Code Review Programme number 5

Consultation Paper

Published on: 29 August 2023

Submission Close: 10 October 2023

Contents

1. What this consultation is about

1.1. This consultation paper presents the Electricity Authority's (Authority) latest set of 'omnibus' proposed changes to the Electricity Industry Participation Code 2010 (Code): the Code Review Programme number 5. The purpose of this paper is to consult with interested parties on the proposed changes.

1.2. Ordinarily, Code change proposals have a single theme and give effect to new policy or market settings, or significant changes in policy settings. In contrast, the Code Review Programme enables the Authority to make a number of relatively small amendments, with different themes, all at once. This allows us to use our resources efficiently and has the benefit of incorporating improvements in the Code that might not otherwise occur.

1.3. The 23 Code amendment proposals in the consultation paper cover a broad range of topics that seek to:

(a) update and clarify different definitions in the Act

(b) address gaps in various Code provisions

(c) reduce unnecessary delay in Code provisions becoming effective

(d) clarify obligations on participants

(e) update the Code to respond to developing technology and changing operational practices.

1.4. Consistent with the Authority's statutory objectives, the primary aim of these proposed changes is to promote the efficient operation of the electricity industry for the long-term benefit of consumers.

1.5. Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) of the Act provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. More detail about the regulatory statements is set out in section 3 of this paper.

1.6. For each discrete proposal, the regulatory statement is included in the relevant table for the proposed amendment in Appendix A.

1.7. The Authority also proposes to make a number of minor corrections to the Code. These are included in Appendix C of this paper. These changes are considered technical and non-controversial under section 39(3)(a) of the Act. Although the Authority is not required to consult on technical and non-controversial changes, it invites comment on all proposals in the Code Review Programme number 5.

How to make a submission - Online submissions available for this consultation

1.8. The Authority's preference is to receive submissions using its online system – Information Provision Platform – Electricity Authority Information Provision Platform (https://info.ea.govt.nz/)

1.9. The Information Provision platform allows you to build your submissions in draft form and to follow your internal approval process before submitting the final version. Once you have submitted the final version, the Information Provision platform will email a copy of your submission to you as confirmation of receipt.

1.10. If you cannot send your submission via the Information Provision platform, please post a copy of your submission to Electricity Authority CRP#5 Consultation, PO Box 10041, Wellington 6143. We will acknowledge receipt of posted submissions using email or text message if you supply contact details.

1.11. Please note the Authority intends to publish all submissions received. If you consider the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

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

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

1.12. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.13. However, please note that all submissions received by the Authority, including any parts the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material you said requested not be published.

When to make a submission

1.14. Please deliver your submission by 5pm on Tuesday 10 October 2023

1.15. The Information Provision system will send you an acknowledgement and copy of your submission electronically. Please check your “junk items” folder as some email systems may automatically tag this response. Please contact the Authority at info@ea.govt.nz or 04 460 8860 if you do not receive this acknowledgement within one business day.

2. Code Review Programme number 5

2.1. The 23 Code change proposals in this Code Review Programme number 5 are set out in Appendix A. Each proposal has a unique proposal number (in its top row) for ease of reference. The Authority has described and assessed each proposal separately, since each proposal is discrete from the others. This means the format of this consultation paper is different from the consultation papers the Authority usually publishes.

2.2. For each proposal in Appendix A, there is a problem definition, a proposed solution (including proposed Code drafting), and an assessment against the Authority's statutory objectives (section 15 of the Act), the Code content requirements (section 32(1) of the Act), and the Authority's Code amendment principles. Each proposal in Appendix A also contains a regulatory statement that includes:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the costs and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

2.3. Because each proposal stands on its own, after submissions have been assessed, some proposals may proceed unchanged, some may proceed with changes, and others may not proceed. Showing the draft changes separately allows submitters to assess how each proposed amendment would affect Code obligations.

Table 1: List of proposed amendments in Appendix A

Reference number	Topic	Page
CRP5-001	Definitions of business day and national holiday	8
CRP5-002	Automatic removal of a profile that fails an audit	12
CRP5-003	Statistical recertification validity period for electronic meters	15
CRP5-004	Clearing manager divergence report	19

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 in Appendix A, the regulatory statement is included in the relevant table for the proposed amendment.

3.2. The primary economic benefit described in the regulatory statements is a reduction in transaction costs across the electricity industry, which is a productive efficiency benefit. Having said this, some of the proposals explicitly promote the competition and reliability limbs of the Authority’s main objective and/or the Authority’s additional objective. In addition, by improving the clarity and operation of the Code, the proposed amendments could also deliver dynamic efficiency benefits. Lastly, the Authority notes that 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]

[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

4. Technical and Non-Controversial Code amendments

4.1. This Code Review Programme number 5 also includes a standalone proposal to correct minor typographical and other errors in the Code. These errors include outdated cross-references, incorrect headings, incorrectly bolded terms, and other minor drafting errors. These amendments are considered technical and non-controversial 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.

4.2. 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 5.

5. Submission questions

Code amendment proposals

5.1. For each proposal, we are asking the same questions. Please complete a new submission form for each proposal you wish to comment on.

5.2. Please select the proposal number at the top of each submission form. A printable copy of the form is in Appendix B if you are unable to use the Information Provision platform.

5.3. The questions are:

Q1. Do you agree the issue(s) identified by the Authority need attention? Any comments?
Q2. Do you agree with the objectives of the proposed amendment? Any comments?
Q3. Do you agree the benefits of the proposed amendment outweigh its costs? Any comments?
Q4. Do you agree the proposed amendment is preferable to any other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.
Q5. Do you have any comments on the drafting of the proposed amendment?
Q6. Do you have any further comments on the proposal?
Q7. Is any part of your submission confidential? If yes, please explain which part, why it is confidential and provide a publishable replacement (refer paragraphs 1.9 to 1.11 of the consultation paper)

Technical and non-controversial amendments

5.4. Only complete this section if you have feedback on the technical and non-controversial amendments. Please insert the row number at the top of each submission form.

Q1. Do you agree the issue identified by the Authority is technical and non-controversial? Any comments?
Q2. Do you have any feedback on the issue identified?
Q3. Is any part of your submission confidential? If yes, please explain which part, why it is confidential and provide a publishable replacement (refer paragraphs 1.9 to 1.11 of the consultation paper)

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.

6. Attachments

6.1. The following appendices are attached to this paper.

(a) Appendix A Proposed amendments

(b) Appendix B Format for submissions

(c) Appendix C Technical and non-controversial amendments

Appendix A Proposed amendments

CRP5-001 Definitions of business day and national holiday

Reference number(s)	CRP5-001 Definitions of business day and national holiday
Problem definition	There are three problems with the definitions of "business day" and "national holiday" in Clause 1.1 of Part 1 of the Code. <u>Problem 1</u> The definition of "national holiday" is out of date because it does not reflect the 2022 amendment to the Holidays Act 2003 to include, as a public holiday, the day on which a public holiday is observed to acknowledge Matariki (Te Rā Aro ki a Matariki/Matariki Observance Day). This means the definition of "national holiday" in the Code does not include all national public holidays under the Holidays Act 2003. To address this problem, to date the Authority has had to process and publish a declaration of non-business day for the purposes of the Code pursuant to the process set out in paragraph (b) of the definition of "business day". <u>Problem 2</u> The definition of "national holiday" is out of date because it includes "Queen's Birthday". Following the death of Queen Elizabeth II and the ascention of King Charles III, this holiday is now known as King's Birthday. <u>Problem 3</u> Wellington Anniversary Day is not excluded from the definition of "business day" in the Code. However, it has been delcared a non-business day each year. The reasons for this are the Authority and the clearing and reconcilation managers are based in Wellington, as are the banks used by the clearing manager. Without a non-business day declaration, staff would be required to work on Wellington Anniversary Day to ensure Code-required deadlines are able to be met. The non-business day declaration process involves the application of the Authority's internal resources each year to process and publish these declarations. These costs could be avoided if the definition of business day in the Code is amended to exclude Wellington Anniversary Day.
Proposal	<u>Problem 1</u> Amend the definition of "national holiday" in clause 1.1 of Part 1 to include Te Rā Aro ki a Matariki/Matariki Observance Day. <u>Problem 2</u> Amend the definition of "national holiday" in clause 1.1 of Part 1 to replace the words "Queen's Birthday" with the wording used in the Public Holidays Act of "the birthday of the reigning Sovereign (observed on the first Monday in June)".

	Problem 3 Amend the definition of "business day" in clause 1.1 of Part 1 to exclude Wellington Anniversary Day.
Proposed Code amendment	**1.1 Interpretation** (1) In this Code, unless the context otherwise requires,— … **business day** means,— (a) for the purposes of Part 6, any day of the week other than Saturday, Sunday, or a public holiday within the meaning of the Holidays Act 2003; and (b) for the rest of the Code, any day of the week except Saturdays, Sundays, **national holidays**, the day observed as Wellington Anniversary Day, and any other day from time to time declared by the **Authority** not to be a **business day** by notice to each **registered participant** … **national holiday** means any day on which any of the following are observed as a statutory holiday: (a) Good Friday: (b) Easter Monday: (c) ANZAC Day: (d) the birthday of the reigning Sovereign (observed on the first Monday in June) ~~Queens Birthday~~: (da) Te Rā Aro ki a Matariki/Matariki Observance Day: (e) Labour Day: (f) Christmas Day: (g) Boxing Day: (h) New Year's Day: (i) the day after New Year's Day: (j) Waitangi Day
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and sections 32(1)(c) and 32(1)(e) of the Act, because it would contribute to the efficient operation of the electricity industry and the performance by the Authority of its functions. The proposed amendment would improve the efficient operation of the electricity industry, and the performance by the Authority of its functions, by reducing the Authority's internal resources needed each year to process and publish declarations of non-business days, provide certainty to the industry about the treatment of Wellington Anniversary Day and Matariki, and reduce industry costs of processing declarations. Further, if for some reason the declarations weren't published, those days would be treated as ordinary working days, which could create a number of problems.

	The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 electricity market operational costs by: a) reducing the Authority's internal resource to create, review and publish non-business day declarations each year b) improving certainty for participants and reducing the participant's need to identify and process the declarations each year c) avoiding the costs that could be created if Matariki and/or Wellington Anniversary Day were treated as business days, if a declaration were not made.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a postitive net benefit, for the reasons set out below. *Costs* The Authority considers there are zero or negligible costs to participants from this Code amendment. *Benefits* We expect the proposed Code amendment's main benefit will be to release several hours (full time equivalent) of the Authority's staff time. This will support the efficient operation of the electricity industry by enabling this time to be put to higher priority work. It will also provide greater certainty for participants as it will confirm the Authority's approach to the treatment of business days for the

	purposes of the Code. There will be a small costs saving for particpants in not having to process declarations. Finally, it will avoid the costs that could be created if for some reason non-business declarations were not made.
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.

CRP5-002 Automatic removal of profiles failing audit

Reference number(s)	CRP5-002 Automatic removal of profiles failing audit
Problem definition	A profile is defined in the Code as a "fixed or variable electricity consumption pattern asigned to a particuar group of meter registers or unmetered loads", and are used to convert monthly consumpotion totals into half-hour volumes for the reconcilation process. The Code requires all profiles to be approved and published by the Authority. Profiles are audited every two years and many profiles fail the audit due to minor issues with their application. In most cases, minor issues have little market impact and the reconcilation participants agree corrective actions. Clause 37(1) of Schedule 15.5 of the Code, however, requires the Authority to immediately remove *any* profile that fails an audit from the list of approved profiles. This can have a significant impact on reconciliation participants out of proportion to the impact of the minor issues identified by the audit. The reconcilation participant may have already completed the corrective action or be in the process of completing the action. Additionally, some profile owners permit their profiles to be used by other reconcilation participants. If a profile is removed, there is an impact on these other reconcilation participants even though they may be fully compliant.
Proposal	Amend the Code to provide for profiles which fail an audit to remain on the list of approved profiles if the reconcilation participant, auditor and Authority agree to corrective action and that corrective action is completed within a reasonable time. Any corrections to the resulting reconcilation volumes will be washed up by the reconcilation manager in the three-month washup cycle.
Proposed Code amendment	Schedule 15.5 … **37 Removal of profiles** (1) If ~~The **Authority** must immediately remove~~ a **profile** ~~that~~ fails an **audit**, the **Authority** must remove the **profile** from the list of approved **profiles** held by the **Authority** unless: (a) either: (i) in the case of an **audit** performed by the **Authority**, the **participant** and the **Authority** agree corrective actions no later than 5 **business days** after the date the **audit** is completed; or (ii) in the case of an **audit** performed by the **Authority's** appointed **audit** agent, the **participant**, the **Authority** and the **audit** agent agree corrective actions no later than 5 **business days** after the date the **audit** is submitted to the **Authority**; and (b) the **Authority** is satisfied that the agreed corrective actions have been performed no later than 3 months after the date the **audit** was completed.

	(1A) Despite subclause (1), the **Authority** must immediately remove a **profile** that fails an **audit** if the **participant** advises the **Authority** that the **participant** will not agree to or perform the corrective actions. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The use of profiles improves the accuracy of the reconciliation process. The proposed amendment would improve the efficient operation of the electricity industry by allowing participants time to correct minor issues with the application of audit profiles and continue to use the profiles while doing so. Any inaccuracies that are introduced during this period can be corrected in the next available reconciliation washup. If the parties cannot agree, then the washup process can be used to correct non-compliant reconciliation submissions, including any introduced during the time after the audit was completed. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions
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 objectives 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 electricity market operational costs by reducing the resource needed to remove a profile when this is not necessary, and participants costs for updating the electricity registry and their reconciliation processes to use another approved profile

Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendement would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers there are zero or negligible costs to participants from this Code amendment. There will be negligible costs to the Authority from this Code amendment. Any costs associated with agreeing corrective action with participants and monitoring performance are likely to be lower than the current costs associated with managing the process around failed audits. *Benefits* We expect the proposed Code amendement's main benefit will be reduce participants' and the Authority's time to manage the process around failed audits.
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.

CRP5-003 Statistical recertification validity period for electronic meters

Reference number(s)	CRP5-003 Statistical recertification validity period for electronic meters
Problem definition	Problem 1 As the industry has evolved, category 1 metering installations class 2.0 electromechanical (Ferraris disc) meters are no longer common, and the vast majority of meters used are electronic (static) class 1.0 meters, which are inherently more accurate than class 2.0 meters. When initially certifying a category 1 metering installation the maximum validity period is 15 years regardless of the meter type or class installed. Clause 16 of Schedule 10.7 of the Code provides for recertification of category 1 metering installations by statistical sampling. When determining the certification validity period for each metering installation, Table 5 of AS/NZS 1284 must be used. Table 5 has separate rows for different meter accuracy class meters and refers to Australian Standards. The scope of AS/NZS 1284 covers all meters for all metering installations, not just category 1 metering installations. Row 1 is used for 'general purpose' meters to AS 1284.1, and row 2 refers to 'Class 1' meters to AS 1284.5 (superseded by AS62053.21). Within the detail of the Australian Standard AS 1284.1 the scope of this standard is for "… induction watt-hour meters…" and AS62053.21 is "…static watt-hour meters …". Table 5 of AS/NZS 1284 lists the validity period for meters that pass testing within the tightest tolerance (criteria 1) as 7 years for general purpose meters (tolerance of ±2.0%) but only 5 years for Class 1 meters (tolerance of ± 1.5%). This means that when recertifying the modern meter fleet, row 2 should be used to determine the validity period. This reduces the maximum validity period to 5 years instead of the 7 years that was expected by the Authority and the industry when the statistical sampling method was introduced. This introduces an effective penalty for using modern electronic, more accurate meters, that isn't present when the metering installation is initially certified. This has also created some confusion in the industry. The Authority is aware, through its industry monitoring and compliance functions, that some in the industry have been recertifying using the longer period and have only recently realised that the Code requires recertification using the shorter period. Problem 2 Clause 16 of Schedule 10.7 of the Code refers to "AS/NZS 1284" however the correct reference for the standard for Electricity metering In-service compliance testing is "AS/NZS 1284.13:2002".

Proposal	Problem 1 As the statistical sampling regime is only permitted to be used on category 1 metering installations, allow the longer validity period of 7 years to apply for electronic meters that comply with the relevant criteria 1 tolerance. Problem 2 Update the AS/NZS standard reference. This is a technical and non-controversial change but we include it here (rather than in Appendix C) for completeness. Technical and non-controversial changes do not require a regulatory statement, so the discussion below is focused on the proposal in relation to Problem 1.
Proposed Code amendment	**Schedule 10.7** … **16 Recertification of group of category 1 metering installations by statistical sampling** (1) A **metering equipment provider** may arrange for an **ATH** to **recertify** a group of **category 1 metering installations** for which the **metering equipment provider** is responsible using a statistical sampling process set out in subclause (2). (2) To **recertify** a group of **category 1 metering installations**, an **ATH** must— (a) select a sample from the group, using a statistical sampling process— (i) prescribed in AS/NZS 1284.13:2002; or (ii) that is approved and **published** by the **Authority**; and (aa) use the pass/fail criteria in AS/NZS 1284.13:2002 to evaluate whether the group meets the **recertification** requirements of this Part; and (ab) if the group meets the **recertification** requirements of this Part use the appropriate maximum validity period set out in Table 5 of AS/NZS 1284.13:2002 as the **certification** validity period for each **metering installation** in the group, except that if a class 1 static (electronic) **meter** sample is within the accuracy tolerance of ± 1.5%, the appropriate maximum validity period for that group is 7 years; and (b) **recertify** each **metering component** in the **metering installation** in the sample using— (i) the **fully calibrated certification** method; or (ii) the **selected component certification** method; and

	(c) advise the **metering equipment provider** as soon as reasonably practicable, if the group— (i) meets the **recertification** requirements of this Part; or (ii) fails to meet the **recertification** requirements of this Part. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The proposed amendment for problem 1 would improve the efficient operation of the electricity industry by reducing the costs of recertifying category 1 metering installations containing electronic meter(s). Over 97% of all metering installations are category 1 and over 90% of these contain electronic meters. The amendment would also remove confusion in the industry. The proposed amendment for problem 2 corrects an incorrect reference, reducing the costs for participants to determine the correct referenced Standard. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions.
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 objectives 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 problems 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 for problem 1 is to reduce electricity market operational costs by permitting electronic meters (that make up the vast majority of the meter fleet) to be recertified for up to 7 years (rather than 5 years) if they meet the accuracy tolerance specified. The objective of the proposal for problem 2 is to correct an incorrect reference. This proposal is technical and non-controversial so does not require a regulatory statement.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendement would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the costs of the proposed Code amendment on participants to be zero. *Benefits* We expect the proposed Code amendment's main benefit will be to reduce the costs for metering equipment providers of recertifying electronic meters in category 1 metering installations. An additional 2 years (from 5 to 7 years) for meters where the tested sample meets the highest accuracy tolerances will be a significant reduction in these costs.There will also be a benefit from removing confusion in the industry over this issue.
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.

CRP5-004 Clearing manager divergence report

Reference number(s)	CRP5-004 Clearing manager divergence report
Problem definition	Clause 14.68 of the Code requires the clearing manager to give the Authority a monthly 'divergence report'. The clause has been amended previously and most of the items the divergence report must include have been revoked. Now, divergence reports only report on whether invoices were or will be published late (in breach of clause 14.18 of the Code), and if so why. This information is already provided in the clearing manager's separate monthly report required under clause 3.14 of the Code and the monthly reporting requirements in the market operation service provider agreement between the Authority and the clearing manager. This information is also reportable under clause 3.14A, which requires the clearing manager to report alleged breaches of the Code as soon as practicable after it becomes aware of the alleged breach. Producing a divergence report is therefore a duplication of the same information already reported to the Authority.
Proposal	Revoke clause 14.68 of the Code to remove the requirement for the clearing manager to provide monthly divergence reports.
Proposed Code amendment	**14.68** ~~**Monthly divergence reports to be prepared by clearing manager**~~ *[Revoked]* ~~(1) The **clearing manager** must report to the **Authority** in writing under this clause.~~ ~~(2) The **clearing manager** must give the report to the **Authority**—~~ ~~(a) on the 10th **business day** of each calendar month; or~~ ~~(b) if exceptional circumstances prevent the **clearing manager** from providing the report by that day, as soon as reasonably practicable after that day.~~ ~~(3) The report must include—~~ ~~(a) *[Revoked]*~~ ~~(b) *[Revoked]*~~ ~~(c) *[Revoked]*~~ ~~(d) *[Revoked]*~~ ~~(e) situations in which information about an amount owing was or will be issued late and whether or not the delay was caused by the **clearing manager**; and (f) **if there is a delay in the** clearing manager **advising a participant** of an amount owing under clause 14.18, the part of the process that was delayed.~~

Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and sections 32(1)(c) and 32(1)(e) of the Act, because it would contribute to the efficient operation of the electricity industry and the performance by the Authority of its functions. The proposed amendment would improve the efficient operation of the electricity industry, and the performance by the Authority of its functions, by: a) eliminating the clearing manager's need to produce duplicate reports b) eliminating the Authority's need to manage and store duplicate reports. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 electricity market operational costs by: a) eliminating the clearing manager's costs for producing duplicate reports b) eliminating the Authority's costs for managing and storing duplicate reports
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendement would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers there would be no additional costs associated with the proposal, because it will remove an existing, duplicative reporting requirement.

	Benefits We expect the proposed Code amendment’s main benefit will be to reduce the costs and resource requirements of the clearing manager and Authority to produce, provide, manage and store the monthly divergence reports.
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.

CRP5-005 Mechanism for publishing invoices by the clearing manager

Reference number(s)	CRP5-005 Mechanism for publishing invoices by the clearing manager
Problem definition	<u>Problem 1</u> In 2018 the Authority and NZX completed a major upgrade of the wholesale information and trading system (WITS) and clearing manager systems. As part of this upgrade the clearing manager stopped providing participants' invoices for amounts owing and payable through the WITS system. Invoices are now provided through the clearing manager's external system, the Electricity Clearing Portal. This was done to separate a participant's financial information from its trading information to prevent unauthorised changes, and to separate the WITS and clearing systems to simplify the contractual separation of these two service providers. Since 2018 invoices have been provided via the clearing system rather than WITS however, the Code was not updated at that time to reflect these changes. Clause 14.23 still requires the clearing manager to provide invoices through WITS, and several other clauses still require or refer to the clearing manager providing relevant financial information through WITS (clauses 13.199, 13.208, 13.211, 14.71, 14.72 and 14.75). Clause 14.24 requires participants to acknowledge receipt of invoices through WITS. <u>Problem 2</u> The Code requires the clearing manager to follow backup procedures for making relevant information available if WITS is unavailable. Clause 13.211(2) of the Code requires the WITS manager to consult with the Authority, generators, ancillary service agents, purchasers and the clearing manager before specifying the backup proceedures for the system. This consultation requirement was included when the Code was first written and the clearing (and WITS) systems were being set up, but has now been superseded by the current specified process. The backup procedures are agreed in the service provider agreements between the Authority and the clearing mananger and the WITS manager and are widely known to all participants. These are known as the "disaster recovery" processes and are tested with participants every six months in accordance with the agreements. All participants can continue to operate when the clearing manager (and WITS manager) are operating their disaster recovery systems. Clause 13.23(2) contains a similar provision for the WITS maanger to consult on backup procedures. For the same reasons, these procedures are well established in the service provider agreement between the Authority and WITS manager. The proceedures are widely known to all participants, and are also tested with participants every six months. <u>Problem 3</u> Clause 14.23(1)(b) of the Code requires the clearing manager to post or hand deliver invoices if the participant requests it. These

	methods of delivery are no longer practical and are not used in practice. Over the past few years, changes made to the postal system by NZ Post means that invoices posted 2 business days before the 20th of the month are unlikely to be received in time for the participant to make payment by 1pm on the 20th. There are also practical issues with hand delivery especially as most participants are not based in the same city as the clearing manager (Wellington). The clearing manager already offers two methods of invoice delivery – download from the clearing manager's external system or email. <u>Problem 4</u> Clause 14.23(1)(aa) was inserted in 2017 and requires the clearing manager to, when advising a participant of amounts owing and payable, "publish" the information. The definition of "publish" in clause 1.1 of the Code requires the clearing manger, as a participant, to make the information available to the public by publishing it on its website. Currently, the clearing manager publishes aggregated information, and some individualised information for specific services (block settlement differences and constrained amounts), however individual participant invoice information is commercially sensitive and should not be published.
Proposal	<u>Problem 1</u> Amend clauses 13.199, 13.208, 13.211, 14.23, 14.71, 14.72 and 14.75 to replace references to WITS and the WITS manager with references to the clearing manager providing information through the clearing manager's external system. Revoke clause 14.24 of the Code to remove the requirement for participants to acknowlege, through WITS, receipt of information from the clearing manager under Subpart 4 of Part 14 of the Code and for the clearing manager to follow up participants that do not confirm receipt. <u>Problem 2</u> Amend clauses 13.23(2) and 13.211(2) of the Code to remove the requirement to consult on backup procedures, and replace the requirement to consult with the Authority with a requirement to agree backup procedures with the Authority. <u>Problem 3</u> Revoke clause 14.23(1)(b) of the Code to remove the requirement to post or hand deliver information to the participant. <u>Problem 4</u> Amend clause 14.23(1)(aa) of the Code to clarify that the clearing manager is only required to publish aggregated information.
Proposed Code amendment	**13.23 Backup procedures if WITS is unavailable** (1) If **WITS** is unavailable to receive **bids** or **offers** or to confirm the receipt of **bids** or **offers**, each **purchaser** and **generator** or the **system operator**, as the case may be, must follow the

backup procedures specified in the **market operation service provider agreement** between ~~by~~ the **WITS manager** and the **Authority** ~~from time to time~~.

