1; or (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force. (2) Clause 16A.24 applies to a **reconciliation participant** to which subclause (1) applies as if the **audit** completed under that subclause were the initial **audit** required under clause 16A.24(a). **16A.31 Dispatchable load purchaser audits** (1) If, immediately before the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, a **dispatchable load purchaser** was required to provide a final **audit** report to the **Authority** by a date

	Clause	Issue	Proposed amendment
			determined in accordance with clause 11(1) of Schedule 15.1, the **dispatchable load purchaser** must ensure that an **audit** is completed in accordance with this Part by the later of— (a) the date determined in accordance with clause 11(1) of Schedule 15.1; or (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force. (2) Clause 16A.25 applies to a **dispatchable load purchaser** to which subclause (1) applies as if the **audit** completed under that subclause were the initial **audit** required under clause 16A.25(a). **16A.32 Distributed unmetered load audits** (1) A **retailer** that is responsible for **distributed unmetered load** on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force must ensure that an **audit** is completed in accordance with this Part no later than 12 months after that date. (2) Clause 16A.26(1) applies to a **retailer** to which subclause (1) applies as if the **audit** completed under that subclause were the initial **audit** required under clause 16A.26(1)(a).

	Clause	Issue	Proposed amendment
41.	Clause 17.38(2)	Reference to clause 8.55(b) is no longer correct as a result of having added new subclause (2).	(2) Actual administrative costs approved by the Commission under rule 11.1.2 of section IV of part C of the **rules** and in force immediately before this Code came into force, are deemed to be actual **administrative costs** under clause ~~8.55(b)~~8.55(1)(b).
42.	Clause 17.75	Clause heading includes "the", but headings shouldn't include articles.	**17.73 Access to ~~the~~ registry**
43.	Clause 17.151(1)	Reference to clause 3.62 of section III of part G of the rules is incorrect, because there is no such clause. Should refer to clause 3.6.2. Also, the reference to "system operator' should be in bold as it is a defined term.	(1) A notification provided to the ~~system operator~~ **system operator** under rules 3.6 to ~~3.62~~ 3.6.2 of section III of part G of the **rules** immediately before this Code came into force…
44.	Clause 17.154	References to clauses 3.91 and 3.92 are incorrect, because there are no such clauses. Should refer to clauses 3.9.1 and 3.9.2.	A notification of a dispatch made in accordance with rules ~~3.91 and 3.92~~3.9.1 and 3.9.2 of section III of part G of the **rules** that was in force immediately before this Code came into force…
Part B – proposed amendments that relate to more than one Part of the Code			
45.	Parts 1, 12, and 13	The term 'losses' is defined, so should be in bold in each place it occurs throughout the Code. However, some instances are not in bold.	*Clause 1.1(1) definition of 'compensation factor':* **compensation factor** means 1 of the following factors used to compensate for errors, ~~losses~~ **losses**, or ratios within a **metering installation**, to produce accurate **volume information**: … *Clause 1.1(1) definition of 'contract price':* **contract price** means, in respect of a **risk management contract**, a single price that has, in accordance with clause 13.220, been calculated time weighted, adjusted to a location factor for the relevant **grid zone area**, and corrected for ~~losses~~ **losses**, for the purposes of subpart

	Clause	Issue	Proposed amendment
			5 of Part 13 *Clause 1.1(1) definition of 'generating unit net':* **generating unit net** means the output of a **generating unit** measured or calculated at its **point of connection**, but does not include **generating unit load** or any other active or **reactive power** supplied (including ~~losses~~ **losses**) between the **generating unit** and the **point of connection** *Clause 1.1(1) definition of 'station net':* **station net** means the sum of all **generating unit net** outputs for **generating units** at a single **generating station**, measured or calculated at its **point of connection**, but excludes **generating unit load** and any other active or **reactive power** (including ~~losses~~ **losses**) supplied between the **generating station** and the **point of connection** *Clause 13.33(c):* (c) a change to loss characteristics, including loss functions, for any transmission line of the transmission system or of the **HVDC link**, or for any transformer, represented in the algorithms described in Schedule 13.3 that causes any ~~losses~~ **losses** or marginal ~~losses~~ **losses** to change by 5% or more; or *Clause 7(g)(i) and (iii) of Schedule 13.3:* (i) the AC transmission system configuration, capacity and ~~losses~~ **losses**; and (ii) … (iii) transformer configuration, capacity and ~~losses~~ **losses**; and