(2) ~~The backup procedures referred to in subclause (1) must be specified by the WITS manager following consultation with the~~ ~~**Authority** and each **purchaser, generator** and the **system operator**.~~ *[Revoked]*

…

13.199 Clearing manager to make details of constrained off amounts available

The **clearing manager** must, at the time specified in clause 13.197, **publish** ~~make~~ the details of **constrained off amounts** ~~available on **WITS**~~ for each **generator** and each **dispatched purchaser** for the previous **billing period** as follows:

…

13.208 Clearing manager to make details of constrained on amounts available

The **clearing manager** must, at the time specified in clause 13.206, **publish** ~~make~~ the details of **constrained on amounts** ~~available on **WITS**~~ in relation to each **generator**, **ancillary service agent**, and **dispatched purchaser** for the previous **billing period** calculated in accordance with clauses 13.204 and 13.205 as follows:

…

13.211 Backup procedures if the clearing manager's external system ~~WITS~~ is unavailable

(1) If the **clearing manger's** external system ~~**WITS**~~ is unavailable for the purposes of making information available under clauses 13.199 and 13.208, the **clearing manager** must follow ~~the~~ backup procedures specified in the **market operation service provider agreement** between it and the **Authority** ~~by the **WITS manager** from time to time~~.

(2) ~~The **WITS manager** must specify the backup procedures referred to in subclause (1) following consultation with the **Authority**, **generators**, **ancillary service agents**, and **purchasers**, and the **clearing manager**.~~ *[Revoked]*

…

14.23 Procedure for advising participant of amounts owing and payable

(1) When advising a **participant** of amounts owing and payable under this subpart, the **clearing manager** must—

(a) submit the information to each relevant **participant** through the **clearing manager's** external system ~~**WITS**~~; and

(aa) **publish** ~~the~~ aggregated information within one month after each **billing period.**~~; and~~

(b) *[revoked]* ~~if the **participant** requests, post or hand deliver the information to the **participant**.~~

(2) Proof of making ~~submitting~~ the information available on the **clearing manager's** external system ~~to **WITS**~~ is deemed to be proof of the advice under subclause (1)~~, despite the procedures set out in this clause and in clause 14.24~~.

…

14.24 *[Revoked]* ~~**Participant to confirm receipt**~~

~~(1) Each **participant** that receives information from the **clearing manager** under this subpart must immediately confirm, through **WITS**, receipt of the information sent by the **clearing manager** under clause 14.23(1)(a) or (b).~~

~~(2) If, by 1200 hours on the **business day** after submitting the information under clause 14.23(1), the **clearing manager** has not received confirmation from a **participant** that the **participant** has received the information, the **clearing manager** must check whether the **participant** has received the information.~~

~~(3) If the **participant** has not received the information, the **clearing manager** must resubmit the information through **WITS**.~~

~~(4) Delayed confirmation by a **participant** that the information has been received does not extend the payment period set out in clause 14.31~~

…

14.71 Clearing manager to make block dispatch settlement differences available

(1) By 0900 hours on the 2nd **business day** after the **clearing manager** has advised **participants** of amounts owing under clause 14.18, the **clearing manager** must **publish** ~~make~~ the following information ~~available for **participants** on **WITS**~~:

…

14.72 Clearing manager to make block dispatch settlement differences available later if ~~WITS~~ clearing manager's system unavailable

(1) If the **clearing manager's** system ~~**WITS**~~ is unavailable to make the information set out in clause 14.71 available, the **clearing manager** is not obliged to follow any backup procedures in respect of making the information available.

	(2) The **clearing manager** must **publish** ~~make~~ the information ~~available on **WITS**~~ as soon as reasonably possible after its system ~~**WITS**~~ becomes available. … **14.75 Notices** (1) Except as expressly provided in this Code, a notice or demand given or required to be given under this Part may be given by being delivered or transmitted to the intended recipient at its address or electronic address as last advised in writing to the sender and may be posted to such address by prepaid post. (2) Subject to subclause (3),— (a) a notice or demand delivered by hand is deemed to be delivered on the date of such delivery; and (b) a notice or demand delivered by post is deemed to be delivered on the 2nd **business day** following the date of posting; and (c) a notice or demand ~~transmitted through~~ made available on the **clearing manager's external** system ~~**WITS**~~ is deemed to be delivered on the date it was ~~transmitted~~ made available. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and sections 32(1)(c) and 32(1)(e) of the Act, because it would contribute to the efficient operation of the electricity industry and the performance by the Authority of its functions. The proposed amendment would improve the efficient operation of the electricity industry, and the performance by the Authority of its functions by: c) ensuring the Code is aligned with current agreed procedures and existing practice and is fit for purpose d) eliminating consideration of alleged Code breaches for matters the Authority is unlikely to investigate. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the 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 objectives 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 electricity market operational costs by: c) aligning the Code with agreed procedures and existing practice d) eliminating the Authority's costs in considering any alleged Code breaches where it is unlikely to investigate.
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 there would be no additional costs associated with the proposal because it will align the Code with existing agreed procedures and practice. *Benefits* A benefit of the proposed Code amendment is to avoid unnecessary compliance costs that may arise from an allegation that the relevant Code provisions have been breached. A further benefit is to make it easier for participants to understand the mechanism for the publication of invoices by the clearing manager, which would produce a productive economic efficiency benefit.
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.

CRP5-006 Provision of information to the clearing manager

Reference number(s)	CRP5-006 Provision of information to the clearing manager
Problem definition	<u>Problem 1</u> At times the clearing manager must obtain information from a participant to gain a better understanding of risk within the market and to meet its obligations under legislation such as the Anti-Money Laundering and Countering Financing of Terrorism Act 2009 (AML/CFT Act). The clearing manager needs information from participants from time to time to effectively perform its role under the Code, for example, to gain a detailed understanding of potential shifts in a participant's market exposure and to satisfy the clearing manager's obligations under sections 11 and 31 of the AML/CFT Act, which mandate customer due diligence and monitoring. Currently the clearing manager makes voluntary requests for this type of information. However, we understand that some participants do not always respond to these requests, despite repeated follow-up. This increases the clearing manager's operational overhead and inefficiencies in repeatedly following up requests. As there is no current obligation on a participant to respond to requests for relevant information under the Code, there are no enforcement options open to the Authority for a participants' failure to provide information necessary for the clearing manager to fulfil its relevant legal obligations that arise as a result of its role under the Code. <u>Problem 2</u> If the clearing manager cannot meet its due diligence obligations in relation to a clearing participant under the AML/CFT Act then it is required under section 37 of that Act to cease doing business with the clearing participant. This places the clearing manager in an awkward position, as they must comply with the AML/CFT Act however the Code has no explicit remedies for this situation. The clearing manager needs to wait for the participant to default under one of the current default provisions (settlement default or prudential default) before it can take action to have the participant removed from the market.
Proposal	<u>Problem 1</u> Add a new clause into Part 14 of the Code requiring clearing participants to provide information that is reasonably required by the clearing manager to carry out its role. This clause is similar to the obligation in clause 15.18 of Part 15 on reconcilation participants to provide relevant information to the reconcilation manager. <u>Problem 2</u>

	Add an explicit default event into clause 14.41 for a participant that the clearing manager must cease doing business with under the AML/CFT Act.
Proposed Code amendment	**14.1A Clearing manager may require additional information** (1) The **clearing manager** may require information from a **clearing participant** by notice to the **clearing participant** where the information is necessary for the purpose of the **clearing manager** carrying out its role in accordance with this Code. (2) Information required under sub-clause (1) may include information that the **clearing manager** reasonably requires, in the course of carrying out its role in accordance with the Code, to comply with its obligations under legislation other than the Code. (3) A **participant** who receives a notice under subclause (1) must, as soon as practicable, provide the information required in the notice to the **clearing manager**. **14.41 Definition of an event of default** (1) Each of the following events constitutes an **event of default**: … (j) if the **clearing manager** is prohibited from continuing a business relationship with a **participant** under the Anti-Money Laundering and Countering Financing of Terrorism Act 2009.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, 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 reducing the resources required by the clearing manager to follow up participants who do not provide information the clearing manger requires to fulfil its functions, and clarify that the clearing manager has an explicit remedy under the Code if they are prohibited from doing business with a participant under the AML/CFT Act. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity, or the performance by the Authority of its functions
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 objectives 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 electricity market operational costs by: (a) making it easier for the clearing manager to obtain the information it requires to fulfil its role under the Code, including its legal obligations under other legislation; (b) ensuring the clearing manager has a clear path to take under the Code.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the proposed amendment would place little, if any, additional costs on participants. Information is already requested by the clearing manager on a voluntary basis. *Benefits* We expect the proposed Code amendment's main benefits will be to reduce the clearing manager's costs in following up requests for information, and to avoid unnecessary compliance costs that may arise from an allegation that the clearing manager has breached the Code if they comply with their obigations under the AML/CFT Act. There is also a benefit to other participants in that the relevant participant's market exposure can be limited as the process to exit it from the market can start sooner.
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.

CRP5-007 Definitions of ‘at risk HVDC transfer’ and ‘configuration’

<table>
<tr><td>Reference number(s)</td><td>CRP5-007 Definitions of ‘at risk HVDC transfer’ and ‘configuration’</td></tr>
<tr><td>Problem definition</td><td><u>Problem 1: The Code overstates the amount of instantaneous reserves required by the HVDC link</u>

The term ‘at risk HVDC transfer’ in clause 1.1(1) of the Code is used in clause 8.59 of the Code. Clause 8.59 contains the formula by which the availability costs for instantaneous reserves are allocated to payers (generators and Transpower, as owner of the HVDC link).

Typically, at risk HVDC transfer is a function of the amount of electricity injected by the HVDC link at Haywards (north transfer) or Benmore (south transfer). When Pole 2 and Pole 3 of the HVDC link are both transferring electricity in the same direction, at risk HVDC transfer is also a function of the amount of additional power one pole can quickly provide should the other pole trip. This ability to provide rapid additional power is the pole’s overload capability.

The higher a pole’s overload capability, the less instantaneous reserve the system operator must procure to cover the risk of the other pole tripping and causing an under-frequency event.

On 30 November 2016, Transpower (as the owner of the HVDC link) increased the overload capability of Pole 2 to:

a) 650 MW for 15 minutes for power received at Haywards from Benmore

b) 619 MW for 15 minutes for power received at Benmore from Haywards.

Currently, this is not reflected in the definition of ‘at risk HVDC transfer’ in the Code. Therefore, the instantaneous reserve allocation formula in clause 8.59 does not correctly factor in the risk posed by a trip of Pole 3 of the HVDC link. As a result, Transpower, as owner of the HVDC link, is being allocated more instantaneous reserves costs than is justified by the risk of Pole 3 tripping.

<u>Problem 2: The Code refers to the decommissioned Pole 1</u>

Clause 1.1(1) of the Code refers to Pole 1 of the HVDC link in the definitions of ‘at risk HVDC transfer’ and ‘configuration’. This is incorrect. Pole 1 of the HVDC link was decommissioned on 1 August 2012.The reference to Pole 1 is therefore redundant.

<u>Problem 3: The label for the defined term “configuration” is too generic</u>

The Code defines ‘configuration’ in clause 1.1(1) to refer to the configuration of the HVDC link. However, the Code also uses the word ‘configuration’ throughout the Code (Parts 1, 6, 8, 10, 12, 13, 14 and 17) in an undefined manner, with the intention that the term is given its ordinary meaning.

Using the same word in a defined and undefined manner makes the Code harder to interpret and understand.</td></tr>
</table>

Proposal	<u>Problem 1</u> Amend the definition of 'at risk HVDC transfer' to replace — a) in Table 1, the number '263' with the number '325' b) in Table 2, the number '263' with the number '308' The values '325' and '308' take account of losses, such that: • 325 MWh per trading period (650 MW) received at Haywards equates to 350 MWh per trading period (700 MW[2]) sent from Benmore • 308 MWh per trading period (616 MW) received at Benmore equates to 333 MWh per trading period (666 MW[3]) sent from Haywards. We note the definition of Problem 1 says Transpower has increased the overload capability of Pole 2 to 619 MW for 15 minutes for power received at Benmore. However, this appears to use a different line resistance (11.25 ohms) to the line resistance (12 ohms) used to calculate Pole 2's 650 MW overload capability for power received at Haywards. Using the 12 ohm line resistance for south flows on Pole 2 gives a Pole 2 overload capability of 616 MW, rather than 619 MW, for power received at Benmore. Transpower has advised the Authority that the line resistance for Pole 2 varies significantly with the temperature of the overhead lines and the subsea cables across Cook Strait. Typical values observed range from 9.9 ohms to 13.48 ohms. Given this range, the Authority's preference is to use 12 ohms as the line resistance for Pole 2 rather than 11.25 ohms. For reasons of consistency, the Authority proposes to replace the value '263' in the definition of 'at risk HVDC transfer' with '325' and '308' respectively based on a line resistance of 12 ohms for both north and south flows on Pole 2. The Authority has also considered whether halving the MW values of '650' and '616' is an appropriate approach to calculating the MWh values ('325' and '308') required under clause 8.59, given that the duration of Pole 2's overload capability has fallen from 30 minutes to 15 minutes. The Authority considers the approach of halving the MW values remains acceptable. Treating the duration of Pole 2's overload capability as 30 minutes for the purposes of the formula in clause 8.59 has no effect on the relative allocation of availability costs between generators and the HVDC owner. This is because 15 minutes is the duration of the longest form of instantaneous reserve[4] purchased by the system operator and therefore allocated in accordance with the formula in clause 8.59. Put another way, Pole 2's revised overload capability still covers the period over which sustained instantaneous reserve operates. So, if Pole 3 trips, Pole 2's overload capability can reduce the amount of

[2] This value accords with Transpower's Bipole Operating Policy TP.OG.48.02 Issue 17 Appendix C2.
[3] This value accords with Transpower's Bipole Operating Policy TP.OG.48.02 Issue 17 Appendix C2.
[4] Sustained instantaneous reserve.

	sustained instantaneous reserve needed to cover the Pole 3 trip for the maximum period (15 minutes) over which the sustained instantaneous reserve might be required to operate. Therefore, allocating the availability costs of sustained instantaneous reserve between generators and the HVDC owner as though Pole 2's 650 / 616 MW (received) overload capability was for 30 minutes is appropriate.[5] <ins>Problem 2</ins> Amend the definitions of 'at risk HVDC transfer' and 'configuration' in clause 1.1(1) to remove references to Pole 1 and remove the definition of '$INJ_{Pole2HAYt}$' from the definition of 'at risk HVDC transfer', which is no longer necessary in light of the removal of references to Pole 1. <ins>Problem 3</ins> Rename the defined term 'configuration' in clause 1.1(1) as 'HVDC link configuration', and make consequential amendments in clauses that use the term 'configuration' in the way in which it is defined, to replace these terms with the defined term 'HVDC link configuration'.
Proposed Code amendment	1.1 Interpretation (1) In this Code, unless the context otherwise requires,— ... **at risk HVDC transfer** means the quantity of **MWh** for each **trading period** calculated in accordance with Tables 1 and 2, where— $INJ_{HVDCHAYt}$ is the **electricity** injected from the **HVDC link** into the North Island **grid assets** at the North Island **HVDC injection point** in **trading period** t; and $INJ_{HVDCBENt}$ is the **electricity** injected from the **HVDC link** into the South Island **grid assets** at the South Island **HVDC injection point** in **trading period** t; and ~~$INJ_{Pole2HAYt}$ is the **electricity** injected from Pole 2 of the **HVDC link** into the North Island **grid assets** at the North Island **HVDC injection point** in **trading period** t~~ Table 1: HVDC northward transfer – if **electricity** is injected at the North Island **HVDC injection** point in the relevant **trading period**

[5] If the duration of Pole 2's overload capability was to be less than the maximum duration of sustained instantaneous reserve, then the MWh numbers used in the definition of 'at risk HVDC transfer' would need to be revised down accordingly. This would be in recognition of the need for additional sustained instantaneous reserve to cover the period between the end of Pole 2's overload capability (eg, 10 minutes) and the end of the sustained instantaneous reserve cover.

HVDC configuration at the beginning of trading period t	**At risk HVDC transfer north in trading period t (expressed in MWh)**
~~Pole 1 one half pole only~~	~~$INJ_{HVDCHAYt}$~~
Pole 2 only	$INJ_{HVDCHAYt}$
Pole 3 only	$INJ_{HVDCHAYt}$
~~Pole 2 and Pole 1 one half pole~~	~~$INJ_{Pole2HAYt}$~~
Pole 3 and Pole 2 bipole **round power**	$INJ_{HVDCHAYt}$
Pole 3 and Pole 2 bipole not **round power**	max(0,$INJ_{HVDCHAYt}$ – ~~263~~ 325)

Table 2: HVDC southward transfer – if electricity is injected at the South Island HVDC injection point in the relevant trading period

HVDC configuration at the beginning of trading period t	**At risk HVDC transfer south in trading period t (expressed in MWh)**
Pole 2 only	$INJ_{HVDCBENt}$
Pole 3 only	$INJ_{HVDCBENt}$
Pole 3 and Pole 2 bipole **round power**	$INJ_{HVDCBENt}$
Pole 3 and Pole 2 bipole not **round power**	max(0,$INJ_{HVDCBENt}$ – ~~263~~308)

…

HVDC link configuration~~, in relation to the HVDC link,~~ means the following modes of operation of the **HVDC link**:

(a) ~~Pole 1 one half pole only~~:*[Revoked]*

(b) Pole 2 only:

(c) Pole 3 only:

(d) ~~Pole 2 and Pole 1 one half pole:~~*[Revoked]*

(e) Pole 3 and Pole 2 bipole **round power**:

(f) Pole 3 and Pole 2 bipole not **round power**

…

8.19 Contributions to frequency support in under-frequency events

…

(4) The **HVDC owner** must at all times ensure that, while **electrically connected**, its **assets** contribute to supporting frequency during an **under-frequency event** in either **island** by—

…

(d) subject to the level of transfer and the **HVDC link** **configuration** ~~configuration~~ at the beginning of the **under-frequency event**, if the **HVDC link** itself is not the cause of the **under-frequency event**, modifying the instantaneous transfer on the **HVDC link** by up to 250 **MW** with the objective of limiting the difference between the North Island and South Island frequencies to no greater than 0.2 Hertz.

…

12.107 Transpower to identify interconnection branches, and propose service measures and levels

…

(4) The information required under subclause (1) is—

…

(c) the transfer capacity in the North and South transfer for each ~~**configuration** of the~~ **HVDC link** **configuration** expressed as follows:

(i) DC sent in **MW**:

(ii) AC received in **MW**; and.

…

12.112 Exceptions to clause 12.111

…

(1) **Transpower** is not required to comply with clause 12.111(1)(a) or (2) if—

…

(ea) in relation to the **HVDC link**—

…

(ii) the ~~**configuration** of the~~ **HVDC link** **configuration** is—

(A) Pole 3 and Pole 2 bipole **round power**; or

(B) Pole 3 and Pole 2 bipole not **round power**; or

…

13.30 Standing data on HVDC capability to be provided to system operator

(1) In addition to the **asset owner** obligations to provide information under clauses 2(5) and (6), and 3(1) of **Technical Code** A of Schedule 8.3, the **HVDC owner** must provide standing data on the capability of the **HVDC link** to the **system operator** consistent with ~~the **configuration** of~~ the **HVDC link** **configuration**.

…

(3) Subclause (2)(d) applies only if—

(a) the **HVDC owner** is operating the **HVDC link** in accordance with—

(i) a **commissioning** plan agreed with the **system operator** under clause 2(6) to (9) of **Technical Code** A of Schedule 8.3; or

(ii) a test plan provided to the **system operator** under clause 2(6) to (9) of **Technical Code** A of Schedule 8.3; and

(b) the ~~**configuration** of the~~ **HVDC link** **configuration** is—

(i) Pole 3 and Pole 2 bipole **round power**; or

(ii) Pole 3 and Pole 2 bipole not **round power**.

…

13.58A Inputs for price-responsive schedule and non-response schedule

(1) The **system operator** must prepare a **price-responsive schedule** using the following inputs:

(a) **offers** and **reserve offers**; and

(b) the potential output of all **intermittent generating stations**, determined using the most recent **forecast of generation potential** for each **intermittent generating station** submitted under clause 13.18A; and

(b) **nominated bids**; and

(c) the forecast prepared by the **system operator** under clause 13.7A(1); and

(d) **difference bids**; and

(e) information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 about—

(i) the AC transmission system configuration, capacity, and **losses**; and

	(ii) the capability of the **HVDC link** including ~~its~~ the **HVDC link** **configuration**, the capacity of the **HVDC link**, the **losses** in the **HVDC link**, the direction of any transfer limit on the **HVDC link**, and any minimum or maximum transfer limits on the **HVDC link**; and (iii) transformer configuration, capacity, and **losses**; and … (2) The **system operator** must prepare a **non-response schedule** using the following inputs: … (d) information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 referring to— (i) the AC transmission system configuration, capacity, and **losses**; and (ii) the capability of the **HVDC link** including ~~its~~ the **HVDC link** **configuration**, the capacity of the HVDC **link**, the **losses** in the **HVDC link**, the direction of any transfer limit on the **HVDC link**, and any minimum or maximum transfer limits on the **HVDC link**; and (iii) transformer configuration, capacity, and **losses**; and … **13.69B Inputs for dispatch schedule** (1) The **system operator** must use the following inputs to prepare a **dispatch schedule**: … (g) information from the **grid owner** (clauses 13.29 to 13.34) and revised information from the **grid owner** (clause 13.33) about— (i) the AC transmission system configuration, capacity and **losses**; and (ii) the capability of the **HVDC link** including ~~its~~ the **HVDC link** **configuration**, the capacity of the **HVDC link**, the losses in the **HVDC link**, the direction of any transfer limit on the **HVDC link**, and any minimum or maximum transfer limits on the **HVDC link**; and (iii) transformer configuration, capacity, and **losses**; and …
Assessment of proposed Code amendment against the Authority's	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it promotes the efficient operation of the electricity industry.

objective and section 32(1) of the Act	The Authority considers the proposed amendment would promote the efficient operation of the electricity industry by ensuring the instantaneous reserve allocation formula in clause 8.59 of the Code correctly factors in the risk posed by a trip of Pole 3 of the HVDC link. This would result in a more accurate allocation of instantaneous reserves costs across Transpower, as the owner of the HVDC link, and generators with generating units greater than 60 MW. The Authority considers the proposed Code amendment would also promote the efficient operation of the electricity industry by making it easier for participants to understand and comply with their obligations. The proposed Code amendment is expected to have little or no effect on competition, the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 a Code amendment to resolve.
Principle 3: Quantitative Assessment	The 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 accurately allocate instantaneous reserve costs, so that Transpower and generators with generating units over 60 MW are encouraged to make efficient operating decisions.
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* Transpower has identified that some software changes are required to its ancillary services processing tools to implement the proposed Code amendment. Transpower estimates these costs will be less than $10,000. The Authority expects the proposed Code amendment

	would place little additional economic cost on other industry participants.[6] *Benefits* The primary benefit of the proposed amendment is that it would facilitate more accurate allocation of instantaneous reserves costs. This, in turn, would facilitate the efficient operation of the electricity industry, by reducing the potential distortion of operational decisions by generators who are allocated instantaneous reserve costs. A minor benefit of the proposed amendment would be making it easier for participants to understand and comply with their obligations.
Evaluation of alternative means of achieving the objectives of the proposed amendment	The Authority has identified an alternative means of achieving the objective of the proposed Code amendment to address the first identified problem. Under this alternative, the Code would be amended to provide for the system operator to advise the clearing manager if the HVDC risk subtractor value changes. However, this alternative would cost more and take more time to implement than the Code amendment proposal. This is because the alternative would require the system operator and clearing manager to make system and process changes that are not required under the Code amendment proposal. The Authority considers this Code amendment proposal is preferable to the alternative for the following reasons: a) it is lower cost and quicker to implement than the alternative b) it is extremely rare for the HVDC risk subtractor value to change (eg, because of an unplanned fault on the HVDC link).

[6] Ie, excluding any wealth transfers between participants.

CRP5-008 When assumption of rights and obligations take effect

Reference number(s)	CRP5-008 When assumption of rights and obligations take effect
Problem definition	Clause 1.5 provides for a participant to assume the rights and obligations of another participant by giving notice in the form set out in Schedule 1.1. Clause 1.5(3) states that the earliest the notice can take effect is 30 business days after the date that the notice is given to the Authority. This is to give the Authority time to consider and approve the notice pursuant to clause 1.5(4). However, in practice the Authority does not require 30 business days to process such notices. Of the 12 notices processed since 2015, all but two were processed in five business days or less and only one took more than 10 business days. The requirement to wait 30 business days before a notice can take effect delays the benefits to the participants of aggregating their rights and obligations. Benefits include the reduction in the costs of providing prudential security for both participants and reduced internal administration costs for participants.
Proposal	Amend the Code to reduce the minimum period before a notice under Schedule 1.1 may take effect, subject to a provision for the Authority to specify a longer period should it consider that is necessary to process an application.
Proposed Code amendment	**1.5 Special definition of “purchaser” and “participant”** … (2) A **participant** (participant A) may, by notice in the form set out in Schedule 1.1, give notice to the **Authority** that, from a date specified in the notice, participant A will assume all rights and obligations under Parts 8, 13, 14, and 14A of this Code of another **participant** named in the notice (participant B) in participant B’s capacity as a **purchaser** and a **participant** that incurs financial obligations under this Code or owes an amount to the **clearing manager**. … (3) A notice given under subclause (2) takes effect from the first **trading period** on: (a) the date specified in the notice~~. That date~~, which must be at least ~~30~~10 **business days** after the date that the notice is given to the **Authority**, or (b) if the **Authority** reasonably considers additional time is required in any particular case, any later date specified by the **Authority** in a notice given to the **participant** (participant A) within 10 **business days** after the date the **Authority** receives the notice in subclause (2). …
Assessment of proposed Code amendment	The proposed Code amendment is consistent with the Authority’s statutory objectives, 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 ensuring the benefits to participants from

against section 32(1) of the Act	aggregating their rights and obligations accrue as early as possible, while still giving the Authority adequate time to process an application. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions
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 objectives 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 electricity market operational costs by ensuring the benefits to participants from aggregating their rights and obligations accrue as early as possible.
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 costs of the Code amendment to be zero. *Benefits* We expect the proposed Code amendment's main benefit will be to allow the benefits to participants from aggregating their rights and obligations accrue as early as possible.
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.

CRP5-009 Prohibiting ICPs being connected in series

Reference number(s)	CRP5-009 Prohibiting ICPs being connected in series
Problem definition	Clause 3 of Schedule 11.1 provides that any new ICP must be able to be electrically disconnected without electrically disconnecting another ICP. <u>Problem 1</u> This clause ensures that any new ICP is connected to a network in such a way that it can be independently disconnected without disconnecting any other ICP. However, it does specify that a new ICP must not be connected in such a way that disconnecting any other ICP also disconnects the new ICP. The result is that the Code does not explicitly prohibit ICPs from being connected in series. This is problematic, because if an ICP is connected in series this could lead to consumers being disconnected inadvertently if an ICP in series upstream is disconnected. In addition, a new ICP that is connected in series downstream of the first ICP's meter will result in consumption being recorded twice, by both the upstream meter and the downstream meter. This results in the upstream consumer paying for the downstream consumption, and once identified, requires arrangements with the retailer to credit back overpayments and the retailer to adjust submission volumes. <u>Problem 2</u> The wording this clause simply refers to an 'ICP' and does not expressly distinguish between the two applicable events – the physical connection of a new ICP to a network, and the creation of a new ICP identifier. This has the potential to cause confusion.
Proposal	<u>Problem 1</u> Amend the Code to prevent a distributor from connecting new ICPs (or creating new ICP identifiers) in series, subject to the existing exceptions in subclauses 3(a) and 3(b) of Schedule 11.1, which provide for ICPs which are required to be connected in series as part of their function. <u>Problem 2</u> Amend the Code to clarify that clause 3 of Schedule 11.1 applies to both new physical connections and newly created ICP identifiers.
Proposed Code amendment	**Schedule 11.1** … **3 Electrically disconnecting** <u>(1) Subject to subclause (2), a **distributor** must not create an</u> ~~Each~~ **ICP** <u>**identifier** or connect an **ICP**</u> created after 7 October 2002 <u>unless:</u> ~~must~~ <u>(a) the **ICP identifier** is for an **ICP** that can</u> be ~~able to be~~ **electrically disconnected** without **electrically**

	disconnecting another **ICP**~~, except for the following ICPs:~~; (b) the **ICP** can be **electrically disconnected** without **electrically disconnecting** another **ICP**. (2) Subclause (1) does not apply if the **ICP** is: (a) ~~an ICP that is~~ the **point of connection** between a **network** and an **embedded network**: (b) an **ICP** that represents the consumption calculated by the difference between the total consumption for the **embedded network** and all other **ICPs** on the **embedded network**. (3) A **distributor** must not: (a) connect a new **ICP** to an existing **ICP** in series unless the existing **ICP** is of the type described in subclause (2)(a) or (2)(b); or (b) create a new **ICP identifier** for a new or existing **ICP** in series with an existing **ICP** unless the existing **ICP** is of the type described in subclause (2)(a) or (2)(b) and the distributor is responsible for both the new and existing **ICPs**.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act. This is because the proposed Code amendment would, by ensuring that an ICP is not connected in such a way that it can be inadvertently disconnected by the disconnection of a different ICP: - contribute to the reliable supply of electricity to consumers; and - protect the interests of domestic and small business consumers in relation to the supply of electricity to those consumers. The proposal would also improve the efficient operation of the electricity industry by clarifying the application of the clause to both physical connections and the creation of new ICP identifiers, and by reducing the need for investigation and remediation if a consumer is inadvertently disconnected. The proposed Code amendment is expected to have no effect on competition or the performance by the Authority of its functions
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 objectives 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 address a small misalignment between the intent and the actual wording of the Code, by explicitly prohibiting ICPs from being connected in series and clarifying that the clause applies to both physical connections and the creation of new ICP identifiers.
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 costs of this amendment to be negligible. *Benefits* The proposal would have small benefits for the reliability of supply to electricity consumers, in ensuring ICPs are able to be independently disconnected without affecting any other ICP. The proposal would also improve the efficient operation of the electricity industry by clarifying the application of the clause to both physical connections and the creation of new ICP identifiers, and by ensuring that consumption is not double counted, which occurs when an ICP is connected in series downstream of the first ICP's meter. This will prevent inaccuracies in the reconciliation process and customer invoices.
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.

CRP5-010 Definition of reconciliation participant

<table>
<tr><td>Reference number(s)</td><td>CRP5-010 Definition of ‘reconciliation participant’</td></tr>
<tr><td>Problem definition</td><td>
Clause 1(1) of the Code defines ‘reconciliation participant’ as follows:
<blockquote> reconciliation participant means a participant (excluding the Authority (even if the Authority acts as a market operation service provider) and the Rulings Panel) who is any of the following:
(a) a retailer when purchasing electricity from, or selling electricity to, the clearing manager:
(b) a generator:
(c) a network owner:
(d) a distributor:
(e) a person who purchases electricity from or sells electricity to the clearing manager </blockquote>
The Authority has identified several problems with this definition.
<u>Problem 1: The definition of ‘reconciliation participant’ includes some secondary network providers that do not need to provide information for reconciliation</u>
Under section 131A of the Electricity Industry Act 2010 (Act), the Code applies to secondary network providers as if they are distributors. This means that, under the Code, secondary network providers are, like distributors, also reconciliation participants.[7]
Section 131A of the Act means there are hundreds, possibly thousands, of secondary network providers that come within the Code’s definition of ‘reconciliation participant’. However, some of these secondary network providers do not need to provide information to the reconciliation manager for reconciliation. Therefore, they should not be included in the definition of ‘reconciliation participant’.
A secondary network is defined in subsection 131A(2) of the Act as equipment used, designed, or intended for use in, or in connection with, the conveyance of electricity, that is indirectly connected to the national grid. There are three common types of secondary network — customer networks, embedded networks, and network extensions.
A customer network provides retail and network services to consumers connected to it (eg, some office buildings, residential apartment complexes, camp grounds, marinas, hotels, and motels).
An embedded network provides network services to consumers connected to it and is reconciled separately from the network to which it is connected (eg, some shopping malls, retirement villages, residential apartment complexes, and office buildings). An embedded network provider does not provide retail services to consumers connected to the embedded network.
</td></tr>
</table>

[7] The Code adopts the Act’s definition of ‘distributor’, which means that, under the Code, a secondary network provider is a distributor. Since the Code defines “reconciliation participant” to include distributors, a secondary network provider is therefore a reconciliation participant.

	A network extension provides (owns) the network infrastructure used to convey electricity to consumers connected to it but is not reconciled separately from the network to which it is connected (eg, some office buildings and residential apartment complexes). A network extension provider does not provide retail services to consumers connected to the network extension. Information from embedded network owners or operators is required for accurate and timely reconciliation of the electricity market. No such information is required from customer network providers or network extension providers. Therefore, there is no need to include customer network providers or network extension providers in the definition of 'reconciliation participant'. Leaving the definition of 'reconciliation participant' unchanged would also increase the risk of Code obligations being inadvertently placed on customer network providers and network extension providers, should future changes be made to reconciliation participants' obligations under the Code. <u>Problem 2: The definition of 'reconciliation participant' includes local network owners or operators that do not need to provide information for reconciliation</u> The definition of 'reconciliation participant' includes network owners. Because the definition of 'network' includes local networks, this means that local network owners or operators come within the definition of 'reconciliation participant'. However, many of these participants do not have to provide information for reconciliation and, therefore, do not need to be included in the definition of reconciliation participant. Removing these local network owners or operators from the definition of reconciliation participant would remove the risk of Code obligations being inadvertently placed on these participants, should future changes be made to reconciliation participants' obligations under the Code. <u>Problem 3: The definition of 'reconciliation participant' includes some generators that do not need to provide information for reconciliation</u> The definition of 'reconciliation participant' includes all generators. However, some generators do not provide information for reconciliation and, therefore, do not need to be included in the definition of reconciliation participant. It also means there is the risk of Code obligations being inadvertently placed on generators that do not provide information for reconciliation, should future changes be made to reconciliation participants' obligations under the Code. In addition, by including all generators in the definition of 'reconciliation participant', generators who provide metering information to the relevant grid owner for use in market pricing, but who do not provide information for reconciliation, must be certified as a reconciliation participant. A more efficient approach would be to require these generators to be certified as a generator providing metering information for pricing purposes.

	Problem 4: The definition of 'reconciliation participant' does not refer to 'dispatchable load purchasers' by name Dispatchable load purchasers are a reconciliation participant under subparagraph (e) of the definition of 'reconciliation participant'. The Code defines dispatchable load purchasers as 'purchasers', and a 'purchaser' in turn is defined under the Code to mean a person who buys electricity from the clearing manager. This is an opaque way of defining a dispatchable load purchaser as a reconciliation participant. The Code would be much clearer if the definition of 'reconciliation participant' explicitly referred to dispatchable load purchasers. Problem 5: The definition of 'reconciliation participant' does not need to refer to the Authority or the Rulings Panel The definition of "reconciliation participant" explicitly excludes the Authority and the Rulings Panel as a reconciliation participant. This exclusion is unnecessary. Section 7(3) of the Act says the Authority is an industry participant to the extent that the Authority performs functions as an industry service provider. However, the definition of 'reconciliation participant' does not include any industry service provider roles. As a result, the Authority is not a reconciliation participant even in circumstances where the Authority is performing any functions as an industry participant. The reference to the Rulings Panel in the definition of reconciliation participant is unnecessary because section 7 of the Act does not list the Rulings Panel as an industry participant. Problem 6: Part 15 of the Code needs to sometimes refer to 'participant' rather than 'reconciliation participant' Under the revised definition of 'reconciliation participant' in this Code amendment proposal, references to 'reconciliation participant' in several clauses in Part 15 of the Code should instead just be references to 'participant'. This is to avoid the amended definition of 'reconciliation participant' being circular in meaning. In the relevant Part 15 clauses there is further definition that limits the application of the clause. Therefore, removal of the word 'reconciliation' does not widen the scope of the obligations any further than currently.
Proposal	The Authority proposes to amend the Code, as follows: • Amend the definition of 'reconciliation participant' so that it includes only those participants that must provide information for reconciliation under clauses 15.4-15.11, and make several consequential amendments to clauses in Part 15, including replacing the term 'reconciliation participant' with 'participant', thereby avoiding the amended definition being circular in meaning. • Insert new clause 13.138C, to require generators that no longer fall within the definition of reconciliation participant, and therefore no longer need to be certified and audited as a

	reconciliation participant, to still be certified and audited if they provide metering information to the relevant grid owner as part of the pricing process. • Insert new clause 16A.25A to specify the time frame for a generator to undertake an audit under proposed new clause 13.138C. • Amend the definition of 'reconciliation participant' to expressly include a dispatchable load purchaser and make several consequential amendments to clauses in Part 15. • Remove the references to the Authority and the Rulings Panel from the definition of reconciliation participant. • Make minor consequential amendments to the following clauses in Part 15, to clarify their meaning—clauses 15.5, 15.37A and 15.38, and clauses 2B to 8 of Schedule 15.1.
Proposed Code amendment	**1.1 Interpretation** (1) In this Code, unless the context otherwise requires,— … **reconciliation participant** means a **participant** ~~(excluding the **Authority** (even if the **Authority** acts as a **market operation service provider**) and the **Rulings Panel**)~~ that ~~who—~~ (a) is ~~any~~ one of the following: (i)~~(a)~~ a **retailer** when purchasing **electricity** from, or selling **electricity** to, the **clearing manager**: (ii)~~(b)~~ a **generator**: (iii)~~(c)~~ a **network** owner: (iv)~~(d)~~ a **distributor**: (v)~~(e)~~ a person who purchases **electricity** from or sells **electricity** to the **clearing manager**, including a **dispatchable load purchaser**: and (b) provides information to the **reconciliation manager** in accordance with clauses 15.4 to 15.11 … **Part 13** … **13.138C Generators to arrange for regular audits** Each **generator** with one or more obligations under clauses 13.136 to 13.138 of this Code must, in respect of these obligations,— (a) obtain and maintain **certification** under Schedule 15.1 to be permitted to perform, or to have performed by an agent or agents, any of these obligations; and (b) arrange to be **audited** regularly under Part 16A.

…

Part 15

…

15.4 Submission information to be delivered for reconciliation

(1) Each ~~**reconciliation**~~ **participant** must, by 1600 hours on the 4th **business day** of each **reconciliation period**, ensure that **submission information** has been delivered to the **reconciliation manager** for all **NSPs** for which the ~~**reconciliation**~~ **participant** is recorded in the **registry** as having traded **electricity** during the **consumption period** immediately before that **reconciliation period**, in accordance with Schedule 15.3.

(2) Each ~~**reconciliation**~~ **participant** must, by 1600 hours on the 13th **business day** of each **reconciliation period**, ensure that **submission information** has been delivered to the **reconciliation manager** for all **points of connection** for which the ~~**reconciliation**~~ **participant** is recorded in the **registry** as having traded ~~trading~~ **electricity** during any **consumption period** being reconciled in accordance with clauses 15.27 and 15.28, and in respect of which the ~~**reconciliation**~~ **participant** has obtained revised **submission information**, in accordance with Schedule 15.3.

15.5 Preparing and submitting submission information

(1) In preparing and submitting **submission information**, a ~~**reconciliation**~~ **participant** must ensure that **volume information** for each **ICP** is allocated to the **NSP** indicated by the data in the **registry** for the relevant **consumption period** at the time the ~~**reconciliation**~~ **participant** assembles the **submission information**.

(2) In preparing and submitting **submission information**, a ~~Each~~ ~~**reconciliation**~~ **participant** must derive **volume information** in accordance with Schedule 15.2.

(3) If a notice under clause 15.13 is in force for an **embedded generating station** in relation to a **point of connection**, a ~~**reconciliation**~~ **participant** ~~who~~ that trades at the **point of connection** is not required to comply with clause 15.4 or this clause in relation to **electricity** generated by the **embedded generating station** to which the notice relates.

15.37A Reconciliation participants ~~and dispatchable load purchasers~~ to arrange for regular audits

Each **reconciliation participant** ~~and each~~ ~~**dispatchable load purchaser**~~ with one or more obligations under this Part must arrange to be **audited** regularly ~~in accordance with~~ under Part 16A in respect of these obligations ~~the~~ ~~**reconciliation participant's**~~ ~~or~~ ~~**dispatchable load purchaser's**~~ ~~obligations under this Part~~.

15.38 Functions requiring certification

(1) Subject to clauses 2A and 2B of Schedule 15.1, a **reconciliation participant** ~~(except an **embedded generator** selling **electricity** directly to another **reconciliation participant**)~~ must obtain and maintain **certification** ~~in accordance with~~ under Schedule 15.1 ~~in order~~ to be permitted to perform, or to have performed by ~~way of~~ an agent or agents, any of the following functions ~~in compliance with~~ under this Code:

(a) maintaining **registry** information and performing **ICP** switching (except if the maintenance of **registry** information is carried out by a **distributor** ~~in accordance with~~ under Part 11):

(b) gathering and storing **raw meter data**:

(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**:

(iv) *[Revoked]*

(d) delivery of:

(i) a report under clause 15.6 and the calculation of the number of **ICP days** detailed in the report:

(ii) **electricity supplied** information under clause 15.7:

(iii) information from **retailer** and **direct purchaser half hourly** metered **ICPs** under clause 15.8:

(da) *[Revoked]*

(db) *[Revoked]*

(e) provision of **submission information** for **reconciliation**~~:~~

~~(f) provision of **metering information** to the relevant **grid owner** in accordance with subpart 4 of Part 13~~.

(1A) A **dispatchable load purchaser** must obtain and maintain **certification** ~~in accordance with~~under Schedule 15.1 ~~in order~~ to be permitted to perform, or to have performed by ~~way of~~ an agent or agents, any of the following functions ~~in compliance with~~under this Code:

(a) gathering and storing **raw meter data**:

(b) 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**:

(c) providing **dispatchable load information**.

~~(1B) For the purposes of subclause (1A), each reference to a **reconciliation participant** in Schedule 15.1 is to be read as a reference to a **dispatchable load purchaser**.~~

(2) *[Revoked]*

…

Schedule 15.1

1 Contents of this Schedule

This Schedule sets out—

(a) *[Revoked]*

(b) the requirement for—

(i) **reconciliation participants** to be **certified** to perform the functions specified in clause 15.38; and

(ii) **generators** that are not **reconciliation participants** to be **certified** to perform any of the obligations specified under clauses 13.136 to 13.138;~~,~~ and

(ba) the process for obtaining and renewing that **certification.**

(c) *[Revoked]*

…

2A Requirement for certification

(1) Despite clause 15.38(1) and (1A), a **reconciliation participant** that is required to obtain **certification** under clause 15.38 must obtain **certification** no later than,—

(a) in the case of a **reconciliation participant** that is recorded in the **registry** as being responsible for fewer than 100 **ICPs** of the kind described in subclause (2), 12 months after the **reconciliation participant** first performs a function specified in clause 15.38(1); or

(b) in every other case, the later of—

(i) 6 months after the date on which the **reconciliation participant** first performs, including by using an agent, a function specified in clause 15.38~~(1)~~; or

(ii) the date on which the **reconciliation participant** is recorded in the **registry** as being responsible for 100 or more **ICPs** of the kind described in subclause (2).

(2) The kind of **ICP** referred to in subclause (1) is an **ICP** at which there is—

	(a) 1 or more **category 1 metering installations** and no other kind of **metering installation**; and (b) no **unmetered load**. (3) A **generator** that is not a **reconciliation participant** and that is required to obtain **certification** under clause 13.138C must obtain **certification** no later than 6 months after the date on which the **generator** first performs, including by using an agent, an obligation under clauses 13.136 to 13.138. **2B ~~Reconciliation participants~~Participants to obtain Authority approval before performing certain functions** (1) A **reconciliation participant** that proposes to perform a function listed in clause 15.38~~(1)~~ without obtaining **certification** (in reliance on clause 2A) must obtain the **Authority's** prior approval. (1A) A **generator** that is not a **reconciliation participant** and that proposes to perform an obligation under clauses 13.136 to 13.138 without obtaining **certification** (in reliance on clause 2A) must obtain the **Authority's** prior approval. (2) The **Authority** must give its approval if it is satisfied, on the basis of information provided to it by the **~~reconciliation~~ participant** specified in subclause (1) or subclause (1A), that the **~~reconciliation~~ participant** complies with ~~such of~~ the requirements specified in subclause (3) ~~as are relevant~~ that apply to the **~~reconciliation~~ participant**. (3) The requirements are that the **~~reconciliation~~ participant** must— (a) be capable of producing **submission information** accurately: (aa) where required, be capable of providing the **half-hour metering information** required under clauses 13.136 to 13.138: (b) be capable of performing the functions described in clause 15.38(1)(d): (c) be capable of switching an **ICP** in accordance with Schedule 11.3: (d) be capable of managing an **ICP** in accordance with Schedule 11.1: (e) understand its obligations under this Code. **3 Performance of ~~reconciliation~~ participant's obligations by agent** A **~~reconciliation~~ participant** may perform any obligation under this Schedule by using an agent, and for that purpose, every act or omission of a **~~reconciliation~~ participant's** agent is deemed to be an act or omission of the **~~reconciliation~~ participant**. **4 Obtaining certification**

(1) A ~~**reconciliation**~~ **participant** requiring **certification** to perform the functions specified in clause 15.38 or the obligations under clauses 13.136 to 13.138 must apply in writing to the **Authority** in the **prescribed form**, at least 2 months before the intended date of **certification**.

(2) When making an application under subclause (1), t~~T~~he ~~**reconciliation**~~ **participant** must:

(a) promptly provide such other information as the **Authority** may reasonably request; and

(b) indicate to the **Authority** the information gathering, processing and management functions the **participant** intends to perform and who it intends to use to perform those functions.

~~(3) The **reconciliation participant** must indicate to the **Authority** the information gathering, processing and management functions it intends to perform and who it intends to use to perform those functions.~~

5 Granting certification

(1) The **Authority** must grant **certification** to a **reconciliation participant** or **generator** only if—

(a) the **Authority** is satisfied, on the basis of an **audit** report provided to the **Authority** under Part 16A, that the ~~**reconciliation**~~ **participant** meets the requirements relevant to the functions specified in clause 15.38 or the obligations under clauses 13.136 to 13.138 for which the ~~**reconciliation**~~ **participant** is seeking **certification**.

(b) *[Revoked]*

(2) A ~~**reconciliation**~~ **participant** is responsible for appointing an **auditor** to undertake the **audit** required by subclause (1).

(3) *[Revoked]*

6 Lists of certified reconciliation participants

The **Authority** must **publish**, and keep updated~~,~~—

(a) a list of ~~**certified**~~ ~~**reconciliation**~~ **participants** **certified** under clause 13.138C and clause 15.38 including ~~includes~~, for each ~~**reconciliation**~~ **participant**, the date on which the **certification** expires.

(b) *[Revoked]*

7 Renewal of certification

(1) **Certification** must not be granted for a term of more than 24 months.

(2) The **Authority** must renew a ~~**reconciliation**~~ **participant's certification** for a further term of not more than 24 months if the **Authority** is satisfied on the basis of an **audit** report provided to the **Authority** under Part 16A that the ~~**reconciliation**~~ **participant** continues to meet the requirements specified in clause 5.

8 Changes that affect certification

(1) *[Revoked]*

(1A) If there is a material change to a ~~**reconciliation**~~ **participant's** systems or processes such that an **audit** is required under clause 16A.11, the **Authority** must, on receiving the **audit** report required by that clause, decide whether to continue the ~~**reconciliation**~~ **participant's certification**.

(2) The **Authority** must, by notice to the ~~**reconciliation**~~ **participant**, continue the ~~**reconciliation**~~ **participant's certification** if the **Authority** is satisfied that the ~~**reconciliation**~~ **participant** will continue to meet the requirements in clause 5 after the change has come into effect.

(3) A ~~**reconciliation**~~ **participant's certification** is revoked if—

(a) ~~a **reconciliation**~~the **participant** fails to provide an **audit** report to the **Authority** ~~in accordance with~~under clause 16A.11; or

(b) the **Authority** gives written notice to the ~~**reconciliation**~~ **participant** that the **Authority** is not satisfied that the ~~**reconciliation**~~ **participant** will continue to meet the requirements in clause 5 after the change has come into effect.

Part 16A

16A.1 Contents of this Part

This Part specifies obligations on **participants** that perform functions under Parts 10, 11, 13 and 15 in respect of **audits** required under the following clauses:

(a) 10.17A (**Metering equipment providers** and **ATHs** to arrange for regular **audits**):

(b) 10.17B (**Authority** and **participant** requested **audits**):

(c) 11.8B (**Metering equipment providers** to arrange for regular **audits**):

(d) 11.10 (**Distributors** to arrange for regular **audits**):

(e) 11.11 (**Authority** and **participant** requested **audits**):

(ea) 13.138C (**Generators** to arrange for regular **audits**):

(f) 15.37A (**Reconciliation participants** ~~and dispatchable load purchasers~~ to arrange for regular **audits**):

(g) 15.37B (**Retailers** to arrange for **audits** in respect of **distributed unmetered load**):

(h) 15.37C (**Authority** and **participant** requested **audits**).

…

	Subpart 6A—Generator audits **16A.25A Time frame for generator audits** In relation to **audits** required under clause 13.138C, a **generator** (or an applicant for **certification** as a **generator**) must ensure that— (a) an initial **audit** is completed no later than 2 months before the date on which the **generator** (or the applicant for **certification** as a **generator**) is required to be **certified** as a **generator** under clause 2A of Schedule 15.1; and (b) further **audits** are completed as specified by the **Authority** under clause 16A.14.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry. The Authority considers the proposed amendment would do this primarily by: • clarifying and simplifying the Code, which makes it easier for participants to understand and meet their Code obligations • removing the risk of Code obligations being inadvertently placed on participants that the current definition of 'reconciliation participant' captures, but who are not required to provide information for reconciliation • making future Code changes relating to reconciliation participants simpler and lower cost for the Authority to develop. The Authority considers the proposed Code amendment would have no effect on competition or the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives, and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed Code amendment is consistent with principle 2 because it is expected to enable the Authority and participants to operate more efficiently.

Principle 3: Quantitative Assessment	It has not been practicable to quantify all of the costs and benefits of the proposed Code amendment. Hence, a partial quantitative assessment of the proposed amendment's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The primary objectives of the proposal are: • to clarify and simplify the Code • to remove the risk of Code obligations being inadvertently placed on participants that the current definition of 'reconciliation participant' captures, but who do not provide information for reconciliation. This is expected to reduce the ongoing operating costs of the Authority and those distributors and generators that are not required to provide information for reconciliation.
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 have a negligible economic cost. There will be a very minor cost associated with some participants updating their procedures (eg, generators that no longer fall within the definition of reconciliation participant no longer needing to be certified and being audited under Part 13 of the Code instead of Part 15[8]). *Benefits* The primary benefits of the proposal are: • to clarify and simplify the Code • to remove the risk of reconciliation participant obligations being inadvertently placed on distributors and generators that do not have to provide information for reconciliation • to make it simpler and lower cost for the Authority to make Code changes relating to reconciliation. As noted above, section 131A of the Act means there are hundreds, possibly thousands, of secondary network providers that come within the Code's definition of 'reconciliation participant'. This is not necessary for accurate and timely reconciliation of the electricity market, nor for accurate and timely pricing and settlement of the market. Similarly, there are a number of generators and local network owners or operators that the definition of reconciliation participant captures, but who do not need to provide information for reconciliation.

8 The Authority considers these generators would face no other incremental cost from this obligation being moved from Part 15 to Part 13 of the Code, since the audit requirements themselves would not change.