	Clause	Issue	Proposed amendment
			Clause 15(d)(i) and (iii) of Schedule 13.3: (i) the AC transmission system configuration, capacity and ~~losses~~ **<u>losses</u>**; and (ii) … (iii) transformer configuration, capacity and ~~losses~~ **<u>losses</u>**; and
46.	Parts 1 and 10	The certification of interim certified metering installations has now expired. However, there are still many metering installations that were previously 'interim certified', but which are still being used despite their certification having expired. As a result of there still being some such metering installations in use, we can only revoke some of the references to interim certified metering installations. Also, in the definition of 'fully certified metering installation', the terms 'metering installation', 'certified', and interim certified metering installation' should be in bold as they are defined terms.	*Clause 1.1(1)* **fully certified metering installation** means a ~~certified~~ <u>**metering installation** that has been **certified**</u> ~~metering installation~~ other than an ~~interim certified metering installation~~ **<u>interim certified metering installation</u>** *Clause 19(5), (6), & (7) of Schedule 10.7* ~~(5) If a **metering component** that must be **certified** under this Part and which is in an **interim certified metering installation** is modified, or replaced with a **metering component** that is not **certified** under Schedule 10.8, the **interim certified metering installation's certification** is not cancelled.~~ ~~(6) Despite subclause (5), if an **ATH** modifies an **interim certified metering installation** by replacing a **metering component** that must be **certified** under this Part with an equivalent **certified metering component**, the **interim certified metering installation's certification** is not cancelled.~~ ~~(7) A replacement **metering component** under subclauses (5) and (6) must comply with this Code.~~ *Clause 44(4) of Schedule 10.7*

	Clause	Issue	Proposed amendment
			(4) If an **ATH** has not performed an inspection of a **metering installation**~~, other than an **interim certified metering installation**,~~ within the specified timeframe under clause 45(1) or 46(1), the **certification** of the **metering installation** is automatically cancelled on the date by which the **metering installation** was required to have been inspected. *Clause 28(1) of Schedule 15.5* (1) Statistical samples must be drawn using the methodology described in Appendix 2. Sampling information must be taken from **fully certified metering installations**. ~~An **interim certified metering installation** must not be used for this purpose.~~
47.	Parts 1, 11, 12, and 13	In theory, all references to 'transfer' in the Code should be in bold as it is a defined term. And all references to 'transfer should therefore have the defined meaning. However, in most places, the definition in Part 1 shouldn't apply, as the definition is too narrow. In addition, some clauses in Part 11 then define transfer to have another meaning, but there is no need to define the term, as the meaning would be clear without the definition. Also, clause 13.115 then defines the term "transferring generator" and	*Clauses 1.1(1)* ~~**transfer** means transfer, sell, assign or otherwise dispose of an ownership interest~~ *Clause 11.8(1)(b)* (b) a **distributor** wishes to change the record in the **registry** of an **ICP** that is not recorded as being usually connected to an **NSP** in the **distributor's network**, so that the **ICP** is recorded as being usually connected to an **NSP** in the **distributor's network** ~~(a "transfer")~~. *Clause 25(2) & (4) of Schedule 11.1* (2) If a **distributor** wishes to change the record in the **registry** of an **ICP** that is not

	Clause	Issue	Proposed amendment
		uses the term in bold, when items in bold should only be those that are defined in Part 1, not terms defined within a clause for a limited application.	recorded as being usually connected to an **NSP** in the **distributor's network**, <u>to transfer the **ICP** so that</u> <u>it</u> ~~the **ICP**~~ is recorded as being usually connected to an **NSP** in the **distributor's network** ~~(a "transfer")~~, the **distributor** must give written notice to the **reconciliation manager**, the Authority, and each affected **reconciliation participant** of the transfer. (4) A **distributor** who is required to give written notice of a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2. *Clause 1 of Schedule 11.2* 1 This Schedule applies if a **distributor** (the applicant **distributor**) wishes to change the record in the **registry** of an **ICP** that is not recorded as being usually connected to an **NSP** in the **distributor's network**, <u>to transfer the **ICP**</u> so that <u>it</u> ~~the **ICP**~~ is recorded as being usually connected to an **NSP** in the applicant **distributor's network** ~~(a "transfer")~~. *Clause 12.107(4)(c)* (c) the ~~**transfer**~~ <u>transfer</u> capacity in the North and South Island transfer for each **configuration** of the **HVDC link** expressed as follows: … *Clause 13.115* (1) A **generator** who has acquired **auction rights** at an **auction** (the "~~**transferring generator**~~ <u>transferring generator</u>") may ~~**transfer**~~ <u>transfer</u> all or some of those rights to another **generator**.