	While there is no economic benefit from these participants being reconciliation participants, there is a cost. These participants must periodically review the obligations on reconciliation participants to confirm whether a Code amendment affects them. For its part, the Authority must ensure a proposed Code amendment relating to reconciliation participants does not inadvertently place obligations on the distributors and generators described above. Avoiding these additional operating costs would represent a productive economic efficiency benefit. This benefit arising from the proposed amendment is likely to be greater than the expected cost of the amendment. The Authority might, on average, process a Code amendment that affects reconciliation participants at least once every two years.[9] The Authority may save 2–3 days of staff time developing future Code amendment proposals relating to reconciliation participants as a result of this proposal. A subset of the distributors and generators that do not provide information for reconciliation may save 2 hours of staff time per proposed Code amendment as a result of this proposal.[10] For the purposes of this cost-benefit assessment, a subset of 25–50[11] distributors and generators are assumed to save 2 hours once every 2 years. Based on these assumptions, the Authority estimates an avoided cost saving with a net present value of $12,000–$25,000.[12] In addition to this quantified benefit is the improved clarity of the Code resulting from the proposal. Although this benefit is very difficult to quantify, it is expected to be reasonably material.
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.

9 Noting this estimate of future Code amendments is based on the frequency of historical Code amendments.

10 Some of these distributors and generators are assumed to not save any time, because they would ordinarily not check for compliance with new Code obligations, or because an agent acts for several of them.

11 The Authority considers this a reasonable estimate considering there are at least several hundred of these participants.

12 Assuming a 15-year discount period and a real discount rate of 8%. (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%. In this case, for ease of analysis, we have used a point estimate of 8%. We have chosen 8%, rather than 6%, to minimise the risk of overstating the net benefit of the proposed Code amendment.)

CRP5-011 Definitions of ‘embedded network’ and ‘electrical installation’

Reference number(s)	CRP5-011 Definitions of ‘embedded network’ and ‘electrical installation’
Problem definition	Problem 1 Section 131A(1) of the Electricity Industry Act 2010 (Act) states that the Act, regulations made under the Act, and the Code apply, with all necessary modifications, to a ‘secondary network provider’ as if that provider were a distributor. Section 131A(2) defines a ‘secondary network’ and a ‘secondary network provider’ as follows: **secondary network** means equipment that— (a) is used, designed, or intended for use in, or in connection with, the conveyance of electricity; and (b) is indirectly connected to the national grid. **secondary network provider** means a business that— (a) is engaged in the conveyance of electricity on a secondary network; and (b) provides services that are substantially similar to the services provided by a distributor. The Authority considers an embedded network is a secondary network under section 131A(2) of the Act. In turn, this means the Code regulates a provider engaged in the conveyance of electricity on an embedded network as if that provider were a distributor. However, the way in which ‘embedded network’ is currently defined in the Code, and the sequence of defined terms it engages, creates ambiguity on this point. Currently, clause 1.1 of the Code defines ‘embedded network’ as follows: **embedded network** means a system of **lines**, substations, and other **works**, used primarily for the conveyance of **electricity**, that— (a) is indirectly connected to the **grid** through 1 or more other **networks**; and (b) has 1 or more **ICP identifiers** recorded in the **registry** as being connected to it. The Code defines ‘lines’ and ‘works’ as having the meaning given to them by section 5 of the Act. The Act defines ‘lines’ to mean ‘works used or intended to be used to convey electricity’. The Act then defines ‘works’ as follows: **works**— (a) means any fittings (as defined in section 2(1) of the Electricity Act 1992) that are used, designed, or intended for use in or in connection with the generation, conversion, transformation, or conveyance of electricity; but (b) does not include any part of an electrical installation (as

	defined in section 2(1) of the Electricity Act 1992). Section 2(1) of the Electricity Act defines 'electrical installation' as follows: **electrical installation**— (a) means— (i) in relation to a property with a point of supply, all fittings beyond the point of supply that form part of a system that is used to convey electricity to a point of consumption, or used to generate or store electricity; and (ii) in relation to a property without a point of supply, all fittings that form part of a system that is used to convey electricity to a point of consumption, or used to generate or store electricity; but (b) does not include any of the following: (i) an electrical appliance: (ii) any fittings that are owned or operated by an electricity generator and that are used, designed, or intended for use in or in association with the generation of electricity, or used to convey electricity from a source of generation to distribution or transmission lines: (iii) any fittings that are used, designed, or intended for use in or in association with the conversion, transformation, or conveyance of electricity by distribution or transmission lines. This sequence of defined terms creates ambiguity in the Code. If the definitions are relied upon, the lines and equipment that make up an embedded network beyond the point of supply would be excluded from the definition of 'embedded network' in the Code. This is because these lines and equipment are an 'electrical installation', and electricial installations are expressly excluded from the definition of 'works' in the Act. This incorrectly suggests that a business engaged in the conveyance of electricity on an embedded network beyond the point of supply would not be regulated by the Code, because they would not be a distributor (defined in section 5 of the Act as a business engaged in the conveyance of electricity on 'lines' other than lines that are part of the national grid). The Authority considers the application of the Code to embedded network providers could usefully be clarified by amending the definition of 'embedded network' in Part 1 of the Code. <u>Problem 2</u> Clause 1.1 of the Code defines 'electrical installation' as follows: **electrical installation** means,— (a) *[revoked]*:

	(b) all fittings that form part of a system for conveying **electricity** at any point from an **ICP** to any point from which **electricity** conveyed through that system may be consumed (including any fittings that are used or designed or intended for use by any person in, or in relation to, the generation of **electricity** for that person's use and not for supply to any other person), but does not include any electrical appliance. This definition is materially inconsistent with the definition of 'electrical installation' in the Electricity Act 1992, set out under Problem 1. In particular, the Code defines an electrical installation to include 'any fittings that are used or designed or intended for use by any person in, or in relation to, the generation of electricity for that person's use and not for supply to any other person'. This has the opposite effect of the definition of 'electrical installation' in the Electricity Act, which is that all fittings owned by an electricity generator and used in the generation of electricity are excluded from an electrical installation under that Act. This has the effect of excluding fittings used in the generation of electricity for a person's own supply. Generally it is not good regulatory practice for definitions of the same term to have different meanings or effects under related legislative instruments. This can cause confusion as to the respective obligations of industry participants. This can also potentially give rise to unintended outcomes.
Proposal	<u>Problem 1</u> To address Problem 1, the Authority proposes to amend the definition of 'embedded network' to remove the references to 'lines' and 'works', and to make the definition consistent with the definition of 'secondary network' in section 131A of the Act. <u>Problem 2</u> To address Problem 2, the Authority proposes to: a) replace the defined term 'electricial 'installation' with a new defined term, 'electricial facility', in Part 1 of the Code and replace all uses of the term 'electrical installation' with 'electrical facility' except for references to 'electrical installation' contained in the templates in Part 12A of the Code[13] for the reason discussed below, and b) remove the reference to 'electrical installation' in clause

[13] Refer specifically to:

- Schedule 12A.1, Appendix A: Default agreement – Distributions on behalf of distributor
- Schedule 12A.1, Appendix B: Default agreement – Provision of trust and co-operative company information
- Schedule 12A.1, Appendix C: Default agreement – Provision of consumption data
- Schedule 12A.4, Appendix A: Default distributor agreement for distributors and traders on local networks (interposed).

	11.30B(4), in a manner that improves the clarity of the clause. The Authority considers it appropriate to retain, for the time being, the defined meaning of 'electrical installation' in the templates in Schedule 12A.1 and Schedule 12A.4, since any changes to this meaning are more appropriately considered as part of the Authority's review of the regulatory settings for distribution networks.
Proposed Code amendment	**1.1 Interpretation** (1) In this Code, unless the context otherwise requires,– … **decommissioning** means— (a) the permanent removal from service of— (i) an **asset**; or (ii) a **point of connection**; or (iii) a **metering installation** asociated with a **point of connection**; or (b) for the purposes of Parts 11 and 15, the permanent removal of a **point of connection** by— (i) permanently removing an **electrical facility~~installation~~** associated with the **point of connection**; or (ii) changing the allocation of electrical loads between **points of connection** with the effect of making the **point of connection** obsolete; or (iii) in the case of a **distributor**-only **ICP** for an **embedded network**, the **embedded network** ceasing to exist and **decommission** and **decommissioned** have corresponding meanings … **electrical facility~~installation~~** means,— (a) *[revoked]* (b) all fittings that form part of a system for conveying electricity at any point from an **ICP** to any point from which **electricity** conveyed through that system may be consumed (including any fittings that are used or designed or intended for use by any person in, or in relation to, the generation of **electricity** for that person's use and not for supply to any other person), but does not include any electrical appliance,— and **electrical facilities** has a corresponding meaning … **embedded network** means equipment that is used, designed, or intended for use in, or in connection with, ~~a system of **lines**, substations, and other **works**, used primarily for~~ the conveyance of **electricity**, and that— (a) is indirectly connected to the **grid** through 1 or more other **networks**; and

	(b) has 1 or more **ICP identifiers** recorded in the **registry** as being connected to it … **ICP** means an installation control point being 1 of the following— (a) a **point of connection** at which the **electrical** **facility** ~~**installation**~~ for a **retailer's** customer is connected to a **network** other than the **grid**: connected to the **grid** through 1 or more other **networks**; and (b) a **point of connection** between a **network** and an **embedded network**: (c) a **point of connection** between a **network** and **shared unmetered load** … **11.30B Provision of information on electricity plan comparison site** … (4) The information required by subclause (1) must also be clearly and prominently provided at least once every calendar year to each customer ~~whose **electrical installation** is connected~~ the **retailer** supplies **electricity** to at an **ICP** referred to in subclause (1). … **Schedule 11.1** … **13 "New" status** The **ICP** status of "New" must be managed by the relevant **distributor** and indicates that— (a) the associated **electrical** **facilities** ~~**installations**~~ are in the construction phase; and (b) the **ICP** is not ready for the **trader** to authorise the **electrical connection** of the **ICP**. **14 "Ready" status** (1) The **ICP** status of "Ready" must be managed by the relevant **distributor** and indicates that— (a) the associated **electrical** **facilities** ~~**installations**~~ are ready for connecting to the **electricity** supply; or (b) the **ICP** is ready for the **trader** to authorise the **electrical connection** of the **ICP**. (2) Before an **ICP** is given the "Ready" status, the relevant **distributor** must— (a) identify the **trader** that has taken responsibility for the **ICP**; and (b) ensure that the **ICP** has a single **price category** code.

	… **17 "Active" status** (1) The **ICP** status of "Active" must be managed by the relevant **trader** and indicates that— (a) the associated **electrical** <u>facilities</u> ~~installations~~ are **electrically connected**; and (b) a **trader** must provide information related to the **ICP**, in accordance with Part 15, to the **reconciliation manager** for the purpose of compiling **reconciliation information**. (2) Before an **ICP** is given the "Active" status, the **trader** must ensure that— (a) the **ICP** has only 1 **embedded generator**, **direct purchaser**, or customer of a **retailer**; and (b) the **electricity** consumed is quantified by a **metering installation** or a method of calculation approved by the **Authority**. … **20 "Decommissioned" status** (1) The **ICP** status of "Decommissioned" must be managed by the relevant **distributor** and indicates that the **ICP** is permanently removed from future switching and reconciliation processes. (2) **Decommissioning** occurs when— (a) **electrical** <u>facilities</u> ~~installations~~ associated with the **ICP** are physically removed; or (b) there is a change in the allocation of electrical loads between **ICPs** with the effect of making the **ICP** obsolete; or (c) in the case of a **distributor**-only **ICP** for an **embedded network**, the **embedded network** no longer exists.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it would promote the efficient operation of the electricity industry by reducing costs for various parties in interpreting and applying the Code by clarifying that: a) a person engaged in the conveyance of electricity on an embedded network is regulated by the Code b) an electrical installation (to be renamed electrical facility) includes fittings used or designed or intended for use in, or in relation to, the generation of electricity for use by the person at the installation. The proposed Code amendment is expected to have little or no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.

Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 remove costs associated with parties interpreting the Code.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a postitive net benefit, for the reasons set out below. *Costs* The Authority considers there would be zero or negligible costs from this Code amendment. *Benefits* The Authority considers the benefit of the proposed Code amendment would be a saving in time and effort (and therefore cost) for parties wanting to know: a) whether a person engaged in the conveyance of electricity on an embedded network is regulated by the Code and the way in which that person is regulated because the amendment clarifies that embedded networks fall within the definition of "secondary network" in section 131A of the Act. b) whether the Code places regulatory obligations on an installation that includes fittings used or designed or intended for use in, or in relation to, the generation of electricity for use by the person at the installation.
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.

CRP5-012 Retention of metering records

Reference number(s)	CRP5-012 Retention of metering records
Problem definition	Subclause 4(3) of Schedule 10.6 of the Code requires a metering equipment provider (MEP) to keep metering records for metering installations it is, or was, responsible for. The subclause reads as follows: **4 Metering equipment provider record keeping and documentation** … (3) A **metering equipment provider** must retain **metering records** relating to— (a) a **metering component** in a **metering installation** for which it is or was responsible, for at least 48 months after the **metering component** is removed from the **metering installation**, even if— (i) the **metering installation** is subsequently **decommissioned**; or (ii) the **metering equipment provider** ceases to be responsible for the **metering installation**; and (b) a **metering installation** for which it is responsible, for at least 48 months after the date on which— (i) the **metering installation** is **decommissioned**; or (ii) the **metering equipment provider** ceases to be responsible for the **metering installation**. <u>Problem 1</u> In February 2016, the Authority amended subclause 4(3) of Schedule 10.6 to clarify that an MEP must keep metering records for at least 48 months after the MEP ceases to be responsible for the metering installation. However, paragraph 4(3)(b) has proved open to different interpretations about how long an MEP must keep metering records relating to a metering installation. As a result, participants and the Authority are incurring unncessary transaction costs interpreting MEPs' obligations under that paragraph. Currently, paragraph 4(3)(b) can be interpreted in two ways: a) an MEP must keep metering records relating to a metering installation for at least 48 months only if: i) the metering installation is decommissioned, or ii) the MEP ceases to be responsible for the metering installation b) an MEP must keep metering records relating to a metering installation indefinitely, in the absence of: i) the metering installation being decommissioned, or ii) the MEP ceasing to be responsible for the metering installation. <u>Problem 2</u> Subclause 4(3) of Schedule 10.6 does not address how long metering records must be kept if a metering installation is recertified. How long records should be retained depends on the type of recertification involved.

	Recertification using statistical sampling (for category 1 metering installations only) or comparative recertification (for category 2 metering installations only) relies on the metering installation's original certification. Therefore, the metering records for the original certification must be retained as part of verifying the accuracy of the metering installation. On the other hand, the metering records for a metering installation that is recertified using either the selected component method or the fully calibrated method need not be kept for longer than 48 months after the certification expires. This is because these two types of recertification involve the full suite of tests required to verify the accuracy of the metering installation. <u>Problem 3</u> If an MEP were to cease being an MEP, the benefit of retaining the metering records would be lost if those records were to be destroyed at the time the MEP ceases business. This loss could be avoided if the MEP were required to pass the metering records to the MEP(s) that were taking over responsibility for the affected metering installations. Currently, the Code does not provide for this, nor is it clear that the MEP(s) taking over responsibility for the affected metering installations must retain the metering records as if they were the original MEP.
Proposal	<u>Problem 1</u> Amend clause 4 of Schedule 10.6 to clarify that an MEP must keep metering records for a metering installation it is or was responsible for, unless: a) the metering installation is decommissioned, in which case the MEP must retain the records for at least 48 months after the metering installation is decommissioned or b) the MEP ceases to be responsible for the metering installation, in which case the MEP must retain the records for at least 48 months after the MEP ceases to be responsible for the metering installation. <u>Problem 2</u> Amend clause 4 of Schedule 10.6 to clarify the obligations on MEPs to retain metering records for recertified meters. In particular, clarify that an MEP may stop keeping metering records only if at least 48 months have passed since the metering installation was recertified using either the selected component method or the fully calibrated method. <u>Problem 3</u> Amend clause 4 of Schedule 10.6 to require an MEP that is ceasing to be an MEP to pass metering records to the MEP(s) that are taking over responsibility for the affected metering installations. The incoming MEP(s) must retain the metering records provided by the outgoing MEP in accordance with clause 4 of Schedule 10.6.
Proposed Code amendment	**Schedule 10.6** … **4 Metering equipment provider record keeping and documentation** … (3) A **metering equipment provider** must retain **metering records** relating to—

	~~(a)~~ a **metering component** in a **metering installation** for which it is or was responsible, for at least 48 months after the **metering component** is removed from the **metering installation**, even if— (a)~~(i)~~ the **metering installation** is subsequently **decommissioned**; or (b)~~(ii)~~ the **metering equipment provider** ceases to be responsible for the **metering installation**.~~; and~~ ~~(b) a **metering installation** for which it is responsible, for at least 48 months after the date on which—~~ ~~(i) the **metering installation** is **decommissioned**; or~~ ~~(ii) the **metering equipment provider** ceases to be responsible for the **metering installation**.~~ (4) A **metering equipment provider** must retain **metering records** relating to a **metering installation** for which it is or was responsible, unless: (a) the **metering installation** is **decommissioned**; or (b) the **metering equipment provider** ceases to be responsible for the **metering installation**; or (c) the **metering installation** has been **recertified** in accordance with clause 11 of Schedule 10.7 or clause 13 of Schedule 10.7. (5) If subclause (4)(a), 4(b) or 4(c) applies, the **metering equipment provider** must retain the **metering records** until at least 48 months have passed since the event described in those subclauses. **4A Transfer of metering records** (1) A **metering equipment provider** that intends to cease being a **metering equipment provider** (MEP A) must transfer its **metering records** to the **metering equipment provider** (MEP B) that is taking responsibility for the **metering components** or **metering installations** that MEP A is responsible for. (2) If a **metering equipment provider** (MEP B in subclause (1)) receives **metering records** under subclause (1), it must retain those **metering records** in accordance with clause 4.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objectives, 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: • Reducing the possibility of metering records being destroyed in an untimely manner because of an MEP ceasing to be an MEP. This would reduce costs associated with resolving issues with metering installations (eg, customer complaints regarding metering accuracy). • Clarifying the Code requirements relating to the retention of metering records by MEPs. This would reduce the cost to MEPs of understanding and complying with the Code. The proposed Code amendment is expected to have no effect on competition, the reliable supply of electricity, the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions.
Assessment against Code	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.

amendment principles	
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 electricity market operational costs by: a) clarifying when MEPs can dispose of old metering records, and b) reducing the possibility of metering records being destroyed in an untimely manner because of an MEP ceasing to be an MEP.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers that the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the incremental cost associated with addressing Problems 1 and 2 would be very small. It would relate to MEPs making minor updates to their policies / procedures. The Authority considers the incremental cost associated with addressing Problem 3 would also be minor. This cost would relate to an outgoing MEP providing the incoming MEP(s) with relevant metering records, and the incoming MEP(s) retaining these records. The Authority considers this cost would be minimal because of: a) the metering records being electronic and easily transferable and storable,[14] and b) the expected infrequency of an MEP ceasing to be an MEP. *Benefits* The Authority considers the incremental benefit associated with the amendment would be small. It would relate to the Code obligations for the retention of metering records by MEPs being clearer, which would reduce: a) the time and effort spent by MEPs, auditors and Authority staff interpreting the obligations. This ongoing saving in effort is expected to be larger than the one-off cost for MEPs to update relevant policies / procedures

[14] The Authority understands many MEPs choose to keep records indefinitely because the cost of doing so is low.

	b) costs associated with resolving issues / disputes with metering installations. These disputes are likely to be in relation to the accuracy of the metering installation and/or the correction of errors in metering information. *Net benefit* The Authority considers, on balance, that the benefits are likely to be larger than the cost associated with resolving the issues. This is based on the Authority's obervations over the years of the time and effort expended by affected parties in relation to metering disputes.
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.

CRP5-013 Retention of ATH records

Reference number(s)	CRP5-013 Retention of ATH records
Problem definition	Clause 13 of Schedule 10.4 requires an ATH[15] to retain certain records (ATH records). The clause reads as follows: **13 Retention of ATH records** An **ATH** must, for each activity regulated under this Part in relation to a **metering installation** and **metering component** that it **certifies** and a **metering component** that it **calibrates**, retain, for at least 48 months after the date of **decommissioning** the **metering installation** or **removal** of a **metering component**,— (a) all of its records, certificates, and reports; and (b) all **certification reports** produced by the **ATH.** <u>Problem 1</u> Clause 13 of Schedule 10.4 is overly difficult to interpret, because it combines requirements for retention of metering installation records and requirements for retention of metering component records. Participants and the Authority are incurring unncessary transaction costs interpreting ATHs' obligations under the clause. <u>Problem 2</u> As currently worded, clause 13 of Schedule 10.4 has the effect of requiring an ATH to keep indefinitely: a) ATH records relating to a metering component, in the absence of the metering component being removed from the metering installation, b) ATH records relating to a metering installation, in the absence of the metering installation being decommissioned. This imposes an unnecessary cost on ATHs. ATH records kept for longer than 48 months after expiry of the certification to which the records relate are unlikely to ever be used. This is because the 48 month period aligns with the end of the settlement wash-up process under the Code. <u>Problem 3</u> If an ATH were to cease being an ATH, the benefit of retaining the ATH records would be lost if those records were to be destroyed at the time the ATH ceases business. This loss could be avoided if the ATH were required to pass the ATH records to the metering equipment provider(s) (MEP(s)) with responsibility for the metering installations to which the ATH records relate. Currently, the Code does not provide for this.
Proposal	<u>Problem 1</u> Amend Schedule 10.4 of the Code to separate out ATHs' retention obligations in relation to metering installation records and metering component records. Clause 13 would set out ATHs' obligations for the

[15] The Code defines an "ATH" in clause 1.1(1) to mean a person who is approved under Schedule 10.3 to operate an approved test house.

	retention of records for metering components. New clause 13A would set out ATHs' obligations for the retention of ATH records for metering installations. Problem 2 Amend clause 13 of Schedule 10.4 and add new clause 13A of Schedule 10.4 to require an ATH to keep ATH records for at least 48 months after expiry of the certification to which the records relate. Problem 3 Amend clause 13 of Schedule 10.4 and draft new clause 13A of Schedule 10.4 to require an ATH that is ceasing to be an ATH to pass ATH records to the MEP(s) that are responsible for the affected metering installations. The Authority proposes a consequential amendment to Schedule 10.6, to require the MEP who is receiving these ATH records to retain them for at least 48 months after the expiry of the certification to which the records relate.
Proposed Code amendment	**Schedule 10.4** … **13 Retention of ATH records** relating to **metering components** (1) An **ATH** must, for each activity regulated under this Part in relation to a ~~**metering installation** and~~ **metering component** that it ~~**certifies** and a **metering component** that it~~ **calibrates** or **certifies**, retain~~,~~ the following records relating to that **metering component** for at least 48 months after the **certification** expiry date of ~~**decommissioning**~~ the ~~**metering installation** or **removal** of a~~ **metering component**,— (a) all of ~~it's~~ the **ATH**'s records, certificates, and reports: and (b) all **certification reports** produced by the **ATH**: and (c) all **calibration reports** produced by the **ATH**. (2) If an **ATH** intends to cease being an **ATH**, the **ATH** must transfer the records described in subclause (1) to the **metering equipment provider** recorded in the **registry** as responsible for the **metering installation** where the **metering component** is installed. **13A Retention of ATH records relating to metering installations** (1) An **ATH** must, for each activity regulated under this Part in relation to a **metering installation** that the **ATH certifies**, retain the following records relating to that **metering installation** for at least 48 months after the **certification** expiry date of the **metering installation**: (a) all of the **ATH's** records, certificates, and reports: and (b) all **certification reports** produced by the **ATH.** (2) If an **ATH** intends to cease being an **ATH**, the **ATH** must transfer the records described in subclause (1) to the metering equipment provider recorded in the **registry** as being responsible for the **metering installation.**

	Schedule 10.6 … **4A Metering equipment provider retention of ATH records** If a **metering equipment provider** receives an **ATH** record under clause 13(2) of Schedule 10.4 or clause 13A(2) of Schedule 10.4, the **metering equipment provider** must retain that record for at least 48 months after the date of expiry of the **certification** of the **metering installation** or **metering component** to which the record relates.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objectives, 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) Clarifying the Code requirements relating to the retention of ATH records. This would reduce the costs ATHs incur understanding and complying with the Code. b) Avoiding the costs of storing ATH records unnecessarily. c) Reducing the possibility of ATH records being destroyed in an untimely manner because of an ATH ceasing to be an ATH. This would reduce costs associated with investigating issues with metering installations (eg, where there may be questions regarding accuracy or calibration of the installation and metering components). The proposed Code amendment is expected to have no effect on competition or the reliable supply of electricity, the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions
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 objectives 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 electricity market operational costs by: a) making it easier for industry participants to understand ATHs' obligations around the retention of metering component records and metering installation records, b) removing the unnecessary retention of ATH records, and c) reducing the possibility of ATH records being destroyed in an untimely manner because of an ATH ceasing to be an ATH.
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 incremental cost associated with addressing Problem 1 would be very small. It would relate to ATHs making minor updates to their policies / procedures. The Authority considers there would be no cost associated with addressing Problem 2. The Authority considers the incremental cost associated with addressing Problem 3 would also be minor. This cost would relate to an outgoing ATH providing MEPs with relevant metering records, and the MEPs retaining these records. The Authority considers this cost would be minimal because: a) ATH records are electronic and easily transferred and stored,[16] and b) the expected infrequency of an ATH ceasing to be an ATH. *Benefits* The Authority considers the incremental benefit associated with addressing Problem 1 would be small. It would relate to the Code obligations for the retention of ATH records being clearer, which would reduce the time and effort spent by ATHs, auditors and Authority staff interpreting the obligations. This ongoing saving in effort is expected to be larger than the one-off cost for ATHs to update relevant policies / procedures. The Authority considers the incremental benefit associated with addressing Problem 2 would also be small. This is because of the low cost of storing ATH records electronically. The Authority considers the main incremental benefit associated with addressing Problem 3 would be a reduction in periodic costs associated with investigations into the accuracy of metering components and metering installations. These investigations might include the cicumstances under which the metering components / installations were certified. *Net benefit* Based on the above analysis, the Authority is satisfied that the benefits of the proposed Code amendment outweigh the costs.

[16] The Authority understands many ATHs choose to keep records indefinitely because the cost of doing so is low.

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.

CRP5-014 Final interrogation of modified or temporarily removed metering installations

Reference number(s)	CRP5-014 Final interrogation of modified or temporarily removed metering installations
Problem definition	Clause 10.23A of the Code sets out who is responsible for the final interrogation of a metering installation that is to be decommissioned. The Authority has identified a gap in the Code, which is that clause 10.23A does not include provisions for the final interrogation of metering installations that are being modified (including through the replacement of a meter) or temporarily removed. This is resulting in market transaction costs being higher than necessary, because participants are unclear about their obligations in relation to final interrogations when a metering installation is modified or temporarily removed. Market settlement uses estimated metering information when there is no final interrogation of a metering installation that is being modified or removed temporarily. Estimated metering information is not as accurate as information from interrogating the meter.
Proposal	Amend clause 10.23A so that it also applies to the final interrogation of a metering installation that is being modified or temporarily removed.
Proposed Code amendment	**10.23A Modifying, removing temporarily or ~~D~~decommissioning of metering installation at ICP** (1) If a **metering installation** at an **ICP** is to be modified, removed temporarily, or **decommissioned**, but the **ICP** is not being **decommissioned**, the **metering equipment provider** that is responsible for modifying, removing temporarily, or **decommissioning** the **metering installation** must,— (a) if the **metering equipment provider** is responsible for **interrogating** the **metering installation**— (i) arrange for a final **interrogation** to take place before the **metering installation** is modified, removed temporarily or **decommissioned**; and (ii) provide the **raw meter data** from the **interrogation** to the **trader** that is recorded in the **registry** as being responsible for the **ICP**; or (b) if another **participant** is responsible for **interrogating** the **metering installation**, advise the other **participant** not less than 3 **business days** before the modification, temporary removal, or **decommissioning**— (i) of the date and time of the modification, temporary removal, or **decommissioning**; and (ii) that the **participant** must carry out a final **interrogation**. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objectives, 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: d) clarifying who is responsible for interrogating the metering installation when the installation is modified or temporarily removed

	or ensuring that occurs e) reducing the possibility of metering installations being modified or temporarily removed without the metering installation first being interrogated f) improving the accuracy of the reconciliation process by using actual meter readings instead of estimates. The proposed Code amendment would also facilitate the accurate invoicing of traders and consumers, which means the proposed amendment would be in the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The proposed Code amendment is expected to have no effect on competition, the reliable supply of electricity, or the performance of the Authority in its functions.
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 objectives 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 electricity market operational costs by: a) clarifying who is responsible for the interrogation of a metering installation that is to be modified or temporarily removed b) reducing the possibility of a loss of metering data because the metering installations was modified or temporarily removed without being interrogated.
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 there may be a small incremental cost associated with the proposed requirement to interrogate metering installations that are being modified or temporarily removed. The reason why we consider this incremental cost would be small is because typically: a) If a metering equipment provider (MEP) is responsible for interrogating a metering installation, the interrogation will occur daily

	or follow the established remote read process for installations being decommissioned. b) If a participant other than an MEP is responsible for interrogating a metering installation, the interrogation will follow the established manual read process for installations being decommissioned. This will generally involve contractors who are already on-site performing the final read as part of the process to modify or temporarily remove the metering installation. c) These costs would be reduced by savings from no longer estimating meter readings. The Authority considers there would also be a very small incremental cost relating to MEPs making minor updates to their policies / procedures. *Benefits* The Authority considers the proposed Code amendment would have three benefits: a) customer bill queries would be expected to fall as a result of actual meter reads being used rather than estimated reads b) market reconciliation and settlement would be more accurate, due to accurate volumes being allocated to the correct periods c) operational cost savings from reduced time and effort spent by industry participants and Authority staff interpreting the obligations around the final interrogation of metering installations that are being modified or temporarily removed. *Net benefit* Based on the analysis above, the Authority is, on balance, satisfied the benefits of the proposed amendment would outweigh the costs. The benefits listed above are expected to be more material in nature than the identified 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.

CRP5-015 Limiting ability to remove an ICP from shared unmetered load

Reference number(s)	CRP5-015 Limiting ability to remove an ICP from shared unmetered load
Problem definition	The Code provides for the supply of unmetered load at a single point of connection that is assigned to multiple ICPs as shared unmetered load. This allows the electricity costs for an unmetered load that benefits multiple consumers (such as streetlights in a private right-of-way or a sewage pump servicing several properties) to be shared between those consumers. Clause 11.14 sets out the process for maintaining shared unmetered load. Clause 11.14(3) permits a trader (usually a retailer) to add an ICP to, or omit an ICP from, the ICPs across which the unmetered load is shared. This ensures that the costs of the unmetered load would continue to be shared equally across the consumers who benefit from it. Clause 11.14(3) can be used to correct an error, to add a new ICP if the consumer at the ICP benefits from the unmetered load (such as if a new house is built which will share the benefits of an existing shared unmetered load) or remove an existing ICP if the consumer at that ICP no longer benefits from the unmetered load (such as if a consumer installs their own sewage pump). However, some retailers are removing ICPs under clause 11.14(3) when they receive the shared unmetered load notice from the distributor as part of the switching process, even though the consumer at the ICP still benefits from the unmetered load. This results in switching customers not contributing to the costs of the unmetered load they continue to benefit from, and the full costs of the unmetered load being shared among the remaining ICPs that are assigned to that load. This is unfair. It also has the potential to undermine the effect of clause 11.14(7), which provides that a trader takes responsibility for shared unmetered load assigned to an ICP for which the trader becomes responsible as a result of a switch. Although the Authority is not aware of any instances of a consumer's ICP being *added* to a shared unmetered load that they do not benefit from, the Code does not expressly prevent this from occurring. This is a potential loophole that could disadvantage consumers and should be addressed on the same basis as ICPs which are *omitted* from shared unmetered load.
Proposal	Amend the Code to limit the trader to only adding or removing an ICP from a shared unmetered load when it is necessary to correct an error, or there is a change to the benefit the consumer at the ICP receives from the shared unmetered load.
Proposed Code amendment	**11.14 Process for maintaining shared unmetered load** (1) This clause applies if **shared unmetered load** is connected to a **distributor's network**. (2) The **distributor** must give written notice to the **registry manager**, and each **trader** responsible under clause 11.18(1)

	for the **ICPs** across which the **unmetered load** is shared, of the **ICP identifiers** of those **ICPs**. (3) A **trader** who receives written notice under subclause (2) must give written notice to the **distributor** if it wishes to add an **ICP** to or omit an **ICP** from the **ICPs** across which the **unmetered load** is shared. (3A) A **trader** giving notice under subclause (3) must give a notice to add or omit an **ICP** only to: (a) add an **ICP** if the **consumer** at the **ICP** benefits from the **shared unmetered load**; or (b) omit an **ICP** if the **consumer** at the **ICP** no longer receives benefit from the **shared unmetered load.** (4) A **distributor** who receives written notice under subclause (3) must give written notice to the **registry manager** and each **trader** responsible for any of the **ICPs** across which the **unmetered load** is shared of the addition or omission of the **ICP**. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry and the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, by ensuring that all consumers that benefit from a shared unmetered load pay their share of the costs for that load. There would also be a minor positive effect on competition as all retailers would be required to provide for the shared unmetered load at an ICP. The proposed Code amendment is expected to have no effect on competition, the reliable supply of electricity or the performance by the Authority of its functions.
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 objectives 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 ensure that shared unmetered load is maintained in such a way that the electricity supply costs are shared equally by all beneficiaries of the unmetered load. In particular, limiting the situations in which an ICP can be removed from shared unmetered load will: - reduce the disproportionate burden on the remaining consumers at the ICPs assigned to that shared unmetered load; and - prevent a consumer from avoiding their share of costs of unmetered load while still receiving a benefit.
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 costs of the proposal to be negligible. The Authority acknowledges that some retailers may not have suitable systems to bill consumers, or supply submission information to the reconcilation manager, for unmetered load (shared or standard unmetered load). This is a business decision for those retailers if they want to have access to the group of customers with unmetered load, which includes a wider pool of customers than just those with shared unmetered load. The Code amendment does not apply retrospectively, so retailers currently supplying ICPs with omited shared unmetered load can continue to do so. *Benefits* We expect the proposed Code amendment's main benefit will be to ensure the correct allocation of the cost of electricity for a shared unmetered load to the consumers that are benefiting from that load.
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.

CRP5-016 Timeframes to update registry when dependent on MEP updates

Reference number(s)	CRP5-016 Timeframes to update registry when dependent on metering equipment provider (MEP) updates
Problem definition	Schedule 11.1 of the Code imposes obligations on distributors and traders to provide certain information about ICPs to the registry manager. If that information changes, the registry manager must be notified of those changes within a specified timeframe. In particular: - a distributor must normally give notice no later than 3 business days after the change (except in relation to some changes to the NSP identifier) (Clause 8(2) of Schedule 11.1); and - a trader must give notice no later than 5 business days after the change (Clause 10(2) of Schedule 11.1). There are situations where traders and distributors may be unable to update the registry within the timeframe specified by the Code, because the metering equipment provider (MEP) must first populate the metering information on the registry. Under clauses 2–3 of Schedule 11.4, MEPs must update the registry within 10 business days of making certain changes, or 15 business days if they are becoming the responsible MEP for the ICP. Functionality in the registry enforces these requirements to ensure the integrity of the registry data, and to prevent consequential issues for other traders and the reconciliation process. As a result, a trader or distributor may breach the Code by not updating the registry within the timeframe specified by the Code, because the registry functionality prevents them from doing so. For example if a metering installation changes from NHH to HHR, registry functionality prevents the trader from updating the profile or submission type to HHR on the registry, until the updated metering details are populated by the MEP. This may not occur until 15 business days after the physical change to the metering.
Proposal	Amend the Code to recognise the dependencies on MEPs and set the timeframe for distributors and traders to update the registry to start from the date the MEP populates the information on the registry.
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) Subject to subclause (2A), t~~T~~he **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:

(aa) in the case of a change to the information provided under clause 7(1)(g), where the change is backdated, no later than 3 **business days** after the **distributor** and the **trader** responsible for the **ICP** agree on the change; and

(ab) in the case of **decommissioning** an **ICP**, by the later of—

(i) 3 **business days** after the **registry manager** has advised the **distributor** under clause 11.29 that the **ICP** is ready to be **decommissioned**; and

(ii) 3 **business days** after the **distributor** has **decommissioned** the **ICP**:

(b) in every other case, no later than 3 **business days** after the change takes effect.

(2A) Where the functioning of the **registry** prevents the **distributor** from updating the **registry** until after a **metering equipment provider** has completed its obligations relating to the **ICP** in accordance with schedule 11.4, the timeframes in subclause (2) start from the day the **metering equipment provider** completes those obligations.

(3) A **distributor** is not required to give written notice if information provided in accordance with clause 7(1)(b) changes, and applies for less than 10 **business days**.

(4) If information provided under clause 7(1)(b) changes, and applies for 10 **business days** or more, the **distributor** must—

(a) give the notice under subclause (1) no later than 13 **business days** after the change takes effect; and

(b) include in the notice the date the change occurred as the effective date for the change.

…

10 Traders to change ICP information provided to registry manager

(1) If information about an **ICP** provided to the **registry manager** in accordance with clause 9 changes, the **trader** who trades at the **ICP** must give written notice to the **registry manager** of the change.

(2) Subject to subclause 2A, t~~T~~he **trader** must give the notice no later than 5 **business days** after the change.

(2A) Where the functioning of the **registry** prevents the **trader** from updating the **registry** until after the **metering equipment provider** has completed its obligations relating to the **ICP** in accordance with schedule 11.4, the timeframes in subclause (2) start from the day the **metering equipment provider** has completed those obligations.

	(3) Despite subclause (2), if the **trader** is not able to give the notice within the timeframe specified in subclause (2) because of the implementation of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, the **trader** may give the notice up to 20 **business days** after the change. (4) Subclause (3) and this subclause expire 20 **business days** after the date on which the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011 comes into force.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, 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 ensuring the Code is aligned with the functionality of the registry, thereby reducing costs for both participants and the Authority in reporting and processing alleged Code breaches for matters the Authority is unlikely to investigate. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions.
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 objectives 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 electricity market operational costs by aligning the Code with the functionality of the registry, thereby reducing: - participants' costs for investigating breaches, self-reporting breaches to the Authority and engagement with their auditors - the Authority's costs in assessing and processing audit

	reports and participant self-reported breaches where it is unlikely (although it is a question that needs to be assessed each time) to subsequently appoint an investigator to investigate the matter.
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 costs of the amendment to be negligible. *Benefits* We expect the proposed Code amendment's main benefit will be to avoid unnecessary compliance, assessment and processing costs that may arise from an alleged Code breach.
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.

CRP5-017 Disbursement of interest from the clearing manager's bank accounts

Reference number(s)	CRP5-017 Disbursement of interest from the clearing manager's bank accounts
Problem definition	<u>Problem 1</u> Clause 14.66 of the Code requires the clearing manager to hold an operating account to receive, and pay out, settlement funds under Part 14 of the Code. When a participant prepays the clearing manager under the provisions of clause 14.30, subclause 14.30(5) requires the clearing manager to credit to a participant all interest it receives on the prepaid amount, less any applicable deduction for tax purposes. Prepayments are payments made to the clearing manager before a participant incurs the amount owing (i.e before an invoice is calculated and issued). The Code is, however, silent on the disbursement of interest the clearing manager receives on funds that are not prepayments, such as payments made by participants after an invoice is issued but before the due date. These retained funds are accumulating interest which, less any applicable deduction for tax and bank fees atributed to these accounts, should be regularly disbursed. The Authority considers that interest accummulated on funds held by the clearing manager (other than prepayments) should be disbursed to generators. The Code provides for the situation where a purchaser fails to pay the clearing manager (a default). Any shortfall in payments (that cannot be made up from the purchaser's prudential security) is passed through to the generators by scaling their payments down. This risk has been realised in both of the defaults to date. As generators are bearing the risk, any interest received should be credited to generators to compensate them for carrying this risk. The operating accounts currently hold some accumulated interest. The clearing manager has requested the Authority's advice on managing these funds, as the Code is currently silent on this matter. After the residual funds have been allocated, there needs to be a positive balance in the operating accounts to ensure the bank does not close the accounts or charge any fees for having a zero balance, and to ensure there are sufficient funds to pay any upcoming bank fees owing prior to the next amount of interest being credited. The clearing manager has advised the bank fees are approximately $500 per month. <u>Problem 2</u> Clause 14.66 requires the clearing manager to have an operating account. However, in practice the clearing manager has more than one account and the definition of operating account in Part 1 and the wording in clause 14.66 is not clear there may be more than one account.
Proposal	<u>Problem 1</u> Add a new clause to Part 14 to require the clearing manager to regularly disburse any monies remaining in the operating accounts (after any tax is deducted and to allow for amounts already allocated, anticipated bank fees are paid, and a prudent residual positive

	balance) to generators. The new clause will also set out how the residual funds are to be allocated. Problem 2 Amend the definition of operating account in Part 1 and clause 14.66 to make it clear the clearing manager may have more than one operating account.
Proposed Code amendment	**1.1(1) Interpretation** … **operating account** means the trust account or accounts established by the **clearing manager** in accordance with clause 14.66 … **14.34A Payment of residual funds from operating accounts** (1) In this clause, **residual funds** means any monies left in the **clearing manager's operating accounts** after all amounts owed by the **clearing manager** have been paid in accordance with this Part, less: (a) any applicable deduction for tax purposes; and (b) any amounts that are allocated to be paid to **participants** in accordance with this Part that have not yet been paid; and (c) any amounts required to: (i) pay any bank fees due for the next two months for the **operating accounts**; and (ii) maintain a positive balance in each **operating account** at a level that the **clearing manager** considers is reasonably prudent. (2) The **clearing manager** may use monies in the operating accounts, that are not paid or due to be paid to **participants** in accordance with this Part, to pay any bank fees due or applicable tax owing for the **operating accounts.** (3) The **clearing manager** will determine the amount of **residual funds** to be paid to each **participant** in accordance with subclause (4) as follows: (a) by determining the amount of **residual funds** as at 1600 hours on the third to last **business day** in the months of March and September: (b) by allocating those **residual funds** to each **participant** that the **clearing manager** has paid in accordance with clause 14.34, other than **grid owners**, in direct proportion to the amount the **clearing manager** has paid the **participant** in the immediately preceding six month period compared to the total amount the **clearing manager** has paid all **participants** in accordance with clause 14.34, other than **grid owners**, in that six month period;

	(c) by rounding down the amount allocated to the **participant** to the nearest cent. (4) By 1600 hours on the final **business day** in the months of March and September, the **clearing manager** must: (a) advise each **participant** that the **clearing manager** has paid in accordance with clause 14.34 in the immediately preceding six-month period, other than **grid owners,** of the amount of **residual funds** to be paid to that **participant**, as determined under subclause (3); and (b) pay any **residual funds** in its **operating accounts** in accordance with subclause (3). … **14.66 Clearing manager to establish operating account** (1) The **clearing manager** must establish, in its name, ~~an~~ at least one **operating account** with a **bank**. (2) Each ~~The~~ **operating account** must— (a) be held by the **clearing manager** as a trust account for the benefit of the persons who are entitled to receive payment from the **clearing manager** under this Part; and (b) be clearly identified as such; and (c) subject to this Code, be entirely separate from the **cash deposit accounts** and any other account of the **clearing manager**. (3) The **clearing manager** must obtain an acknowledgement from the **bank** with which each ~~the~~ **operating account** is held that— (a) the funds in that account are held on trust for the purposes set out in clause 14.33; and (b) the **bank** has no right of set-off or combination in relation to the funds.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, 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: - ensuring the clearing manager has clear instruction on how to disburse interest earned on the operating accounts - partly compensating generators for the risk of underpayment due to a purchaser's default they are required to accept. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions

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 objectives 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 electricity market operational costs by: - ensuring the clearing manager has clear instruction on how to disburse interest earned on the operating accounts - partly compensating generators for the risk of underpayment due to a purchaser's default they are required to accept.
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 costs of the amendment to be minor. The clearing manager will need to develop a process to perform the calculations and allocation, and the costs are expected to be a few thousand dollars. *Benefits* We expect the proposed Code amendment's main benefits will be to: - generators, as reimbursement of interest partly compensates them for the underpayment risk they are required to accept - the clearing manager and Authority having a clear prescribed process for dealing withj interest accumulating in the operating accounts.
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.

CRP5-018 Ensuring audit obligations remain in effect

Reference number(s)	CRP5-018 Ensuring audit obligations remain in effect
Problem definition	Part 16A of the Code contains requirements for certain participants to be audited on a regular basis. Once a participant is audited, they must submit the audit report to the Authority for review. The Authority then specifies the date by which the next audit must be completed and submited to the Authority (the 'next audit date'). Under clause 16A.14, the Authority can only advise a participant of the next audit date **after** the Authority has received the audit report from the completed audit. This causes issues in two situations: a) If a participant obtains an exemption from the requirement to be audited, and the date specified as their next audit date passes while the exemption is in effect, there is no provision for the Authority to restore the regular audit obligations on the expiry of the exemption. b) If a participant fails to submit an audit under Part 16A, they are in breach of their obligations under the Code. While the participant may agree to submit an audit as part of any settlement reached with the Authority (thereby triggering the Authority's power to set the next audit date under clause 16A.14), there is no provision for the Authority to restore the regular audit obligations if it declines to take any action in relation to the breach or discontinues an investigation (under the Electricity Industry (Enforcement) Regulations 2010) as there is no settlement agreement in these situations. While the Code does permit the Authority to conduct its own audit of specific obligations (clauses 10.17B, 11.11, and 15.37C), this does not then trigger the requirement for regular audits under Part 16A. In all cases to date when these situations have arisen, the participant concerned has voluntarily completed and submitted an audit, which has then restored the regular audit obligations. However, there is a risk this may not occur in future.
Proposal	Insert a new clause in Part 16A permitting the Authority to require an audit to be completed and submitted under Part 16A if an audit has not been submitted by the previously specified date (because the participant either breached or were exempted from the obligation)
Proposed Code amendment	**16A.14A Authority may require participant to undertake audit** (1) This clause applies if a **participant**— (a) was required to carry out an **audit** in accordance with this Part and failed to complete the **audit** and give a final **audit** report to the **Authority** in accordance with clause 16A.13; or (b) was exempted under section 11 of the **Act** from giving a final **audit** report to the **Authority** in accordance with clause 16A.13 and that exemption has expired or was revoked. (2) The **Authority** may advise the **participant**— (a) if subclause (1)(a) applies, of the date by which the **participant** must complete the next **audit** that the

	participant is required to carry out in accordanace with this Part; or (b) if subclause (1)(b) applies, of the date by which the participant must complete the first **audit** that the **participant** is required to carry out in accordance with this Part since the exemption expired or was revoked. (3) The Authority must not advise the **participant** of a date under subclause (2) that is any earlier than 3 months after the date that the **Authority** gives the advice to the **participant**. (4) The date the **Authority** advises under subclause (2) is the date by which the **participant** must complete the **audit** for the purposes of clause 16A.14.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and sections 32(1)(c) and 32(1)(e) of the Act, because it would contribute to the efficient operation of the electricity industry and the performance by the Authority of its functions by: - ensuring the Authority has the power to require audits under the Code in all relevant situations and - ensuring all participants are regularly audited for compliance with the Code, thereby allowing non-compliances to be identified and remedied, thus protecting the integrity of the market processes for all participants. The proposed Code amendment is expected to have no effect on competition, the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 electricity market operational costs and improve the performance by the Authority of its functions by: - ensuring the Authority has the power to require audits under the Code in all relevant situations and - ensuring all participants are regularly audited for compliance with the Code, thereby allowing non-compliances to be identified and remedied, thus protecting the integrity of the market processes for all 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* The Authority considers the costs of the amendment to be negligible. *Benefits* We expect the proposed Code amendment's main benefit will be ensure all participants are subject to audit in all relevant situations and that any non-compliances with the Code are remedied. *Net benefit* Based on the above analysis, the Authority is satisfied that 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.

CRP5-019 Clarifying two clauses in the Part 8 technical codes

Reference number(s)	CRP5-019 Clarifying two clauses in the Part 8 technical codes
Problem definition	Problem 1 Clause 5(1)(c)(ii) of Technical Code A of Schedule 8.3 requires that a generating unit with a speed governor must have an adjustable droop over the range of 0% to 7%. However, mathematically it is not feasible to have 0% droop. Problem 2 Clause 4 of Technical Code B of Schedule 8.3 requires the system operator to use reasonable endeavours to ensure that— a) if necessary, each participant is advised of any independent action required of it if there is a grid emergency; and b) facilities to be put in place by grid owners or other asset owners to manually electrically disconnect demand at each point of connection are specified. The wording of clause 4(b) is unclear as it does not specify whether it is the system operator or the grid owners and other asset owners who must specify what facilities are to be put in place to manually electrically disconnect demand at each point of connection.
Proposal	Problem 1 To address problem 1, the Authority proposes to amend clause 5(1)(c)(ii) of Technical Code A to set a droop range of 1% to 7%. The Authority notes that the Code's definition of 'generating unit'[17] allows for the possibility of a generating unit to not have a speed governor. It is beyond the scope of Code Review Programme 5 to consider amending the requirement in clause 5 of Technical Code A of Schedule 8.3 for a generator to ensure that each of its generating units has a speed governor. The Authority's review of the common quality requirements in Part 8 of the Code will consider this matter.[18] Problem 2 To address problem 2, the Authority proposes to amend clause 4(b) of Technical Code B of Schedule 8.3 to clarify that the system operator must use reasonable endeavours to ensure grid owners or other asset owners specify to the system operator what facilities they have put in place to manually electrically disconnect demand at each point of connection.

[17] See clause 1.1(1) of the Code.

[18] See Future security and resilience project and Part 8 common quality issues consultation paper.

Proposed Code amendment	**Schedule 8.3, Technical Code A – Assets** … **5 Specific requirements for generators** (1) Each **generator** must ensure that— … (c) each of its **generating units** has a speed governor that— (i) provides stable performance with adequate damping; and (ii) has an adjustable droop over the range of ~~0%~~ 1% to 7%; and (iii) does not adversely affect the operation of the **grid** because of any of its non-linear characteristics; and … **Schedule 8.3, Technical Code B – Emergencies** … **4 Obligations of the system operator** The **system operator** must use reasonable endeavours to ensure that— (a) if necessary, each **participant** is advised of any independent action required of it if there is a **grid emergency**; and (b) ~~facilities to be put in place by~~ **grid owners** or other **asset owners** specify to the **system operator** the facilities they have in place to manually **electrically disconnect demand** at each **point of connection** ~~are specified~~.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it promotes the efficient operation of the electricity industry. The Authority considers the proposed amendment would promote the efficient operation of the electricity industry by making it easier for participants to understand and comply with their obligations. The proposed Code amendment is expected to have little or no effect on competition, the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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 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 reduce electricity market operational costs by clarifying the Code, thereby making it easier for industry participants to understand and comply with their Code obligations.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers there would be little or no incremental cost associated with addressing each of the identified problems. This is because the proposed Code amedments would align the Code with current industry practice. *Benefits* The proposed amendment’s benefit is to make it easier for participants to understand and comply with their Code obligations. *Net benefit* Based on the above analysis, the Authority is satisfied that 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.