	Clause	Issue	Proposed amendment
			(2) The **generator** who acquires the rights by ~~**transfer**~~ <u>transfer</u> takes them on the same terms that apply to the ~~**transferring generator**~~ <u>transferring generator</u>. <u>(3) A **generator** may transfer its rights by transferring, selling, assigning, or otherwise disposing of its ownership interest.</u>
Part C – proposed revocations of transitional provisions in Part 17			
48.	Clause 17.3	These clauses were all required for the transition from the previous legislation (including the Electricity Governance Rules 2003) to the Electricity Industry Participation Code 2010. However, they have now served their purpose, so can be revoked.	
49.	Clause 17.4		
50.	Clause 17.6		
51.	Clause 17.8		
52.	Clause 17.9		
53.	Clause 17.10		
54.	Clause 17.11		
55.	Clause 17.12		
56.	Clause 17.13		
57.	Clause 17.16(2)		
58.	Clause 17.17(1) and (3)		
59.	Clause 17.20		
60.	Clause 17.22		
61.	Clause 17.23		
62.	Clause 17.24		
63.	Clause 17.25		
64.	Clause 17.26		
65.	Clause 17.27		
66.	Clause 17.28		
67.	Clause 17.30		
68.	Clause 17.31		
69.	Clause 17.32(2)		

	Clause	Issue	Proposed amendment
70.	Clause 17.33		
71.	Clause 17.34 (3), (4), and (6)		
72.	Clause 17.36		
73.	Clause 17.37		
74.	Clause 17.38(1), (3), (4), (5), (6), (7), (8), (9), (10), (11), (12), (13), and (14)		
75.	Clause 17.39		
76.	Clause 17.41		
77.	Clause 17.42		
78.	Clause 17.43		
79.	Clause 17.47(1)		
80.	Clause 17.48		
81.	Clause 17.49		
82.	Clause 17.50(2), (3), (4), (5), (6), (7), (8), (9), (10), and (11)		
83.	Clause 17.51		
84.	Clause 17.52		
85.	Clause 17.53		
86.	Clause 17.54		
87.	Clause 17.55		
88.	Clause 17.56		
89.	Clause 17.57		
90.	Clause 17.58(1), (2), (3), and (5)		
91.	Clause 17.59(2)		
92.	Clause 17.60		
93.	Clause 17.64		
94.	Clause 17.67		
95.	Clause 17.68		
96.	Clause 17.70		
97.	Clause 17.71		

	Clause	Issue	Proposed amendment
98.	Clause 17.72		
99.	Clause 17.73		
100.	Clause 17.74		
101.	Clause 17.75(1) and (3)		
102.	Clause 17.76		
103.	Clause 17.77		
104.	Clause 17.81		
105.	Clause 17.82(2), (3) and (4)		
106.	Clause 17.87		
107.	Clause 17.88		
108.	Clause 17.89		
109.	Clause 17.92		
110.	Clause 17.93		
111.	Clause 17.94		
112.	Clause 17.95		
113.	Clause 17.96		
114.	Clause 17.97(2), (3), (4), (5), and (6)		
115.	Clause 17.98		
116.	Clause 17.99		
117.	Clause 17.100		
118.	Clause 17.101		
119.	Clause 17.101A		
120.	Clause 17.102		
121.	Clause 17.103		
122.	Clause 17.104		
123.	Clause 17.105		
124.	Clause 17.106		
125.	Clause 17.107		
126.	Clause 17.111(1) and (2)		
127.	Clause 17.112		

	Clause	Issue	Proposed amendment
128.	Clause 17.113		
129.	Clause 17.114		
130.	Clause 17.115		
131.	Clause 17.116		
132.	Clause 17.117		
133.	Clause 17.119		
134.	Clause 17.120		
135.	Clause 17.121		
136.	Clause 17.122		
137.	Clause 17.123		
138.	Clause 17.124		
139.	Clause 17.125		
140.	Clause 17.126		
141.	Clause 17.127		
142.	Clause 17.128		
143.	Clause 17.129(1) and (3)		
144.	Clause 17.129A[2]		
145.	Clause 17.130		
146.	Clause 17.131		
147.	Clause 17.132		
148.	Clause 17.133		
149.	Clause 17.134		
150.	Clause 17.136		
151.	Clause 17.139		
152.	Clause 17.141(1)		
153.	Clause 17.142		
154.	Clause 17.144		
155.	Clause 17.145		
156.	Clause 17.146		
157.	Clause 17.147		

[2] Obligation to be moved into Part 13 of the Code.