CRP5-020 Revised timeframe for distributors to change chargeable capacity and installation information in the registry records

Reference number(s)	CRP5-020 Revised timeframe for distributors to change chargeable capacity and installation information in the registry records
Problem definition	On 31 December 2021, the Authority amended clause 8 of Schedule 11.1 to allow a distributor to backdate a price category code change, if the distributor and the trader responsible for the ICP agree a date. This amendment was made as part of Code Review Programme 4. When consulting on a draft of this Code amendment, the Authority received a submission noting that, to correct prior period distribution charges, a trader may want to agree to backdating: a) the chargeable capacity of an ICP[19] b) the distributor installation details of an ICP that are determined by the price category code assigned to the ICP. The Authority agreed this further amendment should be considered but noted we would need to consult on it since it was a substantive change to the scope of the proposed amendment we had consulted on. In our decision to amend clause 8 of Schedule 11.1 we said we would include the proposed further change in Code Review Programme 5. The problem associated with backdating in the registry a change to an ICP's chargeable capacity and/or installation details determined by the ICP's price category code is the same problem that was described for the backdating of price category code changes. That is, a distributor and a trader may agree the distributor's prior period distribution charges for an ICP are incorrect because the ICP's chargeable capacity and/or installation details determined by the ICP's price category code are incorrect. However, if the distributor were to give the registry manager notice of a backdated change to this information, the distributor would breach clause 8(2)(b) of Schedule 11.1 if more than three business days had 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 backdated 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, which is not a desirable regulatory outcome.
Proposal	To address this problem, the Authority proposes to amend clause 8(2)(aa) of Schedule 11.1 of the Code, which was inserted on 31 December 2021 to address the problem relating to backdating of price category code changes. The amendment would allow a distributor to backdate a change to the following pricing-related information provided under clause 7(1) of Schedule 11.1, if the distributor and the trader responsible for the ICP agreed a date for the change to take effect:

[19] The Code defines 'chargeable capacity' to mean the capacity that the distributor may charge for, but that may not be the actual installed capacity at the relevant ICP.

	a) the chargeable capacity of an ICP b) the distributor installation details of an ICP that are determined by the price category code assigned to the ICP.
Proposed Code amendment	**Schedule 11.1 Creation and management of ICPs, ICP identifiers and NSPs** … **8 Distributors to change ICP information provided to registry manager** … (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 clauses 7(1)(g)), 7(1)(h) and 7(1)(i) where the change is backdated, no later than 3 **business days** after the **distributor** and the **trader** responsible for the **ICP** agree on the change; and (ab) in the case of **decommissioning** an **ICP**, by the later of— (i) 3 **business days** after the **registry manager** has advised the **distributor** under clause 11.29 that the **ICP** is ready to be **decommissioned**; and (ii) 3 **business days** after the **distributor** has **decommissioned** the **ICP**: (b) in every other case, no later than 3 **business days** after the change takes effect. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's objectives, 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 accuracy of the ICP information held in the registry. This would facilitate accurate invoicing of traders and consumers, which means the proposed amendment would be in the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The proposed Code amendment is expected to have little or no effect on competition, the reliable supply of electricity, or the performance by the Authority of its functions.
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 objectives 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 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 that 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 would be small for a distributor to update the registry to correct an ICP's chargeable capacity or installation details determined by the ICP's price category code. *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 changes to an ICP's chargeable capacity and/or installation details determined by the ICP's price category code in the registry outside the three business day timeframe currently permitted by the Code.
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.

CRP5-021 Clarifications to hedge settlement agreements

Reference number(s)	CRP5-021 Clarifications to hedge settlement agreements
Problem definition	Clause 14.8(2) of the Code requires a hedge settlement agreement to be submitted to the clearing manager in one of the forms set out in Schedule 14.4, or on an alternative form approved by the Authority. Schedule 14.4 includes three forms, all three are similar but cover a different type of hedge product. <u>Problem 1</u> Some hedge agreements have different pricing for weekday and weekend trading periods, but the hedge settlement agreement forms in Schedule 14.4 do not adopt the definition of 'business day' used in the Code or specify how public holidays should be priced when they fall on a weekday. This causes difficulties for the clearing manager, whose systems are designed to work on the Code definition of business day. <u>Problem 2</u> The the terms of the hedge settlement agreement forms set out in Schedule 14.4 do not specify how hedges will be settled on the days daylight savings starts or ends. These two days do not have the standard 48 trading periods (or 24 hours). The day daylight savings starts has 46 trading periods (23 hours) and the day daylight savings ends has 50 trading periods (25 hours). This causes issues for the clearing manager when a hedge settlement agreement spans daylight savings start or end dates but specifies the number of trading periods or hours for each day. <u>Problem 3</u> The service provider agreement between the clearing manager and the Authority includes an obligation on the clearing manager to publish hedge settlement agreement amounts by the 5th business day of the month (paragraph 5.3 of schedule 2). The purpose of this obligation is to give the parties to a hedge settlement agreement advance notice of the settlement amounts to enable identification of any potential issues. If issues are notified to the clearing manager by the 7th business day of the month, the clearing manager has time to correct the calculations before invoices are issued on the 9th business day of the month following the billing period (as required by clause 14.18 of the Code). These steps are in addition to the formal billing requirements and dispute provisions in Part 14 of the Code. The Code does not contain any reference to these additional steps, and while the service provider agreement is published on the Authority's website, parties may be unaware of the requirement on the clearing manager and the parties' ability to identify and seek resolution of issues with hedge settlement agreement amounts before needing to invoke the formal dispute proceedure under clause 14.25 of the Code.
Proposal	Amend all three forms of hedge settlement agreement in Schedule 14.4 to include: • Clarification for how the clearing manager will manage the the settlement when day, business day and non-nusiness day are specified in the underlying hedge

	• Clarification for how the clearing manager will manage the days daylight savings starts and ends • The clearing manager's obligation to advise the parties of the calculated amounts by the 5th business day and when the parties can raise issues with the calculations before the invoices are issued.
Proposed Code amendment	**Schedule 14.4** **Form 1** … **3 Payment of hedge settlement amounts** In relation to a **billing period**: (a) if the **aggregate floating amount** exceeds the **aggregate fixed amount**: (i) the **floating price payer** must pay the **clearing manager** an amount equal to the **hedge settlement amount** in relation to that **billing period**; and (ii) the **clearing manager** must pay the **fixed price payer** an amount equal to the **hedge settlement amount** in relation to that **billing period**, on the relevant **settlement date**; and (b) if the **aggregate fixed amount** exceeds the **aggregate floating amount**: (i) the **fixed price payer** must pay the **clearing manager** an amount equal to the **hedge settlement amount** in relation to that **billing period**; and (ii) the **clearing manager** must pay the **floating price payer** an amount equal to the **hedge settlement amount** in relation to that **billing period**, on the relevant **settlement date**. (c) the **clearing manager** must calculate the amounts to be payable by and to the **parties** and advise each **party** of those amounts by the 5th **business day** of the month following the **billing period**. If either **party** notifies the clearing manager in writing by the 7th **business day** of the month following the **billing period** of any issues with the amounts the clearing manager has advised are to be payable , the **clearing manager** will use reasonable endeavours to correct the issues before issuing invoices on the 9th **business day** of the month following the **billing period** under clause 14.18(2) of the **Code.** …

5 Other provisions

(a) The **fixed price** is inclusive of any additional costs arising due to carbon charges.

(b) Where the terms of this **hedge settlement agreement** include reference to:

(i) day, this means both **business days** and non-**business days**

(ii) weekday, this means a **business day**

(iii) weekend, this means non-**business days**.

(c) Where daylight savings starts or ends during the **term** of this **hedge settlement agreement**, the **clearing manager** will calculate the **fixed amounts** and **floating amounts** for the days on which daylight savings starts or ends in the same way the **clearing manager** calculates the sale and purchase of **electricity** for these days.

…

Form 2: Cap/Floor Calculation Period Price

…

3 Payment of hedge settlement amounts

In relation to a **billing period**:

(a) the **option buyer** must pay the **clearing manager** an amount equal to the **option premium** for that **billing period**; and

(b) the **clearing manager** must pay the **option seller** an amount equal to the **option premium** for that **billing period**; and

(c) the **option seller** must pay the **clearing manager** an amount equal to the **cash settlement amount** for that **billing period**; and

(d) the **clearing manager** must pay the **option buyer** an amount equal to the **cash settlement amount** for that **billing period**,

on the relevant **settlement date**.

(e) the **clearing manager** must calculate the amounts to be payable by and to the **parties** and advise each **party** of those amounts by the 5th **business day** of the month following the **billing period**. If either **party** notifies the clearing manager in writing by the 7th **business day** of the month following the **billing period** of any issues with the amounts the clearing manager has advised are to be payable, the **clearing manager** will use reasonable endeavours to correct the issues before issuing invoices on the 9th **business day** of the month following the **billing period** under clause 14.18(2) of the **Code**.

…

5 Other provisions

(a) The **strike price** is inclusive of any additional costs arising due to carbon charges.

(b) Where the terms of this **hedge settlement agreement** include reference to:

(i) day, this means both **business days** and non-**business days**

(ii) weekday, this means a **business day**

(iii) weekend, this means non-**business days**

(c) Where daylight savings starts or ends during the **term** of this **hedge settlement agreement**, the **clearing manager** will calculate the **calculation period premium** and **calculation period settlement amounts** for these days in the same way the **clearing manager** calculates the sale and purchase of **electricity** for these days.

…

Form 3: Cap/Floor Average Price

…

3 Payment of hedge settlement amounts

In relation to a **billing period**:

(a) the **option buyer** must pay the **clearing manager** an amount equal to the **option premium** for that **billing period**; and

(b) the **clearing manager** must pay the **option seller** an amount equal to the **option premium** for that **billing period**; and

(c) the **option seller** must pay the **clearing manager** an amount equal to the **cash settlement amount** for that **billing period**; and

(d) the **clearing manager** must pay the **option buyer** an amount equal to the **cash settlement amount** for that **billing period**,

on the relevant **settlement date**.

(e) the **clearing manager** must calculate the amounts to be payable by and to the **parties** and advise each **party** of those amounts by the 5th **business day** of the month following the **billing period**. If either **party** notifies the clearing manager in writing by the 7th **business day** of the month following the **billing period** of any issues with the amounts the clearing manager has advised are to be payable, the **clearing manager** will use reasonable endeavours to correct the issues before issuing invoices

	on the 9th **business day** of the month following the **billing period** under clause 14.18(2) of the **Code.** … **5 Other provisions** (a) The **strike price** is inclusive of any additional costs arising due to carbon charges. (b) Where the terms of this **hedge settlement agreement** include reference to: (i) day, this means both **business days** and non-**business days** (ii) weekday, this means a **business day** (iii) weekend, this means non-**business days** (c) Where daylight savings starts or ends during the **term** of this **hedge settlement agreement,** the **clearing manager** will calculate the **calculation period premium** and **option period settlement amounts** for these days in the same way the **clearing manager** calculates the sale and purchase of **electricity** for these days. …
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because it would contribute to the efficient operation of the electricity industry by making it easier for participants to clearly understand how the underlying hedge will be settled and the process for identifying and seeking resolution of any issues with the settlement amounts, in addition to the procedures set out in Part 14 of the Code. The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers, or the performance by the Authority of its functions.
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 objectives 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 electricity market operational costs by: • removing ambiguity about how weekends, weekdays and daylight savings start and end dates will be managed when the underlying hedge is being settled; and • ensuring the parties understand the clearing manager's process for advising parties of the amounts payable under hedge settlement agreements and the parties' rights to notify errors in the amounts calculated by the clearing manager and seek resolution of any errors before engaging the formal procedures in Part 14 of the Code.
Evaluation of the costs and benefits of the proposed amendment	The Authority considers the proposed Code amendment would have a positive net benefit, for the reasons set out below. *Costs* The Authority considers the costs of the amendment are negligible. *Benefits* We expect the proposed Code amendment's main benefit will be reduced time spent by the clearing manager following up with participants when underlying hedges are not clear or do not align with the clearing manager's processes. The Authority considers that this benefit will 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.

CRP5-022 Part 6A dispensation scheme for specified persons

Reference number(s)	CRP5-022 Part 6A dispensation scheme for specified persons
Problem definition	Part 6A of the Code includes corporate separation, arm's-length rules and other rules (collectively referred to as 'the arm's-length rules'), which are intended to promote competition in the electricity industry by restricting relationships between a distributor and a generator or a retailer. The arm's-length rules were shifted into new Part 6A of the Code from Part 3 of the Electricity Industry Act 2010 (Act) by the Electricity Industry Amendment Act 2022 (Amendment Act). The arm's-length rules in Part 6A of the Code apply to industry participants and 'specified persons'. Section 32(6) of the Act (inserted by the Amendment Act) defines a specified person as 'a person (other than an industry participant) who is involved in both classes of industry aprticipant that are the subject of any provisions made in accordance with subsection (3)'. Section 32(3) permits the Code to impose obligations on a specified person 'for the purpose of restricting relationships between 2 classes of industry participants, where those relationships may not otherwise be at arm's length'. Parliament's intention, in shifting the arm's-length rules from the Act to the Code and including the new concept of 'specified person' in section 32 of the Act, was to enable the Code to regulate specified persons and industry participants in a like manner. However, because section 11 of the Act only permits the Authority to grant an exemption from the obligation to comply with the Code or specific provisions of the Code to an *industry participant* there is no current mechanism for a specified person in appropriate circumstances to obtain a similar exemption. Previously, a specified person would have been able to apply to the Authority under section 90 of the Act for an exemption from compliance with the arm's-length rules, when they were contained in the Act. The Amendment Act provided for existing exemptions already granted under section 90 to continue in effect, but did not itself expressly provide for the Authority to grant new exemptions for specified persons. In August 2023 the Authority made an urgent Code amendment to introduce a Part 6A dispensation scheme to address this problem. Urgent Code amendments expire after 9 months. This proposal is to make that urgent Code amendment permanent. Should the Act be amended in future to address this issue in another way it may be that this Code-based dispensation scheme would no longer be necessary and could then be revoked.
Proposal	Amend the Code to introduce a Part 6A dispensation scheme for specified persons. This would provide specified persons with a pathway to apply for a dispensation that would exclude them from the obligation to comply with Part 6A or any provisions of Part 6A, should the Authority consider a dispensation appropriate in the circumstances and subject to any conditions the Authority considers reasonably necessary.

Proposed Code amendment	**1.1 Interpretation** (1) In this Code, unless the context otherwise requires,— … **Part 6A dispensation** means an exclusion from compliance with Part 6A or any provisions of Part 6A granted by the **Authority** in accordance with the process set out in clause 6A.9 … **specified person** has the meaning given in section 32(6) of the **Act** … **6A.9 Authority may grant Part 6A dispensation to specified person** (1) A **specified person** may apply to the **Authority** for a **Part 6A dispensation** in respect of their involvement in two or more classes of industry participant that are the subject of this Part, or specific provisions of this Part. (2) The application must be submitted in the form and by the means specified by the **Authority**. (3) Where the **Authority** receives an application under this clause, it may grant a **Part 6A dispensation** to a **specified person** if the **Authority** is satisfied that— (a) it is not necessary, for the purpose of achieving the **Authority's** objectives under section 15 of the **Act**, for the **specified person** to comply with this Part or the specific provisions of this Part; or (b) granting a **Part 6A dispensation** in respect of the **specified person** would better achieve the **Authority's** objectives than requiring compliance. (4) The **Authority** must give reasons for its decision under subclause (3). (5) The **Authority** may grant a **Part 6A dispensation** on any terms or conditions that it reasonably considers are necessary. (6) The **Authority** may amend or revoke a **Part 6A dispensation** granted under subclause (3) by issuing a notice that identifies the **specified person** subject to the **Part 6A dispensation** and gives reasons for the amendment or revocation, but only if the **Authority**— (a) has given notice of the proposed amendment or revocation to the **specified person** subject to the **Part 6A dispensation** and given them a reasonable opportunity to comment; and

	(b) in relation to an amendment, is satisfied that the amendment is necessary or desirable for the purpose of achieving the **Authority's** objectives in section 15; and (c) in relation to a revocation, is no longer satisfied of the matters in subclause (3). (7) The **Authority** must publish a list of all current **Part 6A dispensations** granted under this clause.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives and with section 32(1)(c) and (e) of the Act. Providing a pathway for specified persons to obtain a dispensation from the Part 6A provisions in appropriate circumstances contributes to the efficient operation of the electricity industry and the performance by the Authority of its functions by treating industry participants and specified persons subject to those provisions in a similar manner. The arm's-length rules impose obligations designed to promote competition in the electricity industry. In some cases, however, the Authority may consider that compliance with the arm's-length rules is not necessary to promote competition in the electricity industry, or that a dispensation may better promote the efficient operation of the electricity industry, for the long-term benefit of consumers. The proposed Code amendment would ensure the Authority can thereby administer the Code in a way that best promotes the Authority's objectives. It would operate similar to the Part 8 dispensation scheme administered by the System Operator. The Authority has granted similar exemptions (under section 90 of the Act) in the past. The proposed Code amendment would ensure a specified person can be treated in a similar way as a person in a similar position who had earlier obtained an exemption under section 90 of the Act, as these existing exemptions continue to apply. The proposed Code amendment is expected to have no effect on the reliable supply of electricity, or the interests of domestic and small business consumers in relation to the supply of electricity to those consumers.
Assessment against Code amendment principles	The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles, to the extent they are relevant.
Principle 1: Lawfulness	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objectives 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. It addresses an identified area of inconsistency of treatment of persons in similar positions in relation to requirements for compliance with Part 6A and which the proposed Code amendment will 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 provide a pathway for a specified person to apply to the Authority for a dispensation that would exclude the application of some or all of the Part 6A provisions.
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 costs of administering the Part 6A dispensation scheme will not signficantly increase the Authority's overall costs, because, prior to the 2022 amendments, it was responsible for considering and determining similar applications under section 90 of the Act. *Benefits* We expect the proposed Code amendment's main benefit will be to support the efficient operation of the electricity industry by enabling the Authority to exclude the application of Part 6A in appropriate cases, namely where the Authority is satisfied that compliance with Part 6A is not necessary to promote competition in the electricity industry and/or where a dispensation will promote the efficient operation of the electricity industry. The proposed Code amendment will also provide certainty to those affected, restore those specified persons to a similar position to that they were in prior to the Amendment Act and provides them with a similar pathway as exists for industry participants. It is expected to reduce costs for specified persons and associated industry participants in some situations, by providing providing a mechanism to seek a dispensation that could have the effect of reducing compliance costs (if the Authority considers it appropriate to grant a dispensation).
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, in the absence of legislative amendment.

CRP5-023 Change to the date default transmission agreement schedules take effect

Reference number(s)	CRP5-023 Change to the date default transmission agreement schedules take effect
Problem definition	In its submission on the Authority's consultation paper "Changes to the Benchmark agreement for SRAM funding to reflect the new TPM", Transpower requested drafting changes to clauses 12.10 and 12.13. These clauses currently provide that the schedules in the default transmission agreement template take effect two months after they are accepted, amended by Transpower, or determined by the Rulings Panel. The two-month delay in schedules taking effect creates a risk that there is a period not covered by appropriate contractual terms.
Proposal	Amend the Code to provide that that the schedules in the default transmission agreement template once accepted, amended by Transpower, or determined by the Rulings Panel, be deemed to apply as a default transmission agreement from the date a participant becomes a designated transmission customer or an earlier agreement expires or terminates (rather than the status quo which is 2 months after this date).
Proposed Code amendment	**12.10 Default transmission agreements** … (4) If the **designated transmission customer** accepts the schedules as proposed by **Transpower** under subclause (2)(b)(v) to (viii), or as amended by Transpower under subclause (2)(c), the draft **default transmission agreement** proposed under subclause (2)(b)(v) to (viii), or as amended by Transpower under subclause (2)(c), (as applicable) is deemed to apply ~~applies~~ as a **default transmission agreement** from the date ~~that is 2 months after~~ the **participant** became a **designated transmission customer**. … (6) If a dispute is referred to the **Rulings Panel**, under subclause (5)— (a) the **default transmission agreement** as determined by the **Rulings Panel** in accordance with clauses 12.45 to 12.48 is deemed to apply ~~applies~~ between **Transpower** and the **designated transmission customer** from the date ~~that is 2 months after~~ the **participant** became a **designated transmission customer** ~~or the date on which the **Rulings Panel** makes its determination or its determination is expressed to come into effect, whichever is later~~; and (b) until ~~if~~ the **Rulings Panel** makes ~~has not made~~ a determination, ~~by the date that is 2 months after the **participant** became a **designated transmission customer**,~~ the draft **default transmission agreement** proposed under subclause (2)(b)(v) to (viii), or as amended by **Transpower** under subclause (2)(c), (as applicable) is deemed to apply as a **default transmission agreement** from the date the **participant** became a **designated transmission customer** ~~applies as a **default transmission agreement** until the date on~~

~~which the **Rulings Panel** makes its determination or the determination comes into effect~~.

…

12.13 Expiry or termination of transmission agreements

<u>If a **participant** and **Transpower** are party to an existing **transmission agreement** or written agreement to which clause 12.49 applies, and do not enter into a **transmission agreement** before the existing agreement expires or terminates, upon expiry or termination of the relevant agreement the provisions in clause 12.10 apply with all necessary modifications.</u>

~~If a **transmission agreement**, or an existing written agreement to which clause 12.49 applies, expires or terminates on or after the date that is 2 months after the **participant** became a **designated transmission customer** and **Transpower** and the **designated transmission customer** do not enter into a new **transmission agreement** within 2 months of that date, the following procedure applies:~~

~~(a) within 10 **business days**, the **designated transmission customer** must provide **Transpower**, at the address for service for **Transpower** registered at the New Zealand Companies Office, with—~~

~~(i) the **designated transmission customer's** full name; and~~

~~(ii) the **designated transmission customer's** physical address, postal address and electronic address to which notices under the **default transmission agreement** are to be sent; and~~

~~(iii) the name of the contact person of the **designated transmission customer** to whom such notices should be addressed:~~

~~(b) within 20 business days of receipt of the **designated transmission customer's** details under paragraph (a), **Transpower** must provide the **designated transmission customer** with a draft **default transmission agreement** completed in accordance with the **default transmission agreement template**, which must include—~~

~~(i) the **designated transmission customer's** details as provided under paragraph (a); and~~

~~(ii) **Transpower's** physical address, postal address and electronic address to which notices under the **default transmission agreement** are to be sent; and~~

~~(iii) the contact person to whom notices under the **default transmission agreement** should be addressed; and~~

~~(iv) **Transpower's** designated bank account for the purposes of receiving payments under the **default transmission agreement**; and~~

~~(v) draft Schedules 1 and 2, which set out the **connection locations**, **points of service** and **points of connection** of the assets owned or operated by the~~

	~~**designated transmission customer** to the **grid**; and~~ ~~(vi) a draft Schedule 4 setting out, in the same form as the diagram in Schedule 4 of the **default transmission agreement template**, the configuration of the connection assets in relation to each **connection location** listed in Schedule 1; and~~ ~~(vii) a draft Schedule 5 setting out proposed service levels for each **connection location** listed in Schedule 1 determined in accordance with clause 12.10(3); and~~ ~~(viii) if applicable, a draft Schedule 6, including identifying the facilities, facilities area, and land that are to be subject to the access and occupation terms set out in that schedule and the licence charges under that schedule:~~ ~~(c) the **designated transmission customer** and **Transpower** may discuss the schedules proposed under paragraph (b)(v) to (viii), as a result of which **Transpower** may amend any of the schedules:~~ ~~(d) the **designated transmission customer** must advise **Transpower** in writing within 20 business days of receiving the draft **default transmission agreement** under paragraph (b) above whether—~~ ~~(i) it accepts the schedules as proposed by **Transpower** under paragraph (b)(v) to (viii); or~~ ~~(ii) if **Transpower** has amended any of those schedules under paragraph (c), it accepts the schedules as amended:~~ ~~(e) if the **designated transmission customer** accepts the schedules as proposed by **Transpower** under paragraph (b)(v) to (viii), or as amended by **Transpower** under paragraph (c), the **default transmission agreement** applies as a binding contract between **Transpower** and the **designated transmission customer**, effective from the date on which the previous **transmission agreement** or existing written agreement to which clause 12.49 applies expired or was terminated:~~ ~~(f) if **Transpower** and a **designated transmission customer** are unable to agree on the terms of any of the schedules to a **default transmission agreement** proposed by **Transpower** under paragraph (b)(v) to (viii), or as amended by **Transpower** under paragraph (c), either party may refer the matter to the Rulings Panel for determination under clauses 12.45 to 12.48:~~ ~~(g) if a dispute has been referred to the Rulings Panel in accordance with paragraph (f)—~~ ~~(i) the draft **default transmission agreement** provided under paragraph (b) applies as a **default transmission agreement** between **Transpower** and the **designated transmission customer**, effective from the date on which the previous **transmission agreement** or existing written agreement to which clause 12.49 applies expired or was terminated, until the~~

	~~date on which the Rulings Panel makes its determination or the determination comes into effect; and~~ ~~(ii) the **default transmission agreement** as determined by the Rulings Panel in accordance with clauses 12.45 to 12.48 applies from the date determined by the Rulings Panel.~~
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed Code amendment is consistent with the Authority's statutory objectives, and section 32(1)(c) of the Act, because the Authority considers it to be desirable to promote the efficient operation of the electricity industry. The proposed amendment promotes the efficient operation of the electricity industry by providing clarity about the contractual terms that apply under transmission agreements between designated transmission customers and Transpower for all periods that a participant is a designated transmission customer. Without the amendment there is a 2 month gap which creates contractual uncertainty, potential for dispute, and therefore inefficiency and potential additional cost. The proposed Code amendment is not expected to have any significant effect on any of the other matters in section 32(1).
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 objectives 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 provide clarity about the contractual terms that apply under transmission agreements between designated transmission customers and Transpower for all periods that a participant is a designated transmission customer.
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 *Benefits*

	We expect the proposed Code amendment's main benefit will be to provide certainty for Transpower and transmission customers by ensuring that all the contractual terms of the default transmission agreements come into effect concurrently and reducing the risk associated with not having contractual terms in place for a period of 2 months. This will support the efficient operation of the electricity industry by providing certainty for Transpower and transmission customers about what contractual terms apply and when.
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 B Format for Submissions

Printable form - Code amendment proposals

Submitter		
Are you submitting as?	Individual / Industry participant / Other organisation	
Proposal number	CRP5-0__ __	

Questions	Submission
Q1. Do you agree the issue(s) identified by the Authority need attention? Any comments?	Yes / No. Comments:
Q2. Do you agree with the objectives of the proposed amendment? Any comments?	Yes / No. Comments:
Q3. Do you agree the benefits of the proposed amendment outweigh its costs? Any comments?	Yes / No. Comments:
Q4. Do you agree the proposed amendment is preferable to any other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	Yes / No. Details of your preferred option:
Q5. Do you have any comments on the drafting of the proposed amendment?	
Q6. Do you have any further comments on the proposal?	
Q7. Is any part of your submission confidential? If yes, please explain which part, why it is confidential and provide a publishable replacement (refer paragraphs 1.9 to 1.11 of the consultation paper)	Yes / No. If yes, comments:

Printable form - Technical and non-controversial amendments

Submitter	
Are you submitting as?	Individual / Industry participant / Other organisation
Row number	

Questions	Comment
Q1. Do you agree the issue(s) identified by the Authority needs attention? Any comments?	Yes / No. Comments:
Q2. Do you agree with the objectives of the proposed amendment? Any comments?	Yes / No. Comments:
Q3. Is any part of your submission confidential? If yes, please explain which part, why it is confidential and provide a publishable replacement (refer paragraphs 1.9 to 1.11 of the consultation paper)	Yes / No. If yes, comments:

Appendix C Technical and Non-Controversial amendments

	Clause	Issue	Proposed amendment
Part A – Proposed amendments to individual clauses			
1.	1.1(1) definition of 'domestic consumer'	This term is not used in the Code and the definition is inconsistent with the definition of 'domestic consumer' in the Electricity Industry Act 2010.	**domestic consumer** *[Revoked]*~~means a person who acquires electricity for personal, domestic or household use or consumption and does not acquire electricity or hold himself or herself out as acquiring electricity for the purpose of resupplying it in trade or consuming it in the course of production or manufacture~~
2.	1.1(1) definition of 'EIE System'	Reference to 'Authority' should be in bold because it is a defined term.	**EIE System** means an Electricity Information Exchange System being any system prescribed by the **Authority** under clause 11.32EG
3.	2.16(2)(a)	Reference to 'Code' should not be in bold as it is not a defined term.	(2) The **Authority** may specify information under subclause (1) only for the purposes set out in section 45(a) of the **Act** being to carry out the **Authority's** monitoring functions which are to— (a) monitor compliance with the **Act**, the regulations and the Code under section 16(1)(c) of the **Act**; …
4.	2.16(3)	Reference to 'Code' should not be in bold as it is not a defined term. Reference to 'Authority' should be in bold because it is a defined term.	(3) The **Authority** may not specify information under subclause (1) for the purpose of investigating or enforcing compliance with the **Act**, the regulations and the Code …
5.	7.4(2)	Reference to clause 7.19 should be a reference to clause 7.22. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(2) Clauses 7.13 to 7.22~~7.19~~ apply to any amendment or replacement of the **security of supply forecasting and information policy** or **emergency management policy**.
6.	7.16(4)(b)	Replace 'sub-clause' with 'subclause' and unbold full stop. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(b) raise any issues it has identified under subclause ~~sub-clause~~ (2) with the **system operator**.

7.	7.19(1)	Reference to clauses 7.16(5)(a) and 7.18(4)(a) should be references to 7.16(4)(a) and 7.18(3)(a), and reference to clause 7.20 should be a reference to clause 7.21. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(1) The **Authority's** consent to consultation under subclause 7.16(4~~5~~)(a) or 7.18(3~~4~~)(a) or to direct the **system operator** under clause 7.17(1) does not affect the **Authority's** decision regarding approval of a **system operation document** under clause ~~7.20~~7.21.
8.	7.19(2)(b)	Reference to clause 7.19 should be a reference to clause 7.22, and other amendments to this paragraph fix a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(b) must advise the persons it consults ~~consulted~~ with under clause 7.20~~7.19~~ that the **Authority** has not consented to the consultation ~~under this clause~~ and that the risk described in paragraph (a) arises.
9.	7.21(1)	Reference to subclause 7.20(4) should be a reference to subclause 7.20(5)	(1) Following consultation, or if clause 7.20(5)~~7.20(4)~~ applies, the **system operator** must provide the **Authority** with a report that sets out the following: (a) the information required by clause 7.20(2)(a), regardless of whether or not consultation was carried out, but incorporating any changes made following consultation: (b) a summary of any submissions received and the **system operator's** response to each: (c) a list of any changes made to the proposed amendments to the **system operation document** after consultation and the reasons for the changes: (d) if clause 7.20(5)~~7.20(4)~~ applies, the reasons why the **system operator** considered that consultation was not required: (e) a final draft of the proposed amendments to the **system operation document** (either as amendments to the **system**

			operation document or a replacement **system operation document**).
10.	8.10(2)	Reference to clause 7.19 should be a reference to clause 7.22. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(2) Clauses 7.13 to 7.22~~7.19~~ apply to any amendment or replacement of the **policy statement.**
11.	8.42(2)	Reference to clause 7.19 should be a reference to clause 7.22. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(2) Clauses 7.13 to 7.22~~7.19~~ apply to any amendment or replacement of the **procurement plan**.
12.	Schedule 8.1, clause 6(2)	Reference to clause 7.18 should be a reference to clause 7.22. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(2) If changes are required to the **procurement plan**, the draft decision must be conditional on the **procurement plan** being amended appropriately in accordance with clauses 7.13 to 7.22~~7.18~~.
13.	Schedule 8.6, clause 2(2)	Reference to clause 7.18 should be a reference to clause 7.22. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(2) Clauses 7.13 to 7.22~~7.18~~ apply to any amendment or replacement of the **AUFLS technical requirements report**.
14.	Schedule 8.6, clause 2(2)	Reference to clause 7.18 should be a reference to clause 7.22. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	(2) Clauses 7.13 to 7.22~~7.19~~ apply to any amendment or replacement of the **system operator rolling outage plan**.
15.	9.2	Subclauses (2) and (3) should be revoked. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System	**9.2 System operator must prepare and publish system operator rolling outage plan**

		Operation Documents) 2023.	(1) The **system operator** must prepare and **publish** a **system operator rolling outage plan**. (2) *[Revoked]*~~Before **publishing** a **system operator rolling outage plan** the **system operator** must submit to the **Authority** for approval a **draft system operator rolling outage plan**.~~ (3) *[Revoked]*~~Clause 7.5(3) to (11) applies to the approval of the **system operator rolling outage plan** by the **Authority** as if references to the **security of supply forecasting and information policy** and the **emergency management policy** were a reference to the **system operator rolling outage plan**.~~
16.	9.3	This clause requires amendment to fix a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	**9.3 Incorporation of system operator rolling outage plan by reference** (1) The **system operator rolling outage plan** is incorporated by reference in this Code~~ in accordance with section 32 of the **Act**~~. (2) Clauses 7.13 to 7.22 apply to any amendment or replacement of the **system operator rolling outage plan**.~~Subclause (1) is subject to Schedule 1 of the **Act**, which includes a requirement that the **Authority** must give notice in the Gazette before an amended or substituted **system operator rolling outage plan** becomes incorporated by reference in this Code.~~
17.	9.5	This clause should be revoked. This fixes a drafting error identified with the Electricity Industry Participation Code Amendment (System Operation Documents) 2023.	Revoke clause 9.5
18.	10.25(2)(c)	Reference to 'certification' should be in bold as it is a defined term.	(c) within 5 **business days** after the date of **certification** of each **metering installation**, advise the **reconciliation manager** of— (i) the **participant identifier** of the **metering**

			equipment provider for the **metering installation**; and (ii) the **certification** expiry date of the **metering installation**.
19.	10.33B(a)	The words 'electrically disconnect' should be in bold as this is a defined term.	Unless a **trader** is recorded in the **registry** as being responsible for an **ICP** or is meeting its obligation under clause 10.33A(5)(a) in respect of an **ICP**, the **trader** must not— (a) **electrically disconnect** the ICP; or …
20.	11.30A(1)	The word 'Act' should be in bold as this is a defined term.	(1) Each **retailer** and **distributor** must provide information in the circumstances specified in subclauses (2) and (3) about the dispute resolution scheme identified under clause 3 of Schedule 4 of the **Act**.
21.	11.32E(c)	Update reference from Privacy Act 1993 to Privacy Act 2020.	(c) the Privacy Act 2020~~1993~~, where applicable.
22.	11.32EB(1)(b)	Update reference from Privacy Act 1993 to Privacy Act 2020.	(b) that complying with the request would otherwise cause the **retailer** to breach its obligations under the Privacy Act 2020~~1993~~ (where it applies); or
23.	Clause 10 of Schedule 11.1	Subclauses (3) and (4) are transitional provisions which are now spent and can be revoked.	**10 Traders to change ICP information provided to registry manager** (1) If information about an ICP provided to the registry manager in accordance with clause 9 changes, the trader who trades at the ICP must give written notice to the registry manager of the change. (2) The trader must give the notice no later than 5 business days after the change. (3) *[Revoked]*~~Despite subclause (2), if the trader is not able to give the notice within the timeframe specified in subclause (2) because of the implementation of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, the trader may~~

			~~give the notice up to 20 business days after the change.~~ (4) *[Revoked]*~~Subclause (3) and this subclause expire 20 business days after the date on which the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011 comes into force.~~
24.	12.60	Reference to 'Authority' should be in bold because it is a defined term.	The **Authority** may initiate a review of the **grid reliability standards** for any reason consistent with the statutory objective of the **Authority** in section 15 of the **Act** and the purpose and principles set out in clauses 12.56 and 12.57.
25.	12.67	Reference to 'Authority' should be in bold because it is a defined term.	The **Authority** may initiate a review of the **core grid determination** for any reason consistent with the statutory objective of the **Authority** in section 15 of the **Act** and the purpose and objectives set out in clauses 12.64 and 12.65 respectively.
26.	13.69B(1)(g)	Reference to 'losses' should be in bold because it is a defined term.	(1) The system operator must use the following inputs to prepare a dispatch schedule: … (g) information from the **grid owner** (clauses 13.29 to 13.34) and revised information from the **grid owner** (clause 13.33) about— (i) the AC transmission system configuration, capacity and **losses**; and (ii) the capability of the **HVDC link** including its **configuration**, capacity, **losses**, the direction of any transfer limit, and any minimum or maximum transfer limits; and (iii) transformer configuration, capacity and **losses**:

27.	Clauses 17(b) and 17(c) of Schedule 13.3	Reference to 'location factor' should not be in bold because this term is not intended to have the defined meaning applied in this context. Clause 1.1(1) defines 'location factor' only for the purposes of subpart 5 of Part 13. References in paragraphs (b) and (c) should not be bolded, for consistency with references to 'location factor' used elsewhere in this clause 17 of Schedule 13.3.	**17 What modelling system must take into account when calculating prices** The modelling system must calculate the prices in clause 16 consistent with the objective function, and consistent with the quantities of **electricity** and **instantaneous reserve** scheduled, while meeting all constraints, and in particular— … (b) subject to the rights of the **system operator** described in clause 13, a **generator** at a **grid injection point** must be scheduled to generate a quantity of **electricity** from a price band if the price determined by the modelling system at the **reference point** multiplied by the marginal location factor at that **grid injection point** is greater than or equal to the price offered in that price band; and (c) subject to the rights of the **system operator** described in clause 13, a **generator** at a **grid injection point** must not be scheduled to generate a quantity of **electricity** from a price band if the price determined by the modelling system at the **reference point** multiplied by the relevant marginal location factor at that **grid injection point** is less than the price offered in that price band; and …
28.	Clause 5(1)(d) of Schedule 12A.1, Appendix C	Update reference from Privacy Act 1993 to Privacy Act 2020.	(d) … provided the Distributor ensures that any applicable provisions of the Privacy Act 2020~~1993~~ are complied with in respect of the transfer;
29.	Clause 7 of Schedule 12A.1, Appendix C	Update reference from Privacy Act 1993 to Privacy Act 2020.	(1) Each party acknowledges and agrees that it must comply at all times with the Privacy Act 2020~~1993~~ to the extent it applies in relation to the Consumption Data. (2) The Trader must make any disclosures, and obtain any

			authorisations, needed under the Privacy Act 2020~~1993~~ to enable the Distributor to use the Consumption Data for the Permitted Purposes and Other Purposes.
30.	13.3D(6)	Reference to 'Authority' should be in bold because it is a defined term.	(6) The **Authority** must consult with the **participants** referred to in subclause (5)(a) on any proposed amendments to the terms and conditions specified and **published** by the **Authority** under subclause (2).
31.	13.6	Pricing manager functions have been discontinued and references revoked from the Code by the Electricity Industry Participation Code Amendment (Real Time Pricing) 2022 (RTP amendment). That Code amendment transferred the remaining pricing manager functions to the clearing manager. Reference to the pricing manager in clause 13.6(2) should be replaced with a reference to the clearing manager, consistent with the underpinning policy of the RTP amendment, and the reference to pricing manager in clause 16.6(5) should be omitted entirely as that clause already refers to the clearing manager. These references to the pricing manager were excluded inadvertently from the RTP amendment.	**13.6 Requirements for generators when submitting offers** (1) Each **generator** with a **point of connection** to the **grid**, and each **embedded generator** required by the **system operator** to submit an **offer** under clause 8.25(5), must— (a) submit to the **system operator** an **offer** for each **trading period** in the **schedule period**, under which the **generator** is prepared to sell **electricity** to **the clearing manager**; and (b) ensure that the **system operator** receives an **offer** at least 71 **trading periods** before the beginning of the **trading period** to which the **offer** relates. (2) Despite subclause (1), a **generator** must give at least 5 **business days'** notice in writing to the **system operator** and the **clearing ~~pricing~~ manager** before the **generator** makes an **offer** for the 1st time in respect of the **generating plant** that is the subject of the **offer**. (3) The notice must state— (a) the **point of connection** to the **grid** at which **electricity** generated by the **generator** is sold to the **clearing manager** under clause 14.3 or 14.4; and (b) whether the **generating plant** is an **intermittent generating station**. (4) A **generator** must comply with any request from the **system operator** for information concerning **generating plant** that is the subject

			of a notice under subclause (2) if the **system operator** requires the information for the purposes of scheduling and **dispatch** in accordance with this Code. (5) Despite subclause (1), if a **generator** intends to permanently cease to submit **offers** to the **system operator** in respect of any **generating plant**, the **generator** must give at least 5 **business days'** notice in writing to the **system operator**~~, the **pricing manager**,~~ and the **clearing manager**.
32.	13.173A(2)	Reference to 'Authority' should be in bold because it is a defined term.	(2) The **clearing manager** must, no later than 1700 hours on the 2nd **business day** following the **trading day** on which the written notice referred to in subclause (1) was given, provide a report to the **Authority** that includes the following:
33.	13.182A(2)	The clearing manager is responsible for making interim prices available on WITS under clause 13.167, but this clause does not require the clearing manager to make final prices available on WITS or specify when it must do so. The real time pricing project placed the obligation on the clearing manager but the clause wording does not make it clear that the clearing manager must make the change on WITS to switch the interim price to a final price.	(2) If this clause applies, the relevant **interim price** or **interim reserve price** becomes a **final price** or **final reserve price** (as applicable) when the **clearing manager** makes the **final price** or **final reserve price** available on **WITS**, which must be after 1300 hours but no later than at 1400 hours on the 1st **business day** following the **trading day** on which the **clearing manager** made the **interim price** or **interim reserve price** available on **WITS**.
34.	13.182B(2)	The clearing manager is responsible for making interim prices available on WITS under clause 13.167, but this clause does not require the clearing manager to make final prices available on WITS or specify when it must do so. The real time pricing project placed the obligation on the clearing manager but the	(2) If this clause applies, the **relevant interim price** or **interim reserve price** becomes a **final price** or **final reserve price** (as applicable) when the **clearing manager** makes the **final price** or **final reserve price** available on **WITS**, which must be as soon as practicable after the **Authority** has made available on **WITS** a notice under clause 13.173C(2) advising that no **pricing error** has occurred.

		clause wording does not make it clear that the clearing manager must make the change on WITS to switch the interim price to a final price.	
35.	13.192(1)(c)	Clause is not clear as to what constitutes a constrained off situation for nominated dispatch bids.	(1) A **constrained off situation** occurs when— … (c) ~~all~~ load to which a **nominated dispatch bid** (other than a **dispatch notification purchaser bid**) applies is not **dispatched**, and where ~~despite~~ the price in the **nominated dispatch bid** is ~~being~~ above the **final price** at the relevant **GXP**.
36.	13.194(2)	Clause is not clear that the bid quantity (Q_b) in the formula is only where the bid price is above the final price. The intent of the constrained off calculations was consulted as part of the real time pricing project, but the Code drafting contains errors that need to be corrected. This change reflects the way the clearing manager is calculating constrained off.	(2) If a **constrained off situation** occurs in relation to a **dispatch-capable load station** during a **trading period**, the **clearing manager** must calculate the **constrained off amounts** for each **dispatch-capable load station**, for each affected **nominated dispatch bid** price band, using the following formula: $ConOffAmt_{disp} = ConOffQ * (-P_b - P_f)$ where $ConOffAmt_{disp}$ is the **constrained off amount** for a **dispatch-capable load station** for the **nominated dispatch bid** price band ConOffQ is the amount in **MWh** by which Q_b exceeds the highest of Q_{disp} and Q_{rec} where Q_b is the quantity, in **MWh**, in the **nominated dispatch bid** ~~price~~ band where the bid price is above the final price Q_{disp} is the **dispatched** quantity, in **MWh** in the **trading period**, calculated under subclause (3), **dispatched** for the **nominated dispatch bid** price band in the **trading period** Q_{rec} is the **reconciled quantity** provided by the **reconciliation**

			manager under clause 15.20C allocated by the **clearing manager** to the **nominated dispatch bid** price band in the **trading period** P_b is the price bid for the **nominated dispatch bid** price band for the **dispatch-capable load station** that was constrained off P_f is the **final price** for the **trading period** at the **grid exit point**.
37.	13.202(1)(d)	Clause is not clear what constitutes a constrained on situation for nominated dispatch bids.	(1) A **constrained on situation** occurs when— … (d) ~~any~~ load to which a **nominated dispatch bid** (other than a **dispatch notification purchaser bid**) applies is **dispatched**~~,~~ and ~~despite~~ the price in the **nominated dispatch bid** is ~~being~~ below **the final price** at the relevant **GXP**.
38.	13.204(1)(aa)	There is a drafting error in the formula for ConOnQ and a missing term in the calculation. The intent of the constrained on calculations was consulted on as part of the real time pricing project, but the Code drafting contains errors that need to be corrected. This change reflects the way the clearing manager is calculating constrained on.	(aa) the **clearing manager** must calculate the **constrained on amounts** for a **constrained on situation** described in clause 13.202(1)(d) for each **dispatch-capable load station** for each affected **nominated dispatch bid** price band, using the following formula: $ConOnAmt = ConOnQ^* (P_o - P_f)$ where ConOnAmt is the **constrained on amount** for a **dispatch-capable load station** for the **nominated dispatch bid** price band ConOnQ is the amount in **MWh** by which ~~is~~ the lowest ~~smaller~~ of Q_{disp} and Q_{rec} exceeds Q_b where Q_b is the quantity, in **MWh**, in the **nominated dispatch bid** price band where the bid price is below the final price …
39.	13.218(2)	Reference to 'Authority' should be in bold because it is a defined term.	(2) Despite subclause (1), a **party** specified in that subclause may, at the **Authority's** discretion, not be required to submit certain information …

40.	13.273(1)(a)	Reference to 'Authority' should be in bold because it is a defined term.	(a) provide a clearance by notice in writing in respect of the **materially large contract** if it is satisfied that either clause 13.269(1)(a) or 13.269(1)(b) is met, in which case the **Authority** must specify which clause it is satisfied in respect of;
41.	13.273(2)	Reference to 'Authority' should be in bold because it is a defined term.	(2) The **Authority** may use the information provided to it in the application and any other information the **Authority** considers relevant for the purposes of its decision, including any further information the **Authority** requests from the **generator**.
42.	13.281(2)	Reference to 'Authority' should be in bold because it is a defined term.	(2) If the **Authority** considers that the non-compliance of the **generator** is minor or there is any other reason in the **Authority's** view that means the **generator** should not pay the costs of the audit …
43.	15.36	Subclause (1) requires adjustments 'using the technique set out in subclause (3) specified by the Authority'. The words 'specified by the Authority' are unnecessary as the technique is set out in subclause (3).	15.36New Zealand Daylight Time adjustment techniques (1) **Submission information** provided to, and **reconciliation information** provided by, the **reconciliation manager** must, if applicable, be adjusted for **NZDT** using the technique set out in subclause (3)~~ specified by the **Authority**~~. (2) Any information exchanged between **participants** that contains **trading period** specific data must, if applicable, be adjusted for **NZDT** in accordance with subclause (3). (3) A daylight savings adjustment must be made by using the "**trading period** run on technique", which requires that daylight saving adjustment periods are allocated as consecutive **trading periods** within the relevant day, in the sequence that they occur. …
44.	Clause 13 of Schedule 15.5	Paragraph (c) specifies an alternative scenario to that specified in paragraphs (a) and (b). Where paragraph (c) applies, the chapeau to clause 13 does not apply. Current drafting is	**13 Balancing area derived profiles approved in accordance with Appendix 1 of Schedule 15.5** (1) The **reconciliation manager** must calculate the **trading period** information by applying

		ambiguous. The clause needs to be divided into two subclauses and a small consequential change needs to be made to new subclause (2) to maintain the intended meaning.	the **balancing area** derived **profile** code specified in the submission file provided by the **reconciliation participant**, if— (a) the **profile** code has been approved by the **Authority** for use as a **balancing area** derived **profile** in accordance with Schedule 15.5; and (b) the **profile owner** has given written notice to the **reconciliation manager** of the approved **profile** code, and that the **profile owner** has authorised the **reconciliation participant** to use the approved **profile** code.~~; and~~ (2)~~(c)~~ I~~i~~f the **Authority** has not approved the **profile** code, or submitted the **profile** to the **reconciliation manager** in accordance with clause 12(1) of Appendix 1 of Schedule 15.5, the **reconciliation manager** must calculate the **trading period** information using ~~use~~ the final residual **profile** shape as defined in Schedule 15.5.
45.	17.80	This transitional provision refers to the wrong clauses in the rules and the Code.	**17.80 Traders to provide ICP information to registry** Information provided by a trader to the registry under clause 3~~2~~ of schedule E1 of part E of the **rules** that had not been changed by the trader under clause 3A~~2A~~ of schedule E1 of part E of the **rules** immediately before this Code came into force, is deemed to be information provided to the registry under clause 9~~7~~ of Schedule 11.1.
46.	17.108	This transitional provision deems a certification given before the Code came into force as 'certification given under clause 12.35'. However, that clause now refers to 'confirmation' not 'certification'	**17.108 Increased services and reliability** A certification given under rule 5.1 of section II of part F of the **rules** immediately before this Code came into force, is deemed to be confirmation ~~a certification~~ given under clause 12.35
47.	17.137	This transitional provision is no longer required. It deems backup procedures in place	Revoke clause 17.137

		before the Code came into force as 'backup procedures specified by the market administrator' for the purposes of clauses 13.23, 13.36, 13.52, 13.55, 13.67 and 13.191. Those clauses have now either been revoked or amended so they no longer require the market administrator to specify backup procedures.	
48.	17.138	This transitional provision is no longer required. It deems backup procedures in place before the Code came into force as 'backup procedures specified by the market administrator under clause 13.211'. That clause has now been amended so it no longer requires the market administrator to specify backup procedures.	Revoke clause 17.138
49.	17.169	This transitional provision is no longer required. It deems information stipulated by the pricing manager before the Code came into force as in the manner and form for half-hour metering information 'stipulated by the pricing manager under clause 13.138'. That clause has now been amended so that it no longer refers to the pricing manager stipulating half-hour metering information.	Revoke clause 17.169
50.	17.184	This transitional provision is no longer required. It deems a list of values provided to the pricing manager before the Code came into force as a list of values provided under clause 13.189. The pricing manager's functions have since been discontinued and in any event this transitional provision is no longer required.	Revoke clause 17.184