	Clause	Issue	Proposed amendment
158.	Clause 17.148		
159.	Clause 17.149		
160.	Clause 17.150		
161.	Clause 17.156		
162.	Clause 17.157		
163.	Clause 17.158		
164.	Clause 17.159		
165.	Clause 17.160		
166.	Clause 17.161		
167.	Clause 17.162		
168.	Clause 17.163		
169.	Clause 17.165		
170.	Clause 17.166		
171.	Clause 17.167		
172.	Clause 17.168		
173.	Clause 17.169(2)		
174.	Clause 17.170		
175.	Clause 17.171		
176.	Clause 17.172		
177.	Clause 17.173		
178.	Clause 17.174		
179.	Clause 17.175		
180.	Clause 17.176		
181.	Clause 17.177		
182.	Clause 17.178		
183.	Clause 17.179		
184.	Clause 17.180		
185.	Clause 17.181		
186.	Clause 17.182		
187.	Clause 17.183		
188.	Clause 17.185		
189.	Clause 17.186		
190.	Clause 17.187		
191.	Clause 17.188		

	Clause	Issue	Proposed amendment
192.	Clause 17.189		
193.	Clause 17.190		
194.	Clause 17.196(4) and (5)		
195.	Clause 17.197		
196.	Clause 17.198		
197.	Clause 17.199		
198.	Clause 17.200		
199.	Clause 17.201		
200.	Clause 17.202		
201.	Clause 17.203		
202.	Clause 17.204		
203.	Clause 17.206		
204.	Clause 17.207		
205.	Clause 17.208		
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207.	Clause 17.210		
208.	Clause 17.211		
209.	Clause 17.212		
210.	Clause 17.213		
211.	Clause 17.214		
212.	Clause 17.215		
213.	Clause 17.216		
214.	Clause 17.217		
215.	Clause 17.218		
216.	Clause 17.219		
217.	Clause 17.220		
218.	Clause 17.222(1), (3) and (4)		
219.	Clause 17.223		
220.	Clause 17.224		
221.	Clause 17.225		
222.	Clause 17.226		
223.	Clause 17.227		

	Clause	Issue	Proposed amendment
224.	Clause 17.228		
225.	Clause 17.229		
226.	Clause 17.230		
227.	Clause 17.231		
228.	Clause 17.232		
229.	Clause 17.233		
230.	Clause 17.234		
231.	Clause 17.235		
232.	Clause 17.236		
233.	Clause 17.237		
234.	Clause 17.238		
235.	Clause 17.239		
236.	Clause 17.240		
237.	Clause 17.241		
238.	Clause 17.242(2)		
239.	Clause 17.243		
240.	Clause 17.244		
241.	Clause 17.245		
242.	Clause 17.246		
243.	Clause 17.247		
244.	Clause 17.248		
245.	Clause 17.249		
246.	Clause 17.250		
247.	Clause 17.251		
248.	Clause 17.252		
249.	Clause 17.253		
250.	Clause 17.254		
251.	Clause 17.255		
252.	Clause 17.256		
253.	Clause 17.257		
254.	Clause 17.258		
255.	Clause 17.259		
256.	Clause 17.260		
257.	Clause 17.261		

	Clause	Issue	Proposed amendment
258.	Clause 17.262(1)		
259.	Clause 17.265(1)		
260.	Clause 17.266		
261.	Clause 17.267		
262.	Clause 17.270(1)		
263.	Clause 17.272		
264.	Clause 17.275		
265.	Clause 17.276		
266.	Clause 17.277		
267.	Clause 17.278		
268.	Clause 17.279		
269.	Clause 17.280(1)		
270.	Clause 17.284		
271.	Clause 17.285(2)		
272.	Clause 17.286(1), (2), and (4)		
273.	Clause 17.287(1), (2), (3), (5), (6), (10), (11), and (12)		
274.	Clause 17.289		
275.	Clause 17.290		
276.	Clause 17.291		
277.	Clause 17.295A	Shifted to become clause 16A.27	
278.	Clause 17.295B	Shifted to become clause 16A.28	
279.	Clause 17.295C	Shifted to become clause 16A.29	
280.	Clause 17.295D	Shifted to become clause 16A.30	
281.	Clause 17.295E	Shifted to become clause 16A.31	

	Clause	Issue	Proposed amendment
282.	Clause 17.295F	Shifted to become clause 16A.32	
283.	Clause 17.296		