Part B – Proposed amendments to reflect 2022 amendments to the Act			
51.	2.19(1)(b)	Clause needs updating to reflect the Authority's additional objective in section 15(2) of the Act.	(1) Before **publishing** a notice under clause 2.16, the **Authority** must be satisfied that— (a) the benefits of the **Authority** obtaining the information outweigh the costs of the information requirements set out in the proposed notice; and (b) the information requirements set out in the proposed notice promote one or more of the **Authority's** objectives in section 15 of the **Act**.
52.	2.22(1)(b)	Clause needs updating to reflect the Authority's additional objective in section 15(2) of the Act.	(1) If a **participant** identifies to the **Authority** any information under clause 2.21, the **Authority** will determine whether— … (b) if there are reasons to keep the information confidential as determined by the **Authority**, those reasons are outweighed by other considerations which render it desirable for the **Authority** to make all or any part of the information publicly available in order to give effect to one or more of the **Authority's** objectives ~~of the~~ ~~**Authority**~~ in section 15 of the **Act** …
53.	2.22(5)(a)	Clause needs updating to reflect the Authority's additional objective in section 15(2) of the Act.	(5) Subclause (4) does not prevent the **Authority** from— (a) using the information identified under clause 2.21 for any purpose in connection with one or more of the ~~objective of the~~ **Authority's** objectives ~~out~~ in section 15 of the **Act** or the **Authority's** functions in section 16 of the **Act** or section 14 of the Crown Entities Act 2004; …
54.	3.2A	Clause needs updating to reflect the Authority's additional objective in section 15(2) of the Act. Amend clause to refer to section 15 of the Act for consistency with other references to the objectives.	**3.2A Market operation service providers to assist Authority to give effect to Authority's ~~statutory~~ objectives** (1) Each **market operation service provider** must perform its obligations under this Code in a way that assists the **Authority** to give

			effect to the **Authority's** ~~statutory~~ objectives in section 15 of the **Act**. (2) The **system operator** must progressively increase the extent to which it assists the **Authority** to give effect to the **Authority's** ~~statutory~~ objectives in section 15 of the **Act**. …
55.	12.60	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act.	The **Authority** may initiate a review of the **grid reliability standards** for any reason consistent with the main ~~statutory~~ objective of the Authority in section 15 of the **Act** and the purpose and principles set out in clauses 12.56 and 12.57.
56.	12.67	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act.	The **Authority** may initiate a review of the **core grid determination** for any reason consistent with the main ~~statutory~~ objective of the Authority in section 15 of the **Act** and the purpose and objectives set out in clauses 12.64 and 12.65 respectively.
57.	12.78	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act.	The purpose of the **transmission pricing methodology** is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of **Transpower's** services are allocated in accordance with the **Authority's** main objective in section 15 of the **Act**.
58.	12.79	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act.	**12.79 Main s~~S~~tatutory objective** **Transpower**, in developing the **transmission pricing methodology**, and the **Authority**, in approving the **transmission pricing methodology**, must assess the **transmission pricing methodology** against the **Authority's** main objective in section 15 of the **Act**.
59.	12.81(2)	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act.	(2) The process and guidelines must be developed in accordance with the **Authority's** main objective in section 15 of the **Act**.
60.	12.89(1)	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to	(1) **Transpower** must develop its proposed **transmission pricing methodology** consistent with—

		the main objective in section 15(1) of the Act.	(a) any determination made under Part 4 of the Commerce Act 1986; and (b) the **Authority's** main objective in section 15 of the **Act**; and (c) any guidelines **published** under clause 12.83(b).
61.	Clause 4(2)(a) of Schedule 12A.4	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act. This preserves the effect of the provisions prior to the 2022 Amendments. This does not prevent future Code amendments to give effect to the Authority's additional objective.	(2) The principles are that a **distributor's operational terms** must— (a) be consistent with the **Authority's** main objective ~~set out~~ in section 15 of the **Act**; …
62.	Clause 4(e) of Schedule 13.4	Clause needs updating to clarify that the reference to the Authority's statutory objective is a reference to the main objective in section 15(1) of the Act.	Before the Authority approves an application, it must take into account— (e) the **Authority's** main objective in section 15 of the **Act**.
Part C – Proposed amendments to Part 6A of the Code (introduced by the 2022 amendments to the Act)			
63.	6A.1	a. Reference to 'distributor' should be in bold because it is a defined term in clause 1.1(1) of the Code. b. The term 'retailer' is defined in clause 1.1(1) as well as in clause 6A.2, but as we explain below the definitions are effectively the same. As a result, we propose deleting the definition of 'retailer' from clause 6A.2 below and bolding the term 'retailer' in clause 6A.1. c. Add semicolon and 'or' to paragraph (2)(a)(i) in accordance with the Authority's normal drafting approach for the Code. d. Reference to 'distribution agreement' should be replaced with reference to 'distributor agreement' and	(1) The purpose of this Part is to promote competition in the electricity industry by restricting relationships between a **distributor** and a generator or a **retailer**, where those relationships may not otherwise be at arm's length. (2) In general terms, this Part imposes rules in respect of **distributors** as follows: (a) corporate separation and arm's-length rules, if a person is involved both in a **distributor** and in either or both of— (i) a generator that generates more than 50 MW of generation connected to the **distributor's** network~~:~~; or (ii) a **retailer** that retails more than 75 GWh per year to customers connected to the **distributor's** network:

		emboldened, because it is a defined term in clause 1.1(1). That meaning is appropriate to replace 'distribution agreement', which is not defined or used elsewhere in the Code.	(b) **distributor agreement** ~~distribution agreement~~ rules, if— (i) a connected retailer retails more than 5 GWh per year to customers connected to the **distributor's** local network; or (ii) a connected generator has a capacity of more than 10 MW of generation that is connected to any of the **distributor's** networks: (c) rules preventing persons involved in **distributors** from paying **retailers** in respect of the transfer of retail customers: (d) no-discrimination rules that apply when **distributors**, or electricity trusts or customer co-operatives involved in **distributors**, pay dividends or rebates. …
64.	6A.2	Clause includes defined terms that apply "In this Part", but defined terms should also apply to Schedule 6A.1, as they did prior to the Electricity Industry Amendment Act 2022. This is problematic as some terms (such as "associate") are defined in clause 6A.2 but are used in Schedule 6A.1.	**6A.2 Interpretation** In this Part and Schedule 6A.1, unless the context otherwise requires,— …
65.	6A.2 definition of 'assets'	Defined term is unnecessary. The definition (incorporated from the Act) reflects the ordinary meaning and usage of the term, and the term is only used once in Part 6A. Including defined terms in such circumstances is not consistent with the Authority's Drafting Manual. In any event, clause 1.1(2) of the Code already incorporates defined terms from the Act.	**assets** *[Revoked]*~~has the meaning given in section 5 of the Act~~
66.	6A.2 definition of 'associate'	a. Reference to 'Act' should be in bold because it is a	**associate** has the meaning given to it by ~~in~~ section 6A of the **Act**

		defined term in clause 1.1(1) of the Code. b. Wording is not consistent with standard terminology used in the Code for references to the Act.	
67.	6A.2 definition of 'business'	a. Reference to 'Act' should be in bold because it is a defined term in clause 1.1(1) of the Code. b. Wording is not consistent with standard terminology used in the Code for references to the Act.	**business** has the meaning given to it by ~~in~~ section 5 of the **Act**
68.	1.1(1) definition of 'business'	The Code already contains a definition of business which is different to the definition in clause 6A.2. To avoid confusion, clause 1.1 definition of 'business' requires amendment to signal that a different definition applies in Part 6A and Schedule 6A.1.	**business** means, except in Part 6A and Schedule 6A.1, the business carried out as a **participant**
69.	6A.2 definition of 'consumer'	Defined term is unnecessary. Term only used in Part 6A in the definition of 'customer' – see below.	**consumer** *[Revoked]*~~has the meaning given in section 5 of the Act~~
70.	6A.2 definition of 'customer'	Defined term is unnecessary. The definition reflects the ordinary meaning and usage of the term. The term was originally defined in a similar way in clause 1.1(1) of the Code but the definition was revoked in an earlier Code Review Programme on the basis that it was unhelpful and inefficient to give commonplace terms a definition that is no different to their ordinary meaning. The same rationale applies to the use of this term in Part 6A and revoking the definition would result in a consistent approach across the Code.	**customer** *[Revoked]*~~, in respect of a retailer, means a consumer to whom that retailer sells electricity~~
71.	6A.2 definition of 'director'	Defined term is unnecessary. The definition reflects the ordinary	**director** *[Revoked]*~~has the meaning given in **section 6A** of the Act~~

		meaning and usage of the term. Including defined terms in such circumstances is not consistent with the Authority's Drafting Manual. The term is used elsewhere in the Code without it being defined and revoking the definition would result in a consistent approach across the Code.	
72.	6A.2 definition of 'financial year'	a. Reference to 'Act' should be in bold because it is a defined term in clause 1.1(1) of the Code. b. Wording is not consistent with standard terminology used in the Code for references to the Act.	**financial year** has the meaning given to it by ~~in~~ section 6A of the **Act**
73.	1.1(1) definition of 'financial year'	The Code already contains a definition of 'financial year' which is different to the definition in clause 6A.2. To avoid confusion, clause 1.1(1) definition of 'financial year' requires amendment to signal that a different definition applies in Part 6A and Schedule 6A.1.	**financial year** means, except in Part 6A, Schedule 6A.1 and Schedule 12.4, the financial year adopted by a participant from time to time, being a 12 month period as a participant determines
74.	6A.2 definition of 'generator'	a. Reference to 'Act' should be in bold because it is a defined term in clause 1.1(1) of the Code. b. Wording is not consistent with standard terminology used in the Code for references to the Act.	**generator** has the meaning given to it by in section 5 of the **Act**
75.	1.1(1) definition of 'generator'	The Code already contains a definition of 'generator' which is different to the definition in clause 6A.2. To avoid confusion, clause 1.1(1) definition of 'generator' requires amendment to signal that a different definition applies in Part 6A and Schedule 6A.1.	**generator** means, except in Part 6A and Schedule 6A.1, a person who owns **generating units** connected to a **network**, or any person who acts, in respect of Parts 13, 14 and 15, on behalf of any person who owns such **generating units**, and includes **embedded generators**, **intermittent generators**, **type A co-generators**, and **type B co-generators**
76.	6A.2 definition of 'involved in'	a. Reference to 'Act' should be in bold because it is a defined term in clause 1.1(1) of the Code.	**involved in** has the meaning given to it by ~~in~~ section 6A of the **Act**

		b. Wording is not consistent with standard terminology used in the Code for references to the Act.	
77.	6A.2 definition of 'network'	a. Reference to 'Act' should be in bold because it is a defined term in clause 1.1(1) of the Code. b. Wording is not consistent with standard terminology used in the Code for references to the Act.	**network** has the meaning given to it by ~~in~~ section 5 of the **Act**
78.	1.1(1) definition of 'network'	The Code already contains a definition of 'network' which is different to the definition in clause 6A.2. To avoid confusion, clause 1.1(1) definition of 'network' requires amendment to signal that a different definition applies in Part 6A and Schedule 6A.1	**network** means, except in Part 6A and Schedule 6A.1, the **grid**, a **local network** or an **embedded network**
79.	1.1(1) definition of 'retailer'	As noted above, defined term is unnecessary as the term is already defined in clause 1.1(1). The definition in clause 6A.2 (incorporated from the Act) is 'a business engaged in retailing' and 'retailing' is defined in the Act as 'the sale of electricity to a consumer other than for the purpose of resale'. Clause 1.1(1) already defines 'retailer' in substantially the same way, referring to 'a participant who supplies electricity to another person for any purpose other than for resupply by the other person'.	**retailer** *[Revoked]* ~~has the meaning given in section 5 of the Act~~
80.	6A.2 definition of 'total capacity'	a. Reference to 'Act' should be in bold because it is a defined term in clause 1.1(1) of the Code. b. Wording is not consistent with standard terminology used in the Code for references to the Act.	**total capacity** has the meaning given to it by ~~in~~ section 73(3) of the **Act**
81.	6A.3	a. Reference to 'distribution' should be in bold because it	**6A.3 Corporate separation and arm's-length rules applying to**

		is a defined term in clause 1.1(1). b. References to 'distributor' should be in bold because it is a defined term in clause 1.1(1). c. References to 'retailer' should be in bold because it is a defined term in clause 1.1(1). d. Reference to 'electricity' should be in bold because it is a defined term in clause 1.1(1).	**distributors and connected generators and connected retailers** (1) The person or persons who carry on the business of **distribution** must carry on that business in a different company from the company that carries on the business of a connected generator or a connected retailer. (2) Every person who is involved in a **distributor**, and every person who is involved in a connected generator or a connected retailer, must comply, and ensure that the person's businesses comply, with the arm's-length rules. (3) In this clause, unless the context otherwise requires,— **connected generator**, in relation to a **distributor**, means a generator— (a) that has a total capacity of more than 50 MW of generation that is connected to any of the **distributor's** networks; and (b) in respect of which the **distributor**, or any other person involved in the **distributor**, is involved **connected retailer**, in relation to a **distributor**, means a **retailer**— (a) that is involved in retailing more than 75 GWh of **electricity** in a financial year to customers who are connected to any of the **distributor's** networks; and (b) in respect of which the **distributor**, or any other person involved in the **distributor**, is involved.
82.	6A.4	a. Reference to 'distributor' should be in bold because it is a defined term in clause 1.1(1). b. Reference to 'distribution' should be in bold because it is a defined term in clause 1.1(1).	**6A.4 Distributor ~~Distribution~~ agreements** (1) Every director of a **distributor** in respect of which there is a connected retailer or a connected generator must ensure that— (a) the **distribution** business has a comprehensive, written **distributor agreement**

		c. References to 'distribution agreement' should be replaced with references to 'distributor agreement' and emboldened, because it is a defined term in clause 1.1(1). That meaning is appropriate to replace 'distribution agreement', which is not defined or used elsewhere in the Code. d. References to 'line function services' should be in bold as it is a defined term in clause 1.1(1). e. References to 'Authority' should be in bold because it is a defined term in clause 1.1(1). f. References to 'publicise' should be replaced with references to 'publish' and emboldened. The term 'publicise' is no longer used in the Code. In an earlier Code Review Programme the Code was amended to consistently use the term "publish", which is defined in clause 1.1(1) in substantially the same way as "publicise" is defined in the Act. Both terms mean a requirement to make the information available to the public at no cost on their website.	~~distribution agreement~~ that provides for the supply of **line function services** and information to the connected retailer or connected generator (as the case may be); and (b) the terms of that **distributor agreement** ~~distribution agreement~~ do not discriminate in favour of one business and do not contain arrangements that include elements that the business usually omits, or omit elements that the business usually includes, in **distributor agreements** ~~distribution agreements~~ with parties that are— (i) connected or related only by the transaction or dealing in question; and (ii) acting independently; and (iii) each acting in its own best interests; and (c) the business operates in accordance with that **distributor agreement** ~~distribution agreement~~; and (d) the business **publishes** ~~publicises~~ that **distributor agreement** ~~distribution agreement~~ and provides it to the **Authority**. (2) A **distributor agreement** ~~distribution agreement~~ required by **subclause (1)(a)** must be entered into, in the case of a business to which the corporate separation rule does not apply, as if the distribution business (3) In this clause, unless the context otherwise requires,— **connected generator**, in relation to a **distributor**, means a generator— (a) that has a total capacity of more than 10 MW of generation that is connected to any of the **distributor's** networks; and (b) in respect of which the **distributor**, or any other person involved in the **distributor**, is involved

			connected retailer, in relation to a **distributor**, means a retailer— (a) that is involved in retailing more than 5 GWh of electricity on the **distributor's** local network in a financial year to customers who are connected to that network; and (b) in respect of which the **distributor**, or any other person involved in the **distributor**, is involved **local network** means a network operated by a **distributor** in a contiguous geographic area or areas. (4) The directors of the **distributor** must ensure that there is also **published** ~~publicised~~, and provided to the **Authority**, a certificate signed by those directors stating whether, in the preceding calendar year,— (a) the terms in the **distributor agreement** ~~distribution agreement~~ are a true and fair view of the terms on which **line function services** and information were supplied in respect of the retailing or generating to which the agreement relates; and (b) this clause was otherwise fully complied with. (5) A director breaches this Code if the director— (a) refuses or knowingly fails to comply with this clause; or (b) allows a **distributor agreement** ~~distribution agreement~~ or a certificate to be **published**~~publicised~~ or provided to the **Authority** knowing that it is false or misleading in a material particular.
83.	6A.5	a. Colon at end of paragraphs (2)(a) and (b) should be semicolon, and 'and' should be inserted in accordance with the Authority's normal drafting approach for the Code. b. References to 'distributor' should be in bold because it	**6A.5 Person involved in distributor must not pay for transfer of retail customers to connected retailers** (1) A **distributor**, and any other person listed in subclause (2), must not pay, or offer to pay, any consideration to a **retailer** in respect of the transfer to a connected retailer of any retail

		is a defined term in clause 1.1(1). c. Reference to 'electricity' should be in bold because it is a defined term in clause 1.1(1).	customers who are connected to the **distributor's** networks. (2) The persons are— (a) the **distributor** or any other person involved in the **distributor**~~:~~; and (b) a connected generator in respect of the **distributor** or any other person involved in the connected generator~~:~~; and (c) a connected retailer in respect of the **distributor** or any other person involved in the connected retailer. (3) To avoid doubt, subclause (1) includes a prohibition on— (a) any agreement to acquire the assets or voting securities of another **retailer** (regardless of whether any, or only nominal, consideration is attributed to customers) as a result of which there is a transfer of responsibility for retailing **electricity** to customers; and (b) any consideration that is directly or indirectly or in whole or in part in respect of the transfer of any of another **retailer's** customers or customer accounts. (4) A person who knowingly fails to comply with this clause breaches this Code. (5) In this clause,— **agreement** has the same meaning as in clause 10 of Schedule 2 of the Act **connected generator** has the same meaning as in clause 6A.4 **connected retailer** has the same meaning as in clause 6A.4.
84.	6A.6	a. Colon at end of paragraphs (3)(a) and (b) should be semicolon, and 'and' should be inserted in accordance with the Authority's normal drafting approach for the Code.	**6A.6 No discrimination when paying rebates or dividends** (1) This clause applies if a **distributor** has a connected retailer. (2) Every person listed in subclause (3) must ensure that any rebates or dividends or other similar

		b. References to 'distributor' should be in bold because it is a defined term in clause 1.1(1). c. Reference to 'retailer' should be in bold because it is a defined term in clause 1.1(1).	payments paid do not discriminate between— (a) customers of the connected retailer; and (b) customers of other **retailers** where those customers are connected to the **distributor's** networks. (3) The persons are— (a) the directors of the **distributor**~~:~~; and (b) the trustees of any customer trust or community trust that is involved in the **distributor** and the connected retailer~~:~~; and (c) the directors of any customer co-operative that is involved in the **distributor** and the connected retailer. …
85.	6A.7	a. As above, reference to 'distribution agreements' should be replaced with reference to 'distributor agreements' and emboldened as 'distributor agreement' is defined in clause 1.1(1) and that meaning is appropriate to replace distribution agreement in Part 6A. b. References to 'distributor' should be in bold because it is a defined term in clause 1.1(1). c. References to 'Authority' should be in bold because it is a defined term in clause 1.1(1). d. Reference to 'electricity' should be in bold because it is a defined term in clause 1.1(1). e. As above, reference to 'publicised' should be replaced with reference to 'published' and emboldened as it is a defined term in clause 1.1(1).	**6A.7 Disclosure of information to Authority** (1) Each director of a **distributor** referred to in clause 6A.4(1) (**distributor agreements** ~~distribution agreements~~) must ensure that the **distributor** discloses the quantity of **electricity** sold each financial year by connected retailers to customers who are connected to its local network (within the meanings in that clause). (2) The disclosure must be made in a statement to the **Authority** within 2 months after the end of the financial year. (3) The statement must be in the form prescribed by the **Authority** from time to time. (4) The statement must be **published** ~~publicised~~ by the **Authority** and the **distributor**. (5) A director breaches this Code if the director— (a) refuses or knowingly fails to comply with this clause; or (b) provides the statement to the **Authority** knowing that it is

			false or misleading in a material particular.
86.	6A.8	a. References to 'Authority' should be in bold because it is a defined term in clause 1.1(1). b. As above, reference to 'publicised' should be replaced with reference to 'published' and emboldened as it is a defined term in clause 1.1(1).	**6A.8 Directors must report compliance with arm's-length rules** (1) Each director of a business to which the arm's-length rules apply must provide to the **Authority**, no later than 31 March in each year, a statement confirming whether the director has complied with all of the arm's-length rules during the preceding calendar year. (2) The directors and the **Authority** must ensure that the statement is **published**~~publicised~~. (3) A director breaches this Code if the director— (a) refuses or knowingly fails to comply with this clause; or (b) provides the statement to the **Authority** knowing that it is false or misleading in a material particular.
87.	Schedule 6A.1, clause 2(1)	Definition of 'manager' in the Act should be expressly included in the Schedule, as it was prior to the 2022 amendments. The term 'manager' is used throughout Schedule 6A.1. While clause 1.1(2) of the Code would incorporate the Act's definition of 'manager', expressly including it in clause 2(1) will promote accessibility.	(1) In this schedule,— … **manager** has the meaning given to it by section 5 of the **Act** …
88.	Schedule 6A.1, clause 3	a. Clause numbering and terminology of 'rules' used in this clause (eg at 11(2) and (3)) is not consistent with Authority's Code Drafting Manual. This has the potential to be confusing as paragraph numbering restarts at 1, and the term 'rules' is defined in clause 1.1(1) as the Electricity Governance Rules 2003, which preceded the Code. Clause 3 should be divided into separate sequential clauses, existing cross headings should become	**3 Arm's-length rules** The arm's-length rules are set out in clauses 3A to 3M.~~as follows:~~ ~~*Duty to ensure arm's-length objective is met*~~ **3A Duty to ensure arm's length objective is met** ~~1~~ Business A and every parent of business A, and business B and every parent of business B, must take all reasonable steps to ensure that the arm's-length objective in clause 1 is met. ~~*Arm's-length test*~~

		clause headings, and other numbering issues should be corrected. b. Reference to 'electricity' should be in bold because it is a defined term in clause 1.1(1). c. Reference to 'retailer' should be in bold because it is a defined term in clause 1.1(1).	**3B Arm's-length test** ~~2~~ Business A, and every parent of business A, must not enter into a transaction in which business B, or any parent of business B, is interested if the terms of the transaction are terms that unrelated parties in the position of the parties to the transaction, each acting independently and in its own best interests, would not have agreed to. ~~*Duty not to prefer interests of business B*~~ **3C Duty not to prefer interests of business B** ~~3~~ A director or manager of business A must not, when exercising powers or per- forming duties in connection with business A, act in a manner that the director or manager knows or ought reasonably to know would prefer the interests of business B over the interests of business A. ~~*Duty not to discriminate in favour of business B*~~ **3D Duty not to discriminate in favour of business B** ~~4~~ Business A must not, in providing services or benefits, discriminate in favour of business B or the customers, suppliers, or members of business B. ~~*Duty to focus on interests of right ultimate owners*~~ **3E Duty to focus on interests of right ultimate owners** ~~5~~ A director or manager of business A must, when exercising powers or performing duties in connection with business A, act in the interests of the ultimate members of business A in their capacity as such, and must neither subordinate the interests of those members to the interests of the members of business B nor, to the extent that the members or ultimate beneficial members of each business overlap, take account of that fact or have regard

			to their dual capacity as members of business B and business A. ~~*Duty of directors and managers of parents of business A*~~ **3F Duty of directors and managers of parents of business A** ~~6~~ A director or manager of a parent of business A must not, when exercising powers or performing duties in connection with business A, act in a manner that the director or manager knows or ought reasonably to know would favour the interests of business B, or of the customers, suppliers, or members of business B in that capacity, over the interests of business A or the customers, suppliers, or members of business A. ~~*At least 2 independent directors*~~ **3G At least 2 independent directors** ~~7~~ At least 2 directors of business A must— (a) be neither a director nor a manager of business B; and (b) not be an associate of business B, other than by virtue of being a director of business A. ~~*No cross-directors who are executive directors*~~ **3H No cross-directors who are executive directors** ~~8~~ A director of business A may be a director of business B, but must not— (a) manage business B on a day-to-day basis; or (b) be an associate of business B, other than by virtue of being a director of business A or business B; or (c) be involved in business B (other than by having material influence over business B by virtue of being a director of business B). ~~*Separate management rule*~~

			3I Separate management rule ~~9~~(1) This clause applies if business A is involved in— (a) a generator that has a total capacity of more than 50 MW and that is connected to any of business A's networks; or (b) a **retailer** that retails more than 75 GWh of **electricity** in a financial year to customers who are connected to any of business A's networks. (2) A manager of business A must not— (a) be a manager of business B; or (b) be an associate of business B, other than by virtue of being a manager of business A; or (c) be involved in the business of business B. ~~*Directors and managers must not be placed under certain obligations*~~ **3J Directors and managers must not be placed under certain obligations** ~~10~~(1) Subject to subclause (2), no person may place a director or manager of business A under an obligation, whether enforceable or not, to act in accordance with the directions, instructions, or wishes of business B, or any director or manager or associate of business B, or any parent of business B, and no director or manager may submit to any such obligation. (2) A common parent, or a cross-director or a cross-manager, of both business A and business may place a director or manager under an obligation referred to in subclause (1) if doing so does not contravene another of the arm's-length rules. ~~*Restriction on use of information*~~ **3K Restriction on use of information** ~~11~~(1) Business A must not disclose or permit the disclosure to business

			B, or use or permit the use for the purposes of business B, of restricted information of business A. (2) An electricity trust that is a parent of business A (**trust A**), business A, and every parent of trust A must not disclose or permit the disclosure to business B, an electricity trust that is a parent of business B (**trust B**), or any parent of trust B, or use or permit the use for the purposes of business B or trust B, of restricted information of business A or trust A. (3) In this clause ~~these rules~~, **restricted information** is information received or generated, and held, by business A or trust A that is connected with its business, being information that— (a) is not available to the competitors or potential competitors of business B or trust B; and (b) if disclosed to business B or trust B, would put, or be likely to put, business B or trust B in a position of material advantage in relation to any competitor or potential competitor. (4~~2~~) This clause ~~rule~~ does not prevent cross-directors under clause 3H ~~rule 8~~ from having access to normal board information. (5~~3~~) A manager of business A who is not prohibited from being a manager of business B under clause 3I ~~rule 9~~ may use restricted information of both business A and business B, but only to the extent that the use does not contravene another of the arm's-length rules. ~~*Records*~~ **3L Records** (1)~~12~~ Every business to which this schedule applies must keep at it registered office a register of transactions entered into between business A, or any parent of

			business A, and business B, or any parent of business B. (2)~~13~~ Business A must, within 10 working days of entering into such transaction, enter in its register details sufficient to identify the nature and import of the transaction. ~~*Practical considerations*~~ **3M Practical considerations** (1)~~14~~ Business A and every parent of business A must ensure that its practical arrangements, such as use of accommodation, equipment, and services, do not contravene this schedule. (2)~~15~~ Business A and every parent of business A must ensure that its selection and appointment of advisors does not prejudice compliance with clauses 3G to 3K~~rules 7 to 11~~.
89.	Schedule 6A.1, clause 4	Cross-references need to be updated to reflect changes to clause 3.	**4 Rules do not limit objective** The arm's-length rules in clauses 3A to 3M~~clause 3~~ do not limit the generality of the arm's-length objective in clause 1.

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010
Regulations	Electricity Industry (Enforcement) Regulations 2010